September 25, 2013

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

Re: California Independent System Operator Corporation
Docket No. ER13-___-000

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with Additional Performance Based Refinements

Dear Secretary Bose:

The California Independent System Operator Corporation submits the attached amendments to its Fifth Replacement FERC Electric Tariff.

Respectfully submitted,

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TABLE OF CONTENTS

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Dear Secretary Bose:

The California Independent System Operator Corporation (ISO) submits for filing the attached amendments to its Fifth Replacement FERC Electric Tariff.[1] These tariff amendments provide necessary market design modifications targeted at considering the characteristics of variable energy resources as the state of California moves to increase their presence in the ISO markets. In support of these efforts, the amendments (1) lower the energy bid floor from negative $30/MWh to negative $150/MWh; and (2) change the bid cost recovery settlement rules to pay bid cost recovery separately for the day-ahead and real-time markets rather than netting bid costs and market revenues across the two markets. In addition, the ISO proposes to modify its payment rules for start-up and minimum load costs, unrecovered energy bid costs, and residual imbalance energy. These changes are necessary to streamline uplift payments and in some cases are also necessary to eliminate the potential incentives for adverse market behavior targeted at unjustly expanding bid cost recovery or residual imbalance energy payments.

The ISO requests an effective date for the amendments proposed in this filing of April 1, 2014. This coincides with the date on which the ISO expects to implement its new fifteen-minute real-time market in support of the Commission's requirement for fifteen minute scheduling in FERC Order No. 764. These important changes in the

[1] These amendments are submitted pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d, and Part 35 of the rules and regulations of the Federal Energy Regulatory Commission (FERC or Commission), 18 C.F.R. Part 35, and in compliance with Order No. 714 Electronic Tariff Filings, Order No. 714, FERC Stats. & Regs. ¶ 31,276 (2008).

spring of 2014 will be followed by the implementation of the ISO's Energy Imbalance Market (EIM) with PacifiCorp in the fall of 2014. These complete set of changes are all scheduled to be implemented in 2014 and require careful coordination of software and system development. Therefore, the ISO respectfully requests an order by November 27, 2013, to give the ISO and participants sufficient time to consider the outcome of the Commission's order as it approaches important software and system development milestones to meet all of these important enhancements in 2014.

I. EXECUTIVE SUMMARY

The proposed tariff amendments are part of the ISO's continued efforts at creating a market structure that reflects the characteristics of variable energy resources and creating appropriate incentives for all resources to provide the needed economic bids that will enable the ISO to dispatch its fleet of resources more economically. The proposed rule changes come out of two separate but related market design enhancement efforts.

First, the rule changes arise out the need to consider the increased presence of variable energy resources in the fleet of supply resources available to the ISO in operating the grid. The ISO's primary market design goal is to provide proper market signals for resources to bid-in the needed services and for the ISO to optimize those bids through its markets, and only resort to non-market means in extraordinary circumstances. The California energy industry has already experienced a significant amount of penetration by variable energy resources and is poised to increase their presence by requiring 33 percent of supply coming from renewable energy resources by 2020, a short six years away. The ISO has supported these state goals continuously by finding ways to integrate such resources reliably in its markets and operations, but not without some challenges. In particular, the ISO market currently lacks sufficient supply of real-time economic bids to enable the ISO market systems to economically balance energy supply and demand. This is often most critical during off-peak hours that are susceptible to much higher levels of over-generation as renewable energy production increases.

Over three years ago, the ISO undertook an extensive process, which included a number of important studies that evaluate changing system needs in light of the evolution of the ISO fleet of resources as the state targets increased penetration of variable energy resources and the retirement of existing fossil-fueled resources. Soon after, the ISO launched an important stakeholder effort, referred to as the Renewable Integration Market Product Review (RIMPR) process, to carefully consider the ISO's existing market rules and the adoption of enhancements to reliably and economically integrate the additional variability expected from these resources.

Secondly, the market rule changes arise out of the need to consider carefully the ISO's bid cost recovery rules, which are the ISO's method for compensating resources for their start-up and minimum load costs and for guaranteeing a resource's bid costs if committed or dispatched by the ISO. Having considered the separation of the bid cost recovery for the day-ahead and real-time market, and faced with adverse market behavior targeted at expanding such payments over the past two years, the ISO undertook an important stakeholder effort in 2012 to evaluate its bid cost recovery settlement rules in the context of separate day-ahead and real-time bid cost recovery. This resulted in a number of proposed rule changes designed to ensure resources that respond to ISO dispatches are provided adequate payments for recovery of bid costs, whilst eliminating the opportunity for unilaterally expanding such uplift payments.

While the proposed changes were not unanimously and uniformly supported by all stakeholders, they benefited by substantial stakeholder input and were shaped by modifications made specifically to address stakeholder concerns. The proposed rule changes were also a product of significant input by the ISO Market Surveillance Committee (MSC) and the ISO Department of Market Monitoring (DMM).

Modifications to provide appropriate market signals for increased real-time economic bids from variable energy resources

In an effort to incent and send the appropriate price signals for increased real-time economic bids, the ISO proposes to reduce the energy bid floor to account for the opportunity cost of curtailment faced by wind and solar resources. Positive energy bids represent the lowest price at which a resource is willing to provide energy to the market. In contrast, a negative bid represents the maximum price that a resource is willing to pay to provide energy to the market. If a resource has been awarded a day-ahead energy schedule, a negative bid in the real-time market represents the minimum price the resource is willing to be paid to not deliver its day-ahead schedule. The ISO is proposing to reduce that floor to negative $150/MWh, which would allow participants to express a lower price at which they are willing to not produce their day-ahead scheduled amounts.

The current floor is a soft-floor, which allows participants to be paid per a lower bid if they submit detailed cost information with the Commission justifying the lower bid; however, variable energy resources cannot surmount such justifications given they do not have the same fuel cost structure as do thermal resources. As a result, variable energy resources do not have the incentive to provide economic bids into the ISO markets. In addition, energy bids less than negative $30/MWh cannot set any locational marginal price. Lowering the energy bid floor to negative $150/MWh will provide the market with better price signals to indicate the need for decremental energy in over-generation conditions. The enhanced price signals will not only incent current resources to provide more economic bids into the market, they will also signal the need for investment in new resources capable of responding to ISO dispatch instructions.

At the current negative $30/MWh level, the bid floor is insufficient to cover the opportunity costs of renewable energy resources to provide decremental energy bids. These resources receive production tax credits and contractual energy payments to generate that are significantly greater than $30/MWh. Therefore, even in over-generation conditions, the current bid floor encourages these resources to produce as much as possible resulting in reliability challenges.

The ISO proposes to lower the bid floor below the opportunity costs for providing energy for the majority of the renewable energy fleet, thereby incentivizing renewable and additional conventional resources to submit decremental energy bids that can be dispatched during periods of over-generation. Absent this incentive, the ISO is faced with increasing challenges in operating the system reliably during periods of over-generation, during which the ISO is constrained to curtail generation on a pro rata basis absent a deeper pool of real-time economic bids.

The implementation of this change will coincide with the ISO's restructuring of the ISO market to allow for fifteen-minute scheduling and clearing of all energy products in a fifteen-minute market. Under the new market design, variable energy resources will have greater incentives to participate economically in the ISO real-time market because they will no longer face the current scheduling rigidity requiring participating intermittent resources to submit hourly self-schedules. The lowering of the bid floor together with the real-time market redesign restructures the market to align with the technological capabilities of renewable resources.

Modifications to bid cost recovery accounting procedures to eliminate disincentives to submit real-time economic bids

- *Separation of day-ahead and real-time bid cost recovery*

The ISO proposes to separate the accounting of bid cost recovery amounts for the day-ahead and real-time markets to create an incentive for more economic bids in the real-time. Bid cost recovery is the process by which the ISO ensures that scheduling coordinators are able to recover their energy bid costs for supply resources that are scheduled or dispatched by the ISO market. This is necessary because in certain instances the ISO market may schedule or dispatch a resource in intervals where the locational marginal price is below the resource's bid price for that interval. The ISO accounts and pays for such costs as well as a resource's start-up and minimum load costs through the bid cost recovery mechanism to the extent the resource does not recover sufficient market revenues in the day-ahead and real-time markets to cover these costs. The ISO's proposal to separate the day-ahead and real-time bid cost recovery renders the ISO's bid cost recovery consistent with similar mechanisms in other ISOs and RTOs in other parts of the country.

Currently the ISO offsets the day-ahead and real-time surpluses and shortfalls so that any revenue from one market can offset the need to pay for shortfalls in another. However, offsetting costs and revenues across the two markets can lower a resource's overall bid cost recovery, which may discourage scheduling coordinators from submitting economic bids in the real-time market. Because resources generally have a revenue surplus in the day-ahead market, netting real-time revenue shortfalls against day-ahead market surpluses reduces the incentives to submit economic bids to be dispatched in the real-time market. This works against the ISO's goal to stimulate greater supply of real-time economic bids.

These proposed changes were generally supported by stakeholders and, as discussed further below, the ISO is proposing additional measures to address concerns that market participants may further expand bid cost recovery payments by persistently deviating from ISO instructions once the two processes are separated. While the separation is expected to increase the uplift cost of providing bid cost recovery, the ISO expects that cost to be moderate and outweighed by the benefits of having an increased pool of economic bids in the real-time. While the ISO cannot guarantee that the real-time economic bids will come with these changes, the ISO's goal is to eliminate the identified barriers and provide the correct pricing incentives, in anticipation that market participants will act rationally and respond to those incentives.

- *Additional refinements for short-starts and minimum load cost payments*

The ISO also proposes two additional changes to its bid cost recovery rules as they pertain to special characteristics of certain resources. First, the ISO proposes rules to accomplish the separation of day-ahead and real-time bid cost recovery for short-start resources when the day-ahead and real-time commitments overlap for operating hours. The ISO proposes to pay a short-start's resources start-up costs based on their day-ahead start-up costs when the resource is re-optimized in the real-time market. Second, the ISO proposes to calculate the real-time minimum load costs as the incremental change in minimum load costs between day-ahead and real-time for multi-stage generating resources to ensure resources are appropriately compensated for real-time minimum load when subject to modifications from their day-ahead schedule. Both of these rules are necessary in light of the ISO's goal of separating the day-ahead and real-time bid cost recovery to incentivize more real-time bids. Finally, the ISO also proposes to account for negative minimum load costs in the real-time bid cost recovery calculations when the real-time market de-commits a unit from its day-ahead schedule.

- *Modification of the day-ahead market metered energy adjustment factor to incentivize real-time bids and fine tune existing ISO rules to dissuade participants from engaging in adverse market behavior*

The current bid cost recovery provisions include a day-ahead market metered energy adjustment factor to align day-ahead bid cost recovery payments with actual energy produced by a resource. The application of this factor scales a resource's day-ahead bid cost recovery payments to the extent the resource operates below its day-ahead schedule. Currently, the ISO applies this factor even if the ISO has dispatched a resource to operate below its day-ahead schedule in the real-time market. This application discourages parties from submitting economic bids in the real-time market that would allow a resource to be dispatched below its day-ahead schedule. To remedy this situation, the ISO proposes to modify this factor so that the ISO will not reduce a resource's day-ahead bid cost recovery payment if it performs consistent with an ISO dispatch below its day-ahead schedule. In addition, the proposal includes a threshold to prevent penalizing small deviations from schedule or dispatch that are unintentional or unavoidable.

The ISO also proposes to strengthen existing rules in applying the day-ahead metered energy adjustment factor adopted in 2011 in two emergency filings. These rules are necessary to dissuade participants from engaging in combined day-ahead and real-time bidding strategies that forces the ISO to dispatch the resources and continue to pay the resource its day-ahead bid cost recovery. The rules require further refinements in light of the ISO's proposal to separate day-ahead and real-time bid cost recovery.

- *Replacement of the real-time metered energy adjustment factor with a real-time performance metric to improve incentives for resources to follow instructions*

The ISO currently scales real-time bid cost recovery cost and market revenue calculations and payments for under-delivery of energy dispatched by the real-time market. Consistent with the ISO proposal to separate day-ahead and real-time bid cost recovery, the ISO proposes to replace the real-time metered energy adjustment factor with a real-time performance metric and apply the metric to resources' bid costs and revenue associated with energy produced in real-time, including their minimum operating level. The real-time performance metric differs from the real-time metered energy adjustment factor because it evaluates performance relative to both upward and downward real-time dispatches. In addition, the real-time performance metric is designed to ensure payments are scaled down based on performance to ensure there are no incentives for parties to engage in adverse market practices for the purpose of expanding real-time bid cost recovery payments. The ISO proposes to apply the real-time performance metric to day-ahead bid costs and market revenues in certain cases for this same reason. The real-time performance metric also includes a threshold to avoid penalizing small deviations from dispatch that are likely to be unintentional and unavoidable.

Refinements to the bid cost recovery and residual imbalance energy payments to address potential incentives for market behavior that would otherwise expand such uplift beyond their intended purpose.

The ISO has determined that under certain circumstances, resources can garner greater bid cost recovery uplift, as well as residual imbalance energy payments, by deviating from real-time ISO dispatch. The ISO first identified this issue last year and made an emergency filing to eliminate this incentive with respect to residual imbalance energy payments.[2] The ISO did not propose any changes to bid cost recovery payments for this purpose at that time because it had observed that the netting of bid costs and market revenues across markets dampens these incentives. However, in proposing to separate the day-ahead and real-time bid cost recovery calculations, this issue must now be addressed.

The experience over the past two years with market behavior targeted at expansion of bid cost recovery payments is evidence that the ISO must take preventative measures to ensure the bid cost recovery rules include proper

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[2] *California Indep. Sys. Operator Corp.,*141 FERC ¶ 61,069 (2012) (October 26, 2012 Order).

disincentives for adverse market behavior. The ISO proposes the following refinements to its bid cost recovery and residual imbalance energy payments to remove such incentives.

The ISO proposes to implement a persistent deviation metric that evaluates a resource's deviations over a two-hour rolling window, to be applied to bid cost and market revenue calculations and to residual imbalance energy payments. This metric will calculate the extent to which a resource follows its real-time dispatch in a given 10-minute settlement interval. This metric is designed to take into account inadvertent or unavoidable deviations by allowing a few deviations within each rolling window. Persistent deviations, the ISO will base a resource's real-time bid cost recovery calculations and residual imbalance energy settlement on the minimum of the locational marginal price, the resource's default energy bid, and the resource's economic bid (with a symmetrical charge for decremental energy).

With respect to residual imbalance energy, the ISO proposes to reinstate the settlement rules for residual imbalance energy as they existed prior to the changes made in 2012, and instead apply the persistent deviation metric as discussed above, which provides a more refined method for mitigating the possible expansion of residual imbalance energy payments by persistent deviations.

The ISO proposes to extend the same rules that apply to bid cost recovery and residual imbalance energy for ramping energy associated with exceptional dispatches to instances in which a resource re-rates its minimum operating level in the real-time to levels above the amounts registered in the ISO's master file. The ISO has determined that in such cases, the same adverse incentives are in place when a resource re-rates its minimum load in the real-time. Therefore, the ISO proposes to settle the resource's residual imbalance energy and calculate the resource's energy bid costs based on the locational marginal price instead of its bids.

Finally, the ISO has found that resources could inflate bid cost recovery payments by ignoring an ISO instruction to shut down. Although this is not a significant issue today given the ISO's current practice of netting bid costs and market revenues across markets, with the separation of the day-ahead and real-time bid cost recovery settlement there may be greater incentives to deviate from a real-time shut-down in order to retain their minimum load costs. The ISO proposes to address this potential outcome by not including minimum load costs in bid cost recovery if a resource persistently deviates to avoid a shut-down instruction or does not follow a shut-down instruction when issued. Similarly, minimum load costs will not be paid to resources that start up without an ISO instruction.

II. BACKGROUND

A. Need To Increase The Volume Of Real-Time Economic Energy Bids.

The magnitude and frequency of real-time variable conditions is expected to increase as more variable energy resources integrate onto the ISO grid in order to support achievement of California's 33 percent Renewable Portfolio Standards (RPS). In that regard, as discussed in the ISO's 20 percent RPS Study, operational conditions that call for curtailment of variable energy resources are expected to increase in frequency and magnitude. These conditions include over-generation in spring during high hydro conditions, light load conditions, and, over time, during some daily ramp intervals, depending on how other resources are scheduled and bid.[3]

A fundamental issue that needs to be addressed, as the penetration of variable energy resources on the ISO system increases, is the potentially inadequate quantity of economic bids to curtail production in real-time during periods of over-generation. The ISO's 20 percent RPS Study and its 33 percent RPS Study both showed the adverse economic consequences of having inadequate economic bids when there are over-generation conditions and prices are negative. Over the past few years, the ISO has faced numerous instances where there were insufficient decremental bids in the market, thereby indicating that a reduction in the bid floor is needed even in the near term. Instances of over-generation with a corresponding lack of decremental bids to help manage congestion on the grid more effectively and economically have occurred with some frequency.[4] The ISO expects such instances will increase in upcoming years as substantially more variable energy resources come on-line.[5]

Prices in the ISO market may be negative due to cleared negative bids or from other factors such as the lack of decremental economic bids that can lead to an insufficiency of downward ramping capability. This is exacerbated during periods of over-generation from self-scheduled variable energy resources. In the event that energy offers are insufficient to meet the ISO's forecast of ISO demand, the power balance constraint may need to be relaxed by setting the pricing parameter to a the ISO price cap and floor, for incremental and decremental energy, respectively.[6] This is to ensure that all economic bids are used before curtailment of self-schedules set at an even lower penalty price. In other words, rather than using economic bids from the

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3 *Integration of Renewable Resources, Operational Requirements and Generation Fleet Capability at 20% RPS,* August 31, 2010 (20% RPS Study"), Attachment C hereto. (http://www.caiso.com/Documents/Integration-RenewableResources-OperationalRequirementsandGenerationFleetCapabilityAt20PercRPS.pdf.)

4 Attachment D shows the frequency of negative real-time prices for the period January 2010-June 2011. An indication of the frequency of decremental bid insufficiency is found in Table 4-1 in the 20% RPS Study, which shows the number of 5-minute intervals with negative prices by season and hour of day from April 1, 2009 to June 30, 2010. Attachment D also contains excerpts from DMM's 2012 Annual report indicating the category and instances of negative price swings over 2011-2012.

5 *See* 20% RPS Study at 18; ISO's Market Surveillance Committee (MSC) *Final Opinion on Integration: Market and Product Review, Phase 1,* issued December 8, 2011, p. 1, Attachment E hereto.

6 *See* ISO Tariff Section 27.4.3.4 Insufficient Supply to Meet CAISO Forecast of CAISO Demand in the RTM. Depending on the combined impact of different binding constraints, the actual market clearing price can actually surpass the bid cap and bid floor.

market, the power balance constraint will use pre-determined parameters to curtail generation. The impact of relaxing the power balance constraint on the market is that prices will either spike or drop depending on which pricing parameter is relaxed. The infeasibility of the power balance constraint and repeated occurrences of it binding is an indication of frequent potential over-generation conditions, which is a reliability concern. This is also an indication that there is a lack of effective economic bids in the affected intervals as the constraint would not bind and would not be relaxed if there was a sufficient amount of bids available to clear the market.

The DMM reported that most negative prices in 2012 occurred when the power balance constraint needed to be relaxed in the market software due to shortages of downward ramping capacity. Increased real-time economic bids would lessen the pressure on the power balance constraint. While this would not eliminate negative prices in the ISO markets, it would enable the ISO to clear its market on more economic signals for a resource's willingness to curtail rather than having to rely on administratively set pricing parameters.

Under the current market design, if the ISO is unable to address over-generation through the market because there is an insufficient supply of decremental bids, the ISO must issue out-of-market non-economic instructions *(i.e.*, instructions not based on energy bids) to resources to reduce their output in order to balance the system.[7] As a result, system optimization benefits are lost as the out of market dispatches are largely driven by reliability needs. In addition, without economic bids from renewable resources, which represent a large portion of the supply fleet, ISO operators often have to take actions such as decommitting thermal resources that, due to start-up constraints, may not be available for several hours after the decommitment. This results in both economic and reliability concerns. These non-economic, manual dispatch instructions result in a less efficient curtailment of resources because there are no means to establish the economic order for the curtailments to be based on.

Given the expectancy of increased over-generation and negative pricing conditions in the future, market design changes that will increase the provision of economic bids are critical to improving the ISO's capability to manage over-generation conditions, real-time congestion, and possibly system ramps, in a more efficient, cost effective, and reliable manner. Having a more flexible real-time market with an increased volume of economic bids is a more efficient, cost-effective, and reliable way to address over-supply and other grid conditions compared to out-of-market dispatches

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[7] Such instructions are determined by the market optimization through the use of market parameters that are outside the allowable range of economic bids and, hence, may result in an inefficient decremental dispatch of plants with higher willingness to pay to remain in operation. Although this discussion focuses on supply resources, the energy bid floor is also relevant to demand resources, including both internal load and exporters that may be willing to increase their purchases of energy to relieve over-generation if the price were low enough.

and administratively set prices. With a deeper pool of economic bids, including bids from variable energy resources, the ISO will be able to efficiently "procure" decreases in generation when needed under negative prices. Simply stated, price-responsive curtailment of variable energy resources will often be the most efficient solution to economically meet the ISO's downward-flexibility requirements, which will continue to increase as more variable energy resources are added to the system. This will result in lower renewable integration costs.

Also, having resources submit economic bids[8] and respond to ISO dispatch instructions will enhance system reliability and allow the ISO to more efficiently dispatch resources to meet system needs based on the economic order established from the decremental bids. If the ISO has to resort to curtailments outside of economic dispatch, they will be done on a pro rata basis (which may lead to cycling of thermals by running such resources down to their minimum load to respect inter-temporal constraints and could lead to a shortage of generation when the over-generation stops and the ISO needs those resources again.

The ISO notes that the New York Independent System Operator, Inc. (NYISO) and the Mid-Continent Independent System Operator, INC. (MISO) have faced similar issues to those the ISO seeks to address here. For example, in its comment on the FERC Notice of Inquiry Seeking Comment on the Integration of Variable Energy Resources, the NYISO noted that negative locational marginal prices in the absence of sufficient decremental bids has caused wind plants to curtail at higher quantities than would have been necessary if the decremental dispatch was conducted through the economic dispatch function of the ISO.[9] Further, the NYISO indicated that the clustering of wind resources in certain parts of the state was leading to transmission system constraints and, because wind resources are not dispatchable, the NYISO typically had to employ "manual" methods to ensure that wind reductions were effectuated.[10] NYISO recognized that this was an inefficient means of handling wind reductions.[11]

Similarly, in a November 1, 2010 tariff amendment filing, MISO indicated that because intermittent resources are not considered in the real-time security constrained economic dispatch, intermittent resources do not receive dispatch instructions and the MISO must manually curtail their output in order to manage congestion and minimum

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8 Economic bids represent a resource's marginal cost of providing energy.

9 (http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/04/NYISO_Cmmnts_VERs_NOI_041510.pdf)

10 *See New York Indep. Sys. Operator, Inc*., 127 ¶ 61,130 (2009).

11 *Id*.

load conditions.[12] MISO stated that this manual curtailment of intermittent resources resulted in market and operational inefficiencies. MISO recognized how the increased participation of intermittent resources would be beneficial to the system.

B. ISO's Bid Cost Recovery Settlement Rules.

The ISO market[13] contains a bid cost recovery mechanism to ensure that resources that are committed by the ISO through its market are properly compensated for their start-up, minimum load and energy bid costs.[14] Mr. Cooper provides a description of the ISO bid cost recovery process and examples that explain how these amounts are settled.[15]

Energy bid costs are based on the bid price submitted by scheduling coordinators for providing energy. In certain instances the ISO may commit or dispatch a resource for intervals in which the megawatt-hour levels committed or dispatched are associated with bid prices on the resource's bid curve that exceed the market clearing price. This occurs when, in a given interval, a resource is ramping to or from the operating point instructed by the ISO but the resource had a bid for the interval that was higher than the bid at which it was dispatched, or bid lower than the locational marginal price in the case of decremental energy. This means that for those intervals the market clearing price would not suffice to cover the resource's energy bid costs.

The ISO pays for start-up and minimum load costs separately from the energy bid costs. Start-up costs consist of the cost of starting the resource up from a cold start and minimum load costs consist of the cost of maintaining the resource at the minimum operating level at which it is synchronized to the grid and capable of providing energy to the ISO grid. Paying for these costs separately allows the ISO to derive and pay for the marginal cost providing energy only. Startup and minimum load costs are based on either costs as registered with the ISO or on proxy costs calculated through an established formula.[16] The ISO only pays for all of these costs to the extent that the resource does not recover them through the market revenues it earns in the ISO's day-ahead and real-time markets for energy and ancillary services.

The bid cost recovery mechanism has been a critical component of the ISO market design based on locational marginal pricing.[17] The ISO (i) accounts for all the

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12 *See Midwest Indep. Transmission Sys. Operator, Inc*., 134 FERC ¶ 61,141 (2010).

13 Mr. Cooper provides a detailed description of the relevant features of the ISO market. *See* Exhibit ISO-No. 1 at 4-17.

14 *See* Section 11.8 of the ISO Tariff.

15 *See* Exhibit ISO-No. 1 at 10-13.

16 *See* Section 30.4 of the ISO Tariff.

17 *California Indep. Sys. Operator Corp.,* 116 FERC ¶ 61,274 (2006) (MRTU 2006 Order).

start-up and minimum load, and energy bid costs, (ii) accounts for the market revenue earned through the markets, and then (iii) nets those costs and revenues to determine the amount of the total bid costs that are not recovered by the ISO markets through what is termed the bid cost recovery method. This accounting mechanism is designed to ensure that the resource does not receive payment if it recovers sufficient revenues from across all the ISO energy and ancillary services markets.

Under the current bid cost recovery mechanism rules, the ISO nets the market revenues across the individual market days and then across the day-ahead and real-time markets for the same trading day. Therefore, if the resource recovers enough revenue from the day-ahead market to cover its costs for its real-time schedule, the resource does not receive any unrecovered bid cost payments.

As the ISO considers changes to modify the existing rules, the ISO must consider carefully how any rule changes or existing rules might create incentives to inflate these payments through adverse market behavior. In 2011, FERC approved two emergency tariff amendments to mitigate for the expansion of bid cost recovery payments through market behavior that would not be economic but for the expansion of bid cost recovery uplift payments.[18] The events leading to the two emergency amendments clearly indicate the need for special consideration of bid cost recovery rules and how they are modified in any given tariff amendment related to such payments.

C. The Stakeholder Process.

The ISO initiated the Renewable Integration Market and Product Review (RIMPR) stakeholder process in July 2010 with the goal to "identify and develop potential changes to wholesale market design, including market products and procedures, needed to accommodate the expected substantial increase in production by variable energy resources over the next decade."[19] The ISO's review evolved into two separate design efforts: (i) phase 1, in which the ISO and stakeholders identified short term solutions for renewable integration that do not require significant market redesign, the outcome of which are the changes proposed in this tariff amendment; and (ii) phase 2, which consists of the Renewable Integration – Market Vision and Roadmap presented to the Board in October 2011 and which provides a plan to address longer-

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[18] *California Indep. Sys. Operator Corp.*, 135 FERC ¶ 61,110 (2011) (May 4, 2011 Order); and 136 FERC ¶ 61,118 (2011) (August 19, 2011 Order).

[19] *Discussion Paper, Renewable Integration: Market and Product Review*, July 8, 2010, http://www.caiso.com/Documents/DiscussionPaperonRenewableIntegrationMarketandProductReview08-Jul-2010.pdf.

term solutions.[20] Any elements adopted by the ISO as the result of this longer-term stakeholder initiative will be the subject of future tariff amendments.

The scope of the RIMPR 1 market design effort was initially comprised of three elements:

(1) re-evaluate the Participating Intermittent Resource Program (PIRP) for intermittent resources;
(2) lower the energy bid floor to provide additional incentives for market participants, including intermittent, to submit decremental bids (*i.e.,* bids to decrease scheduled production); and
(3) balance the effects of changing PIRP and the bid floor on generation suppliers by reconsidering the methodology used to net bid cost recovery overall settlement periods in a trade day.

The ISO conducted an extensive stakeholder process to develop and finalize the RIMPR 1 tariff amendments proposed herein.[21] There were numerous opportunities for stakeholders to provide input into the process. During the first stage of RIMPR 1, there were nine opportunities for stakeholders to provide written comments to the ISO (including separate comments on a discussion paper and on an issue paper). Also, the ISO held 12 stakeholder meetings/calls and three MSC meetings to discuss the RIMPR 1 issues. The ISO issued seven straw proposals during the first stage of RIMPR 1, which reflects the significant extent to which the ISO considered stakeholder input in developing its proposals.

The ISO also received important feedback from both the MSC and the ISO's DMM.[22] The MSC held open meetings on November 19, 2010, September 30, 2011, and December 8, 2011, to discuss the Phase 1 issues. On December 8, 2011, the MSC adopted the MSC Opinion, which is attached herein as Attachment E, offering its view of the ISO's proposals. As discussed in greater detail *infra,* the MSC "supports the decrease in the bid floor to -$150/MWh" and the "separate calculation of BCR for the day-ahead and real-time markets."

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[20] *Briefing on Renewable Integration – Market Vision and Roadmap*, October 20, 2011, http://www.caiso.com/Documents/111027BriefingonRenewableIntegration_MarketVision_and_Roadmap_Memo.pdf.

[21] The complete record of the Phase 1 stakeholder process (including all straw proposals, presentations, and stakeholder comments) can be found at http://www.caiso.com/informed/pages/stakeholderprocess/renewablesintegrationmarketproductreviewphase1.aspx.

[22] Written comments provided by the ISO's Department of Market Monitoring during the stakeholder process are included in Attachment F.

At the December 15-16, 2011, ISO Board of Governors Meeting, ISO management submitted proposals to (1) reduce the energy bid floor from negative $30 to negative $150 and (2) change the bid cost recovery netting methodology. Based on discussions with stakeholders, ISO management removed proposed changes to PIRP from the renewable integration market and product review Phase 1 proposal.[23]

As noted in its Board memorandum, as part of the proposal for changing the bid cost recovery netting methodology, ISO management was developing bid cost recovery measures with stakeholders to align with incentives to follow ISO-issued dispatch instructions. The memorandum indicated that, given the complexity of these new measures, additional development time was necessary to ensure that the new measures work as intended and to provide stakeholders with sufficient time to consider the impacts of these new measures. Accordingly, ISO management requested Board-approval only of (1) the reduction in energy bid floor, and (2) the main elements of the proposal to change the bid cost recovery netting methodology. That would allow the stakeholder process to focus on additional bid cost recovery measures that are appropriate as the result of separating the calculation of bid cost recovery between the day-ahead and real-time markets. These additional matters were the subject of the second stage of the RIMPR 1 process, and the stakeholder activities in connection with that stage are discussed below. The Board approved the proposed tariff changes as described in the Board memorandum and authorized ISO management to make all necessary filings with the Commission following Board approval of the remaining bid cost recovery elements to be discussed in a subsequent stakeholder process.

Immediately after the Board approved the phase 1 proposal, ISO staff commenced the stakeholder process to address what additional rules might be necessary to address the incentives that might arise with the separation of the day-ahead and real-time bid cost recovery mechanisms.[24] The stakeholder process was launched with the posting of a straw proposal on February 24, 2012. Over a period of approximately twelve months, the ISO issued five more policy documents and conducted six stakeholder calls and meetings to evaluate and determine appropriate rules for issues identified by the ISO and market participants. The MSC considered issues related to the bid cost recovery mitigation in 2 of its public meetings, in which stakeholders provided additional refinements considered and adopted in the final design. The MSC issued two additional opinions on this matter. They first issued an

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[23] ISO management indicated that later in 2012 it would commence a new stakeholder process to consider revisions to PIRP. ISO management provided the following materials to the Board, in addition to the MSC opinion: (1) a memorandum and a presentation to the Board, both entitled *Decision on Renewable Integration- Market and Product Review Phase 1*; and (2) a matrix summarizing stakeholder comments. These materials are attached to this filing as Attachment G.

[24] The complete record of the Bid Cost Recovery Mitigation Measures stakeholder process is available at: http://www.caiso.com/informed/Pages/StakeholderProcesses/BidCostRecoveryMitigationMeasures.aspx.

opinion on May 7, 2012, discussing earlier versions of the ISO's proposals[25] and a second opinion on December 5, 2012, at the completion of the stakeholder process.[26] The ISO considered this input and modified its proposal to address the issues identified therein.

The ISO worked closely with its DMM to validate its analysis and ensure the proposed rule changes did not create unintended adverse outcomes. DMM issued three sets of comments on the various drafts of the ISO proposal and ultimately supported the ISO final proposal as reflected in its final set of comments issued on December 5, 2012, supporting the ISO's final proposal.[27]

On June 28, 2013, the ISO posted draft tariff language for the RIMPR 1/BCR proposed changes. Two sets of stakeholder comments were submitted proposing edits to the ISO proposals. The ISO reposted the proposed tariff language on September 6, 2013 and additional comments were received. Stakeholders submitted mostly editorial comments to the language, except for SCE who suggested the inclusion of an additional rule change discussed further below. On September 5, 2013 the ISO conducted an additional stakeholder conference call to address more substantive modifications proposed by the ISO and on September 11, 2013, the ISO held the final stakeholder call to review the proposed tariff language.

III. DESCRIPTION OF TARIFF AMENDMENTS

A. Modifications to Provide Appropriate Market Signals for Increased Real-Time Decremental Economic Bids From Variable Energy Resources.

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[25] *See MSC, Opinion on Bid Cost Recovery Mitigation Measures and Commitment Costs Refinements,* May 7, 2012. Available at: http://www.caiso.com/Documents/MSCFinalOpinion-BidCostRecoveryMitigationMeasures_CommitmentCostsRefinement.pdf, and provided in Attachment H.

[26] *See MSC, Opinion on Mitigation Measures for Bid Cost Recovery*, December 5, 2012. Available at: http://www.caiso.com/Documents/FinalOpinionBidCostRecoveryMitigationMeasures.pdf, and provide in Attachment I.

[27] *See DMM, Comments on Bid Cost Recovery Mitigation Measures, Second Revised Draft Final Proposal*, November 14, 2012. Available at: http://www.caiso.com/Documents/DMM-Comments-BidCostRecoveryMitigationMeasuresSecondRevisedDraftFinalProposal.pdf and provided in Attachment J. *DMM, Comments on Bid Cost Recovery Mitigation Measures, Third Revised Draft Final Proposal*, December 4, 2012. Available at http://www.caiso.com/Documents/DMM_CommentsThirdRevisedDraftFinalProposalBidCostRecoveryMitigationMeasuresDec5_2012.pdf, and provided in Attachment K. *DMM, Comments on Bid Cost Recovery Mitigation Measures, Revised Draft Final Proposal*, October 1, 2012. Available at http://www.caiso.com/Documents/DMM%20Comments-BidCostRecoveryMitigationMeasuresRevisedDraftFinalProposal_01oct2012.pdf, and provided in Attachment L.

1. Lowering the bid floor to provide the appropriate incentives for variable energy resources to economically bid in the real-time is just and reasonable.

A supply resource uses its energy bids for two main purposes: first, to specify the minimum price at which it is willing to provide energy to the market, and second, to specify the maximum price it is willing to pay to "buy back" in real-time energy it sold in the day-ahead market. Energy bids for the latter purpose are commonly called decremental bids because they are bids by a supplier to reduce or decrement its real-time output relative to its accepted energy schedule. The ISO spot markets currently require that the economic bids submitted by scheduling coordinators to buy and sell energy be no greater than the cap of $1,000 per MWh and no less than the floor of negative $30 per MWh.

Negative bids serve an important function in the spot markets; among other things, they are used by supply resources to elicit payments to decrement their energy production from previously scheduled levels, and by demand (including exporters) to elicit payments to increase their energy purchases from the market at times when there is excess supply. The ISO market currently lacks a sufficient supply of decremental energy bids to enable the ISO market systems to economically reduce energy supply or increase demand when needed to balance excess supply. This is especially the case during off-peak hours that are susceptible to much higher levels of over-generation.

As indicated above, the issue of over-generation will become magnified as more and more variable energy resources are brought on line to meet the state of California's 33 percent Renewable Portfolio Standard (RPS) target. The reliable integration of large quantities of variable energy resources into the supply fleet will create an increased need for a liquid supply of decremental bids to manage real-time congestion and over-generation conditions. In that regard, the ISO's 20 percent RPS Study concluded, among other things, that the ISO should pursue incentives to encourage greater participation in the ISO's economic dispatch by variable energy resources.[28] The 20% RPS Study also found that if such resources could become more price-responsive, they could help address congestion and over-generation and reduce the ISO's need to rely on reliability-based dispatches.[29]

In order to provide the proper price signals to incent resources to submit economic decremental bids from variable energy resources, the ISO proposes to lower the bid floor from negative $30/MWh to negative $150/MWh. In addition, the floor will be a hard floor in contrast to today's soft floor. In a stakeholder process conducted after the completion of the RIMPR 1 policy changes, the ISO determined that in some cases

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[28] 20% RPS Study at XV, 93.

[29] 20% RPS Study at XV, 15.

the ISO markets experienced inconsistencies in schedules and prices between the scheduling run and pricing run due to the use of a soft bid floor. Under the current market rules, the bid floor is a soft floor such that bids below the bid floor may be submitted and are still included in the determination of the market solution. However, such bids below the bid floor are not allowed to set the price. The ISO found that based on historical data, bids below the bid floor have been consistently submitted to the ISO market. Even though these bids do not set the locational marginal price, this creates the opportunity for inconsistent price and bid awards at least for the resources that submitted the bid below the bid floor. Such bids may also create price inconsistencies for other resources elsewhere in the system. The ISO board approved policy changes on November 1, 2012, that authorize the ISO to seek a tariff amendment to make the bid floor soft when it also seeks to lower it to negative $150 as it is doing in the instant filing. This will eliminate inconsistencies due to the soft bid floor.[30]

The ISO implemented a negative $30/MWh bid floor in connection with its comprehensive market redesign proposal filed on May 1, 2002, in Docket No. ER02-1656. At the time the ISO submitted its market redesign filing, gas-fired generation was the predominant type of generation participating in the ISO markets, and there were a minimal number of variable energy resources in the ISO footprint. The negative $30/MWh bid floor was established to address concerns that, in some cases, generators may incur costs to curtail existing supply schedules; it did not reflect the opportunity costs applicable to variable energy resources operating in today's markets, which might curtail their energy production. [31]

Today, there are significantly more variable resources participating in the ISO markets, and the number is expected to increase in order to meet the State of California's goal of 33 percent RPS by 2020.[32] Variable energy resources generally cannot reduce output economically given the current low level of the energy bid floor. In that regard, the current bid floor level of negative $30/MWh does not provide sufficient incentive for variable energy resources to provide decremental energy bids because it is not sufficient to compensate unit owners for any reductions in energy output from variable energy resources that receive additional revenues outside of the ISO markets for their energy production.[33] These resources generally receive production tax credits,

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30 *See* ISO Board of Governors Memorandum dated October 25, 2012. Available at: http://www.caiso.com/Documents/DecisionEnhancementsImprovePriceConsistency-Memo-Nov2012.pdf, and provided in Attachment M.

31 *California Indep. System Operator Corp.*, 100 FERC ¶ 61,060 at PP 132-35 (2002).

32 The ISO has a total of 8,726 MW solar and wind installed capacity out of 61,826 MW of total installed capacity (14 percent) today. Based on its studies, the ISO has estimated it will have 15,614 MWs of solar and wind installed capacity out of 69,391 MW of total installed capacity (22.5 percent) by 2022.

33 For more background regarding the history for setting the bid floor at negative $30/MWh, refer to the Issue Paper which provides a detailed breakdown.

renewable energy credits and contractual energy payments significantly in excess of $30/MWh. These payments make it unlikely that variable energy resources will be willing to reduce their output for a payment of only $30/MWh. Thus, the ISO believes that lowering the bid floor below the opportunity costs for providing energy is necessary to incent variable energy resources and additional conventional resources to submit decremental energy bids that can be dispatched during low or negatively priced hours. For the reasons set forth below, the ISO believes that the current level necessary to incent sufficient decremental bids is negative $150/MWh.

In determining the level of the bid floor, the ISO reviewed the elements that comprise the potential revenues a wind resource could be getting outside of the ISO markets. The specific data points that the ISO relied on to conclude that, at this time, negative $150/MWh is the appropriate level for the energy bid floor in order to promote increased decremental bids are as follows:

- Renewable energy credits are capped at $50/MWh.
- Tax credits for wind production along with other tax incentives guarantee these resources payments of close to $37/MWh. The renewable energy production tax credit alone, currently at $21/MWh,[34] is the primary federal incentive for wind energy and has been essential to the industry's growth.
- The FERC Electric Quarterly Reports filed by sellers in the ISO area for the 4th quarter of last year reported prices greater than $150/MWh for energy sales during that period.[35]
- Additionally, the California Public Utility Commission confirmed that a recent request for proposal issued for solar photovoltaic facilities had a cap of $295/MWh.
- Contract penalties associated with curtailing energy production places additional pressure on variable energy resources to produce rather than decrement their energy.

The ISO understands that the average payment for a wind resource is somewhere in the vicinity of $130/MWh; therefore, lowering the floor to negative $150/MWh will allow the majority of wind resources to participate in the ISO markets by submitting decremental bids that will not require subsequent filings with the Commission. Stated differently, a negative $150 bid floor will cover the opportunity costs for the majority of wind resources and potentially for some of the solar resources as well.

"*Issues Paper – Renewable Integration Market and Product Review Phase 1*, September 30, 2010" - http://caiso.com/27be/27beb7931d800.html.

[34] The renewable energy production tax credit is an income tax credit of 2.1 cents/kilowatt-hour and is allowed for the production of electricity from utility-scale wind turbines. This incentive was created under the Energy Policy Act of 1992. Through the American Recovery and Reinvestment Act (ARRA), Congress acted to provide a three-year extension of the PTC through December 31, 2012.

[35] The FERC EQR reports are located at: http://www.ferc.gov/docs-filing/eqr.asp.

The ISO recognizes that negative $150 does not cover the opportunity costs for all renewables whose average contract payments combined with the tax credits exceed $150/MWh. For this reason, initially the ISO considered a lower bid floor. However, in response to concerns raised by the MSC, DMM, and market participants, that the lower bid floor might provide further incentives for adverse market behavior, the ISO only proposes to lower the bid floor to negative $150/MWh. In addition, the negative $150 covered a substantial portion of the renewable resources that the ISO should target for its needed increased real-time economic bids.

Finally, as shown in Table 1 below, a negative $150 bid floor is well within the range of the bid floor levels of other ISO/RTOs in the United States.

Table 1 – Comparison of ISO/RTO energy bid floors

ISO/RTO	Energy Bid Floor
PJM	No Bid Floor
NYISO	-$999.99/MWh
MISO	-$500/MWh
ERCOT	-$250/MWh
CAISO	-$30/MWh
ISO-NE	$0/MWh

The ISO notes that, during the stakeholder process, the ISO proposed a staged approach to lowering the energy bid floor. Specifically, the ISO proposed to lower the floor to negative $150/MWh initially and, one year after, automatically lower the floor to negative $300/MWh, much in the same manner that the ISO implemented position limits for convergence bidding.[36] Numerous stakeholders, as well as the MSC[37] and DMM, expressed concerns about the potential consequences of making an automatic change to the bid floor of this magnitude. For example, the MSC expressed concerns about gaming. Because the MSC anticipated that circumstances would be rare when a unit can run profitably at negative $150/MWh, it recommended that further reductions in the

[36] In its October 15, 2010 Order on convergence bidding (*California Ind. Sys. Operator Corp.*, 133 FERC ¶ 61,039 P 117 (2010)), FERC accepted the ISO's proposal to institute position limits that are automatically changed on a pre-set schedule. *"If, based on input provided by the DMM and MSC and on its own analysis, CAISO concludes that it is not appropriate to make the position limits change it will timely make a filing with the Commission to modify the percentage level and/or timetable for the upcoming change."*

[37] MSC Opinion, December 8, 2011, at 7-8. For example, the MSC expressed concerns about gaming. Because the MSC anticipated that circumstances would be rare when a unit can run profitably at negative $150/MWh, it recommended that further reductions in the price floor be implemented only after study of the initial reduction to negative $150 to determine whether it was effective in eliciting more flexibility and whether there were any unanticipated negative impacts. *Id.* at 8.

price floor be implemented only after study of the initial reduction to negative $150 to determine whether it was effective in eliciting more flexibility and whether there were any unanticipated negative impacts.[38] As a result of these concerns, the ISO is proposing to set the bid floor at negative $150 and is not proposing automatically to lower the bid floor to negative $300/MWh after one year. Consistent with the MSC's recommendation, the ISO will evaluate the impact of reducing the bid floor to negative $150/MWh based on a full year's data. If there are no significant unanticipated negative effects, then the ISO will initiate a stakeholder process to lower the bid floor to negative $300/MWh and file the appropriate tariff amendments.[39]

2. MSC Opinion.

On December 8, 2011, the MSC issued a *Final Opinion on Integration: Market and Product Review, Phase 1.* The MSC states that it "strongly supports the goal of encouraging economic bids that would allow for downward generation adjustments in response to negative real-time prices."[40] The MSC adds that "the importance and value to the system, and ultimately, consumers of such increased flexibility will grow significantly as the penetration of variable renewables rises."[41] The MSC supports the proposal to decrease the bid floor to negative $150 MWh.[42]

The MSC notes that lowering the bid floor furthers the ISO's goal of creating better incentives for firms to be more flexible and responsive in both their bids and their operations.[43] The MSC notes that there is a periodic and growing problem with over-generation conditions where the system has too much energy offered at zero or even slightly higher prices. In other words, "too many units are unwilling to reduce their output even though they are paying, through a negative price, for the privilege of producing power."[44] The MSC concludes that given the renewable policies in place that promote this rigidity, there is a need to lower the bid floor to encourage flexible response by generation during over-generation situations.[45] In particular, given the

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38 *Id.* at 8.

39 Significant amounts of solar generation are scheduled to come online in the near future. The ISO believes that further lowering the bid floor to negative $300/MWh will likely provide additional benefits by incenting decremental bids from additional resources including solar resource participation which have higher opportunity costs for providing energy and provide clear signals to incent investment in storage and demand response technologies that can respond quickly to over generation conditions. A negative $300/MWh bid floor will be more appropriate to reflect the opportunity costs for these types of resources.

40 MSC Opinion, December 8, 2011, at 2.

41 *Id*.

42 *Id*.

43 *Id.* at 7.

44 *Id*.

45 *Id*.

present magnitude of tax credits and the cap on the price of renewable credits in California, a negative $150/MWh should be low enough to elicit economic bids from renewable generators.[46] The MSC states that there should be very few circumstances where outside payments and other costs are large enough for a unit to operate profitably at negative $150/MWh.

3. Issues raised by stakeholders.

Most stakeholders support lowering the bid floor from negative $30/MWh to negative $150/MWh and subsequently to negative $300/MWh if the analysis confirms this direction. A few stakeholders raised questions or had other recommendations.

For example, some stakeholders voiced concerns that the majority of negative prices that occur in the current market are driven by uneconomic parameters (power balance constraint) rather than the lack of decremental bids. They suggested that lowering the bid floor will not incent additional decremental bids but instead will increase the incentive to self-schedule to avoid more negative pricing. Based on this concern, ISO staff assessed how often these conditions occurred. Between April 2009 and October 2011 just over 2,300 out of a total of 14,587 negative 5-minute intervals (or approximately 15%) were due to relaxing the power balance constraint. Thus, the data clearly reveals that only a small portion of the negative prices since the start of its locational marginal price-based markets were due to relaxing the power balance constraint.

In any case, these concerns are misplaced. As discussed above, even if in some instances negative prices are set by the need to relax the power balance constraint, the lack of economic negative bids is what leads to the need to relax the power balance constraint. Resources that can provide more negative prices will not "be faced with" negative prices unless they submit those negative bids, and in that case they are indicating their willingness to reduce their supply at those prices.

Stakeholders also requested updated analysis regarding the duration of negative pricing episodes. The concern was that negative prices were fleeting, lasting a single interval or two intervals in many cases. They suggested that lowering the floor bid floor would discourage participation in the real-time due to these unpredictable movements in price. The ISO reviewed the same timeframe noted above and found that out of 14,587 negative 5-minute intervals, only 1,342 were single intervals of negative prices (meaning the intervals before and after were positive) and there were 581 incidents where the negative prices spanned two intervals. Thus, the vast majority of negative prices occurred in three or more consecutive intervals. They were not "fleeting;" rather, most negative prices were sustained through multiple intervals.

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[46] *Id*.

Some parties noted that the bilateral power purchase agreements between load-serving entities and variable energy resources provide the ability for an LSE buyer to curtail the supplier's renewable resource, and questioned why such provisions are not sufficient to enable the ISO to reduce the amount of energy these resources are injecting into the grid under conditions of system over-generation or local congestion. Such provisions are not sufficient because they do not provide a mechanism for the ISO to direct the curtailment of the resources in real time in response to an immediate over-generation or congestion condition. To obtain the real-time curtailment response, the ISO needs to maintain reliable operation under over-generation or congestion conditions, the ISO must have the ability to issue decremental instructions directly to the needed resource, with adequate incentives in place for the instructed resource to respond to the decremental instruction. Lowering the bid cap as proposed herein provides those incentives.

Calpine recommended lowering the bid floor to negative $75/MWh initially and moving in a downward direction at a slower pace. As discussed above, the ISO examined various data points to identify the bid floor level that would be low enough to incent sufficient decremental bids in the ISO markets, especially as the penetration of variable energy resources increases. A negative $75/MWh bid cap is only a marginal improvement to the existing negative $30/MWh bid floor and is well below the revenues that variable energy resources receive outside of the ISO market -- revenues that would need to be accounted for if variable energy resources were to submit decremental bids. A negative $150/MWh bid floor is much closer to that number and will not discourage decremental energy bids from suppliers who do not desire to proceed with the administrative burden of submitting a filing with the Commission to cost justify a bid below the floor.

Powerex advocated for a symmetrical bid cap and floor, setting the bid cap at negative $1000/MWh to avoid potential unintended consequences. The ISO currently does not have a symmetrical bid cap and floor, and the Commission found that such asymmetry is just and reasonable.[47] The Commissioned reaffirmed the justness and reasonableness of an asymmetrical bid floor and bid cap in its orders approving the ISO's locational marginal price-based markets by retaining the negative $30/MWh bid floor and adopting a $500/MWh bid cap on the commencement of the new market (with the bid cap increasing by $250/MWh every year until it reached its current level of $1,000/MWh).[48] Likewise, other independent system operators and regional

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47 When the ISO filed to implement a negative $30/MWh bid floor, certain stakeholders argued that the bid floor and the bid cap should be symmetrical. The Commission acknowledged the argument in its order, but approved a negative $30/MWh bid floor as being just and reasonable. However, the Commission directed the ISO to include in its tariff a provision to allow suppliers the opportunity to justify costs in excess of the negative $30/MWh bid floor. In other words the Commission ordered the ISO to implement a "soft" bid floor. *California Indep. Sys. Operator Corp.*, 100 FERC ¶ 61,060 at 61,255 (2002).

48 *California Indep. Sys. Operator Corp.*, 112 FERC ¶ 61,013 at PP 90-106 (2005).

transmission organizations which have $1,000 MWh bid caps like the ISO do not have symmetrical bid caps and floors

Powerex failed to demonstrate why a symmetrical bid cap and bid floor is necessary or will provide any tangible benefits or market efficiencies. A negative $1,000 MWh bid floor bears no relationship to the actual costs that variable energy resources and or other resources can be expected to incur to curtail their energy production.[49]

Also, both the MSC and DMM opposed reducing the bid floor beyond negative $150 until the ISO completes a study to evaluate the observed impact of a negative $150 bid price floor on relieving over-supply conditions, the cost to generators, whether there were any unanticipated adverse impacts, and whether there is any further need for downward dispatchability.[50] Further, both DMM and the MSC identified a gaming concern with lowering the bid floor even lower. Specifically, a further reduction in the bid floor could create an incentive for suppliers located within “generation pockets” to exercise market power through negatively priced bids that may be needed to mitigate congestion in the real-time market.[51]

SMUD does not believe the ISO should lower the bid floor until participating intermittent resources can submit economic curtailment bid curves. This concern is addressed by the ISO’s proposed implementation of the lower bid floor contemporaneously with the adoption of market rule changes to integrate fifteen minute scheduling rule changes in which variable energy resources will be able to submit economic bids.

B. Bid Cost Recovery Rule Changes Necessary to Incentivize Real-Time Economic Bids.

In the RIMPR 1 stakeholder process, the ISO recognized that in order to address the influx of variable energy resources into the ISO markets, the ISO market rules needed to incentivize greater flexibility from all resources. Consistent with this goal, the

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[49] In a well-functioning, competitive market, suppliers should compete in the decremental energy market by submitting decremental bids that track their avoided costs. As the Commission has recognized: “[i]n a competitive situation, a generator would set its bid at the level of cost it can avoid by not generating.” *California Indep. System Operator Corp.,* 90 FERC ¶ 61,006 (2000).

[50] MSC Opinion, December 8, 2011, at 8; Comments of the Department of Market Monitoring On Renewable Integration Product and Market Review, Fourth Revised Draft Straw Proposal (Nov. 17, 2011) and Comments of the Department of Market Monitoring On Renewable Integration Product and Market Review, Fourth Revised Draft Straw Proposal (Sept. 13, 2011) which are attached as Attachment F hereto.

[51] MSC Opinion, December 8, 2011, at 8; Comments of the Department of Market Monitoring On Renewable Integration Product and Market Review, Fourth Revised Draft Straw Proposal (Nov. 17, 2011).

ISO recognized that netting market revenues from the real-time market created a disincentive to provide economic bids in the real time market. Offsetting day-ahead and real-time market outcomes can lower or eliminate a resource's bid cost recovery payments if there are surpluses or shortfalls in day-ahead to net out any shortfalls or surpluses in the real-time market.[52] Therefore, the netting of costs and revenues across day-ahead and real-time is at odds with the intent of the proposal to lower the energy bid floor because it dilutes the incentive for scheduling coordinators to submit decremental bids in the real-time. In addition, as discussed by Mr. Cooper the current netting rules increase the risks of bidding in the real time market and so it increases the incentive to self-schedule.[53] To reduce these risks, the ISO is proposing to separate bid cost recovery between the day-ahead and real-time markets and isolate recovery for each market based on the costs and revenues incurred for the specific market.

1. Separating the day-ahead and real-time bid cost recovery is necessary to incent needed real-time economic bids.

Under the current market rules, once the ISO has calculated the bid costs and market revenues for the day-ahead market and real-time market separately, the ISO then nets the bid costs and market revenues across the two markets.[54] The day-ahead market is comprised of two procedures. First, the ISO conducts the integrated forward market through which it clears day-ahead bid-in supply and demand, and procures ancillary services requirements. Subsequently, the ISO conducts the residual unit commitment process, through which the ISO commits additional resources based on forecasted demand.[55] The ISO proposes to continue to net bid costs and market revenues in each market over each trading day, but eliminate the additional step of netting across the integrated forward market and the real-time market. Specifically, the ISO will calculate and account for bid cost recovery for the integrated forward market separately from the residual unit commitment and real-time market bid cost recovery, which would continue to be combined.[56] Combining the residual unit commitment and real-time market is appropriate because both of these markets are based on the ISO load forecast, unlike the integrated forward market which is cleared on bid-in demand. The residual unit commitment decision is meant to indicate to the resource that a startup will be necessary for dispatch purposes in the real-time. The only difference between the associated costs for the residual unit commitment as opposed to the real-

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52 *See* Exhibit ISO-No. 1 at 18-20.

53 *Id.* at 20-22.

54 *Id.* at 11-13.

55 *Id.* at 4-5.

56 For ease of discussion, in this document references to the separation of the day-ahead and real-time bid cost recovery processes will mean the separation of the integrated forward market from the combined residual unit commitment and real-time market bid cost recovery.

time commitment costs is the timing of the decision and the state of the system and bids available at the time when each decision is made.[57]

This change will eliminate market settlement rules that currently encourage generators to self-schedule their day-ahead market energy schedules in real-time to avoid being dispatched down and may discourage generators from submitting bids for incremental energy above day-ahead schedules.[58] As discussed by Mr. Cooper, the current netting rules result in the ISO utilizing the market revenue earned in the real-time for following an instruction cleared in the real-time to decrement from their day-ahead schedules to offset a resource's recovery of day-ahead bid cost recovery.[59] The current rules may cause a generator that has a profitable day-ahead position to lose revenue if the ISO dispatches the resources in the real-time. They may also reduce the incentive to submit economic bids in the real-time market in the event a resource is eligible for bid cost recovery based on the day-ahead market because real-time profits will offset this day-ahead bid cost recovery.

The elimination of the netting will incent more real-time economic bids, which in turn will provide the ISO with greater flexibility in the real-time market to deal with variability due to changed conditions and the variability of the output from its fleet of resources that will increase with the increased entry of variable energy resources. As noted by the Market Surveillance Committee, this will improve market efficiency, and will result in an overall decrease in the "as-bid cost" of meeting load on the ISO system.[60] Furthermore, the potential for increased revenues for decreasing one's output is expected to increase with the lowering of the negative bid floor. These current netting rules dampen the effectiveness of the lower bid floor in eliciting more real-time decremental bids because the real-time revenue is used to offset the day-ahead bid cost recovery.

In addition, this change aligns the ISO bid cost recovery rules closer to other ISOs/RTOs across the country that do not net bid cost recovery costs and revenues across their markets.[61]

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57 For convenience purposes, in this transmittal letter, when referring to the separation of bid cost recovery between the day-ahead and real-time bid cost recovery, the ISO will refer to the combined residual unit commitment/real-time bid cost recovery process as the real-time market bid cost recovery process.

58 MSC Opinion, December 8, 2011, at 9.

59 *See* Exhibit ISO-No. 1 at 12-13.

60 MSC Opinion, December 8, 2011, at 10.

61 MISO's tariff provides that MISO provides a day-ahead revenue insufficiency guarantee if, among other things, the production cost and operating reserve cost for a resource committed by MISO are greater than the revenues received for energy and operating reserve in the *day-ahead* energy and operating reserve market. The MISO tariff then states that MISO will provide the real-time sufficiency guarantee if the resource did not recover the sum of the resource's production cost and operating reserve

To incorporate these changes into the ISO tariff, the ISO proposes to modify section 11.8.5 which currently pertains to the unrecovered bid cost uplift payment for resource. The unrecovered bid cost uplift payment is the final calculation of the amounts of uplift the resource is paid if their total market revenues do not cover their bid costs, *i.e.*, the resource incurs a bid cost shortfall. Currently, this section describes the calculation of the bid cost shortfalls and surpluses and nets these amounts within each market first and then across the day-ahead and real-time markets. The ISO is proposing to modify this section to account for the integrated forward market bid cost shortfalls and surpluses separately from the residual unit commitment and real-time shortfalls and surpluses, which will continue to be combined. The ISO is also proposing to modify section 11.8.6.2, in which it describes how the ISO calculates the amounts of integrated forward market, residual unit commitment and real-time market bid cost uplifts for purposes of recovering those amounts. The proposed modifications incorporate the sequential netting of the integrated forward market bid cost uplifts separately from the residual unit commitment and real-time market bid costs, whereas previously they were all sequentially netted together for purposes of determining which amount is allocated in which market.

2. Modifications to compensate for short-start units are necessary to encourage such resources to also submit real-time economic bids.

Consistent with its goal of incenting increased economic real-time bids, the ISO is proposing modifications to the bid cost recovery rules regarding the calculation of start-up costs for short-start resources. Short start resources are defined in the tariff as resources that have: 1) a cycle time less than five hours, which is comprised of their start-up time plus minimum run time, 2) a start-up time less than two hours, and 3) can be fully optimized with respect to this cycle time. These resources may be committed in the day-ahead market, but such commitment is not accompanied by an actual start-up because these resources can start within the time horizon of the real-time market, and these resources are re-optimized in the real-time market, which can result in a de-

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cost through the revenue received through the real-time energy and operating reserve market. *See Mid-Continent Independent System Operator Inc., Open Access Transmission, Energy and Operating Reserve Markets Tariff*, Section 39.2.9. Day-Ahead Energy and Operating Reserve Market Process Version: 3.0.0 Effective: 4/1/2011, subpart p.; and Section 40.3.5 Real-Time Offer Revenue Sufficiency Guarantee Payment Version: 0.0.0 Effective: 7/28/2010, subpart b. vi. Similarly, the ISO New England tariff states a day-ahead credit paid to resources equals any portion of the resource's total day-ahead offer amount in excess of its total day-ahead value, with a similar provision that applies to the real-time market. *See ISO New England, Inc., Transmission, Markets and Services Tariff,* Market Rule 1, Appendix F, Net Commitment Period Compensation Accounting, Sections III.F.2.1.4 and III.F.2.1.14. Similar provisions are contained in the *Amended And Restated Operating Agreement Of PJM Interconnection, L.L.C.*, Schedule 1 Section 3.2.3 Operating Reserves, subpart b; and the *New York Independent System Operator Corp., Market Services Tariff, Attachment C, Formulas for Determining Bid Production Cost Guarantee Payments*.

commitment of the resource. Therefore, the day-ahead commitment of short-start resources is financially binding but it is not operationally binding.

Under the current settlement rules for short-start resources, if the resource is committed in the day-ahead market and then re-optimized and dispatched to a different point in the real-time, its start-up costs are qualified and paid for based on its real-time start-up costs. Day-ahead and real-time start-up costs may vary due to changes in fuel costs between the two days. The short-start resource would be incentivized to attempt to protect its day-ahead bid cost recovery by leaving is day-ahead schedule as a self-schedule in the real-time market or not following its real-time instructions. As explained by Mr. Cooper, a rule change is necessary to align incentives to submit real-time economic bids in the context of separate day-ahead and real-time bid cost recovery.[62]

Under the ISO proposal, if a short-start unit is committed in the day-ahead and the real-time market makes use of that same commitment, then the start-up costs would be attributed to the initial commitment in the day-ahead market so the resource is made whole in the day-ahead. This will enable the resource to account for all of its costs and revenues in the integrated forward market. This is a reasonable approach given that the integrated forward market is the market that first committed the resource and it is within that market that the economic decision to commit the resource was made based on the resource's day-ahead start-up costs.[63]

To incorporate these changes, the ISO proposes to add subsection (h) to Section 11.8.2.1.1, which describes the integrated forward market start-up costs calculations and a similar reference in section 11.8.4.1.1 (h) to indicate the treatment of the costs in such conditions.

3. Compensation of minimum load costs for multi-stage generating resources must be modified to avoid under payment of minimum load costs and encourage economic changes from day-ahead schedules.

In the case of multi-stage generating resources,[64] the assignment of minimum load costs and minimum load energy revenues to either the day-ahead or real-time

[62] *See* Exhibit ISO-No. 1 at 25-27.

[63] In the case of a commitment coming out of the residual unit commitment, which is also part of the day-ahead market, there is no need to apply this new rule. With the separation of the day-ahead and real-time market, the ISO is proposing to continue to net costs and revenues from the residual unit commitment process with real-time costs, since the residual unit commitment is only a commitment and not an economic dispatch.

[64] Multi-stage generating resources are resources that are capable of operating in multiple configurations and are modeled and dispatched as such in the ISO markets. Resource owners are able to register the multiple states and configurations that best reflect the operational characteristics of their

market is complicated by the fact that a change in configuration between those two settlement periods can result in the same generating resource having different minimum load and energy costs for the same operating interval. Therefore, in separating the day-ahead and real-time bid cost recovery, the resource would be able to obtain a double recovery of overlapping minimum load costs. To avoid a double counting of minimum load costs will require modifying the existing methodology by which the ISO accounts for a multi-stage generating resource's minimum load costs.

Specifically, the ISO proposes to assign minimum load costs and energy to either the day-ahead or real-time market bid cost recovery calculation as follows. In cases where the resource is dispatched in one configuration in the integrated forward market, and then later dispatched in a different configuration in the real-time market, the resource will receive only the incremental minimum load costs between the two. These costs can be either positive or negative. This design change captures costs and revenues for a multi-stage generating resource's actual movement between configurations between the day-ahead and real-time. The portion of the real-time market energy and costs that are incurred by the multi-stage generating resource moving from the day-ahead configuration to the real-time configuration is attributed to the real-time.

Mr. Cooper describes four cases that illustrate how the proposed proportioning of minimum load costs would work for over-lapping and for non-overlapping multi-stage generating resources configurations, in both the incremental and decremental directions.[65] These examples illustrate that in some cases the incremental revenue would be positive, reflecting the increased costs the resource might incur in moving from one configuration to another, and in other cases they might be negative, reflecting a reduction in the costs incurred by the resource. These examples illustrate that these rules only apply when the multi-stage generating resource is committed by the ISO in the day-ahead or real-time markets. Therefore, when there is self-commitment in either market, the self-commitment rules as they currently exist in the ISO tariff will continue to apply. Similarly, when the multi-stage generating resource is committed in the same configurations between day-ahead and real-time, there is no need to apply this new rule.[66]

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resources, including the start-up and minimum load costs associated with each configuration they register. The ISO markets are in turn configured to respect the individual constraints of the resource's configurations, which enables the ISO to dispatch such resources more optimally. This market functionality was implemented in the fall of 2010 as adopted by the Commission on September 30, 2010. *See California Indep. Sys. Operator Corp.*, 132 FERC ¶ 61,273 (2010). On July30, 2013, the ISO submitted a tariff amendment to require that all resources that are capable of operating in multiple configurations are registered under this model. *See* FERC Docket No. ER13-2063.

[65] *See* Exhibit ISO-No. 1 at 30-34.

[66] The existing rule in which the ISO calculates whether it is an ISO or self-commitment period applies. *See* Section 11.8.1 of the CAISO Tariff.

To incorporate this proposed change, the ISO proposes modifications to section 11.8.1.3 (a).

4. Day-ahead metered energy adjustment factor must be modified to eliminate disincentives for real-time economic bids and encourage performance consistent with ISO instructions.

The ISO proposes modifications to the day-ahead metered energy adjustment factor to ensure resources are not discouraged from submitting economic bids in the real-time. Under the current bid cost recovery rules, the ISO accounts for energy bid costs and revenues based on the use of a metered energy adjustment factor that is designed to only provide bid cost recovery for delivered energy portions of the resource's energy bid curve.[67]

As part of the RIMPR 1 initiative, the ISO initially determined that in order to incent real-time economic bids it would be necessary to base day-ahead bid cost recovery on scheduled energy and not delivered energy. As such, the ISO initially considered not applying the day-ahead metered energy adjustment factor in the day-ahead market bid cost recovery calculations. The ISO believed then that this was a necessary corollary change consistent with its proposal to eliminate the netting of costs and revenues in the day-ahead market against those in the real-time market. However, the ISO soon determined that completely isolating the day-ahead bid cost recovery from actual real-time performance was not appropriate because in doing so the ISO could be in the position of paying for day-ahead bid cost recovery that is not actually delivered consistent with ISO real-time dispatch.

This market outcome would be contrary to the purpose of the day-ahead market, which is not just a financial day-ahead market, but is conducted daily to establish feasible energy schedules for the next day. The real-time market, in turn, makes incremental changes to these schedules based on changed conditions. If the ISO were to guarantee bid cost recovery payment entirely based on the resource's financial schedule without any regard to whether that schedule was actually delivered, the essential function of the day-ahead market would be eroded and the ISO would not be able to rely on its day-ahead market to facilitate grid operations.

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[67] The ISO adopted the factors to calculate the portions of the energy bid curve that are actually delivered, as required by the Commission in its MRTU 2006 Order. *See* MRTU 2006 Order at P 516. In the day-ahead bid cost recovery the ISO uses a day-ahead metered energy adjustment factor and a separate real-time adjustment factor for the real-time. The metered energy adjustment factors were adopted at the start of the ISO LMP-based markets, but the ISO had not included the definition of these factors in its tariff. The ISO included the definition of the metered energy adjustment factor in its tariff in 2011 after it made an emergency filing to address certain adverse market behavior. *See* May 4, 2011 Order.

The ISO modified its proposal and instead proposes to address this potential adverse incentive through a modified day ahead metered energy adjustment factor that will guarantee payments for day-ahead scheduled amounts if the ISO dispatches a unit downward from its day-ahead schedule in the real-time market, but not provide such payments if the downward deviation is not consistent with the ISO's real-time instructions. Mr. Cooper also explains further the adjustments the ISO proposes to make to the day-ahead metered energy adjustment factor.[68] In summary, the current day-ahead metered energy adjustment factor works to eliminate the accounting of energy bid costs in cases where the resource decrements from its day-ahead schedule even if that decrement is instructed by the ISO.[69] The ISO proposes to modify the day-ahead metered energy adjustment factor, so that in cases where the resource is re-optimized in the real-time to different levels from its day-ahead portion, and the resource actually follows that real-time instruction, the resource's day-ahead bid costs are not reduced. This is accomplished through the application of the day-ahead metered energy adjustment factor to the resource's integrated forward market energy bid cost and market revenue calculations in certain scenarios.[70] This is necessary to scale a resource's day-ahead bid cost recovery payments if the resource does not actually deliver the day-ahead scheduled energy but to avoid penalizing the resource if the non-delivery is as a result of its adherence to an ISO dispatch of the resource in the real-time.[71]

This outcome is still consistent with the Commission's September 2006 Order requirement that the ISO not pay bid cost recovery for day-ahead energy *for deviations from ISO dispatch instructions*. In Paragraph 516 of the September 2006 Order, FERC stipulated that:

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68 *See* Exhibit ISO-No. 1 at 35-39.

69 Based on the emergency bid cost recovery related filings the ISO made in 2011, the ISO does not apply the factor to integrated forward market revenues (*i.e.*, sets the factor to 1) when a resource is decremented in the real-time dispatch from its day-ahead schedule. This has the effect of not scaling the market revenues used to offset the integrated forward market bid costs being calculated for purposes of bid cost recovery. The ISO also does not apply the day-ahead metered energy adjustment factor to integrated forward market costs (or sets the factor to 1) in the case of negatively priced energy bids. This has the effect of accounting all the costs in the integrated forward market.

70 *See* Exhibit ISO-No. 1 at 59-62.

71 Mr. Cooper provides an example that illustrates the difference between the current day-ahead metered energy adjustment factor and the proposed, modified day ahead metered energy adjustment factor. *See* Exhibit ISO-No. 1 at 40-41. The example shows the application of the day ahead metered energy adjustment factor as currently defined would result in a scaling of elements of the day-ahead bid cost recovery calculation in the case that a generating resource has a day-ahead schedule and then follows the ISO's instruction in the real-time market that it decrement from its day-ahead schedule. Under the modified approach proposed in this tariff amendment, the day-ahead bid cost recovery calculation using the revised formula would not be scaled in such cases.

> Resources that fall short of day-ahead dispatch instructions should only be guaranteed the recovery of costs associated with the energy actually provided, and should not receive payments for deviations from dispatch instructions. When a resource's energy bid exceeds the LMP, it is not appropriate to provide an uplift payment to cover the revenue gap for energy *that is not actually produced when instructed*. However, a resource that starts up and provides more energy than is instructed by the CAISO should retain the original recovery calculated by the CAISO in the day-ahead market, since the spot market would be receiving the full amount of energy (and more) that it agreed to pay for in the day-ahead market. However, the resource should not be eligible for any additional bid cost recovery associated with its additional, uninstructed output. Thus, the resource is paid only for scheduled energy, and is not paid for any energy in excess of its schedule. Units that are committed in the day-ahead market, and do not start-up, should not receive any bid cost recovery payments. We direct the CAISO to revise the MRTU Tariff accordingly in a compliance filing to be submitted within 60 days of the date of this order.[72]

Under the ISO proposal, undelivered day-ahead energy will not receive bid cost recovery if the ISO did not issue a decremental instruction for the unit instructing it to not deliver the day-ahead scheduled energy in real-time. It is important to note that the modified day-ahead metered energy adjustment factor will not reduce day-ahead bid cost recovery payments if, in real-time, the ISO dispatches the unit down below its day-ahead scheduled energy, and the unit delivers the dispatched energy. This change is necessary to accomplish the over-arching goal of encouraging increased decremental energy bids in the real-time market, which will help the ISO better manage the integration of variable energy resource in its real-time operations and markets. Moreover, it is consistent with the September 2006 Order because it recognizes the resource's non-delivered day-ahead scheduled energy is due to an ISO dispatch, albeit in the real-time.

Additionally, the ISO proposes to include in its tariff four specific rules intended to avoid the inappropriate expansion of bid cost recovery as a result of the application of the day-ahead metered energy adjustment factor.[73] The rules capture the rule changes the ISO made in 2011 to ensure resources could not engage in bidding practices designed to expand bid cost recovery payment.[74] On May 4, 2011, the Commission approved the ISO's tariff amendment to address a combined bidding strategy that exploited the way in which the ISO applied the day-ahead metered energy adjustment factor at that time. At the time, the ISO added additional rules to its then section 11.8.2.2, which requires the ISO to calculate market revenues based on the delivered

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[72] *See* MRTU 2006 Order at P 516.

[73] *See* Proposed CAISO Tariff Section 11.8.2.5.

[74] *See* May 4, 2011 Order.

portion of the day-ahead schedule to ensure that the tariff accurately calculates the integrated forward market revenues in all dispatch situations. The ISO added the rule that when a resource is dispatched in real-time below the day-ahead schedule, the ISO calculates the market revenue based on day-ahead scheduled energy rather than delivered energy for the portion of the day-ahead schedule above minimum load. The ISO also added a new rule that when a resource is dispatched at the same level as the day-ahead schedule or is incremented above its day-ahead schedule, the ISO will continue to calculate the integrated forward market revenues based on the delivered portions because in such cases market revenue would be fully accounted for. Finally, the ISO added an additional clarification that revenues associated with minimum load energy will be based on delivered energy.

On August 19, 2011, the Commission accepted adjustments to the bid cost recovery rules to eliminate the ability for parties to use negative bidding strategies to expand bid cost recovery payments. Specifically, the ISO adopted a rule that the metered energy adjustment factor would not apply to negatively-priced bids when calculating bid costs for energy scheduled in the day-ahead market. This change was intended to ensure the bid cost recovery calculations would account for the full value of negative bid costs even if the resource delivers less energy in real-time than it was scheduled to deliver in the day-ahead market.

The ISO proposes to modify the rules in section 11.8.2.2 in the instant proceeding to more comprehensively address all the various combinations of positive or negative costs and revenues that can occur. The same principles adopted in 2011 to discourage adverse bidding behavior will continue to apply. However, the ISO is proposing to simplify the language in section 11.8.2.2, which only addresses the market revenue side and explicitly states each rule as it applies to the costs and revenues in proposed section 11.8.2.5.

First, proposed section 11.8.2.5.2 reflects the rule that when the costs and revenues are both positive the costs will be scaled by the application of the metered energy adjustment factor, but not the market revenues. This rule was adopted in the March 2011 emergency filing to ensure the full scope of day-ahead market revenues are used to offset the day-ahead costs in determining whether the resource requires bid cost recovery payments. Second, proposed section 11.8.2.5.2 now also reflects the rule that when the bid costs are positive but the market revenues are negative, the ISO will apply the metered energy adjustment factor to the bid costs and the market revenues. This is to pay only for delivered costs and also to scale the negative revenues from the bid cost recovery calculation, as negative revenues increase bid cost recovery. A third rule specifies in proposed section 11.8.2.5.3 that the ISO will not apply the metered energy adjustment factor to either the costs and revenues if the bids costs are negative and the market revenues are positive or zero. This ensures the metered energy adjustment factor does not inflate bid cost recovery because scaling negative bid costs would increase a resource's bid cost recovery. This provision is the same rule change made in the ISO's June 22, 2011 emergency filing. Finally, a fourth rule is included in proposed section 11.8.2.5.4, to require that if both the costs and revenues are negative, the metered energy adjustment factor will be applied to the market revenue but not the bid costs. This is an extension of the logic described for the previous three circumstances and ensures that the application of the day-ahead metered energy adjustment factor does not have the unintended effect of increasing bid cost recovery.

The ISO builds on these rules and proposes to spell them out specifically in the tariff to illustrate how the day-ahead metered adjustment factor will be applied to both the bid costs and market revenue calculations, or just one of the two to achieve the desired effect. These rules are designed to prevent anomalous outcomes in which the metered energy adjustment factor increases day-ahead bid cost recovery payments rather than reducing them for the reasons discussed above. The day-ahead metered energy adjustment factor will therefore be applied strategically to scale the resources' costs and allow the market revenues to offset the accounting of their costs to reduce or eliminate energy bid cost recovery payments in the integrated forward market. Mr. Cooper provides an explanation of each of the rules.[75]

It is important to note, however that these rules are not intended to preclude the ISO from adjusting bid cost recovery payments if market participants are able to expand their bid cost recovery payments as a result of the use of the day-ahead metered energy adjustment factor. The purpose of the modified factor is to adjust a resource's bid cost payments consistent with its delivery and its adherence to real-time dispatch, without discouraging the resource from submitting economic bids in the real-time. Therefore, a catch-all provision in the tariff is necessary to enable the ISO to adjust a resource's bid cost recovery payments in the event the resource is able to expand their bid cost recovery payments as a result of the metered energy adjustment factor, even if that behavior is not intentional. Therefore, the ISO proposes to include a tariff provision that specifies that in the event that the ISO discovers that there has been an increase in the unrecovered bid cost uplift payment due to the application of the day-ahead metered energy adjustment factor, the ISO will adjust the payment to recover the overpayment in a subsequent billing cycle as permissible under existing Section 11.29. This rule is contained in proposed Section 11.8.2.5. In addition, this same principle will apply to the application of the real-time performance metric as reflected in proposed Section 11.8.4.4.

To incorporate the application of the day-ahead metered energy adjustment factor, the ISO proposes to modify the existing definition for *Day-Ahead Metered Energy Adjustment* Factor to incorporate the principles described above. Also, the ISO proposes to add section 11.8.2.5 to describe the various scenarios in which it applies to the integrated forward market energy bid costs and market revenues. The ISO also

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75 *See* Exhibit ISO-No. 1 at 57-62.

proposes to add references to indicate the application of the day-ahead metered energy adjustment factor as follows: 1) in section 11.8.2 to indicate its general application to bid cost recovery; 2) in section 11.8.2.1.2 to indicate its application to the integrated forward market minimum load costs; 3) 11.8.2.1.2 (c) and (d) to indicate the application of the real-time performance metric in the cases specified therein instead of its application to the integrated forward market minimum load costs; 4) in section 11.8.2.1.5 to indicate its application to the integrated forward market energy bid costs; and 5) in 11.8.2.2 to indicate its application to the integrated forward market revenues.

5. A real-time performance metric must replace the existing real-time metered energy adjustment factor to ensure real-time bid cost recovery is scaled consistent with adherence to ISO instructions in the context of separate day-ahead and real-time bid cost recovery.

The ISO proposes to adopt a new real-time performance metric that will apply to scale bid cost payments in cases where a resource delivers less than its real-time ISO instruction, which includes instances in which incremental energy or decremented energy is under-delivered. This real-time performance metric would replace the existing real-time metered energy adjustment factor, which, similar to the current day-ahead metered energy adjustment factor, was adopted to adjust the accounting of a resource's bid cost and market revenues to ensure that the resource is only paid for their bid costs to the extent the resource actually delivers energy. Consistent with the ISO's proposal to separate the day-ahead and real-time bid cost recovery, it is necessary to also modify the application of the real-time metered energy adjustment factor because the current real-time metered energy adjustment factor scales real-time bid cost and revenue calculations based on the amount of energy the resource actually delivers, regardless of whether the resource is following ISO instructions. The ISO proposes instead to apply a performance metric to the real-time bid cost recovery calculations to scale the bid cost and market revenue calculations, and in some cases the residual unit commitment bid costs and revenues, in proportion to how closely a resource follows ISO real-time dispatch instructions.

The ISO proposes to apply the real-time performance metric to the integrated forward market minimum load cost calculations and incremental integrated forward market bid energy. Under the current market rules, in calculating the integrated forward market minimum load costs the ISO applies a tolerance band performance measurement that compares a resource's metered output with its minimum load to determine whether a resource should receive its integrated forward market minimum load costs. The tolerance band accounts for the minimum load costs so long as the resource reaches its minimum load within a 3 percent or 5 MWh tolerance band. The ISO intends to retain this tolerance band with one exception: the ISO will not apply the tolerance band in accounting for the integrated forward market minimum load costs if a resource is de-committed in the real-time market but was originally committed in the day-ahead market. In such cases, the ISO proposes to instead apply the real-time bid cost recovery performance metric to the integrated forward market minimum load cost.

The rationale for this rule is that the application of just the 3%/5MWh tolerance band could provide incentives not to follow ISO dispatch instructions to shut-down or stay off-line. By applying the real-time performance metric to the integrated forward market minimum load costs instead, elements of the bid cost recovery calculation will be scaled back if the resource were to disregard the ISO instruction to shut-down in real-time. It is also equitable to include minimum load costs in the day-ahead market bid cost recovery calculations in the event a resource is de-committed in real-time because the resource's savings in avoiding these costs are included in the real-time market bid cost recovery calculations.

For similar reasons, the ISO proposed to extend this principle to the settlement of integrated forward market energy bid costs. This proposed rule change is necessary because of an unexpected result in the application of the proposed day-ahead metered energy adjustment factor in cases where a resource is de-committed in the real-time market but was originally committed in the day-ahead market. Specifically, the ISO proposes to apply the real-time performance metric to the integrated forward market energy bid costs and related market revenues instead of the day-ahead metered energy adjustment factor to day-ahead energy bid cost and/or revenues in the case of an ISO-instructed decommitment. The real-time performance metric is more robust than the application of the day-ahead metered energy adjustment factor because the metric, unlike the factor, includes safeguards to reduce the costs considered in bid cost recovery if a resource either: 1) deviates in the opposite direction of the real-time dispatch; or 2) attempts to stay at its day-ahead schedule to hold on to its day-ahead bid cost recovery. These safeguards could potentially reduce the overall day-ahead bid cost recovery uplift to the resource if it does not following real-time decommitment instruction. The application of the day-ahead metered energy adjustment factor does not include these safeguards.

Similar to the ISO's application of the day-ahead metered energy adjustment factor, the ISO proposes to apply the real-time performance metric to the real-time energy bid cost and market revenues calculations pursuant to the four rules described above.

The real-time performance metric is also consistent with the principles articulated by the Commission in the MRTU 2006 Order. The metric will ensure a resource is paid its real-time minimum load costs to the extent the resource performs consistent with the ISO dispatch instructions.[76]

The ISO proposes the following tariff changes to incorporate the real-time performance metric. The ISO proposes to add new Section 11.8.4.4 to incorporate the

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[76] See footnote 72.

rules in applying the real-time performance metric. The ISO also proposes to add references to indicate the application of the real-time performance metric as follows: 1) to proposed section 11.8.2.1.2 (c) to indicate its application to the integrated forward market minimum load costs in the case the resource is decommitted from its day-ahead schedule and proposed section 11.8.2.1.2 (d) for similar treatment of multi-stage generating resources; 2) to section 11.8.2.1.5 to indicate its application to the integrated forward market energy bid cost; 3) proposed section 11.8.2.5 to indicate its application instead of the day-ahead metered energy adjustment factor in certain cases; 4) to section 11.8.3.1.2 to indicate its application to the residual unit commitment minimum load cost; 5) to section 11.8.4.1.2 to indicate its application to the real-time minimum load costs; and 6) section 11.8.4.1.5 to indicate its application to the real-time energy bid costs. The ISO also proposes to add the new definition *Real-Time Performance Metric* to describe the metric.

6. A tolerance band for day-ahead metered adjustment factor and real-time performance metric is necessary to avoid scaling bid cost recovery for deviations from ISO instructions due to legitimate operational constraints.

The ISO proposes to apply a tolerance band to both the day-ahead metered energy adjustment factor and the real-time performance metric. This is necessary to avoid reducing bid cost recovery payments for small deviations from dispatch that may legitimately occur due to ramping constraints or other such operational constraints.

The tolerance band will be bounded based on the highest of 3% of the resource maximum operating point, *i.e.*, Pmax and 5 MWh. The ISO proposes to use the same tolerance band currently in effect in the ISO tariff as a measure of consistency with market performance and justifiable deviations from ISO dispatch.[77] The ISO uses these thresholds for other operating performance by a generating resource such as when the plant-level or configuration-level minimum operating level has been achieved.

The performance metric will also not be calculated during the start-up, shut-down, transition periods from one configuration to another for a multi-stage generating resource, or a resource crosses over a forbidden operating region, as long as the resource is operating consistent with the ISO instruction. This is out of recognition that the output of a resource cannot be controlled exactly during these events. The ISO considers the time periods that the market uses in instructing those events. As long as the unit follows the instruction, there is no performance metric applied in these cases. The current rules for early or late start-up, shut-down, and transition still apply.

[77] *See* CAISO Tariff, Appendix A, *Tolerance Band*, existing defined term.

As part of the performance metric threshold, the ISO also proposes to include in the threshold an additional ramping tolerance amount. The ramping tolerance criterion is designed to accommodate instances in which the resource's ramp rate can change over the course of the interval. For example, when the ISO issues an instruction for a generator to ramp to a different output level, the expected energy based on the new target output level – the dispatch operating target – can differ from the expected energy based on the dispatch operating point which reflects the generator's actual expected incremental movements, minute-by-minute toward the target output level. This difference will exist whenever there is a ramp-rate change within the 5-minute interval window. Mr. Cooper explains how this can occur and provides a depiction of the variations that can occur. As discussed by Mr. Cooper, the ramping threshold will capture variations between total expected energy based on the dispatch operating target, and the total expected energy as calculated for use in energy settlement based on dispatch operating point reflecting the resource's actual position.[78]

The ISO proposes to incorporate the tolerance band by including a reference to its application in proposed sections 11.8.2.5.5 and 11.8.4.4.5. In addition, the ISO proposes to add a new defined term *Performance Metric Tolerance Band* in Appendix A to describe the tolerance band.

7. MSC Opinion.

a. Separation of bid cost recovery for day-ahead and real-time market.

As reflected in the discussion above, the MSC strongly supported the ISO's goal of encouraging economic bids that would allow for downward generation adjustments in response to negative real-time prices.[79] The MSC recognized that there are benefits to implementing both the separation of the day-ahead and real-time bid cost recovery processes and the reduction of the bid floor, as soon as possible. However, at the completion of the RIMPR 1 stakeholder process, the MSC raised a concern that together with decreases in the bid floor, the separation of the day-ahead and real-time bid cost recovery might increase gaming opportunities. At that time the ISO had proposed a performance metric and persistent uninstructed energy measure to address potential issues created by persistent deviations from ISO instruction directed at expanding bid cost recovery payments beyond their intended purpose. The MSC did not support the prior metric and recommended that the ISO take additional time to carefully test and ensure the proposed procedures before the ISO commits to adopting the separation of the bid cost recovery and lowering the bid floor. In response to MSC and stakeholder concerns, the ISO removed the elements of performance metric and

[78] *See* Exhibit ISO-No. 1 at 51-53.

[79] MSC Opinion, December 8, 2011, at 2.

persistent deviation check from the proposal it brought to its board for approval in December 2012 and commenced the BCR Mitigation Measures stakeholder process that led to the proposed changes in this tariff amendment.

b. Modifications to the metered energy adjustment factors.

In its final opinion on the BCR Mitigation Measures, the MSC also noted a concern with the application of the day-ahead metered energy adjustment factor to day-ahead energy schedules as proposed by the ISO at the time. The MSC believed that day-ahead schedules are only financially binding and the participant already faced the consequence having to replace any energy shortfall from day-ahead schedule with purchases in the real-time market based on real-time prices, regardless of whether it received bid cost recovery payments for the day-ahead. The MSC indicated that there is no economic reason for pro-rating the day-ahead bid costs in the bid cost recovery calculations for economic reasons, but agreed with the DMM that there may be reliability reasons for doing so.

In its December 5, 2012, opinion the MSC noted that the proration of day-ahead bid cost recovery when units underperform relative to their day-ahead schedules, may impose significant costs on resources that are uneconomically scheduled for energy above minimum load (which is what is subject to the day-ahead energy adjustment factor), beyond the cost of settling deviations between their day-ahead schedules and real-time output at the real-time price. The MSC recommended that if there is an issue in the ISO real-time prices such that settling deviations between day-ahead schedules and real-time output at real-time prices provides insufficient incentive for resources to adhere to their day-ahead schedules, then any changes to address such a reliability concern should be applied to all resources with day-ahead schedules, not just those who receive bid cost recovery because they were committed uneconomically in the day-ahead market. The ISO does not oppose the possible application of penalties for uninstructed deviations for all resources if warranted based on the performance of its fleet of resources. But in order to adopt such a penalty, the ISO and its stakeholders should analyze the impact of such deviations on other aspects of the ISO markets and operations, and more carefully consider the parameters to be used in any such metric to properly address any identified issues.

The ISO retained the proposal to apply the day-ahead metered energy adjustment factor as modified because it is necessary to safeguard against potential incentives to expand bid cost recovery payments through deviations from the day-ahead market. As discussed above, many of the principles embodied in the day-ahead metered energy adjustment factor were previously approved by the Commission for this reason. Moreover, the ISO believes that, consistent with FERC's September 2006 MRTU Order, the ISO should not pay bid cost recovery for dispatched energy that is not delivered. Ultimately, the MSC supported the ISO's modifications to the day-ahead metered energy adjustment factor, and in particular did so because it does not reduce day-ahead bid cost recovery in the event a resource is dispatched below its day-ahead schedule in real-time and the resource performs accordingly.

8. Issues raised by stakeholders.

a. Separation of the day-ahead and real-time bid cost recovery.

The separation of the day-ahead and real-time bid cost recovery settlement was largely support by stakeholders. Stakeholders also generally supported the modifications to the settlement of short-start and multi-stage generating resources and raised no objections to these two changes specifically. However, like the MSC, a number of stakeholders recommended that the separation of the bid cost recovery costs settlements should be considered in the context of additional analysis of the implications of this separation and any needed performance metrics necessary to address unintended consequences such as the expansion of bid cost recovery payments. For example, Pacific Gas & Electric (PG&E) supported separating day-ahead and real-time bid cost recovery but asked that these changes be considered as part of the Commission-ordered bid cost recovery stakeholder process to address additional bid cost recovery issues and that the ISO should not implement the bid cost recovery changes without considering the changes resulting from the Commission-ordered bid cost recovery stakeholder process. Similarly, SCE expressed its concern that because of the significant complexity of the bid cost recovery process the new proposals required more stakeholder process. Also, SCE did not support the prior implementation schedule where the ISO had proposed to implement the RIMPR 1 changes in spring of 2013.

As discussed above, at the completion of the RIMPR 1 stakeholder process, the ISO commenced an additional stakeholder process to address these specific concerns.[80] The ISO delayed the filing and the implementation of the old RIMPR 1 proposed changes until that stakeholder process was completed. While it is virtually impossible to identify and address all possible permutations of how the proposed rules can be manipulated, the ISO conducted a robust stakeholder process to address the issues identified.

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[80] While it was not clear from PG&Es comments, the ISO believes the Commission-ordered stakeholder process is the process ordered by the Commission in its May 4, 2011, order accepting the ISO's first of the two bid cost recovery emergency tariff amendments. *See* May 4, 2011 Order. That process was completed in 2012 and yielded the changes proposed to the Commission in FERC Docket No. ER13-2064, currently pending before the Commission. While the stakeholder process preceding the instant tariff amendment also addressed similar market behavior issues, the two processes were conducted at different times and in particular the Bid Cost Recovery Mitigation stakeholder process was initiated after the prior stakeholder process was completed.

Stakeholders also expressed concern that separation of the day-ahead and real-time bid cost recovery would result in an inappropriate increase in bid cost recovery costs that would overshadow any improvements in efficiency the ISO would gain from having greater real-time bids. Based on the concerns, the ISO conducted simulations to evaluate the likely impact this will have to bid cost recovery overall. This study and its findings are discussed by Mr. Cooper and were shared with market participants in Section 4.6 of the ISO's draft final proposal.[81] The ISO concluded that the separation of bid cost recovery for the day-ahead and real-time market could increase overall bid cost recovery payments by approximately 20 percent, at most.

While this number is not a *de minimis* amount, the findings of this study do not warrant abandoning the ISO's goal for separating the day-ahead and real-time bid cost recovery. As noted by the MSC, this estimate is based on the assumption that there would be no change in bidding behavior by market participants, which is a necessary assumption when trying to evaluate the impact of a rule change *per se*.[82] However, the whole point of the rule change is to incent different bidding behavior. As also noted by the MSC, if the rule changes are successful in eliciting more economic bids for reducing their output when prices are negative, bid cost recovery payments could actually *decrease*. At a minimum, they would not increase as much as 20 percent.[83] The ISO anticipates that the increase in decremental bids in the real-time expected with the change in market rules proposed in this tariff amendment will alleviate the reduce bid cost recovery payments overall because it anticipates fewer downward price spikes. In summary, the potential benefits of adopting the separation exceed the potential increase in bid cost recovery costs.

b. Modifications to the metered energy adjustment factors.

The ISO first introduced proposed modifications to its day-ahead and real-time scaling factors as part of the RIMPR 1 stakeholder process in 2011. Ultimately, stakeholders expressed wide support for the proposed measures.[84] Through multiple iterations of stakeholder comments, the ISO refined its proposal and ultimately developed the rules it now proposes in the instant filing. For example, the ISO adopted the tolerance band in applying the modified day-ahead metered energy adjustment factor in response to SCE's comments on the second revised draft final proposal.

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81 *See* Exhibit ISO-No. 1 at 23-25; and *See* RIMPR 1 Draft Final Proposal at p. 27.

82 MSC Opinion, December 8, 2011, at 10.

83 *See* Exhibit ISO-No. 1 at 23-25.

84 CDWR-SWP, Calpine, GenOn, NRG, PG&E, and Six Cities all essentially expressed support for the proposed modified day-ahead MEAF. SCE also expressed support for the intent of the modified day-ahead MEAF. WPTF did not oppose the application of the day-ahead metered energy adjustment factor and supported the ISO's modifications to it along the way.

SCE also raised a concern with the ISO's proposed application of the real-time performance metric in such a way that the real-time bid cost recovery is scaled only in proportion of the real-time dispatch by which the resource under-delivered energy and will not scale for over-delivery. In prior versions of the proposal, the ISO proposed to apply the metric to both over-delivery as well as under-delivery of energy relative to ISO dispatch. However, the ISO believed this was especially necessary to further its efforts to integrate renewable resources. In that regard, it is critically important to align incentives for dispatchable resources to meet and not to exceed ISO dispatch to reliably managing the grid under conditions where there is a high presence of highly variable generation and in situations of over-generation. Based on stakeholder feedback, the ISO modified its proposal recognizing that reducing bid cost recovery for over-delivery was not justified because resources are not eligible for bid cost recovery for over-delivered energy that is settled as uninstructed imbalance energy. The ISO believes such a broader penalty for deviations would be more broadly targeted at disincentivizing uninstructed deviations in general and should be considered separately.[85] SCE disagreed with this premise, noting that while uninstructed deviations are not eligible for bid cost recovery, they may have a material impact on reliability, which will become increasingly important with the integration of additional variable energy resources. The ISO maintains that scaling bid cost recovery payments for over-delivery of energy, when the over-delivered energy is not itself potentially eligible for bid cost recovery, is inconsistent with cost causation principles and the issues it sought to address in the stakeholder proceedings in support of the proposed changes.

PG&E also raised a concern that the proposed day-ahead modified metered energy adjustment factor would deviate from the proposed policy when a resource is dispatched downward to match its minimum load output, resulting in a modified day-ahead metered energy adjustment formula value of 0. PG&E noted that this would then remove the resource's ability to recover day-ahead bid cost recovery even when following CAISO dispatch instructions, counter to the stated policy. In response, the ISO proposes to specify in the defined term *Day-Ahead Metered Energy Adjustment Factor* that in cases where the day-ahead metered energy adjustment factor produces a result in which the numerator and denominator is equal to zero, the day-ahead metered energy adjustment factor will be set to 1. In addition, if the denominator produced is zero, but the numerator is a non-zero amount, the day-ahead metered energy adjustment factor will be set to zero.

SCE supported the intent of the day-ahead metered energy adjustment factor but expressed concerns that the modified day-ahead metered energy adjustment factor does not provide an accurate representation of the energy actually delivered. The ISO believes it has captured and addressed all the known anomalous outcomes that could

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85 *See* Comments by Calpine, GenOn, and NRG. Available at: http://www.caiso.com/Documents/Bid%20cost%20recovery%20mitigation%20measures%20-%20papers%20and%20proposals%7CStakeholder%20comments.

arise with the application of the day-ahead metered energy adjustment factor. But it agrees with SCE that the day-ahead metered energy adjustment factor should not have the effect of unjustly increasing bid cost recovery payments. The ISO and stakeholders will continue to evaluate the performance of the day-ahead metered energy adjustment factor in market simulations prior to the implementation.

However, the ISO recognizes that even after the implementation of the new market design, there could be unknown mathematical oddities that result in an outcome contrary to the intended purpose of the day-ahead metered energy adjustment factor, *i.e.*, limit bid cost recovery uplift payments to the amount of energy delivered consistent with ISO real-time dispatches, but not expand such payments beyond cost recovery amounts. In response, the ISO has proposed to add catch-all tariff language in Section 11.8.2.5 providing that the application of the day-ahead metered energy adjustment factor will not increase a bid cost recovery eligible resource's unrecovered bid cost uplift payments, if the ISO determines that it has due to the application of the factor, the ISO will adjust the payment to recover the overpayment, in a subsequent billing cycle as permissible under Section 11.29. During the tariff stakeholder process, stakeholders asked for clarifications to this proposed language but did not oppose the inclusion.

C. Refinements to The Bid Cost Recovery And Residual Imbalance Energy Payments.

The separation of the bid cost recovery between the day-ahead and real-time markets will increase the incentive for submitting economic bids to the real-time market. This is because by separating the bid cost recovery for the two markets, a resource's eligibility for real-time bid cost recovery in any given day is likely to increase. However, increasing resources' eligibility for real-time bid cost recovery can also provide an incentive for adverse market behavior because real-time bid cost recovery payments will no longer be reduced by revenues earned in excess of bid costs in the day-ahead market, and *vice versa*. As a result, as discussed by Mr. Cooper, resources can expand their bid cost recovery payments by persistently deviating from ISO instructions.[86] Therefore, the ISO is proposing several mitigation measures to eliminate the incentives to engage in such adverse market behavior. As discussed above, to address these concerns the ISO conducted an extended stakeholder process to address potential measures for bid cost recovery mitigation. Through this process the ISO was able to strike a balance between dissuading participants from engaging in adverse behavior and ensuring resources are not unfairly penalized for inadvertent deviations that force the resource to forfeit their bid cost recovery. Such draconian measures would eliminate the very incentives for increased real-time economic bids the ISO is striving to implement as a result of increased entry of variable energy resources. Therefore, the proposed rules discussed below recognize that some forms of deviations do not warrant mitigation.

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[86] *See* Exhibit ISO-No. 1 at 62-65.

The ISO will flag each interval in which changes in the resources metered amounts deviate from the changes in output instructed by the ISO a prescribed tolerance amount, described further below. The tolerance amount is what is referred to as the persistent deviation metric, which is based on the number of flagged intervals within a two hour moving time window and is categorized into two zones: (1) equal to or below a low threshold of flagged intervals (3 intervals), the deviations are forgiven; but (2) equal to or above a certain upper threshold (4 intervals), deviations are deemed persistent. For the intervals deemed persistent, the mitigation is applied to all bid cost recovery calculations within the entire two hour window. As discussed below, the ISO proposes a new mitigation measure of real-time bid cost recovery payments and residual imbalance energy when these intervals are flagged by this criteria.

The ISO's market experience over the past two years dealing with market behavior designed to unjustly expand bid cost recovery payments demonstrates the need for measures to eliminate incentives for resources to engage in market behavior that is not otherwise rational but for the purpose of expanding uplift payments such as bid cost recovery payments and residual imbalance energy payments.[87] FERC has previously stipulated that it limits mitigation to circumstances in which the potential to exercise market has been shown.[88] As discussed by Mr. Cooper and further below, there is sufficient evidence that parties if left unaddressed, parties will have the incentive to engage in persistent deviations to expand bid cost recovery payments and residual imbalance energy payments.

1. Proposed changes needed to address potential to expand bid cost recovery payments similar to expansion of residual imbalance energy payments identified in the August 2012 emergency filing.

The ISO made an emergency filing in August of 2012 to address the potential that market participants could inflate their residual imbalance energy payments by submitting high-priced bids associated with over-generation under the then current market design.[89] The ISO determined that a similar potential remains to inflate bid cost recovery payments by persistently over-generating. However, the ISO did not at that time propose changes to eliminate the potential expansion of bid cost recovery payments because under the current market design the potential to inflate bid cost recovery payments is limited by the fact that real-time market revenue shortfalls are

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87 *See* May 4, 2011 Order and August 19, 2011 Order.

88 *California Indep. Sys. Operator Corp.*, 141 FERC ¶ 61,069 at 3 (2012); *citing* Market Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008).

89 *See* October 26, 2012 Order.

netted against day-ahead surpluses, and *vice versa*. The netting of costs and revenues across markets dampens any excess and inappropriate profits a market participant might gain through this strategy. However, in the process of considering the RIMPR 1 changes, the ISO recognized that these adverse incentives are increased with the separation of day-ahead and real-time bid cost recovery.

Despite the existence of this current protection, the ISO continues to monitor bid cost recovery payments and stands prepared to seek necessary relief even under the current market design should the need arise. In light of the deferral of RIMPR 1/BCR Mitigation Measures to spring of 2014, the ISO will continue to monitor the persistent deviations as an indicator of adverse market behavior that may need to be addressed before then.

2. The potential to expand payment for residual imbalance energy requires mitigation when resources are persistently deviated from dispatch instructions.

In the case of residual imbalance energy, the ISO modified the settlement rules last year to ensure that resources could not expand their payments by persistently deviating in the real-time. Residual imbalance energy is a real-time market settlement provision that settles energy attributable to ramping down from a dispatched bid at the end of a previous hour or ramping up to a bid dispatched at the beginning of an upcoming hour. In other words, residual imbalance energy occurs as a resource is ramping into or out of an hour per a dispatch in that hour. Prior to the August 2012 filing, residual imbalance energy was settled at the bid that a resource was being ramped down from or up to the adjacent hour's dispatch level (this bid is referred to as the "reference hour bid"). The ISO's August 28, 2012 amendment modified the settlement so that residual imbalance energy is currently settled as follows:
(1) incremental residual imbalance energy (*i.e.*, above day-ahead scheduled energy) is settled at the greater of (1) the dispatch-interval locational marginal price, or (2) the lessor of (a) the resource's default energy bid price or (b) its reference hour bid price.
(2) decremental residual imbalance energy (*i.e.*, below day-ahead scheduled energy) is settled at the lesser of (1) the dispatch-interval locational marginal price, or (2) the greater of (a) the resource's default energy bid price, or (b) its reference hour bid price.

The Commission accepted the ISO's amendment in its October 26 Order, but encouraged the ISO to work with stakeholders to develop a long-term solution for the settlement of residual imbalance energy. In the stakeholder process preceding the proposed tariff amendments, the ISO developed a solution to address persistent deviations more globally and, therefore, proposes again to modify the settlement of residual imbalance energy.

Specifically, the ISO proposes to undo the changes it previously made and proposes to again settle residual imbalance energy based on the reference bid that led to incur this energy. When a resource does deviate beyond the persistent deviation metric and threshold, the ISO will adjust the settlement of residual imbalance energy as follows: (1) incremental residual imbalance energy will be settled on minimum of (a) the default energy bid, (b) the bid price in the relevant reference bid that led to the residual imbalance energy, or (c) the locational marginal price; and (2) decremental residual imbalance energy will be settled on the maximum of (a) the default energy bid, (b) the bid price in the relevant reference bid that led to the residual imbalance energy, or (c) the locational marginal price. If the bid that led to the residual imbalance energy was mitigated, that mitigated bid will be used as the relevant bid price.[90]

The ISO also proposes that the definition of the reference hour bid for residual imbalance energy be changed to specify that it is the bid that led to the dispatch that a resource is being ramped down from or up to rather than the bid in the adjacent hour that a resource is ramping down from or up to. This is to address the concern that low bids that lead the real-time market to dispatch a resource up followed by high bids leading the real-time market to dispatch the resource down can inflate residual imbalance energy payments in the event the ramp limitations of the unit require it to ramp down for more than one hour. Mr. Cooper explains these circumstances in more detail.[91] The ISO had not proposed to mitigate residual imbalance energy for this purpose in its August 2012 emergency filing because it had not observed such behavior that warranted immediate emergency measures. Therefore, it is now necessary to eliminate these incentives.

To incorporate these rule changes, the ISO proposes modifications to section 11.5.5 that reinstates the language that applied prior to the August 2012 emergency filing and defines further the reference hour bid. The ISO also cross references in section 11.5.5 the application of the persistent deviation metric in proposed section 11.17.

3. Bid cost recovery cost-based compensation when resources are found to be persistently deviating.

The ISO proposes that for resources that fail the persistent deviation metric threshold described below, the ISO will calculate the real-time energy bid costs as follows: (1) the bid basis for incremental optimal energy (*i.e.*, above the day-ahead scheduled energy) for real-time bid cost recovery will be based the minimum of the resource's default energy bid, their submitted bid price or the locational marginal price cleared in the ISO markets; (2) the bid basis for decremental optimal energy (*i.e.*, below

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90 For dynamic system resources, which not subject to local market power mitigation, because they are allowed to negotiate default energy bids, those will be used if they trigger the persistent deviation metric.

91 *See* Exhibit ISO-No. 1 at 82-84.

the day-ahead scheduled energy) will be the maximum of the resource's default energy bid, their submitted bid price or the locational marginal price cleared in the ISO markets.

The ISO proposes modifications to section 11.8.4.1.5 to indicate the application of the real-time persistent deviation metric. In proposed section 11.17, the ISO proposes to include language that defines the persistent deviation metric and in Section 11.17.1.2 specifically it proposes the specific bid-basis on which it will calculate the real-time bid cost recovery in Section 11.8.4.1.5 or the residual imbalance energy in Section 11.5.5.

4. The proposed persistent deviation metric and the threshold rules provide sufficient disincentives for persistent deviations and are not overly punitive toward deviations that result from normal operational constraints.

As discussed in greater length by Mr. Cooper and below, a resource can inflate its real-time bid cost recovery or residual imbalance energy payments by over-generating in real-time when it is operating above its day-ahead schedule.[92] Similarly, it can increase its real-time bid cost recovery payments or decrease the amount it has to pay for negative residual imbalance energy by under-generating when it is operating under its day-ahead schedule. The proposed persistent deviation metric is designed to evaluate a resource's change in output between settlement intervals relative to the amount the ISO dispatched it down between settlement intervals.

The persistent deviation metric will compare the amount the real-time market dispatches a resource down or up in an interval compared to the amount the resource moves down or up. The persistent deviation metric for each settlement interval will be the ratio of (1) the resource's metered energy in the prior interval minus the metered energy in the instant interval; and 2) the metered energy in the prior interval minus the resources total expected energy in the instant interval. The ISO will calculate the persistent deviation metric for each resource for each settlement interval. The ISO will flag a settlement interval if the deviation is in a direction that would inflate bid cost recovery or residual imbalance energy and the metric exceed a threshold, consisting of the following two conditions:

First, a resource cannot deviate from its dispatched change in output level by more than 10% of the dispatched change in output level. For example, if a resource is dispatched to decrease its output by 50 MW in a settlement interval, the settlement interval would be flagged if the resource did not reduce its output by at least 45 MW (*i.e.*, the resource over-generated by more than 5 MW).

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92 *See* Exhibit ISO-No. 1 at 62-64.

Second, the settlement interval will only be flagged under the preceding criteria if the deviation is greater than 10% of its ramp capability over the 10-minute interval. For example, a resource that has a 5 MW/minute ramp rate and can ramp 50 MW over a 10-minute settlement interval will not have settlement intervals flagged for deviations 5 MW or less (50 MW multiplied by 10%). This will avoid triggering the persistent deviation metric for small deviations from small dispatched changes to output level. Mr. Cooper describes in greater detail the cases in which the persistent deviation metric would be evaluated.[93]

The ISO will employ the persistent metric evaluation criteria to determine whether a resource has persistently deviated in a manner that inflated bid cost recovery or residual imbalance energy payments. Therefore, the metric is designed to look at the persistent deviations over a rolling two-hour window, *i.e.*, it will be applied for the twelve ten-minute settlement intervals that comprise the previous two hours, incrementing in hourly intervals.

The ISO will apply the following rules to determine whether the mitigation described in the two conditions above will apply. First, if 3 or fewer intervals out of the previous 12 intervals are flagged as exceeding the persistent deviation metric threshold, the mitigation described above for residual imbalance energy and bid cost recovery will not apply. Second, if 4 or more intervals of the previous 12 intervals are flagged as exceeding the persistent deviation metric threshold, then the mitigation described above for residual imbalance energy and bid cost recovery will apply for all the previous 12 intervals in the window. Third, once an interval is flagged as exceeding the persistent deviation metric threshold, it remains so when it is considered in the evaluation of the following evaluation window. Fourth, once an interval's bid basis has been determined by the second rule, its bid base will not change in later evaluation. However, if an interval's bid base is determined by the first rule in a previous evaluation, it can be re-determined by the second in the next evaluation.

In its December 4, 2012, comments on the ISO's draft final proposal, DMM provided a numerical example of a scenario under which it found it would still be relatively profitable for a generating unit to routinely deviate from ISO dispatch instructions under the ISO's prior proposal.[94] DMM noted that the ISO's final proposal as revised significantly reduces the potential profits from this scenario. The two modifications that it noted provided these benefits were: 1) reducing, from 4 to 3, the number of settlement intervals a resource can deviate during a two-hour period before triggering mitigation for the entire period; and 2) eliminating an intermediate deviation

93 *See* Exhibit ISO-No. 1 at 66-70.

94 http://www.caiso.com/Documents/DMM_CommentsThirdRevisedDraftFinalProposalBidCostRecoveryMitigationMeasuresDec5_2012.pdf.

zone rule that would only mitigate for intervals in which significant deviation occurred, rather than the entire two-hour period. DMM commented that these modifications make the proposal simpler and more effective, and effectively mitigates potential abuses of settlement rules for real-time bid cost recovery and residual imbalance energy, without being overly complex or diminishing incentives to actively participate in the real-time market. DMM provided an analysis to assess the potential profitability for a generating unit to routinely deviate from ISO dispatch instructions under the proposed settlement rules. DMM supported the final proposal but recommended that the ISO monitor the effectiveness of this approach on an ongoing basis.

The ISO has estimated the effect of the application of the persistent deviation metric using market data for September 2012, which demonstrates that the metric and thresholds are not overly broad to unfairly eliminate payments. The results are described by Mr. Cooper.[95] The results of the analysis based on the sample data indicate that 97.5% of resource-hours had 3 or fewer flagged settlement intervals.

The ISO proposes to include section 11.17 to incorporate the details of the persistent deviation metric and the mitigation it will apply when the metric is triggered.

5. MSC Opinion.

As noted above, various forms of the performance metrics were discussed in numerous MSC public meetings, and the ISO adopted many of MSC's recommendations, as appropriate. On May 7, 2012, the MSC provided an opinion on the ISO's proposals on bid cost recovery mitigation based on the ISO's April 6 draft final proposal for BCR mitigation. The MSC expressed its support for the major features of the bid cost recovery mechanism, including the modified day-ahead metered energy adjustment factor and the real-time performance metric. The MSC supported the ISO's proposal to scale components of the bid cost recovery calculation based upon deviations from ISO dispatch instructions. However, The MSC raised some concerns with the intermediate proposal arguing that the measures should be carefully drafted to "effectively guard against intentional inflation of BCR payments arising from unscheduled output," whilst avoiding penalizing "innocent behavior by prorating BCR payments in response to normal scheduling inaccuracies or errors in a way that would undermine the goal of encouraging more resources to participate in the real-time dispatch." The MSC stressed the need to address this through a persistent deviation metric, which is reflected in the instant proposal.

The MSC supported the ISO's evolution of the proposed application of the persistent deviation metric so that only deviations identified as persistent uninstructed deviations would be excluded. The MSC noted that this makes the penalty more

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95 *See* Exhibit ISO-No. 1 at 72.

proportionate to the impact of the potentially intentional over-generation, and will avoid the possible problem that might arise from incenting generators to skew somewhat towards under-generating in order to avoid the risk of losing all energy bid cost recovery.

On December 5, 2012, the MSC supported the ISO's final proposal and commended the ISO in adopting a more simple and transparent approach to monitoring persistent real-time deviation from dispatch instruction.[96] The MSC expressed a concern that the proposed persistent deviation metric in certain intervals will not incur any penalty and yet it produces a strip of excess energy that will be remunerated as-bid. The MSC noted that the original persistent uninstructed imbalance energy proposal attempted to address such behavior. Nevertheless, the MSC supported the metric proposed in the instant filing because the prior metric was too complex and non-transparent. The MSC supports this simpler approach in spite of this limitation because the MSC believes it is not clear that in practice such bidding and operating strategy can be profitably applied within the thresholds of the ISO proposal. In addition, the MSC recommended vigilant monitoring to detect the use of such multi-period deviation strategies and that, if they materialize, an adjustment of parameters may be required or the entire approach may need to be revisited and modified.

The MSC also commented that the choice of parameters such as the 10% tolerance band and the upper and lower thresholds for the deviation persistency metric is *ad hoc*. The MSC believed that the ultimate goal of these parameter choices should be to strike a balance between the economic consequences of errors in mitigation that may over mitigate and thereby deter participation in the real-time market versus errors that miss adverse behavior that results in inflated bid cost recovery payments. Therefore, the MSC recommended that the implementation of the proposed methodology be monitored closely over a trial period of one year, and that the setting of the parameters be re-evaluated at the end of that period based on statistical evidence regarding real-time market participation, frequency of mitigation and real-time bid cost recovery payments. The ISO agrees with this recommendation and after the first year the metric is in effect, the ISO will share and discuss this information with stakeholders and develop any necessary parameter changes.

Finally, the MSC also supports the ISO's approach to only flag deviations that have the potential to inflate bid cost recovery payments as an appropriate balance.

96 *See* MSC Opinion, December 5, 2012, at 1.

6. Issues raised by stakeholders.

While the design and application of the persistent deviation metric was strongly supported by some stakeholders,[97] a small number of stakeholders raised issues with it. The simplification of the metric in its current proposed form was a product of modifications in response to stakeholder concerns over the difficulty to decipher and shadow the results of the metric the ISO initially proposed. The ISO also made many refinements to address concerns that the measures may be overly punitive. For example, initially, the ISO contemplated using the maximum of the default energy bid or the locational marginal price for the extra-marginal bid segments as a resource's cost in the bid cost recovery calculations as a means to mitigate expansion of bid cost recovery by persistent deviations. In response to stakeholder concerns and feedback from the MSC, the ISO significantly revised this element of the proposal so that bid cost recovery and settlement of residual imbalance energy could be based on the submitted bid as mitigated if it is lower than the default energy bid or locational marginal price.

In response to a concern raised by GenOn, the ISO clarified that minimum load energy associated with residual unit commitment is included in real-time bid cost recovery and is, therefore, subject to the real-time performance metric. The reason for this is that, when a resource is committed in the residual unit commitment process, the minimum load energy is part of the bid cost recovery calculations for the real-time market, and real-time market bid cost recovery is subject to the real-time performance metric. The rationale for grouping the residual unit commitment process and real-time together, which was discussed as part of the RIMPR Phase 1 stakeholder initiative, is that residual unit commitments are made based on forecasted real-time conditions. Therefore, these two features of the ISO proposal are linked in a fundamental way.

In earlier versions of the proposed persistent deviation metric, the ISO proposed that the bid costs and settlement of residual imbalance energy would be settled as described above if three or four intervals of the previous 12 intervals are flagged as exceeding the persistent deviation metric threshold. In response to stakeholder comments, the ISO modified these criteria so that four or more intervals needed to be triggered to apply the mitigation. With this change, payments will be reduced when deviations from ISO dispatch are persistent and would inappropriately inflate the bid cost recovery payments, while ensuring that when a resource is not persistently deviating the resource's bid cost recovery payments are not withdrawn.

Some stakeholders expressed concerns regarding the application of the persistent deviation metric. For example, although Calpine states it appreciated the ISO's attempt to separate the "deviants" from the innocent, the ISO should ensure that a significant majority of transactions have their bids honored and fully compensated –

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[97] *See* PG&E Comments, SCE Comments, and Six Cities Comments.

through the formation of locational marginal prices, and if not, through the mechanisms of bid cost recovery. The Western Power Trading Forum (WPTF) also expressed their support for moving away from earlier more stringent designs and asked for additional assurances that the thresholds are appropriately set to achieve the same balance articulated by Calpine. In principle, however, WPTF argued that if performance metrics are needed they should be applied generally, and not through the bid cost recovery mechanism. Calpine also contended that the rolling two-hour window and the administrative limits for violations have no basis. WPTF asked that the ISO provide further technical consideration as part of the tariff language drafting.

The ISO understands that there may be a need to refine the thresholds over time based on its evaluation of the application. The ISO made various refinements to ensure the metric is narrowly tailored to dissuade adverse behavior that could expand bid cost recovery payments. For example, the ISO modified the metric so that the mitigated settlement is triggered if the resource deviates in four or more intervals in the two-hour rolling window. As discussed above, this was expanded to ensure the resources are mitigated only if the deviation can expand bid cost recovery payments.

Recognizing the need to possibly fine tune the metric after it has been employed for some time, the ISO has adopted the MSC's recommendation and has committed to evaluate the thresholds after a year's worth of data on its performance has been collected and make any proper modifications.

Calpine is also concerned that the development cost of programming the metric from the stakeholder side might be much higher than the actual cost of the offense. WPTF shared Calpine's concerns with shadowing the metric. To reduce the costs of programming the metric, the ISO has provided the details of the design for market participants so that it can be more readily incorporated into their shadow systems. This will enable resources to track the ISO's application of the metric over time and be able to take corrective preventative actions to avoid accumulating the penalty at later times.

Calpine also raised a concern that the proposal discriminates between static imports and internal generation because it introduces a cost risk that does not apply to static imports. The concern over the discrimination between internal resources and static schedules is unwarranted because they are not similarly situated. Static hourly schedules are not dispatched in five-minute intervals and not dispatched from their current operating point so they are not able to expand bid cost recovery by persistently deviating.

D. Alignment of Bid Cost Recovery and Residual Imbalance Energy Payments.

1. It is necessary to align bid cost recovery for ramping energy to or from an exceptional dispatch with the settlement of exceptional

dispatch to avoid bid cost recovery of unmitigated bid prices when the exceptional dispatch itself was mitigated.

The ISO's current market rules contain provisions to mitigate the price paid to resources dispatched through exceptional dispatch under certain non-competitive conditions.[98] The ISO now proposes to add rules to align the settlement of exceptional dispatch and the ramping energy going into and out of that exceptional dispatch. This alignment is necessary and important because, under the current settlement provisions, a resource that received an exceptional dispatch to increase output could receive bid cost recovery or residual imbalance energy payments at an unmitigated price when the resource is ramping back down after the exceptional dispatch has ended that was itself mitigated.

The ISO proposes that energy during the ramp-down intervals have the same bid cost used in the bid cost recovery calculation as is used for the exceptional dispatch. This effectively treats the ramping energy the same as exceptional dispatch energy. The "bid basis" means that the bid used for the energy bid cost recovery payment in the current ramping interval is the same bid used in the calculation of the exceptional dispatch payment for the reference exceptional dispatch interval.

The ISO proposes modifications to section 11.8.4.1.5 to incorporate this requirement.

2. It is necessary to align the settlement for bid cost recovery for resources ramping up to or down from a minimum load re-rate.

The ISO proposes to adopt additional settlement rules to align the settlement of minimum load with the ramping energy going into and out of a minimum load re-rate. During the stakeholder process, the ISO determined that the ramping energy associated with a minimum load re-rate should be treated the same in the bid cost recovery calculations as the energy produced during the period of the minimum load re-rate. Mr. Cooper describes the nature of this inconsistency.[99]

To make the settlement consistent, the ISO proposes that in settlement intervals where a resource re-rates up its minimum load, the ISO will calculate the energy bid costs on the basis of the applicable locational marginal process as opposed to using the reference bid. This will effectively make the resource a price taker (*i.e.*, not pay bid cost recovery) for the intervals in which it incurs energy for ramping up to its temporary minimum load level, and then back out of that level after the re-rate has ended. This proposal aligns bid cost recovery payments between the period of the minimum load re-

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[98] *See* CAISO Tariff Section 39.10.

[99] *See* Exhibit ISO-No. 1 at 76-77 and 85.

rate and the energy ramping up to and down from that re-rate. It is important to note that the effecting ramping energy intra-hour remains part of the bid cost recovery calculations and therefore the associated market revenues are used to offset the resource's bid cost recovery for the applicable day.

Similarly, the ISO proposes that, when the ramp down period after a re-rate ends extends past the end of an hour, the residual imbalance energy during the ramp-down period is paid at the locational marginal price.

The ISO proposes modifications to section 11.8.4.1.5 to incorporate this requirement.

3. Minimum load cost recovery should be limited if resources avoid start-up and shut-down instructions for the sole purpose of earning minimum load cost recovery.

The ISO proposes to mitigate minimum load cost recovery in cases where resources generate at a level above their real-time dispatch instructions to avoid a shut-down instruction by the ISO in an effort to recover minimum load cost when the real-time market shuts the unit down. The ISO determined that a generator could position itself consistently at a MW level from which it takes more than one real-time pre-dispatch fifteen-minute interval to ramp down the minimum load level for shut-down. By doing so, the generator can avoid a binding shut-down instruction issued through the real-time unit commitment process and thereby continue to be online at a level above the minimum load. Mr. Cooper explains how this can occur.[100] This creates perverse incentives to not follow an ISO instruction in order to obtain uplift payments that are not reflective of the ISO's economic dispatches.

While this can occur today, because under the existing settlement rules the ISO nets the bid costs and market revenues across the day-ahead and real-time market, the profits earned in the real-time will have a greater chance of offsetting profits earned in the day-ahead market. However, with the separation of the day-ahead and real-time bid cost recovery, resources have a greater incentive to engage in such behavior. Therefore, the ISO proposes to implement this rule change concurrent to the adoption of separate bid cost recovery for the integrated forward market and the real-time market, but stands prepared to act sooner if the need to do so materializes.

The ISO also proposes to calculate a shut-down instruction state variable. This state variable will track positive uninstructed imbalance energy once an advisory shut-down instruction is issued. In so doing, the shut-down instruction state variable will yield the MW level had the generator followed the instruction. Mr. Cooper describes the

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[100] *See* Exhibit ISO-No. 1 at 77-79.

shutdown variable in greater detail.[101] Minimum load costs will be disqualified (that is, not included) in the day-ahead bid cost recovery calculation if the resource was committed in the day-ahead, and minimum load costs will be excluded from the real-time bid cost recovery calculation, if the thresholds are triggered.

In addition, under the current rules, a resource may not follow a binding shut-down instruction it receives through the ISO's automatic dispatch signal, yet continue to be eligible to receive minimum load costs through bid cost recovery. To address this, the ISO proposes that, if the ISO issues a binding shut-down instruction through its automatic dispatch signal, the resource will not be eligible for recovery of minimum load costs from the point of the shut-down instruction forward for the maximum of the duration of the resource's registered minimum down time. In addition, the ISO proposes that, if a resource ignores the binding shut-down issued by the ISO through its automatic dispatch signal in the real-time and it has a day-ahead schedule, the resource will not be eligible for minimum load cost recovery in the day-ahead bid cost recovery calculation for the minimum of 1) the resource's minimum down time, and 2) the day-ahead commitment period.

The ISO also proposes to clarify that a period in which a resource starts up without an ISO instruction to do so will not be considered an ISO commitment period, and thus the resource will not be eligible for cost recovery. This change is proposed in order to forestall a market participant from starting up a resource and running at minimum load in order to receive minimum load cost recovery. Consistent with existing ISO tariff rules, only the time period in which the ISO has committed the resource economically will be considered an ISO commitment period.

Finally, the ISO also proposes that once a resource receives a shut-down instruction in the real-time market, any integrated forward market or real-time market energy bid cost recovery that may otherwise apply pursuant to the rules in Section 11.8 will be based on the relevant energy bid price, as mitigated, that was considered by the real-time market in making the decision to shut down the resource for the length of time defined by the greater of (a) the resource's Minimum Down Time or (b) the period in which it is off after the shut-down time, which is not to exceed the end of the trading day. This additional rule is necessary because once a resource receives a shut-down and it is prevented from starting again for physical characteristics, such as a minimum down time; there is no economic reason for the resource to change its bids. In addition, changing its bid in such scenarios could be used to artificially inflate the resource's bid cost recovery. If the resource lowers its bid in the subsequent intervals, the optimization will not dispatch the resource because of its physical limitation and the bid cost recovery calculations would calculate a shortfall to be accounted for in the bid cost recovery. Mr. Cooper provides an example of this in his testimony. By basing the resource's bid

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[101] *Id*.

cost recovery on the bid used in the initial shut-down decision, there is no incentive to change its bid for the sole purpose of expanding its bid cost recovery payments.

The ISO proposes to add new section 11.17.2 to incorporate these rule changes.

4. Issues raised by stakeholders.

Stakeholders generally supported or did not oppose these proposed changes. SCE commented that it considers exceptional dispatches as uneconomic out-of-market dispatches that do not participate in market price formation, and as such, exceptional dispatches merit as-bid pricing and not the ISO's proposal to use the exceptional dispatch bid as the cost basis in the bid cost recovery calculations for ramping energy associated with exceptional dispatches. SCE recommended that all exceptional dispatches including the ramping energy associated with them, always be mitigated to the higher of the default energy bid or locational marginal price.

This concern does not pertain to the changes the ISO stakeholder and considered in the stakeholder processes preceding this tariff amendment. The ISO is not proposing any changes to the existing exceptional dispatch mitigation rules. Rather, the ISO only proposes to align the bid cost recovery rules associated with the ramping energy produced pursuant to or preceding an exceptional dispatch. As explained above, the alignment is necessary to ensure that if the resource's exceptional dispatch bid is mitigated, the bid basis for the consequential optimal energy produced is the same bid. Under the current rules, exceptional dispatches, subject to certain exceptions, are generally settled based on the higher of the 1) applicable locational marginal price, 2) the energy bid price or 3) the default energy bid price if the resource has been mitigated in the real-time market. The ISO and stakeholders did not evaluate these rules in either of the two stakeholder processes, and any changes should be considered after careful evaluation and coordination with stakeholders.

IV. EFFECTIVE DATES AND REQUEST FOR ORDER

The ISO requests an effective date of April 1, 2014, for the proposed tariff amendments. Because the requested effective date will be more than one-hundred and twenty days after the date this tariff amendment is filed with the Commission, the ISO requests a waiver of Section 35.3 of the Commission's regulations.[102] As discussed further below, good cause exists for granting this waiver. In addition, the ISO respectfully requests that the Commission issue an order no later than November 27, 2013. A timely order is necessary to facilitate the ISO and market participant's implementation of system changes necessary to accommodate the proposed changes in the context of additional market design changes incorporating fifteen-minute scheduling and settlement of energy in the real-time market.

[102] 18 C.F.R. § 35.3 (2013).

The changes proposed herein are part of a comprehensive set of market design adjustments made to facilitate the economic and reliable integration of variable energy resources in the ISO market. Recognizing that industry and policy trends were likely to significantly alter the fleet of resources under the ISO's control, the ISO launched an extensive effort to evaluate its market rules less than two years after it began operations under its new locational marginal price market on April 1, 2009. The ISO identified the need for market design changes to create greater real-time flexibility so that variable resources are given the opportunity to participate more economically and other resources are incentivized to provide greater real-time flexibility. These efforts were significantly bolstered with the Commission's issuance of Order No. 764, requiring that all transmission providers make available fifteen-minute scheduling. The presence of fifteen minute intertie schedules in the ISO market required careful consideration of the real-time pricing and settlement intervals. Recognizing the importance of moving in this direction and the benefits such improvements would provide to the ISO market, the ISO redirected its efforts and concentrated on developing a new fifteen-minute market in which all energy schedules are cleared. This important effort is also scheduled to be launched on April 1, 2014, and the ISO will be submitting the tariff amendment in support of that effort later this year.

The ISO has also entered into an agreement with PacifiCorp to specify the[103] terms under which the ISO will modify and extend its existing real-time energy market systems to provide energy imbalance market service to PacifiCorp, including transmission customers taking transmission service under PacifiCorp's open access transmission tariff. The ISO is currently conducting a stakeholder process to design the energy imbalance market and establish its governing market rules. This new energy imbalance market is scheduled to commence on October 1, 2014, and the ISO will be making additional filings seeking Commission-approval of the rules of the expanded energy imbalance market and the terms of participation in the market.

The ISO and market participants are working on a rigorous schedule to implement these enhancements in time with the charted efforts. The ISO is therefore filing early and asking for an order no later than November 27, 2013, to facilitate the implementation of these significant software and system development efforts. In order to activate the code on production on April 1, 2014, the ISO must push the code onto a production platform in a deactivated state at least two weeks in advance of the effective date, due to the number of software drops involved in the spring release. Currently, the ISO estimates to have five different software drops of this nature at that time. This means that the ISO must maintain the software on its live-track staging system by the 1st of March and for two weeks to perform load and performance testing as well as final regression testing. The current plan is for market simulation to start in February for the

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[103] *See California Indep. Sys. Operator Corp.*, 143 FERC ¶ 61,298 (2013).

spring release, which will last for about a four-week period. To achieve this goal, the ISO's software vendor must have the code developed and delivered at least six weeks before market simulation begins, which is approximately in mid-December 2013. During this six-week period, the ISO must have functional testing, end-to-end system integration, and settlement testing done before it starts the market simulation. An order by the last quarter of November will provide some time for the ISO and its vendor to consider changes that might have to be made as a result of the Commission's order. While this three-week period is limited, it is important to have at least that amount of time to consider the changes and implement them into the software to ensure market simulations are consistent with the rules that will be in place when these amendments become effective.

V. COMMUNICATIONS

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

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VI. SERVICE

The ISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission and the California Energy Commission, and all parties with effective Scheduling Coordinator Service Agreements under the ISO Tariff. In addition, the ISO is posting this transmittal letter and all attachments on the ISO website.

VII. ATTACHMENTS

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

Attachment A Revised ISO Tariff Sheets – Clean

Attachment B	Revised ISO Tariff Sheets – Blackline
Attachment C	ISO's 20% RPS Study
Attachment D	Graph entitled "Frequency of Real-Time Prices By Range – January 2010 to June 2011."
Attachment E	ISO's Market Surveillance Committee, *Final Opinion on Integration: Market and Product Review, Phase 1,* issued December 8, 2011.
Attachment F	Comments on Renewable Integration Product and Market Review: Fourth Revised Draft Straw Proposal, Department of Market Monitoring (Nov. 17, 2011); Comments from the Department of Market Monitoring on Renewable Integration: Product and Market Fourth Revised Draft Straw Proposal (Sept. 13, 2011).
Attachment G	Memorandum and Presentation to the ISO Board of Governors, both entitled *Decision on Renewable Integration - Market and Product Review Phase 1*; and matrix summarizing stakeholder comments.
Attachment H	ISO's Market Surveillance Committee, *Bid Cost Recovery Mitigation Measures and Commitment Costs Refinement,* issued May 7, 2012.
Attachment I	ISO's Market Surveillance Committee, *Opinion on Mitigation Measures for Bid Cost Recovery,* issued December 5, 2012.
Attachment J	Department of Market Monitoring, *Comments on Bid Cost Recovery Mitigation Measures, Second Revised Draft Final Proposal,* November 14, 2012.
Attachment K	Department of Market Monitoring, *Comments on Bid Cost Recovery Mitigation Measures, Third Revised Draft Final Proposal*, December 4, 2012.
Attachment L	Department of Market Monitoring, *Comments on Bid Cost Recovery Mitigation Measures, Revised Draft Final Proposal*, October 1, 2012.

Attachment M	Memorandum to the ISO Board of Governors entitled *Decision on Enhancements to Improve Price Consistency*, October 25, 2012.
Attachment N	Table: Description of Proposed Tariff Changes
Attachment O	Testimony of Bradford Cooper, Exhibit No. ISO-1

VIII. CONCLUSION

For the foregoing reasons, the ISO respectfully requests that the Commission approve this tariff revision as filed. Please contact the undersigned if you have any questions concerning this matter.

Respectfully submitted,

/s/Anna A. McKenna

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Dated: September 25, 2013

Attachment A – Clean Tariff Sheets

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with Additional Performance Based Refinements

California Independent System Operator Corporation

September 25, 2013

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 Locational Marginal Price.

* * *

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. 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.

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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.

11.8.2 IFM Bid Cost Recovery Amount

For purposes of determining the IFM Unrecovered Bid Cost Uplift Payments as determined in Section 11.8.5, and the purposes of allocating Net IFM Bid Cost Uplift as described in Section 11.8.6.4, the CAISO shall calculate the IFM Bid Cost Shortfall or the IFM Bid Cost Surplus as the algebraic difference between the IFM Bid Cost and the IFM Market Revenues for each Settlement Interval, which are determined as described below and subject to the application of the Day-Ahead Metered Energy Adjustment Factor and the Real-Time Performance Metric rules specified in Section 11.8.2.5 and 11.8.4.4, respectively. The IFM Bid Costs shall be calculated pursuant to Section 11.8.2.1 and the IFM Market Revenues shall be calculated pursuant to Section 11.8.2.2.

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11.8.2.1.1 IFM Start-Up Cost

The IFM Start-Up Cost for any IFM Commitment Period shall be equal to the Start-Up Costs submitted by the Scheduling Coordinator to the CAISO for the IFM divided by the number of Settlement Intervals within the applicable IFM Commitment Period. For each Settlement Interval, only the IFM Start-Up Cost in a

CAISO IFM Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the IFM Start-Up Costs for Multi-Stage Generating Resources based on the CAISO-committed MSG Configuration. The following rules shall apply sequentially to qualify the IFM Start-Up Cost in an IFM Commitment Period:

(a) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if there is an IFM Self-Commitment Period within or overlapping with that IFM Commitment Period.

(b) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if the Bid Cost Recovery Eligible Resource is manually pre-dispatched under an RMR Contract prior to the Day-Ahead Market or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule in the Day-Ahead Market anywhere within the applicable IFM Commitment Period.

(c) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if there is no actual Start-Up at the start of the applicable IFM Commitment Period because the IFM Commitment Period is the continuation of an IFM, RUC, or RTM Commitment Period from the previous Trading Day.

(d) If an IFM Start-Up is terminated in the Real-Time within the applicable IFM Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost Recovery Eligible Resource was starting up, the IFM Start-Up Cost for that IFM Commitment Period shall be prorated by the ratio of the Start-Up Time before termination over the total IFM Start-Up Time.

(e) The IFM Start-Up Cost is qualified if an actual Start-Up occurs within the applicable IFM Commitment Period. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Intervals indicates the unit is Off before the time the resource is instructed to be On as specified in its Start Up Instruction and is On in the Settlement Intervals that fall within the CAISO IFM Commitment Period.

(f) The Minimum Load Energy is the product of the relevant Minimum Load and the duration of the Settlement Interval. The CAISO will determine the Minimum Load Energy for Multi-Stage Generating Resources based on the CAISO Commitment Period applicable MSG Configuration.

(g) The IFM Start-Up Cost will be qualified if an actual Start-Up occurs earlier than the start of the IFM Commitment Period if the advance Start-Up is a result of a Start-Up instruction issued in a RUC or Real-Time Market process subsequent to the IFM, or the advance Start-Up is uninstructed but is still within the same Trading Day and the Bid Cost Recovery Eligible Resource actually stays on until the targeted IFM Start-Up.

(h) The Start-Up Costs for a Bid Cost Recovery Eligible Resource that is a Short Start Unit committed by the CAISO in the IFM and that further receives a Start-Up Instruction from the CAISO in the Real-Time Market to start within the same CAISO IFM Commitment Period, will be qualified for the CAISO IFM Commitment Period instead of being qualified for the CAISO RTM Commitment Period and Start-Up Costs for subsequent Start-Ups will be further qualified as specified in Section 11.8.4.1.1(h).

11.8.2.1.2 IFM Minimum Load Cost

The Minimum Load Cost for the applicable Settlement Interval shall be the Minimum Load Cost submitted to the CAISO in the IFM divided by the number of Settlement Intervals in a Trading Hour subject to the rules described below.

(a) For each Settlement Interval, only the IFM Minimum Load Cost in a CAISO IFM Commitment Period is eligible for Bid Cost Recovery.

(b) The IFM Minimum Load Cost for any Settlement Interval is zero if: (1) the Settlement Interval is in an IFM Self Commitment Period for the Bid Cost Recovery Eligible Resource; or (2) the Bid Cost Recovery Eligible Resource is manually pre-dispatched under an RMR Contract prior to the Day-Ahead Market or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule for the applicable Settlement Interval.

(c) If the CAISO commits a Bid Cost Recovery Eligible Resource in the Day-Ahead and the resource receives a Day-Ahead Schedule and the CAISO subsequently de-commits the resource in the Real-Time Market, the IFM Minimum Load Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4.

(d) If a Multi-Stage Generating Resource is committed by the CAISO and receives a Day-Ahead Schedule and subsequently is committed by the CAISO to a lower MSG Configuration where its Minimum Load capacity in the Real-Time Market is lower than the CAISO IFM Commitment Period MSG Configuration's Minimum Load, the resource's IFM Minimum Load Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4.

(e) If the conditions in Sections 11.8.2.1.2 (c) and (d) do not apply, then the IFM Minimum Load Cost for any Settlement Interval is zero if the Bid Cost Recovery Eligible Resource is determined to be Off during the applicable Settlement Interval. For the purposes of determining IFM Minimum Load Cost, a Bid Cost Recovery Eligible Resource is assumed to be On if its metered Energy in a Settlement Interval is equal to or greater than the difference between its Minimum Load and the Tolerance Band, and the Metered Energy is greater than zero (0) MWh. Otherwise, such resource is determined to be Off.

(f) For Multi-Stage Generating Resources, the commitment period is determined based on application of section 11.8.1.3. If application of section 11.8.1.3 dictates that the IFM is the commitment period, then the calculation of the IFM Minimum Load Costs will depend on whether the IFM CAISO Committed MSG Configuration is determined to be On. If it is determined to be On, then, the IFM Minimum Load Costs will be based on the Minimum Load Costs of the IFM committed MSG Configuration. For the purposes of determining IFM Minimum

Load Cost for a Multi-Stage Generating Resource, a Bid Cost Recovery Eligible Resource is determined to be On if its metered Energy in a Settlement Interval is equal to or greater than the difference between its IFM MSG Configuration Minimum Load and the Tolerance Band, and the Metered Energy is greater than zero (0) MWh. Otherwise, such resource is determined to be Off.

(g) The IFM Minimum Load Costs calculation is subject to the Shut-Down State Variable and is disqualified as specified in Section 11.17.2.

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11.8.2.1.5 IFM Energy Bid Cost

For any Settlement Interval, the IFM Energy Bid Cost for Bid Cost Recovery Eligible Resources, except Participating Loads, shall be the integral of the relevant Energy Bid used in the IFM, if any, from the higher of the registered Bid Cost Recovery Eligible Resource's Minimum Load and the Day-Ahead Total Self-Schedule up to the relevant MWh scheduled in the Day-Ahead Schedule, divided by the number of Settlement Intervals in a Trading Hour. The IFM Energy Bid Cost calculations are subject to the application of the Day-Ahead Metered Energy Adjustment Factor, and the Persistent Deviation Metric pursuant to the rules specified in Section 11.8.2.5 and Section 11.17.2.3, respectively. In addition, if the CAISO commits a Bid Cost Recovery Eligible Resource in the Day-Ahead and receives a Day-Ahead Schedule and subsequently the CAISO de-commits the resource in the Real-Time Market, the IFM Energy Bid Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4. If the CAISO commits a Multi-Stage Generating Resource in the Day-Ahead Market and the resource receives a Day-Ahead Schedule and subsequently the CAISO de-commits the Multi-Stage Generating Resource to a lower MSG Configuration where its Minimum Load capacity in the Real-Time Market is lower than the CAISO IFM Commitment Period MSG Configuration's Minimum Load, the resource's IFM Energy Bid Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4. The CAISO will determine the IFM Energy Bid Cost for a Multi-Stage Generating Resource at the Generating Unit or Dynamic Resource-Specific System Resource level. *** * ***

11.8.2.1.7.1 IFM Transition Costs Applicability

Within any eligible IFM CAISO Commitment Period determined pursuant to the rules specified in Section 11.8.1.3, the CAISO shall apply the IFM Transition Costs for the Settlement Intervals in which the Multi-Stage Generating Resource is actually transitioning from the "from" MSG Configuration and reaches the Minimum Load of the "to" MSG Configuration to which the Multi-Stage Generating Resource is transitioning, subject to the Tolerance Band.

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11.8.2.2 IFM Market Revenue

The CAISO will apply the following rules to calculate a Bid Cost Recovery Eligible Resource's IFM Market Revenue used for purposes of calculating its IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses calculated pursuant to Section 11.8.2, and for purposes of allocating the Bid Cost Uplift pursuant to Section 11.8.6. The IFM Market Revenue calculations for both CAISO IFM Commitment Periods and Self-Committed Periods will be subject to the Day-Ahead Metered Energy Adjustment Factor pursuant to the rules specified in Section 11.8.2.5.

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.

11.8.2.2.2 Resource Self-Committed

For any Settlement Interval in a IFM Self-Commitment Period the IFM Market Revenue for a Bid Cost Recovery Eligible Resource is the algebraic sum of: (1) the product of the MWh above the greater of

Minimum Load and Self-Scheduled Energy, in the relevant Day-Ahead Schedule in that Trading Hour and the relevant IFM LMP, divided by the number of Settlement Intervals in a Trading Hour; and (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.

* * *

11.8.2.5 Application of the Day-Ahead Metered Energy Adjustment Factor to IFM Bid Costs and Market Revenues

The CAISO will adjust for each Bid Cost Recovery Eligible Resource the IFM Energy Bid Cost and IFM Market Revenue calculations by multiplying the Day-Ahead Metered Energy Adjustment Factor with the amounts derived as specified in Sections 11.8.2.1.5 and 11.8.2.2, respectively. In addition, the CAISO will apply the Real-Time Performance Metric to the IFM Energy Bid Costs, IFM Minimum Load Costs IFM Pumping Costs and IFM Market Revenues, as described in 11.8.4.4. The CAISO will apply the Day-Ahead Metered Energy Adjustment Factor to the IFM Pumping Bid Costs in the same manner in which the CAISO applies the Day-ahead Metered Energy Adjustment Factor to the IFM Energy Bid Costs as specified in this Section 11.8.2.5 and its subsections. In all cases, regardless of the rules specified below, the application of the Day-Ahead Metered Energy Adjustment Factor shall never increase a Bid Cost Recovery Eligible Resource's Unrecovered Bid Cost Uplift Payments. In the event that the CAISO discovers that there has been an increase in the Unrecovered Bid Cost Uplift Payment due to the application of the Day-Ahead Metered Energy Adjustment Factor, the CAISO will adjust the payment to recover the overpayment in a subsequent billing cycle as permissible under Section 11.29.

11.8.2.5.1 If the IFM Energy Bid Costs and the IFM Market Revenues for the amounts of Day-Ahead Scheduled Energy above the Bid Cost Recovery Eligible Resource's Minimum Load are greater than or equal to zero (0), the CAISO will apply the Day-Ahead Metered Energy Adjustment Factor to the IFM Energy Bid Costs, but not the IFM Market Revenue.

11.8.2.5.2 If the IFM Energy Bid Costs are greater than or equal to zero (0) and the IFM Market Revenues are negative, the CAISO will apply the Day-Ahead Metered Energy Adjustment Factor to both the IFM Energy Bid Costs and IFM Market Revenues.

11.8.2.5.3 If the IFM Energy Bid Costs are negative and IFM Market Revenues are greater or equal to zero, the CAISO will not apply the Day-Ahead Metered Energy Adjustment Factor to IFM Energy Bid Costs or IFM Market Revenues.

11.8.2.5.4 If the IFM Energy Bid Costs and the IFM Market Revenues are both negative, the CAISO will apply the Day-Ahead Metered Energy Adjustment Factor to the IFM Market Revenues, but it will not apply it to the IFM Energy Bid Costs.

11.8.2.5.5 If for any given Settlement Interval, the absolute value of the resource's Metered Energy less its Regulation Energy less the minimum of the Day-Ahead Schedule Energy and Expected Energy, is less than or equal to the Performance Metric Tolerance Band, then the CAISO will not apply the Day-Ahead Metered Energy Adjustment Factor to the IFM Energy Bid Cost or the IFM Market Revenue.

11.8.3 RUC Bid Cost Recovery Amount

For purposes of determining the RUC Unrecovered Bid Cost Uplift Payments as determined in Section 11.8.5 and for the purposes of allocating Net RUC Bid Cost Uplift as described in Section 11.8.6.5, the CAISO shall calculate the RUC Bid Cost Shortfall or the RUC Bid Cost Surplus as the algebraic difference between the RUC Bid Cost and the RUC Market Revenues for each Bid Cost Recovery Eligible Resource for each Settlement Interval. The RUC Bid Costs shall be calculated pursuant to Section 11.8.3.1 and the RUC Market Revenues shall be calculated pursuant to Section 11.8.3.2. The CAISO will include Bid Cost Recovery costs related to Short Start Units committed in Real-Time because of awarded RUC Capacity in RTM Compensation Costs.

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11.8.3.1.1 RUC Start-Up Cost

The RUC Start-Up Cost for any Settlement Interval in a RUC Commitment Period shall consist of Start-Up Cost of the Bid Cost Recovery Eligible Resource submitted to the CAISO for the applicable RUC Commitment Period divided by the number of Settlement Intervals in the applicable RUC Commitment Period. For each Settlement Interval, only the RUC Start-Up Cost in a CAISO RUC Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the RUC Start-Up Cost for a Multi-Stage Generating Resource based on the MSG Configuration committed by the CAISO in RUC.

The following rules shall be applied in sequence and shall qualify the RUC Start-Up Cost in a RUC Commitment Period:

(a) The RUC Start-Up Cost for a RUC Commitment Period is zero if there is an IFM Commitment Period within that RUC Commitment Period.

(b) The RUC Start-Up Cost for a RUC Commitment Period is zero if the Bid Cost Recovery Eligible Resource is manually pre-dispatched under an RMR Contract prior to the Day-Ahead Market or is flagged as an RMR Dispatch in the Day-Ahead Schedule anywhere within that RUC Commitment Period.

(c) The RUC Start-Up Cost for a RUC Commitment Period is zero if there is no RUC Start-Up at the start of that RUC Commitment Period because the RUC Commitment Period is the continuation of an IFM, RUC, or RTM Commitment Period from the previous Trading Day.

(d) The RUC Start-Up Cost for a RUC Commitment Period is zero if the Start-Up is delayed beyond the RUC Commitment Period in question or cancelled by the Real-Time Market prior to the Bid Cost Recovery Eligible Resource starting its start-up process.

(e) If a RUC Start-Up is terminated in the Real-Time within the applicable RUC Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost Recovery Eligible Resource is starting up, the RUC Start-Up Cost is prorated by the ratio of the Start-Up Time before termination over the RUC Start-Up Time.

(f) The RUC Start-Up Cost for a RUC Commitment Period is qualified if an actual Start-Up occurs within that RUC Commitment Period. An actual Start-Up is detected between two consecutive Settlement Intervals when the relevant metered Energy in the applicable Settlement Intervals increases from below the Minimum Load Energy and reaches or exceeds the relevant Minimum Load Energy. The Minimum Load Energy is the product of the relevant Minimum Load and the duration of the Settlement Interval. The CAISO will determine the

Minimum Load Energy for Multi-Stage Generating Resources based on the CAISO-committed MSG Configuration.

(g) The RUC Start-Up Cost shall be qualified if an actual Start-Up occurs. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Intervals indicates the unit is Off before the time the resource is instructed to be On as specified in its Start Up Instruction and is On in the Settlement Intervals that fall within the CAISO RUC Commitment Period.

11.8.3.1.2 RUC Minimum Load Cost

The Minimum Load Cost for the applicable Settlement Interval shall be the Minimum Load Cost of the Bid Cost Recovery Eligible Resource divided by the number of Settlement Intervals in a Trading Hour. For each Settlement Interval, only the RUC Minimum Load Cost in a CAISO RUC Commitment Period is eligible for Bid Cost Recovery. The RUC Minimum Load Cost for any Settlement Interval is zero if: (1) the Bid Cost Recovery Eligible Resource is manually pre-dispatched under an RMR Contract or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule in that Settlement Interval; (2) the Bid Cost Recovery Eligible Resource is not committed or Dispatched in the Real-time Market in the applicable Settlement Interval; or (3) the applicable Settlement Interval is included in an IFM Commitment Period. For the purposes of determining RUC Minimum Load Cost for a Bid Cost Recovery Eligible Resource recovery of the RUC Minimum Load Costs is subject to the Real-Time Performance Metric as specified in Section 11.8.4.4. For Multi-Stage Generating Resources, the commitment period is determined based on application of section 11.8.1.3. The RUC Minimum Load Cost calculation will be subject to the Shut-Down State Variable and disqualified as specified in Section 11.17.2.*** * ***

11.8.3.1.4.1 RUC Transition Costs Applicability

Within any eligible RUC CAISO Commitment Period determined pursuant to the rules specified in Section 11.8.1.3, the CAISO shall apply the RUC Transition Costs for the Settlement Intervals in which the Multi-Stage Generating Resource is actually transitioning from the “from” MSG Configuration and reaches the Minimum Load of the “to” MSG Configuration to which the Multi-Stage Generating Resource is transitioning, subject to the Tolerance Band.

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11.8.3.3.2 MSS Elected Net Settlement

For an MSS Operator that has elected net Settlement, regardless of other MSS optional elections (Load following or RUC opt-in or out), the RUC Bid Costs and RUC Market Revenue are combined with RTM Bid Cost and RTM Market Revenue on an MSS level, consistent with the Energy Settlement as calculated according to Section 11.8.4.3.2.

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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 and 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, 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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11.8.4.1.1 RTM Start-Up Cost

For each Settlement Interval of the applicable Real-Time Market Commitment Period, the Real-Time Market Start-Up Cost shall consist of the Start-Up Cost of the Bid Cost Recovery Eligible Resource submitted to the CAISO for the Real-Time Market divided by the number of Settlement Intervals in the applicable Real-Time Market Commitment Period. For each Settlement Interval, only the Real-Time Market Start-Up Cost in a CAISO Real-Time Market Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the RTM Start-Up Cost for a Multi-Stage Generating Resource based on the MSG Configuration committed by the CAISO in RTM. The following rules shall be applied in sequence and shall qualify the Real-Time Market Start-Up Cost in a Real-Time Market Commitment Period:

(a) The Real-Time Market Start-Up Cost is zero if there is a Real-Time Market Self-Commitment Period within the Real-Time Market Commitment Period.

(b) The Real-Time Market Start-Up Cost is zero if the Bid Cost Recovery Eligible Resource has been manually pre-dispatched under an RMR Contract or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule or Real-Time Market anywhere within that Real-Time Market Commitment Period.

(c) The Real-Time Market Start-Up Cost is zero if the Bid Cost Recovery Eligible Resource is started within the Real-Time Market Commitment Period pursuant to an Exceptional Dispatch issued in accordance with Section 34.9.2 to (1) perform Ancillary Services testing; (2) perform pre-commercial operation testing for Generating Units; or (3) perform PMax testing.

(d) The Real-Time Market Start-Up Cost is zero if there is no Real-Time Market Start-Up at the start of that Real-Time Market Commitment Period because the Real-Time Market Commitment Period is the continuation of an IFM or RUC Commitment Period from the previous Trading Day.

(e) If a Real-Time Market Start-Up is terminated in the Real-Time within the applicable Real-Time Market Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost Recovery Eligible Resource is starting up the Real-Time Market Start-Up Cost is prorated by the ratio of the Start-Up Time before termination over the Real-Time Market Start-Up Time.

(f) The Real-Time Market Start-Up Cost shall be qualified if an actual Start-Up occurs within that Real-Time Market Commitment Period. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Interval(s) indicates the unit is Off before the time the resource is instructed to be On as specified in its Start Up Instruction and is On in the Settlement Interval that falls within the CAISO Real-Time Market Commitment Period. The CAISO will determine that the Multi-Stage Generating Resource is On when, based on its metered Energy, the resource has been detected to have delivered the Minimum Load Energy of the MSG Configuration that CAISO has committed in the Real-Time Market. The Minimum Load Energy is the product of the relevant Minimum Load and the duration of the Settlement Interval.

(g) The Real-Time Market Start-Up Cost for a Real-Time Market Commitment Period shall be qualified if an actual Start-Up occurs earlier than the start of the Real-Time Market Start-Up, if the relevant Start-Up is still within the same Trading Day and the Bid Cost Recovery Eligible Resource actually stays on until the Real-Time Market Start-Up, otherwise the Start-Up Cost is zero for the Real-Time Market Commitment Period.

(h) For Short-Start Units, the first Start-Up Costs within a CAISO IFM Commitment Period are qualified IFM Start-Up Costs as described above in Section 11.8.2.1.1(h). For subsequent Start-Ups of Short-Start Units after the CAISO Shuts Down a resource and then the CAISO issues a Start-Up Instruction pursuant to a CAISO RTM Commitment within the CAISO IFM Commitment Period, the Start-Up Costs shall be qualified as Real-Time Start-Up costs, provided that the resource actually Shut-Down and Started-Up based on CAISO Shut-Down and Start-Up Instructions.

11.8.4.1.2 RTM Minimum Load Cost

The RTM Minimum Load Cost is the Minimum Load Cost of the Bid Cost Recovery Eligible Resource submitted to the CAISO for the Real-Time Market divided by the number of Settlement Intervals in a Trading Hour. For each Settlement Interval, only the RTM Minimum Load Cost in a CAISO RTM Commitment Period is eligible for Bid Cost Recovery. The RTM Minimum Load 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) for all resources that are not Multi-Stage Generating Resources, that Settlement Interval is included in an IFM or RUC Commitment

Period; or (4) the Bid Cost Recovery Eligible Resource is committed pursuant to Section 34.9.2 for the purpose of performing Ancillary Services testing, pre-commercial operation testing for Generating Units, or PMax testing. A resource's RTM Minimum Load Costs for Bid Cost Recovery purposes are subject to the application of the Real-Time Performance Metric as specified in Section 11.8.4.4. For Multi-Stage Generating Resources, the commitment period is further determined based on application of Section 11.8.1.3. For all Bid Cost Recovery Eligible Resources that the CAISO Shuts Down, either through an Exceptional Dispatch or an Economic Dispatch through the Real-Time Market, from its Day-Ahead Schedule that was also from a CAISO commitment, the RTM Minimum Load Costs will include negative Minimum Load Costs for Energy between the Minimum Load and zero (0) MWhs. In addition, for all Multi-Stage Generating Resources that the CAISO commits down to a lower MSG Configuration with its Minimum Load capacity lower than the Day-Ahead CAISO Committed MSG Configuration's Minimum Load capacity, either through an Exceptional Dispatch or an Economic Dispatch through the Real-Time Market, from its IFM MSG Configuration that was also from a CAISO Commitment Period, the Minimum Load Costs will be equal to the RTM Minimum Load Cost less the IFM or RUC Minimum Load Cost, as applicable.

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11.8.4.1.5 RTM Energy Bid Cost

For any Settlement Interval, the RTM Energy Bid Cost for the Bid Cost Recovery Eligible Resource except Participating Loads shall be computed as the sum of the products of each Instructed Imbalance Energy (IIE) portion, 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 Energy Bid prices, the Default Energy Bid price, or the Locational Marginal Price, if any, as further described in Section 11.17, for each Dispatch Interval in the Settlement Interval. For Settlement Intervals for which the Bid Cost Recovery Eligible Resource is ramping up to or down from a rerated Minimum Load that was increased in SLIC for the Real-Time Market, the RTM Energy incurred by the ramping will be classified as Derate Energy and will not be included in Bid Cost Recovery. For a Bid Cost Recovery Eligible Resource that is ramping up to or down from an Exceptional Dispatch, the relevant Energy Bid Cost related to the Energy caused by ramping will be settled on the same basis as the Energy Bid used in the Settlement of the Exceptional Dispatch that led to the ramping. The RTM Energy Bid Cost for a Bid Cost Recovery Eligible Resource, including Participating Loads and Proxy Demand Response Resources, for a Settlement Interval is subject to the Real-Time Performance Metric as described in Section 11.8.4.4 and the Persistent Deviation Metric as described in Section 11.17. Any Uninstructed Imbalance Energy in excess of Instructed Imbalance Energy is also not eligible for Bid Cost Recovery. For a Multi-Stage Generating Resource the CAISO will determine the RTM Energy Bid Cost based on the Generating Unit or Dynamic Resource-Specific System Resource level.

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11.8.4.1.7 RTM Transition Cost

For each Settlement Interval, the RTM Transition Costs shall be based on the MSG Configuration to which the Multi-Stage Generating Resource is transitioning and are allocated to the CAISO commitment period of that MSG Configuration.

11.8.4.1.7.1 RTM Transition Costs Applicability

Within any eligible RTM CAISO Commitment Period determined pursuant to the rules specified in Section 11.8.1.3, the CAISO shall apply the RTM Transition Costs for the Settlement Intervals in which the Multi-Stage Generating Resource is actually transitioning from the “from” MSG Configuration and reaches the Minimum Load of the “to” MSG Configuration to which the Multi-Stage Generating Resource is transitioning, subject to the Tolerance Band.

11.8.4.2 RTM Market Revenue Calculations

The RTM Market Revenue calculations are subject to the Real-Time Performance Metric and the Persistent Deviation Metric as described in Sections 11.8.4.4 and 11.17, respectively.

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 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 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 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 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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11.8.4.3.1 MSS Elected Gross Settlement

For an MSS Operator that has elected gross Settlement, regardless of other MSS optional elections (Load following or RUC opt-in or out), the RTM Bid Cost and RTM Market Revenue of the Real-Time Instructed Imbalance Energy subject to Bid Cost Recovery is determined for each resource in the same way these amounts are determined for a non-MSS resource pursuant to the rules specified in Section 11.8.4. The RTM Bid Cost Shortfall or Surplus for Energy and Ancillary Services in total is determined for each Trading Hour of the RTM over the Trading Day by taking the algebraic difference between the RTM Bid Cost and RTM Market Revenue.

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11.8.4.3.2 MSS Elected Net Settlement

For MSS entities that have elected net Settlement regardless of other MSS optional elections (i.e., Load following or not, or RUC opt-in or out), unlike non-MSS resources, the RUC and RTM Bid Cost Shortfall or Surplus is treated at the MSS level and not at the resource specific level, and is calculated as the RUC and RTM Bid Cost Shortfall or Surplus of all BCR Eligible Resources within the MSS. In calculating the Energy RTM Market Revenue for all the resources within the MSS as provided in Section 11.8.4.2, the CAISO will use the Real-Time Settlement Interval MSS Price. The RUC and RTM Bid Cost Shortfall and Surplus for Energy, RUC Availability and Ancillary Services are first calculated separately for the MSS for each Settlement Interval of the Trading Day, with qualified Start-Up Cost, qualified Minimum Load Cost and qualified Multi-Stage Generator transition cost included into the RUC and RTM Bid Cost Shortfalls and Surpluses of Energy calculation. The RUC and RTM Bid Cost Shortfall or Surplus for Energy for each Settlement Interval is pro-rated by the ratio of the net positive metered Generation to the gross metered Generation of the MSS for that interval. If the MSS metered CAISO Demand is in excess of the MSS Generation in a given Settlement Interval, the CAISO will set the pro-rating ratio for that Settlement Interval to zero. The MSS’s overall RUC and RTM Bid Cost Shortfall or Surplus is then calculated as the algebraic sum of the pro-rated RUC and RTM Bid Cost Shortfalls and Surpluses for Energy, plus the RUC and RTM Bid Cost Shortfalls and Surpluses for Ancillary Services, plus the RUC Availability revenues for each Settlement Interval.

11.8.4.4 Application of the Real-Time Performance Metric

The CAISO will adjust the RTM Energy Bid Cost, the RTM Market Revenues, and RTM Minimum Load Costs, the IFM Minimum Load Cost and IFM Energy Bid Cost calculations, and the IFM Market Revenues determined pursuant to Sections 11.8.4.1.5, 11.8.4.2, 11.8.4.1.2, 11.8.2.1.2, 11.8.2.1.5 and 11.8.2.2, respectively, by multiplying the Real-Time Performance Metric with those amounts for the applicable Settlement Interval, pursuant to the rules specified in this Section 11.8.4.4 and its subsections. The CAISO will apply the Real-time Performance Metric to the IFM Pumping Bid Costs and RTM Pumping Bid Costs in the same manner in which the CAISO applies the Real-time Performance Metric to the RTM Energy Bid Costs as specified in this Section 11.8.4.4, and its subsections. In all cases, regardless of the rules specified below, the application of the Real-Time Performance Metric shall never increase a Bid Cost Recovery Eligible Resource's Unrecovered Bid Cost Uplift Payments. In the event that the CAISO discovers that there has been an increase in the Unrecovered Bid Cost Uplift Payment due to the application of the Real-time Performance Metric, the CAISO will adjust the payment to recover the overpayment, in a subsequent billing cycle as permissible under Section 11.29.

11.8.4.4.1 If the RTM Energy Bid Cost plus the RUC and RTM Minimum Load Costs and the RTM Market Revenues are greater than or equal to zero (0), the CAISO will apply the Real-Time Performance Metric to RTM Energy Bid Costs, RUC and RTM Minimum Load Costs, and not the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the IFM Energy Bid Cost plus the IFM Minimum Load Cost and the IFM Market Revenues are greater than or equal to zero (0), the CAISO will apply the Real-Time Performance Metric instead of Day-Ahead Metered Energy Adjustment Factor to the IFM Minimum Load Costs and IFM Energy Bid Costs, and not the IFM Market Revenues.

11.8.4.4.2 If the RTM Energy Bid Costs plus the RUC and RTM Minimum Load Costs are greater than or equal to zero (0) and the RTM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric to the RTM Energy Bid Costs, RUC and RTM Minimum Load Costs and the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the IFM Energy Bid Costs plus the IFM Minimum Load Cost are greater than or equal to zero (0) and the IFM

Market Revenues are negative the ISO will apply the Real-Time Performance Metric instead of the Day-ahead Metered Energy Adjustment Factor to the IFM Minimum Load Costs and IFM Energy Bid Costs, and IFM Market Revenues.

11.8.4.4.3 If the RTM Energy Bid Costs plus the RUC and RTM Minimum Load Cost are negative and the RTM Market Revenues are greater than or equal to zero (0), the CAISO will not apply Real-Time Performance Metric to the RTM Energy Bid Costs, RUC and RTM Minimum Load Costs or the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the sum of IFM Energy Bid Costs the IFM Minimum Load Costs is negative and IFM Market Revenue is greater than or equal to zero (0), the CAISO will not apply the Real-Time Performance Metric to the IFM Minimum Load Costs, IFM Energy Bid Costs or the IFM Market Revenues.

11.8.4.4.4 If the RTM Energy Bid Costs plus the RUC and RTM Minimum Load Costs, and the RTM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric to the RTM Market Revenues but not the RTM Energy Bid Costs or the RUC and RTM Minimum Load Cost. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the IFM Energy Bid Costs plus the IFM Minimum Load Costs and the IFM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric instead of the Day-Ahead Metered Energy Adjustment Factor to the IFM Market Revenues but not the IFM Minimum Load Costs and IFM Energy Bid Costs.

11.8.4.4.5 If for a given Settlement Interval the absolute value of the resource's Metered Energy, less Regulation Energy and less Expected Energy, is less than or equal to the Performance Metric Tolerance Band, then the CAISO will not apply the Real-Time Performance Metric to the calculation of the RTM Energy Bid Cost, RUC and RTM Minimum Load Cost, or RTM Market Revenue.

11.8.5 Unrecovered Bid Cost Uplift Payment

Bid Cost Recovery Eligible Resources will receive an Unrecovered Bid Cost Uplift Payment as described in this Section below. For Multi-Stage Generating Resources, Unrecovered Bid Cost Uplift Payments will be calculated and made at the Generating Unit level and not the MSG Configuration level. MSS Bid Cost Recovery Eligible Resources by MSS Operators that have elected net settlement will receive Unrecovered Bid Cost Uplift Payment for MSS Bid Cost Recovery Eligible Resources at the MSS level and not by individual resource. MSS Bid Cost Recovery Eligible Resources by MSS Operators that have elected gross settlement will receive Unrecovered Bid Cost Uplift Payments at the MSS Bid Cost Recovery Eligible Resource level like all other resources.

11.8.5.1 IFM Unrecovered Bid Cost Uplift Payment

Scheduling Coordinators shall receive an IFM Unrecovered Bid Cost Uplift Payment for a Bid Cost Recovery Eligible Resource, if the net of all IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses calculated pursuant to Section 11.8.2 over a Trading Day is positive.

11.8.5.2 RUC and RTM Unrecovered Bid Cost Uplift Payment

Scheduling Coordinators shall receive RUC and RTM Unrecovered Bid Cost Uplift Payments for a Bid Cost Recovery Eligible Resource, if the net of all RUC Bid Cost Shortfalls and RUC Bid Cost Surpluses calculated pursuant to Section 11.8.3, and the RTM Bid Cost Shortfalls and RTM Bid Cost Surpluses calculated pursuant to Section 11.8.4, for that Bid Cost Recovery Eligible Resource over a Trading Day is positive. For Metered Subsystems that have elected net settlement, the Unrecovered Bid Cost Uplift Payment will be the sum, if positive, of the RUC, and RTM Bid Cost Shortfall or RUC, and RTM Bid Cost Surplus for each Trading Hour over the Trading Day for all Bid Cost Recovery Eligible Resources in the MSS.

11.8.6 System-Wide IFM, RUC and RTM Bid Cost Uplift Allocation

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11.8.6.2 Sequential Netting of RUC and RTM Bid Cost Uplift

For each Settlement Interval, the Net RUC or Real-Time Market Bid Cost Uplift is determined for the purposes of allocating Net RUC or Real-Time Market Bid Cost Uplift by the following netting rules applied:

(i) The Net RUC Bid Cost Uplift is equal to the greater of zero or any positive RUC Bid Cost Uplift offset by negative Real-Time Market Bid Cost Uplift.

(ii) The Net Real-Time Market Bid Cost Uplift is equal to the greater of zero or any positive Real-Time Market Bid Cost Uplift offset by any negative RUC Bid Cost Uplift.

11.8.6.3 Determination of Total Positive CAISO Markets Uplifts

11.8.6.3.1 Total Positive IFM Uplift

Any positive Net IFM Bid Cost Uplifts are reduced by scaling them with the uplift ratio in Section 11.8.6.3.1(iii) to determine the Total IFM Uplift (for a Settlement Interval) as follows:

(i) The Total IFM Uplift is the Net IFM Bid Cost Uplift for all Settlement Intervals in the IFM Market.

(ii) The Total Positive IFM Uplift is determined as the sum of the positive IFM Bid Cost Uplift for all Settlement Intervals in the IFM Market.

(iii) The uplift ratio is equal to the Total IFM Uplift divided by the Total Positive IFM Uplift.

11.8.6.3.2 Total Positive RUC and RTM Uplift

Any negative RUC and Real-Time Market Bid Cost Uplifts are set to $0 and any positive Net RUC Bid Cost Uplifts and Real-Time Market Bid Cost Uplifts are further reduced by the uplift ratio in Section 11.8.6.3.2(iii) to determine the Total RUC and RTM Uplift as follows;

(i) The Total RUC and RTM Uplift is determined as the sum of the Net RUC Bid Cost Uplift and the Net Real-Time Market Bid Cost Uplift for all Settlement Intervals in the RUC and Real-Time Market.

(ii) The Total Positive RUC and RTM Uplift is determined as the sum of the positive RUC Bid Cost Uplift and positive Real-Time Market Bid Cost Uplift, for all Settlement Intervals in the RUC and Real-Time Market.

(iii) The uplift ratio is equal to the Total RUC and RTM Uplift divided by the Total Positive RUC and RTM Uplift.

11.8.6.4 Allocation of IFM Bid Cost Uplift

For each Trading Hour of the IFM the hourly IFM Bid Cost Uplift is allocated as follows:

11.8.6.4.1 Allocation in the First Tier

The hourly IFM Bid Cost Uplift is allocated in the first tier as follows:

(i) The hourly amount of IFM Bid Cost Uplift allocated to each Scheduling Coordinator is equal to the product of the IFM Bid Cost Uplift rate and the IFM uplift obligation for the Scheduling Coordinator.

(ii) The IFM Bid Cost Uplift rate is equal to the IFM Bid Cost Uplift divided by the sum of the positive IFM Load Uplift Obligations for all Scheduling Coordinators and the IFM system-wide Virtual Demand Award uplift obligation, subject to the condition that the IFM Bid Cost Uplift rate cannot exceed the ratio of the hourly IFM Bid Cost Uplift for the Trading Hour divided by the maximum of (a) the sum of all hourly IFM Load Uplift Obligations for all Scheduling Coordinators in that Trading Hour or (b) the sum of all hourly Generation scheduled in the Day-Ahead Schedule and IFM upward AS Awards for all Scheduling Coordinators from CAISO-committed Bid Cost Recovery Eligible Resources in that Trading Hour.

(iii) The IFM uplift obligation for each Scheduling Coordinator is equal to the sum of the IFM Load Uplift Obligation for the Scheduling Coordinator and any IFM Virtual Demand Award uplift obligation for the Scheduling Coordinator.

(iv) The IFM Load Uplift Obligation for each Scheduling Coordinator, including Scheduling Coordinators for Metered Subsystems regardless of their MSS optional elections (net/gross Settlement, Load following, RUC opt-in/out), is equal to the positive difference between the total Demand scheduled in the Day-Ahead Schedule of that Scheduling Coordinator and the sum of scheduled Generation and scheduled imports from the Self-Schedules in the Day-Ahead Schedule of that Scheduling Coordinator, adjusted by any applicable Inter-SC Trades of IFM Load Uplift Obligations.

(v) The IFM system-wide Virtual Demand Award uplift obligation is calculated for each hour in the IFM and is equal to maximum of zero (0) or the following quantity: the total system-wide Virtual Demand Awards from the IFM minus the total system-wide Virtual Supply Awards from the IFM, plus the minimum of zero (0) or the following quantity: the total amount of Scheduled Demand (which excludes Virtual Demand Awards), minus Measured Demand.

(vi) For each Scheduling Coordinator with positive net Virtual Demand Awards, the IFM Virtual Demand Award uplift obligation is equal to the product of (a) the positive net Virtual Demand Awards for the Scheduling Coordinator divided by the sum of each Scheduling Coordinator's positive net Virtual Demand Award and (b) the IFM system-wide Virtual Demand Award uplift obligation. For each Scheduling Coordinator with negative net Virtual Demand Awards, the IFM Virtual Demand Award uplift obligation is zero (0).

11.8.6.4.2 Allocation in the Second Tier

In the second tier, Scheduling Coordinators, including Scheduling Coordinators for MSS Operators that have elected both to not follow their Load and gross Settlement, will be charged for an amount equal to any remaining hourly IFM Bid Cost Uplift for the Trading Hour in proportion to the Scheduling Coordinator's Measured Demand. Scheduling Coordinators for MSS Operators that have elected to either follow their Load or net Settlement, or both, will be charged for an amount equal to any remaining hourly IFM Bid Cost Uplift for the Trading Hour in proportion to their MSS Aggregation Net Measured Demand.

* * *

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 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 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 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 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 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 Intertie Schedules in response to Dispatch Instructions or real-time scheduling curtailments are not allocated any Net RTM Bid Cost Uplift.

* * *

11.17 Application of the Persistent Deviation Metric

The CAISO will modify the Bid Cost Recovery calculations described in Section 11.8 and Residual Imbalance Energy payments in Section 11.5.5 as described below to address persistent deviations that expand Bid Cost Recovery payments beyond what is necessary for purposes of ensuring Bid Cost Recovery.

11.17.1 Persistent Deviations Threshold and Mitigation

The CAISO will calculate the Persistent Deviation Metric and evaluate each resource's response to a CAISO Dispatch in each Settlement Interval relative to the Persistence Deviation Metric Threshold as described below. The Persistent Deviation Metric Threshold evaluation will be based on the number of Settlement Intervals flagged within a rolling two-Trading Hour window. The CAISO will flag each Settlement Interval pursuant to the threshold conditions specified in Section 11.17.1.1, and apply the Persistent Deviation Metric pursuant to the rules specified in Section 11.17.1.2.

11.17.1.1 Persistent Deviation Threshold Conditions

11.17.1.1.1 Case 1

The CAISO will flag a Settlement Interval (t): (1) if Expected Energy is greater than Day-Ahead Scheduled Energy in that Settlement Interval (t), the Metered Energy is greater than the Expected Energy in that

Settlement Interval (t), and the Metered Energy in the prior Settlement Interval (t-1) is less than the Expected Energy in the given Settlement Interval (t); and (2) if the Metered Energy, less Regulation Energy, less the Expected Energy in that Settlement Interval (t) is greater than ten (10) percent of the amount the resource can be Dispatched at full ramp over the Settlement Interval (t) and the Persistent Deviation Metric is greater than one hundred and ten (110) percent.

11.17.1.1.2 Case 2

The CAISO will flag a Settlement Interval (t): (1) if the Expected Energy exceeds the Day-Ahead Scheduled Energy in that Settlement Interval (t), and Metered Energy in the prior Settlement Interval (t-1) exceeds the Expected Energy in that Settlement Interval (t); and (2) if the Metered Energy less the Regulation Energy and less Expected Energy in that Settlement Interval (t) is greater than ten (10) percent of the amount the resource can be Dispatched at full ramp over the Settlement Interval (t) and the Persistent Deviation Metric is less than ninety (90) percent.

11.17.1.1.3 Case 3

The CAISO will flag a Settlement Interval (t): (1) if the Expected Energy is less than the Day-Ahead Scheduled Energy, and Metered Energy is less than the Expected Energy in that Settlement Interval (t), and Metered Energy in the prior Settlement Interval (t-1) is less than the Expected Energy in the given Settlement Interval (t); and (2) if the Metered Energy less Regulation Energy less Expected Energy in that Settlement Interval (t) is greater than ten percent (10) of the amount the unit could be Dispatched at full ramp over the Settlement Interval (t) and the Persistent Deviation Metric is less than ninety (90) percent.

11.17.1.1.4 Case 4

The CAISO will flag a Settlement Interval (t): (1) if the Expected Energy is less than the Day-Ahead Scheduled Energy, and Metered Energy is less than the Expected Energy in that Settlement Interval (t), and Metered Energy in the prior Settlement Interval (t-1) is greater than the Expected Energy in the given Settlement Interval (t); and (2) if the Metered Energy less Regulation Energy less Expected Energy is greater than (10) percent of the amount the resource can be Dispatched at full ramp over the Settlement Interval (t) and the Persistent Deviation Metric is greater than one hundred and ten (110) percent.

11.17.1.2 Persistent Deviation Adjustments

The ISO will apply the following rules to evaluate the resource's performance relative to the Persistent Deviation Metric Threshold and will apply the Persistent Deviation Metric as specified below.

11.17.1.2.1 Rule 1

If three (3) or fewer Settlement Intervals out of the previous twelve (12) 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) or more Settlement Intervals of the previous twelve (12) Settlement Intervals are flagged as exceeding the Persistent Deviation Metric Threshold, then for all the previous twelve (12) 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 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 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 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 Locational Marginal Price.

11.17.1.2.3 Rule 3

Once a Settlement Interval is flagged as exceeding the Persistent Deviation Metric Threshold, it remains flagged when it is considered in the subsequent rolling two-Trading Hour evaluation window and its bid basis qualification for that Settlement Interval will not change.

11.17.1.2.4 Rule 4

If a Settlement Interval's bid basis is determined by the Rule 1 above in a previous evaluation and it has not been flagged, it can be re-determined and flagged pursuant to the additional rules in a subsequent rolling two-Trading Hour evaluation window based on the Persistent Deviation Metric Threshold.

11.17.2 Shut-Down Adjustment

11.17.2.1 Disqualification Based on Advisory Schedules

From the Dispatch Interval in which the CAISO has determined that the Dispatch Operating Point minus the Shut-Down State Variable is less than or equal to the Minimum Load as registered in the Master File, and until the Shut-Down State Variable is reset, the IFM, RUC or RTM Minimum Load Costs, as applicable, will be disqualified from the Bid Cost Recovery calculation.

11.17.2.2 Disqualification Based on ADS Shut-Down Instruction

In the event that the CAISO issues a binding Shut-Down Instruction through ADS, a resource will not be eligible for recovery of RTM or RUC Minimum Load Costs from the point of the Shut-Down Instruction forward for the duration of the resource's registered Minimum Down Time. If a resource ignores the binding Shut-Down Instruction and it has a Day-Ahead Schedule, the resource is not eligible for IFM Minimum Load Cost recovery as specified in Section 11.8.2.3 for the minimum of 1) the resource's Minimum Down Time, and 2) the IFM Commitment Period.

11.17.2.3 Bid Basis for Settlement Bid Cost Recovery

For any resource that receives a Shut-Down Instruction in the Real-Time Market, any IFM or RTM Energy Bid Cost recovery that may otherwise apply pursuant to the rules in Section 11.8 will be based on the relevant Energy Bid price, as mitigated, that was considered by the Real-Time Market in making the decision to shut down the resource for the length of time defined by the greater of (a) the resource's Minimum Down Time or (b) the period in which it is Off after the Shut-Down time, which is not to exceed the time until the end of the Trading Day.

* * *

39.6.1.4 Minimum Bid Price for Energy Bids

The minimum Energy Bid price shall be negative $150/MWh. These rules apply to all Energy Bids, including Virtual Bids.

* * *

Appendix A
Master Definition Supplement

* * *

- Day-Ahead Metered Energy Adjustment Factor

A factor calculated for the purposes of determining the portions of a Scheduling Coordinator's resource's relevant Day-Ahead Schedule to be included in the Bid Cost Recovery calculations as further specified in the CAISO Tariff based on the resource's actual performance reflected in the Metered Energy which is calculated as the minimum of: (1) the number one (1); or (2) the absolute value of the ratio of the resource's (a) Metered Energy less the Day-Ahead Minimum Load Energy and less the Regulation Energy, and (b) the minimum of (i) the Expected Energy and (ii) the Day-Ahead Scheduled Energy, less the Day-Ahead Minimum Load Energy. In cases where both the denominator and numerator produced by this calculation equal zero (0), the Day-Ahead Metered Energy Adjustment Factor will be set to one (1). If the denominator produced from this calculation equals zero (0), but the numerator is a non-zero number, the Day-Ahead Metered Energy Adjustment Factor will be set to zero (0).

* * *

- Dispatch Interval

The Time Period, which may range between five (5) and thirty (30) minutes, or as described in Section 34.3.2, a ten (10) minute interval for the Real-Time Contingency Dispatch, over which the Real-Time Dispatch measures deviations in Generation and Demand, and selects Ancillary Service and supplemental Energy resources to provide balancing Energy in response to such deviations. The Dispatch Interval shall be five (5) minutes. Following a decision by the CAISO Governing Board, the CAISO may, by seven (7) days' notice published on the CAISO Website, increase or decrease the Dispatch Interval within the range of five (5) to thirty (30) minutes.

* * *

- Dispatch Operating Target

The optimal Dispatch of a resource as calculated by CAISO based on telemetry and representing a single point on the Dispatch Operating Point trajectory in the middle of the Dispatch Interval.

* * *

- 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 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 Schedules. Expected Energy is used as the basis for Settlements.

* * *

- IFM Bid Cost Uplift

The net of the IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses system-wide for a Settlement Interval of all Bid Cost Recovery Eligible Resources with Unrecovered Bid Cost Uplift Payments as specified in Section 11.8.6.2.

* * *

- Performance Metric Tolerance Band

The tolerance band applied to the Day-Ahead Metered Energy Adjustment Factor and the Real-Time Performance Metric as specified in Section 11.8.2.5 and 11.8.4.4, respectively. This tolerance band is the Tolerance Band as defined in this Appendix A plus an additional ramping tolerance. For each Settlement Interval, the ramping tolerance is the difference between (1) the Energy calculated based on the linear curve between two applicable Dispatch Operating Targets; and (2) Expected Energy over the two applicable Dispatch Intervals.

* * *

- 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-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).

- Persistent Deviation Metric Threshold

The CAISO will calculate the Persistent Deviation Metric and will flag the interval based on the threshold described in Section 11.17.

* * *

* * *

- Real-Time Performance Metric

A factor calculated for the purposes of scaling a resource's Real-Time Bid Cost Recovery amounts calculated as the minimum of: (1) the number one (1); or (2) the absolute value of the ratio of the resource's (a) Metered Energy, less the Day-Ahead Scheduled Energy, and less the Regulation Energy, and (b) the total Expected Energy less the Day-Ahead Scheduled Energy. If the CAISO issues a Real-Time Dispatch to the resource that is incremental to its Day-Ahead Schedule and the resource deviates downward from its Day-Ahead Schedule, the Real-Time Performance Metric will be set to zero (0). If the CAISO issues a Real-Time Dispatch to the resource that is decremental to its Day-Ahead Schedule and the resource deviates to a level above its Day-Ahead Schedule, the Real-Time Performance Metric will be set to zero (0). If the resource's total Expected Energy is equal to the Day-Ahead Scheduled Energy and if the Metered Energy minus Regulation Energy is equal to the Day-Ahead Scheduled Energy, then the Real-Time Performance Metric is set to one (1). If the resource's total Expected Energy is equal to the Day-Ahead Scheduled Energy and if the Metered Energy minus the Regulation Energy is not equal to the

Day-Ahead Scheduled Energy, then the Real-Time Performance Metric is set to zero (0). The Real-Time Performance Metric is applied as specified in the Section 11.8.4.4 and is not applied during any Settlement Interval when a resource is Starting Up, Shutting Down, in an MSG Transition Period crossing over a Forbidden Operating Region, or a Dispatch Operating Point correction is performed due to a verbal Dispatch Instruction issued by the CAISO Operator, as long as the resource is in fact in the operational mode instructed by the CAISO.

* * *

- Residual Imbalance Energy

Extra-marginal IIE produced or consumed at the start or end of a Trading Hour outside the hourly schedule-change band and not attributed to Exceptional Dispatch. Residual Imbalance Energy is due to a Dispatch Instruction in the previous Trading Hour or a Dispatch Instruction in the next Trading Hour. Residual Imbalance Energy may overlap only with Day-Ahead Scheduled Energy. Residual Imbalance Energy does not apply to Non-Dynamic System Resources (including Resource-Specific System Resources). Residual Imbalance Energy is settled as bid, based on the Real-Time Energy Bid of the reference hour, as described in Section 11.5.5 and it is not included in BCR as described in Section 11.8.4.

* * *

- Shut-Down State Variable

A state variable to keep track of positive Uninstructed Imbalance Energy once an advisory Shut-Down Instruction is issued to a resource. The Shut-Down State Variable provides the MWh cumulative over the Real-Time Unit Commitment Intervals had the resource followed the Shut-Down Instruction. The Shut-Down State Variable begins to accumulate the positive Uninstructed Imbalance Energy MWh as soon as the advisory schedule includes a zero (0) MW Dispatch Operating Target within the Real-Time Market dispatch horizon and continues to accumulate the positive Uninstructed Imbalance Energy as long as (1) the unit is On, and (2) the Metered Energy less Regulation Energy less the Expected Energy is greater than the Performance Metric Tolerance Band. The Shut-Down State Variable will be reset to zero when the most recent Real-Time Unit Commitment run no longer has a zero (0) MW Dispatch Operating Target within the Real-Time Dispatch horizon or the resource is Off.

Attachment B – Marked Tariff Sheets

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with

Additional Performance Based Refinements

California Independent System Operator Corporation

September 25, 2013

11.5.5 Settlement Amount ~~For~~ for Residual Imbalance Energy

For each Settlement Interval, Residual Imbalance Energy settlement amounts shall be ~~the sum of the two applicable five-minute Dispatch Interval Residual Imbalance Energy settlement amounts. The Residual Imbalance Energy settlement amount for each five-minute Dispatch Interval is calculated as the product of the MWhs of Residual Imbalance Energy for that Dispatch Interval and the RIE Settlement Price. The RIE Settlement Price will be determined as follows: in Dispatch Intervals in which there is incremental Residual Imbalance Energy, i.e., the Residual Imbalance Energy is incremental to the Day-Ahead Schedule Energy for the resource, the RIE Settlement Price is the greater of: 1) the Dispatch Interval LMP; or 2) the lesser of a) the resource's Default Energy Bid, or b)~~ 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. ~~In Dispatch Intervals in which there is decremental Residual Imbalance Energy, i.e., the Residual Imbalance Energy is below the Day-Ahead Schedule Energy for the resource, the RIE Settlement Price RIE Settlement Price is the lesser of: 1) the Dispatch Interval LMP; or 2) the greater of: a) the resource's Default Energy Bid, or b) the Bid that led to the Residual Imbalance Energy from the relevant Dispatch Interval in which the resource was dispatched.~~ 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 Locational Marginal Price.

* * *

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.~~, which is netted across the CAISO Markets. In any Settlement Interval a resource is eligible for Bid Cost Recovery payments only if it is On, or in the case of a Participating Load or a Proxy Demand Resource, only if the resource has actually stopped or started consuming pursuant to the Dispatch Instruction.~~ 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 ~~as~~ 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.

* * *

11.8.1.3 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 ~~the~~:

(a) the IFM Commitment Period and/or RUC Commitment Period MSG Configuration(s) are different ~~than~~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, ~~Minimum Load 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 ~~IFM~~ CAISO IFM Commitment Period and/or ~~RUC~~ CAISO RUC Commitment Period in any MSG Configuration~~(s)~~ 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 ~~IFM~~ CAISO IFM Commitment Period and/or ~~RUC~~ 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 ~~IFM~~ CAISO IFM Commitment Period and/or ~~RUC~~ CAISO RUC Commitment Period MSG Configuration is the same as the ~~RTM~~ 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 ~~IFM~~ CAISO IFM Commitment Period and/or ~~RUC~~ 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 ~~RTM~~ 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 ~~RTM~~ 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 ~~the~~:

(a) the IFM Commitment Period MSG Configuration is different ~~than~~from the ~~RUC~~ 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 ~~RUC~~ 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 ~~IFM~~ 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 ~~IFM~~ 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 IFM Bid Cost Recovery Amount

For purposes of determining the IFM Unrecovered Bid Cost Uplift Payments as determined in Section 11.8.5, and the purposes of allocating Net IFM Bid Cost Uplift as described in Section 11.8.6.4, the CAISO shall calculate the IFM Bid Cost Shortfall or the IFM Bid Cost Surplus as the algebraic difference between the IFM Bid Cost and the IFM Market Revenues for each Settlement Interval, which are determined as described below and subject to the application of the Day-Ahead Metered Energy Adjustment Factor and the Real-Time Performance Metric rules specified in Section 11.8.2.5 and 11.8.4.4, respectively. The IFM Bid Costs shall be calculated pursuant to Section 11.8.2.1 and the IFM Market Revenues shall be calculated pursuant to Section 11.8.2.2. ~~The Energy subject to IFM Bid Cost Recovery is the actual Energy delivered in the Real-Time that is within the Day-Ahead Schedule for each eligible resource.~~

* * *

11.8.2.1.1 IFM Start-Up Cost

The IFM Start-Up Cost for any IFM Commitment Period shall be equal to the Start-Up Costs submitted by the Scheduling Coordinator to the CAISO for the IFM divided by the number of Settlement Intervals within the applicable IFM Commitment Period. For each Settlement Interval, only the IFM Start-Up Cost in a CAISO IFM Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the IFM Start-Up Costs for Multi-Stage Generating Resources based on the CAISO-committed MSG Configuration. The following rules shall apply sequentially to qualify the IFM Start-Up Cost in an IFM Commitment Period:

(a) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if there is an IFM Self-Commitment Period within or overlapping with that IFM Commitment Period.

(b) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if the Bid Cost Recovery Eligible Resource is manually pre-dispatched under an RMR Contract prior to the Day-Ahead Market or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule in the Day-Ahead Market anywhere within the applicable IFM Commitment Period.

(c) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if there is no actual Start-Up at the start of the applicable IFM Commitment Period because the IFM Commitment Period is the continuation of an IFM, RUC, or RTM Commitment Period from the previous Trading Day.

~~(d) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if the Start-Up is delayed by the Real-Time Market past the IFM Commitment Period in question or cancelled by the Real-Time Market before the start-up process has started.~~

(~~e~~d) If an IFM Start-Up is terminated in the Real-Time within the applicable IFM Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost Recovery Eligible Resource was starting up, the IFM Start-Up Cost for that IFM Commitment Period shall be prorated by the ratio of the Start-Up Time before termination over the total IFM Start-Up Time.

(~~f~~e) The IFM Start-Up Cost is qualified if an actual Start-Up occurs within the applicable IFM Commitment Period. An actual Start-Up is detected ~~between two consecutive Settlement Intervals~~ when the relevant metered Energy in the applicable Settlement Intervals indicates the unit is Off before the time ~~increases from below the Minimum Load Energy and reaches~~ the resource is instructed to be On as specified in its Start Up Instruction ~~or~~ and is On ~~exceeds the relevant Minimum Load Energy~~ in the Settlement Intervals that fall within the CAISO IFM Commitment Period.

(f) The Minimum Load Energy is the product of the relevant Minimum Load and the duration of the Settlement Interval. The CAISO will determine the Minimum Load

Energy for Multi-Stage Generating Resources based on the CAISO Commitment Period applicable MSG Configuration.

(g) The IFM Start-Up Cost will be qualified if an actual Start-Up occurs earlier than the start of the IFM Commitment Period if the advance Start-Up is ~~as~~ a result of a Start-Up instruction issued in a RUC or Real-Time Market process subsequent to the IFM, or the advance Start-Up is uninstructed but is still within the same Trading Day and the Bid Cost Recovery Eligible Resource actually stays on until the targeted IFM Start-Up.

(h) The Start-Up Costs for a Bid Cost Recovery Eligible Resource that is a Short Start Unit committed by the CAISO in the IFM and that further receives a Start-Up Instruction from the CAISO in the Real-Time Market to start within the same CAISO IFM Commitment Period, will be qualified for the CAISO IFM Commitment Period instead of being qualified for the CAISO RTM Commitment Period and Start-Up Costs for subsequent Start-Ups will be further qualified as specified in Section 11.8.4.1.1(h).

11.8.2.1.2 IFM Minimum Load Cost

The Minimum Load Cost for the applicable Settlement Interval shall be the Minimum Load Cost submitted to the CAISO in the IFM divided by the number of Settlement Intervals in a Trading Hour subject to the rules described below.

(a) For each Settlement Interval, only the IFM Minimum Load Cost in a CAISO IFM Commitment Period is eligible for Bid Cost Recovery.

(b) The IFM Minimum Load Cost for any Settlement Interval is zero if: (1) the Settlement Interval is in an IFM Self Commitment Period for the Bid Cost Recovery Eligible Resource; or (2) the Bid Cost Recovery Eligible Resource is manually pre-dispatched under an RMR Contract prior to the Day-Ahead Market or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule for the applicable Settlement Interval.

(c) If the CAISO commits a Bid Cost Recovery Eligible Resource in the Day-Ahead and the resource receives a Day-Ahead Schedule and the CAISO subsequently de-commits the resource in the Real-Time Market, the IFM Minimum Load Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4.

(d) If a Multi-Stage Generating Resource is committed by the CAISO and receives a Day-Ahead Schedule and subsequently is committed by the CAISO to a lower MSG Configuration where its Minimum Load capacity in the Real-Time Market is lower than the CAISO IFM Commitment Period MSG Configuration's Minimum Load, the resource's IFM Minimum Load Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4.

(e) If the conditions in Sections 11.8.2.1.2 (c) and (d) do not apply, then the IFM Minimum Load Cost for any Settlement Interval is zero if the Bid Cost Recovery Eligible Resource is determined to be Off during the applicable Settlement Interval.~~; or (3) the Bid Cost Recovery Eligible Resource is determined not actually On during the applicable Settlement Interval.~~ For the purposes of determining IFM Minimum Load Cost, a Bid Cost Recovery Eligible Resource~~, except for a Multi-Stage Generating Resource,~~ is assumed to be On if its metered Energy in a Settlement Interval is equal to or greater than the difference between its Minimum Load ~~Energy~~ and the Tolerance Band, and the Metered Energy is greater than zero (0) MWh. Otherwise, such resource ~~non-Multi-Stage Generating Resources are~~is determined to be Off.

(f) For Multi-Stage Generating Resources, the commitment period is determined based on application of section 11.8.1.3. If application of section 11.8.1.3 dictates that the IFM is the commitment period, then the calculation of the IFM Minimum Load Costs will depend on whether ~~the metered MSG Configuration is equal to or different from the IFM committed MSG Configuration. If~~ the IFM CAISO Committed~~metered~~ MSG Configuration is determined to be On. If it is determined to be On, then~~equal to the IFM committed MSG Configuration~~, ~~then~~ the IFM Minimum Load Costs will be based on the Minimum Load Costs of the IFM committed MSG Configuration. For the purposes of determining IFM Minimum Load Cost for a Multi-Stage Generating Resource, a Bid Cost Recovery Eligible Resource is determined to be On if its metered Energy in a Settlement Interval is equal to or greater than the difference between its IFM MSG Configuration Minimum Load and the Tolerance Band, and the Metered Energy is greater than zero (0) MWh. Otherwise, such resource is determined to be Off.~~If the metered MSG Configuration is different from the IFM committed MSG Configuration, then the IFM Minimum Load Costs will be based on the lower of the Minimum Load Costs of the metered MSG Configuration and the Minimum Load Costs of the IFM committed MSG Configuration. The metered MSG Configuration is determined based on the highest MSG Configuration submitted to the IFM for which the Metered Data is within or above the three (3) percent (or 5 MW) Tolerance Band of the PMin of that highest MSG Configuration submitted to the IFM. Between two (2) (or more) MSG Configurations, the highest MSG Configuration is the MSG Configuration with the PMin value that is the greatest MW value.~~

(g) The IFM Minimum Load Costs calculation is subject to the Shut-Down State Variable and is disqualified as specified in Section 11.17.2.

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11.8.2.1.5 IFM Energy Bid Cost

For any Settlement Interval, the IFM Energy Bid Cost for Bid Cost Recovery Eligible Resources, except Participating Loads, shall be the integral of the relevant Energy Bid used in ~~submitted to~~ the IFM, if any, from the higher of the registered Bid Cost Recovery Eligible Resource's Minimum Load and the Day-Ahead Total Self-Schedule up to the relevant MWh scheduled in the Day-Ahead Schedule, divided by the number of Settlement Intervals in a Trading Hour. ~~The IFM Energy Bid Cost for Bid Cost Recovery~~

~~Eligible Resources, except Participating Loads, and except for any portion of the Day-Ahead Schedule associated with an Energy Bid less than zero, for any Settlement Interval is set to zero for any portion of the Day-Ahead Schedule that is not delivered from the otherwise Bid Cost Recovery Eligible Resource that has metered Generation below its Day-Ahead Schedule; any portion of the Day-Ahead Schedule that is actually delivered remains eligible for IFM Energy Bid Cost Recovery.~~ The ~~delivered~~ IFM Energy Bid Cost calculations are subject to ~~portions of the Day-Ahead Schedule for this calculation are determined using~~ the application of the Day-Ahead Metered Energy Adjustment Factor, and the Persistent Deviation Metric pursuant to the rules specified in Section 11.8.2.5 and Section 11.17.2.3, respectively. In addition, if the CAISO commits a Bid Cost Recovery Eligible Resource in the Day-Ahead and receives a Day-Ahead Schedule and subsequently the CAISO de-commits the resource in the Real-Time Market, the IFM Energy Bid Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4. If the CAISO commits a Multi-Stage Generating Resource in the Day-Ahead Market and the resource receives a Day-Ahead Schedule and subsequently the CAISO de-commits the Multi-Stage Generating Resource to a lower MSG Configuration where its Minimum Load capacity in the Real-Time Market is lower than the CAISO IFM Commitment Period MSG Configuration's Minimum Load, the resource's IFM Energy Bid Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4. ~~The Day-Ahead Metered Energy Adjustment Factor is not applied to IFM Energy Bid Costs that associate with Energy Bids that are less than zero.~~ The CAISO will determine the IFM Energy Bid Cost for a Multi-Stage Generating Resource at the Generating Unit or Dynamic Resource-Specific System Resource level. ~~The CAISO will determine the applicable net IFM Energy Bid Cost surplus or net IFM Energy Bid Cost shortfalls as described in Section 11.8.2.4.~~

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11.8.2.1.7.1 IFM Transition Costs Applicability

Within any eligible IFM CAISO Commitment Period determined pursuant to the rules specified in Section 11.8.1.3, the CAISO shall apply the IFM Transition Costs for the Settlement Intervals in which the Multi-Stage Generating Resource~~s~~ is actually transitioning from the "from" MSG Configuration and reaches the Minimum Load of the "to" MSG Configuration to which the Multi-Stage Generating Resource is transitioning, subject to the Tolerance Band.

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11.8.2.2 IFM Market Revenue

The CAISO will apply the following rules to calculate a Bid Cost Recovery Eligible Resource's IFM Market Revenue used for purposes of calculating its IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses calculated pursuant to Section 11.8.2, and for purposes of allocating the Bid Cost Uplift pursuant to Section 11.8.6. The IFM Market Revenue calculations for both CAISO IFM Commitment Periods and Self-Committed Periods will be subject to the Day-Ahead Metered Energy Adjustment Factor pursuant to the rules specified in Section 11.8.2.5. ~~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.~~

~~**11.8.2.2.1 Instructed Imbalance Energy Greater Than Zero**~~

11.8.2.2.1~~.1~~ CAISO IFM Commitment

For any Settlement Interval in a CAISO IFM Commitment Period ~~in which the resource's Instructed Imbalance Energy is greater than zero (*i.e.*, the resource is dispatched by CAISO in real-time higher than the Day-Ahead Schedule)~~ the IFM Market Revenue for a Bid Cost Recovery Eligible Resource is the algebraic sum of the ~~following three~~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 ~~above the higher of the total day-ahead self-schedules and the Minimum Load submitted to the IFM~~ 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. ~~The delivered portions of the Day-Ahead Schedule in this case are determined based on the Day-Ahead Metered Energy Adjustment Factor.~~

(2) ~~The product of delivered MWh in the relevant Day-Ahead Schedule for portions at or below the Minimum Load submitted to the IFM and the relevant LMP divided by the number of Settlement Intervals in a Trading Hour. The delivered portions of the Day-Ahead Schedule in this case are determined based on the CAISO's determination that the resource was "On" for the applicable Trading Hour as described in Section 11.8.2.1.2;~~

~~(3)~~ 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.

~~**11.8.2.2.1.2** For any Settlement Interval in a IFM Self-Commitment Period the IFM Market Revenue for a Bid Cost Recovery Eligible Resource is the algebraic sum of: (1) the product of the delivered MWh above the greater of Minimum Load and Self-Scheduled Energy, in the relevant Day-Ahead Schedule in that Trading Hour and the relevant IFM LMP, divided by the number of Settlement Intervals in a Trading Hour; and (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. The delivered portions of the Day-Ahead Schedule in this case are determined based on the Day-Ahead Metered Energy Adjustment Factor.~~

~~**11.8.2.2.2 Instructed Imbalance Energy Equal to or Below Zero**~~

~~**11.8.2.2.2.1 CAISO IFM Commitment Period**~~

~~For any Settlement Interval in a CAISO IFM Commitment Period in which the resource's Instructed Imbalance Energy is equal to or less than zero (*i.e.*, the resource is dispatched by CAISO in real-time at or lower than the Day-Ahead Schedule) the IFM Market Revenue for a Bid Cost Recovery Eligible Resource is the algebraic sum of the following three products.~~

~~(1) The product of the scheduled MWh in the relevant Day-Ahead Schedule above the higher of the total day-ahead self-schedules and the Minimum Load submitted to the IFM 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 delivered MWh in the relevant Day-Ahead Schedule for portions at or below the Minimum Load submitted to the IFM and the relevant LMP divided by the number of Settlement Intervals in a Trading Hour. The delivered portions of the Day-Ahead Schedule in this case are determined based on the CAISO's determination that the resource was "On" for the applicable Trading Hour as described in Section 11.8.2.1.2;~~

~~(3) 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.~~

11.8.2.2.2~~.1~~ Resource Self-Committed

For any Settlement Interval in a IFM Self-Commitment Period the IFM Market Revenue for a Bid Cost Recovery Eligible Resource is the algebraic sum of: (1) the product of the MWh above the greater of Minimum Load and Self-Scheduled Energy, in the relevant Day-Ahead Schedule in that Trading Hour and the relevant IFM LMP, divided by the number of Settlement Intervals in a Trading Hour; and (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.

* * *

11.8.2.5 Application of the Day-Ahead Metered Energy Adjustment Factor to IFM Bid Costs and Market Revenues

The CAISO will adjust for each Bid Cost Recovery Eligible Resource the IFM Energy Bid Cost and IFM Market Revenue calculations by multiplying the Day-Ahead Metered Energy Adjustment Factor with the amounts derived as specified in Sections 11.8.2.1.5 and 11.8.2.2, respectively. In addition, the CAISO will apply the Real-Time Performance Metric to the IFM Energy Bid Costs, IFM Minimum Load Costs IFM Pumping Costs and IFM Market Revenues, as described in 11.8.4.4. The CAISO will apply the Day-Ahead Metered Energy Adjustment Factor to the IFM Pumping Bid Costs in the same manner in which the CAISO applies the Day-ahead Metered Energy Adjustment Factor to the IFM Energy Bid Costs as specified in this Section 11.8.2.5 and its subsections. In all cases, regardless of the rules specified below, the application of the Day-Ahead Metered Energy Adjustment Factor shall never increase a Bid Cost Recovery Eligible Resource's Unrecovered Bid Cost Uplift Payments. In the event that the CAISO discovers that there has been an increase in the Unrecovered Bid Cost Uplift Payment due to the application of the Day-Ahead Metered Energy Adjustment Factor, the CAISO will adjust the payment to recover the overpayment in a subsequent billing cycle as permissible under Section 11.29.

11.8.2.5.1 If the IFM Energy Bid Costs and the IFM Market Revenues for the amounts of Day-Ahead Scheduled Energy above the Bid Cost Recovery Eligible Resource's Minimum Load are greater than or equal to zero (0), the CAISO will apply the Day-Ahead Metered Energy Adjustment Factor to the IFM Energy Bid Costs, but not the IFM Market Revenue.

11.8.2.5.2 If the IFM Energy Bid Costs are greater than or equal to zero (0) and the IFM Market Revenues are negative, the CAISO will apply the Day-Ahead Metered Energy Adjustment Factor to both the IFM Energy Bid Costs and IFM Market Revenues.

11.8.2.5.3 If the IFM Energy Bid Costs are negative and IFM Market Revenues are greater or equal to zero, the CAISO will not apply the Day-Ahead Metered Energy Adjustment Factor to IFM Energy Bid Costs or IFM Market Revenues.

11.8.2.5.4 If the IFM Energy Bid Costs and the IFM Market Revenues are both negative, the CAISO will apply the Day-Ahead Metered Energy Adjustment Factor to the IFM Market Revenues, but it will not apply it to the IFM Energy Bid Costs.

11.8.2.5.5 If for any given Settlement Interval, the absolute value of the resource's Metered Energy less its Regulation Energy less the minimum of the Day-Ahead Schedule Energy and Expected Energy, is less than or equal to the Performance Metric Tolerance Band, then the CAISO will not apply the Day-Ahead Metered Energy Adjustment Factor to the IFM Energy Bid Cost or the IFM Market Revenue.

11.8.3 RUC Bid Cost Recovery Amount

For purposes of determining the RUC Unrecovered Bid Cost Uplift Payments as determined in Section 11.8.5 and for the purposes of allocating Net RUC Bid Cost Uplift as described in Section 11.8.6.5, the CAISO shall calculate the RUC Bid Cost Shortfall or the RUC Bid Cost Surplus as the algebraic difference between the RUC Bid Cost and the RUC Market Revenues for each Bid Cost Recovery Eligible Resource for each Settlement Interval. The RUC Bid Costs shall be calculated pursuant to Section 11.8.3.1 and the RUC Market Revenues shall be calculated pursuant to Section 11.8.3.2. The CAISO will include Bid Cost

Recovery costs related to Short Start Units committed in Real-Time because ~~as a result~~ of awarded RUC Capacity ~~will be included~~ in RTM~~RUC~~ Compensation Costs.

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11.8.3.1.1 RUC Start-Up Cost

The RUC Start-Up Cost for any Settlement Interval in a RUC Commitment Period shall consist of Start-Up Cost of the Bid Cost Recovery Eligible Resource submitted to the CAISO for the applicable RUC Commitment Period divided by the number of Settlement Intervals in the applicable RUC Commitment Period. For each Settlement Interval, only the RUC Start-Up Cost in a CAISO RUC Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the RUC Start-Up Cost for a Multi-Stage Generating Resource based on the MSG Configuration committed by the CAISO in RUC.

The following rules shall be applied in sequence and shall qualify the RUC Start-Up Cost in a RUC Commitment Period:

(a) The RUC Start-Up Cost for a RUC Commitment Period is zero if there is an IFM Commitment Period within that RUC Commitment Period.

(b) The RUC Start-Up Cost for a RUC Commitment Period is zero if the Bid Cost Recovery Eligible Resource is manually pre-dispatched under an RMR Contract prior to the Day-Ahead Market or is flagged as an RMR Dispatch in the Day-Ahead Schedule anywhere within that RUC Commitment Period.

(c) The RUC Start-Up Cost for a RUC Commitment Period is zero if there is no RUC Start-Up at the start of that RUC Commitment Period because the RUC Commitment Period is the continuation of an IFM, RUC, or RTM Commitment Period from the previous Trading Day.

(d) The RUC Start-Up Cost for a RUC Commitment Period is zero if the Start-Up is delayed beyond the RUC Commitment Period in question or cancelled by the Real-Time Market prior to the Bid Cost Recovery Eligible Resource starting its start-up process.

(e) If a RUC Start-Up is terminated in the Real-Time within the applicable RUC Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost Recovery Eligible Resource is starting up, the~~,~~ RUC Start-Up Cost is prorated by the ratio of the Start-Up Time before termination over the RUC Start-Up Time.

(f) The RUC Start-Up Cost for a RUC Commitment Period is qualified if an actual Start-Up occurs within that RUC Commitment Period. An actual Start-Up is detected between two consecutive Settlement Intervals when the relevant metered Energy in the applicable Settlement Intervals increases from below the Minimum Load Energy and reaches or exceeds the relevant Minimum Load Energy. The Minimum Load Energy is the product of the relevant Minimum Load and the duration of the Settlement Interval. The CAISO will determine the Minimum Load Energy for Multi-Stage Generating Resources based on the CAISO-committed MSG Configuration.

(g) The RUC Start-Up Cost shall be qualified if an actual Start-Up occurs. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Intervals indicates the unit is Off before the time the resource is instructed to be On as specified in its Start Up Instruction and is On in the Settlement Intervals that fall within the CAISO RUC Commitment Period. ~~earlier than the start of the RUC Start-Up, if the relevant Start-Up is still within the same Trading Day and the Bid Cost Recovery Eligible Resource actually stays on until the RUC Start-Up, otherwise the Start-Up Cost is zero for the RUC Commitment Period.~~

11.8.3.1.2 RUC Minimum Load Cost

The Minimum Load Cost for the applicable Settlement Interval shall be the Minimum Load Cost of the Bid Cost Recovery Eligible Resource divided by the number of Settlement Intervals in a Trading Hour. For each Settlement Interval, only the RUC Minimum Load Cost in a CAISO RUC Commitment Period is eligible for Bid Cost Recovery. The RUC Minimum Load Cost for any Settlement Interval is zero if: (1) the Bid Cost Recovery Eligible Resource is manually pre-dispatched under an RMR Contract or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule in that Settlement Interval; (2) the Bid Cost Recovery Eligible Resource is not committed or Dispatched in the Real-time Market ~~actually On~~ in the applicable Settlement Interval; or (3) the applicable Settlement Interval is included in an IFM Commitment Period. For the purposes of determining RUC Minimum Load Cost ~~n~~for a Bid Cost Recovery Eligible Resource recovery of the RUC Minimum Load Costs is subject to the Real-Time Performance Metric as specified in Section 11.8.4.4. ~~except for a Multi-Stage Generating Resource, is assumed to be On if its metered Energy in a Settlement Interval is equal to or greater than the difference between its Minimum Load Energy and the Tolerance Band. Otherwise, such non-Multi-Stage Generating Resources are determined to be Off.~~ For Multi-Stage Generating Resources, the commitment period is determined based on application of section 11.8.1.3. ~~If application of section 11.8.1.3 dictates that RUC is the commitment period, then the calculation of the RUC Minimum Load Costs will depend on whether the metered MSG Configuration is equal to or different from the RUC committed MSG Configuration. If the metered MSG Configuration is equal to the RUC committed MSG Configuration, then the RUC Minimum Load Costs will be based on the Minimum Load Costs of the RUC committed MSG Configuration. If the metered MSG Configuration is different from the RUC committed MSG Configuration, then the RUC Minimum Load Costs will be based on the lower of the Minimum Load Costs of the metered MSG Configuration and the Minimum Load Costs of the RUC committed MSG Configuration. The metered MSG Configuration is determined based on the highest MSG Configuration submitted to the RUC for which the Metered Data is within or above the three (3) percent (or 5 MW) Tolerance Band of the PMin of that highest MSG Configuration submitted to the RUC. Between two (2) (or more) MSG Configurations, the highest MSG Configuration is the MSG Configuration with the PMin value that is the greatest MW value.~~ The RUC Minimum Load Cost calculation will be subject to the Shut-Down State Variable and disqualified as specified in Section 11.17.2.

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11.8.3.1.4.1 RUC Transition Costs Applicability

Within any eligible RUC CAISO Commitment Period determined pursuant to the rules specified in Section 11.8.1.3, the CAISO shall apply the RUC Transition Costs for the Settlement Intervals in which the Multi-Stage Generating Resource~~s~~ is actually transitioning from the “from” MSG Configuration and reaches the

Minimum Load of the "to" MSG Configuration to which the Multi-Stage Generating Resource is transitioning, subject to the Tolerance Band.

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11.8.3.3.2 MSS Elected Net Settlement

For an MSS Operator that has elected net Settlement, regardless of other MSS optional elections (Load following or RUC opt-in or out), the RUC Bid Costs and RUC Market Revenue are ~~calculated~~ combined with RTM Bid Cost and RTM Market Revenue on an MSS level, consistent with the Energy Settlement as calculated according to Section 11.8.4.3.2. ~~The RUC Bid Cost Shortfall or Surplus is also settled at the MSS level as opposed to the individual resource level as is done for MSS Operators that have elected gross Settlement.~~

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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 and the RTM Market Revenues shall be calculated pursuant to Section 11.8.4.2. The Energy subject to RTM Bid Cost Recovery is the ~~actual Energy delivered in the Real-Time associated with~~ 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, 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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11.8.4.1.1 RTM Start-Up Cost

For each Settlement Interval of the applicable Real-Time Market Commitment Period, the Real-Time Market Start-Up Cost shall consist of the Start-Up Cost of the Bid Cost Recovery Eligible Resource submitted to the CAISO for the Real-Time Market divided by the number of Settlement Intervals in the applicable Real-Time Market Commitment Period. For each Settlement Interval, only the Real-Time Market Start-Up Cost in a CAISO Real-Time Market Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the RTM Start-Up Cost for a Multi-Stage Generating Resource based on the MSG Configuration committed by the CAISO in RTM. The following rules shall be applied in sequence and shall qualify the Real-Time Market Start-Up Cost in a Real-Time Market Commitment Period:

(a) The Real-Time Market Start-Up Cost is zero if there is a Real-Time Market Self-Commitment Period within the Real-Time Market Commitment Period.

(b) The Real-Time Market Start-Up Cost is zero if the Bid Cost Recovery Eligible Resource has been manually pre-dispatched under an RMR Contract or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule or Real-Time Market anywhere within that Real-Time Market Commitment Period.

(c) The Real-Time Market Start-Up Cost is zero if the Bid Cost Recovery Eligible Resource is started within the Real-Time Market Commitment Period pursuant to an Exceptional Dispatch issued in accordance with Section 34.9.2 to (1) perform Ancillary Services testing; (2) perform pre-commercial operation testing for Generating Units; or (3) perform PMax testing.

(d) The Real-Time Market Start-Up Cost is zero if there is no Real-Time Market Start-Up at the start of that Real-Time Market Commitment Period because the Real-Time Market Commitment Period is the continuation of an IFM or RUC Commitment Period from the previous Trading Day.

(e) If a Real-Time Market Start-Up is terminated in the Real-Time within the applicable Real-Time Market Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost Recovery Eligible Resource is starting up the Real-Time Market Start-Up Cost is prorated by the ratio of the Start-Up Time before termination over the Real-Time Market Start-Up Time.

(f) The Real-Time Market Start-Up Cost shall be qualified if an actual Start-Up occurs within that Real-Time Market Commitment Period. An actual Start-Up is detected ~~between two consecutive Settlement Intervals~~ when the relevant metered Energy in the applicable Settlement Interval(s) indicates the unit is Off before the time the resource is instructed to be On as specified in its Start Up Instruction and is On in the ~~increases from below the Minimum Load Energy and reaches or exceeds the relevant Minimum Load Energy~~ a Settlement Interval that falls within the CAISO Real-Time Market Commitment Period. ~~The Minimum Load Energy is the product of the relevant Minimum Load and the duration of the Settlement Interval. The CAISO will determine the Minimum Load Energy for Multi-Stage Generating Resources based on the CAISO-committed MSG Configuration.~~ The CAISO will determine that the Multi-Stage Generating Resource is On when, based on its metered Energy, the resource has been detected to have delivered the Minimum Load Energy of the MSG Configuration that CAISO has committed in the Real-Time Market. The Minimum Load Energy is the product of the relevant Minimum Load and the duration of the Settlement Interval.

(g) The Real-Time Market Start-Up Cost for a Real-Time Market Commitment Period shall be qualified if an actual Start-Up occurs earlier than the start of the Real-Time Market Start-Up, if the relevant Start-Up is still within the same Trading Day and the Bid Cost Recovery Eligible Resource actually stays on until the Real-Time Market Start-Up, otherwise the Start-Up Cost is zero for the Real-Time Market ~~RUC~~ Commitment Period.

(h) For Short-Start Units, the first Start-Up Costs within a CAISO IFM Commitment Period are qualified IFM Start-Up Costs as described above in Section 11.8.2.1.1(h). For subsequent Start-Ups of Short-Start Units after the CAISO Shuts Down a resource and then the CAISO issues a Start-Up Instruction pursuant to a CAISO RTM Commitment within the CAISO IFM Commitment

Period, the Start-Up Costs shall be qualified as Real-Time Start-Up costs, provided that the resource actually Shut-Down and Started-Up based on CAISO Shut-Down and Start-Up Instructions.

11.8.4.1.2 RTM Minimum Load Cost

The RTM Minimum Load Cost is the Minimum Load Cost of the Bid Cost Recovery Eligible Resource submitted to the CAISO for the Real-Time Market divided by the number of Settlement Intervals in a Trading Hour. For each Settlement Interval, only the RTM Minimum Load Cost in a CAISO RTM Commitment Period is eligible for Bid Cost Recovery. The RTM Minimum Load 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 On in that Settlement Interval;~~ (~~4~~3) for all resources that are not Multi-Stage Generating Resources, that Settlement Interval is included in an IFM or RUC Commitment Period; or (~~5~~4) the Bid Cost Recovery Eligible Resource is committed pursuant to Section 34.9.2 for the purpose of performing Ancillary Services testing, pre-commercial operation testing for Generating Units, or PMax testing. A resource's RTM Minimum Load Costs for Bid Cost Recovery purposes are subject to the application of the Real-Time Performance Metric as specified in Section 11.8.4.4. ~~For the purposes of RTM Minimum Load Cost, a Bid Cost Recovery Eligible Resource, other than a Multi-Stage Generating Resource, is determined to not actually be On if the metered Energy in that Settlement Interval is less than the Tolerance Band referenced by the Minimum Load Energy. .~~ For Multi-Stage Generating Resources, the commitment period is further determined based on application of ~~section~~ Section 11.8.1.3. ~~If application of section 11.8.1.3 dictates that the RTM is the commitment period, then the calculation of the RTM Minimum Load Costs will depend on whether the metered MSG Configuration is equal to or different from the RTM committed MSG Configuration. If the metered MSG Configuration is equal to the RTM committed MSG Configuration, then the RTM Minimum Load Costs will be based on the Minimum Load Costs of the RTM committed MSG Configuration. If the metered MSG Configuration is different from the RTM committed MSG Configuration, then the RTM Minimum Load Costs will be based on the~~

~~lower of the Minimum Load Costs of the metered MSG Configuration and the Minimum Load Costs of the RTM Committed configuration. The metered MSG Configuration is determined based on the highest MSG Configuration submitted to the Real-Time Market for which the Metered Data is within or above the three (3) percent (or 5 MW) Tolerance Band of the PMin of that highest MSG Configuration submitted to the Real-Time Market. Between two (2) (or more) MSG Configurations, the highest MSG Configuration is the MSG Configuration with the PMin value that is the greatest MW value. For Settlement Intervals that contain two (2) Dispatch Intervals with two (2) different MSG Configurations, the CAISO will determine the Transition Costs, and Minimum Load Costs based on the sum of the two (2) applicable Dispatch Intervals.~~ For all Bid Cost Recovery Eligible Resources that the CAISO Shuts Down, either through an Exceptional Dispatch or an Economic Dispatch through the Real-Time Market, from its Day-Ahead Schedule that was also from a CAISO commitment, the RTM Minimum Load Costs will include negative Minimum Load Costs for Energy between the Minimum Load and zero (0) MWhs. In addition, for all Multi-Stage Generating Resources that the CAISO commits down to a lower MSG Configuration with its Minimum Load capacity lower than the Day-Ahead CAISO Committed MSG Configuration's Minimum Load capacity, either through an Exceptional Dispatch or an Economic Dispatch through the Real-Time Market, from its IFM MSG Configuration that was also from a CAISO Commitment Period, the Minimum Load Costs will be equal to the RTM Minimum Load Cost less the IFM or RUC Minimum Load Cost, as applicable.

* * *

11.8.4.1.5 RTM Energy Bid Cost

For any Settlement Interval, the RTM Energy Bid Cost for the Bid Cost Recovery Eligible Resource except Participating Loads shall be computed as the sum of the products of each Instructed Imbalance Energy (IIE) portion, 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 Energy Bid prices, the Default Energy Bid price, or the Locational Marginal Price, if any, as further described in Section 11.17, for each Dispatch Interval in the Settlement Interval. For Settlement Intervals for which the Bid Cost Recovery Eligible Resource is ramping up to or down from a rerated Minimum Load that was increased in SLIC for the Real-Time Market, the RTM

Energy incurred by the ramping will be classified as Derate Energy and will not be included in Bid Cost Recovery. For a Bid Cost Recovery Eligible Resource that is ramping up to or down from an Exceptional Dispatch, the relevant Energy Bid Cost related to the Energy caused by ramping will be settled on the same basis as the Energy Bid used in the Settlement of the Exceptional Dispatch that led to the ramping. The RTM Energy Bid Cost for a Bid Cost Recovery Eligible Resource, including ~~except~~ Participating Loads and Proxy Demand Response Resources, for a Settlement Interval is subject to the Real-Time Performance Metric as described in Section 11.8.4.4 and the Persistent Deviation Metric as described in Section 11.17. ~~set to zero for any undelivered Real-Time Instructed Imbalance Energy by the Bid Cost Recovery Eligible Resource.~~ Any Uninstructed Imbalance Energy in excess of Instructed Imbalance Energy is also not eligible for Bid Cost Recovery. ~~The delivered Real-Time Instructed Imbalance Energy for this calculation are determined using the Real-Time Metered Energy Adjustment Factor.~~ For a Multi-Stage Generating Resource the CAISO will determine the RTM Energy Bid Cost based on the Generating Unit or Dynamic Resource-Specific System Resource level.

* * *

11.8.4.1.7 RTM Transition Cost

For each Settlement Interval, the RTM Transition Costs shall be based on the MSG Configuration to which the Multi-Stage Generating Resource is transitioning and are~~is~~ allocated to the CAISO commitment period of that MSG Configuration.

11.8.4.1.7.1 RTM Transition Costs Applicability

Within any eligible RTM CAISO Commitment Period determined pursuant to the rules specified in Section 11.8.1.3, the CAISO shall apply the RTM Transition Costs for the Settlement Intervals in which the Multi-Stage Generating Resource is actually transitioning from the “from” MSG Configuration and reaches the Minimum Load of the “to” MSG Configuration to which the Multi-Stage Generating Resource is transitioning, subject to the Tolerance Band.

11.8.4.2 RTM Market Revenue Calculations

The RTM Market Revenue calculations are subject to the Real-Time Performance Metric and the Persistent Deviation Metric as described in Sections 11.8.4.4 and 11.17, respectively.

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 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 LMP, for each Dispatch Interval in the Settlement Interval. ~~The Instructed Imbalance Energy for this calculation is subject to the Real-Time Metered Energy Adjustment Factor to capture metered energy.~~

~~(b) The product of the delivered MWh at or below the resource's Minimum Load submitted to the Real-Time Market (including Energy from Minimum Load of Bid Cost Recovery Eligible Resources committed in RUC) and the relevant Real-Time Market LMP, for each Dispatch Interval in the Settlement Interval, The delivered portions of the resource's Minimum Load in this case is determined based on the CAISO's determination that the resource was "On" for the applicable Trading Hour as described in Section 11.8.4.1.2; and~~

(~~c~~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.

(~~d~~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 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 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.

* * *

11.8.4.3.1 MSS Elected Gross Settlement

For an MSS Operator that has elected gross Settlement, regardless of other MSS optional elections (Load following or RUC opt-in or out), the RTM Bid Cost and RTM Market Revenue of the Real-Time ~~delivered~~ Instructed Imbalance Energy subject to Bid Cost Recovery is determined for each resource in the same way these amounts are determined ~~identically to the~~for a non-MSS resource pursuant to the rules specified~~following the general principles~~ in Section 11.8.4. The RTM Bid Cost Shortfall or Surplus for Energy and Ancillary Services in total is determined for each Trading Hour of the RTM over the Trading Day by taking the algebraic difference between the RTM Bid Cost and RTM Market Revenue.

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11.8.4.3.2 MSS Elected Net Settlement

For MSS entities that have elected net Settlement regardless of other MSS optional elections (i.e., Load following or not, or RUC opt-in or out), unlike non-MSS resources, the RUC and RTM Bid Cost Shortfall or Surplus is treated at the MSS level and not at the resource specific level, and is calculated as the RUC and RTM Bid Cost Shortfall or Surplus of all BCR Eligible Resources within the MSS. In calculating the Energy RTM Market Revenue for all the resources within the MSS as provided in Section 11.8.4.2, the CAISO will use the Real-Time Settlement Interval MSS Price. The RUC and RTM Bid Cost Shortfall and Surplus for Energy, RUC Availability and Ancillary Services are first calculated separately for the MSS for each Settlement Interval of the Trading Day, with qualified Start-Up Cost ~~and~~ , qualified Minimum Load Cost and qualified Multi-Stage Generator transition cost included into the RUC and RTM Bid Cost Shortfalls and Surpluses of Energy calculation. The RUC and RTM Bid Cost Shortfall or Surplus for Energy for each Settlement Interval is pro-rated by the ratio of the net positive metered Generation to the gross metered Generation of the MSS for that interval. If the MSS metered CAISO Demand is in excess of the MSS Generation in a given Settlement Interval, the CAISO will set the pro-rating ratio for that Settlement Interval to zero. The MSS's overall RUC and RTM ~~IFM~~ Bid Cost Shortfall or Surplus is then calculated as the algebraic sum of the pro-rated RUC and RTM Bid Cost Shortfalls and Surpluses for Energy ~~and~~, plus the RUC and RTM Bid Cost Shortfalls and Surpluses for Ancillary Services, plus the RUC Availability revenues ~~the RTM Bid Cost Shortfalls and Surpluses for AS~~ for each Settlement Interval.

11.8.4.4 Application of the Real-Time Performance Metric

The CAISO will adjust the RTM Energy Bid Cost, the RTM Market Revenues, and RTM Minimum Load Costs, the IFM Minimum Load Cost and IFM Energy Bid Cost calculations, and the IFM Market Revenues determined pursuant to Sections 11.8.4.1.5, 11.8.4.2, 11.8.4.1.2, 11.8.2.1.2, 11.8.2.1.5 and 11.8.2.2, respectively, by multiplying the Real-Time Performance Metric with those amounts for the applicable Settlement Interval, pursuant to the rules specified in this Section 11.8.4.4 and its subsections. The CAISO will apply the Real-time Performance Metric to the IFM Pumping Bid Costs and RTM Pumping Bid Costs in the same manner in which the CAISO applies the Real-time Performance Metric to the RTM

Energy Bid Costs as specified in this Section 11.8.4.4, and its subsections. In all cases, regardless of the rules specified below, the application of the Real-Time Performance Metric shall never increase a Bid Cost Recovery Eligible Resource's Unrecovered Bid Cost Uplift Payments. In the event that the CAISO discovers that there has been an increase in the Unrecovered Bid Cost Uplift Payment due to the application of the Real-time Performance Metric, the CAISO will adjust the payment to recover the overpayment, in a subsequent billing cycle as permissible under Section 11.29.

11.8.4.4.1 If the RTM Energy Bid Cost plus the RUC and RTM Minimum Load Costs and the RTM Market Revenues are greater than or equal to zero (0), the CAISO will apply the Real-Time Performance Metric to RTM Energy Bid Costs, RUC and RTM Minimum Load Costs, and not the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the IFM Energy Bid Cost plus the IFM Minimum Load Cost and the IFM Market Revenues are greater than or equal to zero (0), the CAISO will apply the Real-Time Performance Metric instead of Day-Ahead Metered Energy Adjustment Factor to the IFM Minimum Load Costs and IFM Energy Bid Costs, and not the IFM Market Revenues.

11.8.4.4.2 If the RTM Energy Bid Costs plus the RUC and RTM Minimum Load Costs are greater than or equal to zero (0) and the RTM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric to the RTM Energy Bid Costs, RUC and RTM Minimum Load Costs and the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the IFM Energy Bid Costs plus the IFM Minimum Load Cost are greater than or equal to zero (0) and the IFM Market Revenues are negative the ISO will apply the Real-Time Performance Metric instead of the Day-ahead Metered Energy Adjustment Factor to the IFM Minimum Load Costs and IFM Energy Bid Costs, and IFM Market Revenues.

11.8.4.4.3 If the RTM Energy Bid Costs plus the RUC and RTM Minimum Load Cost are negative and the RTM Market Revenues are greater than or equal to zero (0), the CAISO will not apply Real-Time Performance Metric to the RTM Energy Bid Costs, RUC and RTM Minimum Load Costs or the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the sum of IFM Energy Bid Costs the IFM Minimum Load Costs is negative and IFM Market Revenue is greater than or equal to zero (0), the CAISO will not apply the Real-Time Performance Metric to the IFM Minimum Load Costs, IFM Energy Bid Costs or the IFM Market Revenues.

11.8.4.4.4 If the RTM Energy Bid Costs plus the RUC and RTM Minimum Load Costs, and the RTM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric to the RTM Market Revenues but not the RTM Energy Bid Costs or the RUC and RTM Minimum Load Cost. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the IFM Energy Bid Costs plus the IFM Minimum Load Costs and the IFM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric instead of the Day-Ahead Metered Energy Adjustment Factor to the IFM Market Revenues but not the IFM Minimum Load Costs and IFM Energy Bid Costs.

11.8.4.4.5 If for a given Settlement Interval the absolute value of the resource's Metered Energy, less Regulation Energy and less Expected Energy, is less than or equal to the Performance Metric Tolerance Band, then the CAISO will not apply the Real-Time Performance Metric to the calculation of the RTM Energy Bid Cost, RUC and RTM Minimum Load Cost, or RTM Market Revenue.

11.8.5 Unrecovered Bid Cost Uplift Payment

Bid Cost Recovery Eligible Resources will receive an Unrecovered Bid Cost Uplift Payment as described in this Section below. For Multi-Stage Generating Resources, Unrecovered Bid Cost Uplift Payments will be calculated and made at the Generating Unit level and not the MSG Configuration level. MSS Bid Cost Recovery Eligible Resources by MSS Operators that have elected net settlement will receive Unrecovered Bid Cost Uplift Payment for MSS Bid Cost Recovery Eligible Resources at the MSS level and not by individual resource. MSS Bid Cost Recovery Eligible Resources by MSS Operators that have elected gross settlement will receive Unrecovered Bid Cost Uplift Payments at the MSS Bid Cost Recovery Eligible Resource level like all other resources.

11.8.5.1 IFM Unrecovered Bid Cost Uplift Payment

Scheduling Coordinators shall receive an IFM Unrecovered Bid Cost Uplift Payment for a Bid Cost Recovery Eligible Resource, ~~including resources for MSS Operators that have elected gross Settlement,~~ if the net of all IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses calculated pursuant to Section 11.8.2~~,~~ ~~RUC Bid Cost Shortfalls and RUC Bid Cost Surpluses calculated pursuant to Section 11.8.3, and the~~

~~RTM Bid Cost Shortfalls and RTM Bid Cost Surpluses calculated pursuant to Section 11.8.4 for that Bid Cost Recovery Eligible Resource~~ over a Trading Day is positive. ~~For Multi-Stage Generating Resources, Unrecovered Bid Cost Uplift Payments will be calculated and made at the Generating Unit level or Dynamic Resource-Specific System Resource and not the MSG Configuration level. For MSS Operators that have elected net Settlement, the Unrecovered Bid Cost Uplift Payment is at the MSS level. The MSS IFM, RUC, and RTM Bid Cost Shortfall or IFM. RUC, and RTM Bid Cost Surplus for each market for each Trading Hour is the sum of the IFM, RUC, and RTM Bid Cost Shortfalls and IFM. RUC, and RTM Bid Cost Surpluses for all resources in the MSS. Scheduling Coordinators for MSS Operators that have elected net Settlement will receive an Unrecovered Bid Cost Uplift Payment if the net of all IFM, RUC, and RTM Bid Cost Shortfalls and IFM, RUC, and RTM Bid Cost Surpluses for that MSS over a Trading Day is positive.~~

11.8.5.2 RUC and RTM Unrecovered Bid Cost Uplift Payment

Scheduling Coordinators shall receive RUC and RTM Unrecovered Bid Cost Uplift Payments for a Bid Cost Recovery Eligible Resource, if the net of all RUC Bid Cost Shortfalls and RUC Bid Cost Surpluses calculated pursuant to Section 11.8.3, and the RTM Bid Cost Shortfalls and RTM Bid Cost Surpluses calculated pursuant to Section 11.8.4, for that Bid Cost Recovery Eligible Resource over a Trading Day is positive. For Metered Subsystems that have elected net settlement, the Unrecovered Bid Cost Uplift Payment will be the sum, if positive, of the RUC, and RTM Bid Cost Shortfall or RUC, and RTM Bid Cost Surplus for each Trading Hour over the Trading Day for all Bid Cost Recovery Eligible Resources in the MSS.

11.8.6 System-Wide IFM, RUC ~~And~~ and RTM Bid Cost Uplift Allocation

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11.8.6.2 Sequential Netting of ~~IFM,~~ RUC and RTM Bid Cost Uplift

For each Settlement Interval, the Net ~~IFM,~~ RUC or Real-Time Market Bid Cost Uplift is determined for the purposes of allocating Net ~~IFM,~~ RUC or Real-Time Market Bid Cost Uplift by the following netting rules applied ~~sequentially~~:

~~(i) The Net IFM Bid Cost Uplift, if positive, is reduced to the greater of zero or any positive IFM Bid Cost Uplift offset by negative Real-Time Market Bid Cost Uplift first and offset by any negative RUC Bid Cost Uplift.~~

(i~~i~~) The Net RUC Bid Cost Uplift is equal to the greater of zero or any positive RUC Bid Cost Uplift offset by ~~any remaining~~ negative Real-Time Market Bid Cost Uplift ~~after netting negative Real-Time Market Bid Cost Uplift in (i) and offset by any negative IFM Bid Cost Uplift~~.

(ii~~i~~) The Net Real-Time Market Bid Cost Uplift is equal to the greater of zero or any positive Real-Time Market Bid Cost Uplift offset by any ~~remaining~~ negative RUC Bid Cost Uplift ~~after netting negative RUC Bid Cost Uplift in (i) above and any remaining negative IFM Bid Cost Uplift after netting negative IFM Bid Cost Uplift in (ii)~~.

11.8.6.3 Determination of Total Positive CAISO Markets Uplifts

11.8.6.3.1 Total Positive IFM Uplift

Any positive Net IFM Bid Cost Uplifts are reduced by scaling them with the uplift ratio in Section 11.8.6.3.1(iii) to determine the Total IFM Uplift (for a Settlement Interval) as follows:

(i) The Total IFM Uplift is the Net IFM Bid Cost Uplift for all Settlement Intervals in the IFM Market.

(ii) The Total Positive IFM Uplift is determined as the sum of the positive IFM Bid Cost Uplift for all Settlement Intervals in the IFM Market.

(iii) The uplift ratio is equal to the Total IFM Uplift divided by the Total Positive IFM Uplift.

11.8.6.3.2 Total Positive RUC and RTM Uplift

Any negative ~~IFM,~~ RUC ~~or~~ and Real-Time Market Bid Cost Uplifts are set to $0 and any positive Net ~~IFM Bid Cost Uplifts,~~ RUC Bid Cost Uplifts and~~, or~~ Real-Time Market Bid Cost Uplifts are further reduced by the uplift ratio in Section 11.8.6.3.2(iii) to determine the Total RUC and RTM ~~CAISO Markets~~ Uplift as follows;

(i) The Total RUC and RTM ~~CAISO Markets~~ Uplift is determined as the sum of the ~~Net IFM Bid Cost Uplift, the~~ Net RUC Bid Cost Uplift~~,~~ and the Net Real-Time Market Bid Cost Uplift~~,~~ for all Settlement Intervals in the ~~IFM,~~ RUC and Real-Time Market.

(ii) The Total Positive RUC and RTM ~~CAISO Market~~ Uplift~~,~~ is determined as the sum of the ~~positive IFM Bid Cost Uplift,~~ positive RUC Bid Cost Uplift and positive Real-Time Market Bid Cost Uplift, for all Settlement Intervals in the ~~IFM,~~ RUC and Real-Time Market.

(iii) The uplift ratio is equal to the Total RUC and RTM ~~CAISO Markets~~ Uplift divided by the Total Positive RUC and RTM ~~CAISO Market~~ Uplift.

11.8.6.4 Allocation of ~~Net~~ IFM Bid Cost Uplift

For each Trading Hour of the IFM the hourly ~~Net~~ IFM Bid Cost Uplift is allocated as follows:~~is determined as the sum over the Settlement Intervals in that Trading Hour of the product of any positive Net IFM Bid Cost Uplift remaining in the Settlement Interval after the sequential netting in Section 11.8.6.2 and the application of the uplift ratio as determined in Section 11.8.6.3.~~

11.8.6.4.1 Allocation in the First Tier

The hourly ~~Net~~ IFM Bid Cost Uplift is allocated in the first tier as follows:

(i) The hourly amount of ~~Net~~ IFM Bid Cost Uplift allocated to each Scheduling Coordinator is equal to the product of the IFM Bid Cost Uplift rate and the IFM uplift obligation for the Scheduling Coordinator.

(ii) The IFM Bid Cost Uplift rate is equal to the ~~Net~~ IFM Bid Cost Uplift divided by the sum of the positive IFM Load Uplift Obligations for all Scheduling Coordinators and the IFM system-wide Virtual Demand Award uplift obligation, subject to the condition that the IFM Bid Cost Uplift rate cannot exceed the ratio of the hourly ~~Net~~ IFM Bid Cost Uplift for the Trading Hour divided by the maximum of (a) the sum of all hourly IFM Load Uplift Obligations for all Scheduling Coordinators in that Trading Hour or (b) the sum of all hourly Generation scheduled in the Day-Ahead Schedule and IFM upward AS Awards for all Scheduling Coordinators from CAISO-committed Bid Cost Recovery Eligible Resources in that Trading Hour.

(iii) The IFM uplift obligation for each Scheduling Coordinator is equal to the sum of the IFM Load Uplift Obligation for the Scheduling Coordinator and any IFM Virtual Demand Award uplift obligation for the Scheduling Coordinator.

(iv) The IFM Load Uplift Obligation for each Scheduling Coordinator, including Scheduling Coordinators for Metered Subsystems regardless of their MSS optional elections (net/gross Settlement, Load following, RUC opt-in/out), is equal to the positive difference between the total Demand scheduled in the Day-Ahead Schedule of that Scheduling Coordinator and the sum of scheduled Generation and scheduled imports from the Self-Schedules in the Day-Ahead Schedule of that Scheduling Coordinator, adjusted by any applicable Inter-SC Trades of IFM Load Uplift Obligations.

(v) The IFM system-wide Virtual Demand Award uplift obligation is calculated for each hour in the IFM and is equal to maximum of zero (0) or the following quantity: the total system-wide Virtual Demand Awards from the IFM minus the total system-wide Virtual Supply Awards from the IFM, plus the minimum of zero (0) or the following quantity: the total amount of Scheduled Demand (which excludes Virtual Demand Awards), minus Measured Demand.

(vi) For each Scheduling Coordinator with positive net Virtual Demand Awards, the IFM Virtual Demand Award uplift obligation is equal to the product of (a) the positive net Virtual Demand Awards for the Scheduling Coordinator divided by the sum of each Scheduling Coordinator's positive net Virtual Demand Award and (b) the IFM system-wide Virtual Demand Award uplift obligation. For each Scheduling Coordinator with negative net Virtual Demand Awards, the IFM Virtual Demand Award uplift obligation is zero (0).

11.8.6.4.2 Allocation in the Second Tier

In the second tier, Scheduling Coordinators, including Scheduling Coordinators for MSS Operators that have elected both to not follow their Load and gross Settlement, will be charged for an amount equal to any remaining hourly ~~Net~~ IFM Bid Cost Uplift for the Trading Hour in proportion to the Scheduling Coordinator's Measured Demand. Scheduling Coordinators for MSS Operators that have elected to either follow their Load or net Settlement, or both, will be charged for an amount equal to any remaining hourly ~~Net~~ IFM Bid Cost Uplift for the Trading Hour in proportion to their MSS Aggregation Net Measured Demand.

* * *

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 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 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 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 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 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 Intertie Schedules in response to Dispatch Instructions or real-time scheduling curtailments are not allocated any Net RTM Bid Cost Uplift.

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11.17 ~~[NOT USED]~~ Application of the Persistent Deviation Metric

The CAISO will modify the Bid Cost Recovery calculations described in Section 11.8 and Residual Imbalance Energy payments in Section 11.5.5 as described below to address persistent deviations that expand Bid Cost Recovery payments beyond what is necessary for purposes of ensuring Bid Cost Recovery.

11.17.1 Persistent Deviations Threshold and Mitigation

The CAISO will calculate the Persistent Deviation Metric and evaluate each resource's response to a CAISO Dispatch in each Settlement Interval relative to the Persistence Deviation Metric Threshold as described below. The Persistent Deviation Metric Threshold evaluation will be based on the number of Settlement Intervals flagged within a rolling two-Trading Hour window. The CAISO will flag each Settlement Interval pursuant to the threshold conditions specified in Section 11.17.1.1, and apply the Persistent Deviation Metric pursuant to the rules specified in Section 11.17.1.2.

11.17.1.1 Persistent Deviation Threshold Conditions

11.17.1.1.1 Case 1

The CAISO will flag a Settlement Interval (t): (1) if Expected Energy is greater than Day-Ahead Scheduled Energy in that Settlement Interval (t), the Metered Energy is greater than the Expected Energy in that Settlement Interval (t), and the Metered Energy in the prior Settlement Interval (t-1) is less than the Expected Energy in the given Settlement Interval (t); and (2) if the Metered Energy, less Regulation Energy, less the Expected Energy in that Settlement Interval (t) is greater than ten (10) percent of the amount the resource can be Dispatched at full ramp over the Settlement Interval (t) and the Persistent Deviation Metric is greater than one hundred and ten (110) percent.

11.17.1.1.2 Case 2

The CAISO will flag a Settlement Interval (t): (1) if the Expected Energy exceeds the Day-Ahead Scheduled Energy in that Settlement Interval (t), and Metered Energy in the prior Settlement Interval (t-1) exceeds the Expected Energy in that Settlement Interval (t); and (2) if the Metered Energy less the Regulation Energy and less Expected Energy in that Settlement Interval (t) is greater than ten (10) percent of the amount the resource can be Dispatched at full ramp over the Settlement Interval (t) and the Persistent Deviation Metric is less than ninety (90) percent.

11.17.1.1.3 Case 3

The CAISO will flag a Settlement Interval (t): (1) if the Expected Energy is less than the Day-Ahead Scheduled Energy, and Metered Energy is less than the Expected Energy in that Settlement Interval (t), and Metered Energy in the prior Settlement Interval (t-1) is less than the Expected Energy in the given Settlement Interval (t); and (2) if the Metered Energy less Regulation Energy less Expected Energy in that Settlement Interval (t) is greater than ten percent (10) of the amount the unit could be Dispatched at full ramp over the Settlement Interval (t) and the Persistent Deviation Metric is less than ninety (90) percent.

11.17.1.1.4 Case 4

The CAISO will flag a Settlement Interval (t): (1) if the Expected Energy is less than the Day-Ahead Scheduled Energy, and Metered Energy is less than the Expected Energy in that Settlement Interval (t), and Metered Energy in the prior Settlement Interval (t-1) is greater than the Expected Energy in the given Settlement Interval (t); and (2) if the Metered Energy less Regulation Energy less Expected Energy is greater than (10) percent of the amount the resource can be Dispatched at full ramp over the Settlement Interval (t) and the Persistent Deviation Metric is greater than one hundred and ten (110) percent.

11.17.1.2 Persistent Deviation Adjustments

The ISO will apply the following rules to evaluate the resource's performance relative to the Persistent Deviation Metric Threshold and will apply the Persistent Deviation Metric as specified below.

11.17.1.2.1 Rule 1

If three (3) or fewer Settlement Intervals out of the previous twelve (12) 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) or more Settlement Intervals of the previous twelve (12) Settlement Intervals are flagged as exceeding the Persistent Deviation Metric Threshold, then for all the previous twelve (12) 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 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 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 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 Locational Marginal Price.

11.17.1.2.3 Rule 3

Once a Settlement Interval is flagged as exceeding the Persistent Deviation Metric Threshold, it remains flagged when it is considered in the subsequent rolling two-Trading Hour evaluation window and its bid basis qualification for that Settlement Interval will not change.

11.17.1.2.4 Rule 4

If a Settlement Interval's bid basis is determined by the Rule 1 above in a previous evaluation and it has not been flagged, it can be re-determined and flagged pursuant to the additional rules in a subsequent rolling two-Trading Hour evaluation window based on the Persistent Deviation Metric Threshold.

11.17.2 Shut-Down Adjustment

11.17.2.1 Disqualification Based on Advisory Schedules

From the Dispatch Interval in which the CAISO has determined that the Dispatch Operating Point minus the Shut-Down State Variable is less than or equal to the Minimum Load as registered in the Master File, and until the Shut-Down State Variable is reset, the IFM, RUC or RTM Minimum Load Costs, as applicable, will be disqualified from the Bid Cost Recovery calculation.

11.17.2.2 Disqualification Based on ADS Shut-Down Instruction

In the event that the CAISO issues a binding Shut-Down Instruction through ADS, a resource will not be eligible for recovery of RTM or RUC Minimum Load Costs from the point of the Shut-Down Instruction forward for the duration of the resource's registered Minimum Down Time. If a resource ignores the binding Shut-Down Instruction and it has a Day-Ahead Schedule, the resource is not eligible for IFM Minimum Load Cost recovery as specified in Section 11.8.2.3 for the minimum of 1) the resource's Minimum Down Time, and 2) the IFM Commitment Period.

11.17.2.3 Bid Basis for Settlement Bid Cost Recovery

For any resource that receives a Shut-Down Instruction in the Real-Time Market, any IFM or RTM Energy Bid Cost recovery that may otherwise apply pursuant to the rules in Section 11.8 will be based on the relevant Energy Bid price, as mitigated, that was considered by the Real-Time Market in making the decision to shut down the resource for the length of time defined by the greater of (a) the resource's Minimum Down Time or (b) the period in which it is Off after the Shut-Down time, which is not to exceed the time until the end of the Trading Day.

* * *

39.6.1.4 Minimum Bid Price for Energy Bids

The minimum Energy Bid price shall be negative $150/MWh. These rules apply to all Energy Bids, including Virtual Bids.

~~Energy Bids into the CAISO Markets less than -$30/MWh are not eligible to set any LMP. If the CAISO dispatches a resource with an Energy Bid less than -$30/MWh, the Scheduling Coordinator on behalf of the resource will be eligible to be paid the Bid price upon the submission of detailed information justifying the cost components of the Bid to the CAISO and FERC no later than seven (7) days after the end of the month in which the Bid was submitted. The CAISO will treat such information as confidential and will apply the procedure in Section 20.4 with regard to requests for disclosure of such information. The CAISO shall pay Scheduling Coordinators for amounts in excess of -$30/MWh minimum Bid price upon FERC acceptance of the information justifying the cost components. Virtual Bids may not be less than -$30/MWh.~~

* * *

Appendix A
Master Definition Supplement

* * *

- Day-Ahead Metered Energy Adjustment Factor

~~Is a~~A factor calculated for the purposes of determining the portions of a Scheduling Coordinator's resource's relevant Day-Ahead Schedule to be included in the Bid Cost Recovery calculations as further specified in the CAISO Tariff based on the resource's actual performance reflected in the Metered Energy which is calculated as ~~actually delivered based on the meter, taking into consideration the resource's metered energy. The factor is calculated as follows: The factor is~~ the minimum of: (1) the number one (1); or (2) ~~bounded by 1 or 0, and is~~ the absolute value of the ratio of the resource's (a) Metered Energy ~~minus the Day-Ahead Self-Scheduled Energy~~ less ~~minus~~ the Day-Ahead Minimum Load Energy and less the Regulation Energy, ~~minus the Standard Ramping,~~ and (b) the minimum of (i) the Expected Energy and (ii) the Day-Ahead Scheduled Energy, ~~*minus* the Day-Ahead Self-Scheduled Energy minus~~less the Day-Ahead Minimum Load Energy~~)~~. In cases where both the denominator and numerator produced by this calculation equal zero (0), the Day-Ahead Metered Energy Adjustment Factor will be set to one (1). If the denominator produced from this calculation equals zero (0), but the numerator is a non-zero number, the Day-Ahead Metered Energy Adjustment Factor will be set to zero (0). ~~For resources committed in pumping mode in day-ahead, the day-ahead pumping energy is used instead of the Day-Ahead Scheduled Energy.~~

* * *

- Dispatch Interval

The Time Period, which may range between five (5) and thirty (30) minutes, or as described in Section 34.3.2, a ten (10) minute interval for the Real-Time Contingency Dispatch, over which the Real-Time Dispatch measures deviations in Generation and Demand, and selects Ancillary Service and supplemental Energy resources to provide balancing Energy in response to such deviations. The Dispatch Interval shall be five (5) minutes. Following a decision by the CAISO Governing Board, the

CAISO may, by seven (7) days' notice published on the CAISO Website, increase or decrease the Dispatch Interval within the range of five (5) to thirty (30) minutes.

* * *

- Dispatch Operating Target

The optimal Dispatch of a resource as calculated by CAISO based on telemetry and representing a single point on the Dispatch Operating Point trajectory in the middle of the Dispatch Interval.

* * *

- 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 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 Schedules. Expected Energy is used as the basis for Settlements.

* * *

- IFM Bid Cost Uplift

The ~~system-wide~~ net of the IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses system-wide for a Settlement Interval of all Bid Cost Recovery Eligible Resources with Unrecovered Bid Cost Uplift Payments as specified in Section 11.8.6.2. ~~This amount will be netted according to Section 11.8.6.2 to calculate the Net IFM Bid Cost Uplift before allocation to Scheduling Coordinators.~~

* * *

- Performance Metric Tolerance Band

The tolerance band applied to the Day-Ahead Metered Energy Adjustment Factor and the Real-Time Performance Metric as specified in Section 11.8.2.5 and 11.8.4.4, respectively. This tolerance band is the Tolerance Band as defined in this Appendix A plus an additional ramping tolerance. For each Settlement Interval, the ramping tolerance is the difference between (1) the Energy calculated based on the linear curve between two applicable Dispatch Operating Targets; and (2) Expected Energy over the two applicable Dispatch Intervals.

* * *

- 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-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).

- Persistent Deviation Metric Threshold

The CAISO will calculate the Persistent Deviation Metric and will flag the interval based on the threshold described in Section 11.17.

* * *

~~**- Real-Time Metered Energy Adjustment Factor**~~

~~Is a factor calculated for the purposes of determining the portions of a Scheduling Coordinator's relevant Dispatch Instruction actually delivered based on the meter, taking into consideration the resource's metered energy. The factor is calculated as follows: The factor is bounded by 1 or 0, and is the ratio of the resource's (a) Metered Energy minus Day-Ahead Scheduled Energy minus Standard Ramping minus Real-Time Self-Scheduled Energy, and (b) total Expected Energy minus Day-Ahead Scheduled Energy minus Standard Ramping minus Real-Time Self-Scheduled Energy. For resources committed in pumping mode in real-time, the calculation in b) will effectively lead to the equivalent of real-time pumping energy.~~

* * *

- Real-Time Performance Metric

A factor calculated for the purposes of scaling a resource's Real-Time Bid Cost Recovery amounts calculated as the minimum of: (1) the number one (1); or (2) the absolute value of the ratio of the resource's (a) Metered Energy, less the Day-Ahead Scheduled Energy, and less the Regulation Energy, and (b) the total Expected Energy less the Day-Ahead Scheduled Energy. If the CAISO issues a Real-Time Dispatch to the resource that is incremental to its Day-Ahead Schedule and the resource deviates downward from its Day-Ahead Schedule, the Real-Time Performance Metric will be set to zero (0). If the CAISO issues a Real-Time Dispatch to the resource that is decremental to its Day-Ahead Schedule and the resource deviates to a level above its Day-Ahead Schedule, the Real-Time Performance Metric will be set to zero (0). If the resource's total Expected Energy is equal to the Day-Ahead Scheduled Energy and if the Metered Energy minus Regulation Energy is equal to the Day-Ahead Scheduled Energy, then the Real-Time Performance Metric is set to one (1). If the resource's total Expected Energy is equal to the Day-Ahead Scheduled Energy and if the Metered Energy minus the Regulation Energy is not equal to the Day-Ahead Scheduled Energy, then the Real-Time Performance Metric is set to zero (0). The Real-Time Performance Metric is applied as specified in the Section 11.8.4.4 and is not applied during any Settlement Interval when a resource is Starting Up, Shutting Down, in an MSG Transition Period crossing over a Forbidden Operating Region, or a Dispatch Operating Point correction is performed due to a verbal Dispatch Instruction issued by the CAISO Operator, as long as the resource is in fact in the operational mode instructed by the CAISO.

* * *

- Residual Imbalance Energy

Extra-marginal IIE produced or consumed at the start or end of a Trading Hour outside the hourly schedule-change band and not attributed to Exceptional Dispatch. Residual Imbalance Energy is due to a Dispatch Instruction in the previous Trading Hour or a Dispatch Instruction in the next Trading Hour. Residual Imbalance Energy may overlap only with Day-Ahead Scheduled Energy. Residual Imbalance Energy does not apply to Non-Dynamic System Resources (including Resource-Specific System Resources). Residual Imbalance Energy is settled as bid, based on the Real-Time Energy Bid of the reference hour, as described in Section 11.5.5 and it is not included in BCR as described in Section

11.8.4. ~~The reference hour is the previous Trading Hour, if Residual Imbalance Energy occurs at the start of a Trading Hour, or the next Trading Hour, if Residual Imbalance Energy occurs at the end of a Trading Hour.~~

* * *

- Shut-Down State Variable

A state variable to keep track of positive Uninstructed Imbalance Energy once an advisory Shut-Down Instruction is issued to a resource. The Shut-Down State Variable provides the MWh cumulative over the Real-Time Unit Commitment Intervals had the resource followed the Shut-Down Instruction. The Shut-Down State Variable begins to accumulate the positive Uninstructed Imbalance Energy MWh as soon as the advisory schedule includes a zero (0) MW Dispatch Operating Target within the Real-Time Market dispatch horizon and continues to accumulate the positive Uninstructed Imbalance Energy as long as (1) the unit is On, and (2) the Metered Energy less Regulation Energy less the Expected Energy is greater than the Performance Metric Tolerance Band. The Shut-Down State Variable will be reset to zero when the most recent Real-Time Unit Commitment run no longer has a zero (0) MW Dispatch Operating Target within the Real-Time Dispatch horizon or the resource is Off.

Attachment C – ISO's 20% RPS Study

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with

Additional Performance Based Refinements

California Independent System Operator Corporation

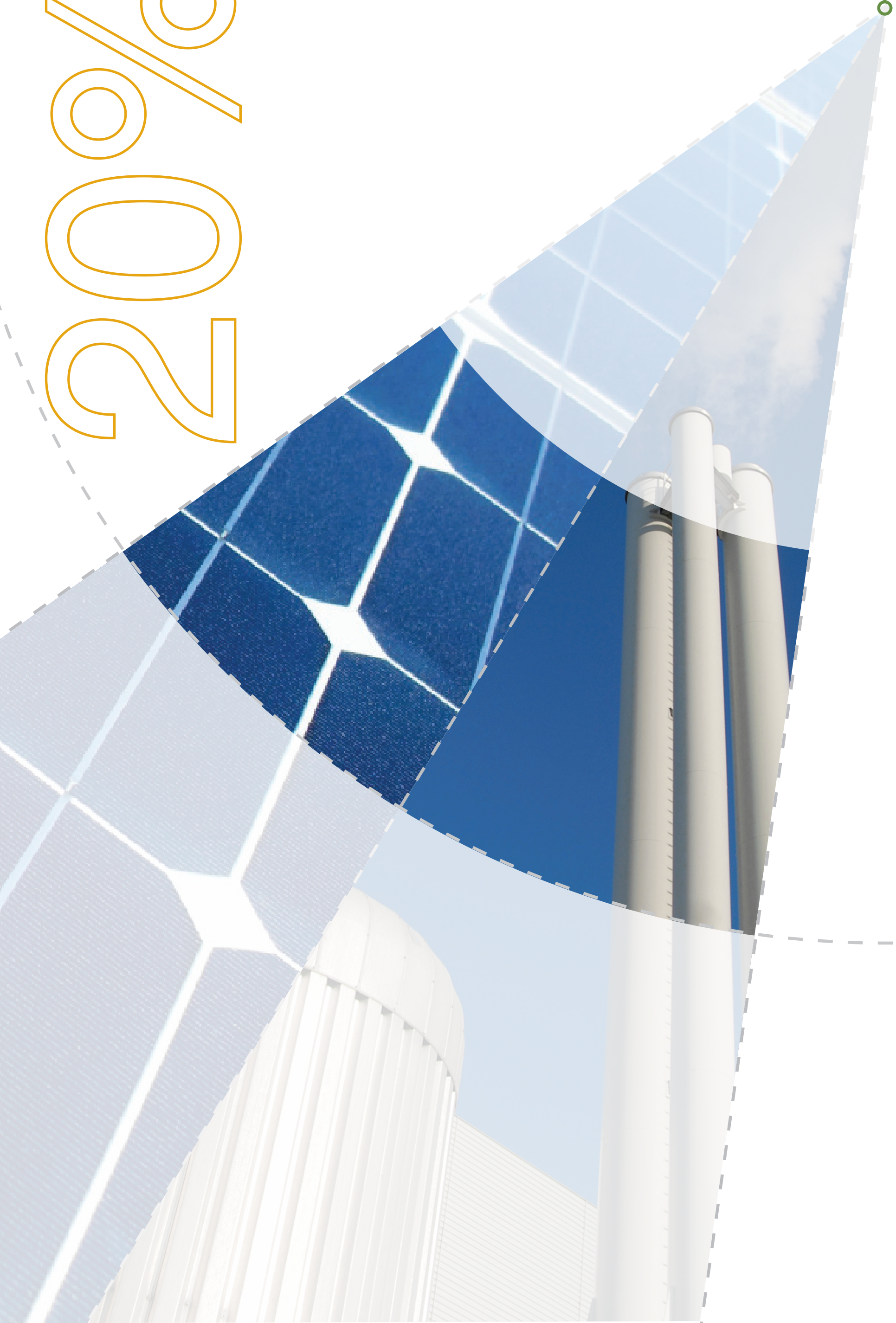
September 25, 2013

20% RPS

INTEGRATION OF RENEWABLE RESOURCES

Operational Requirements and Generation Fleet Capability at **20% RPS**

August 31, 2010



California ISO
Your Link to Power

Table of Contents

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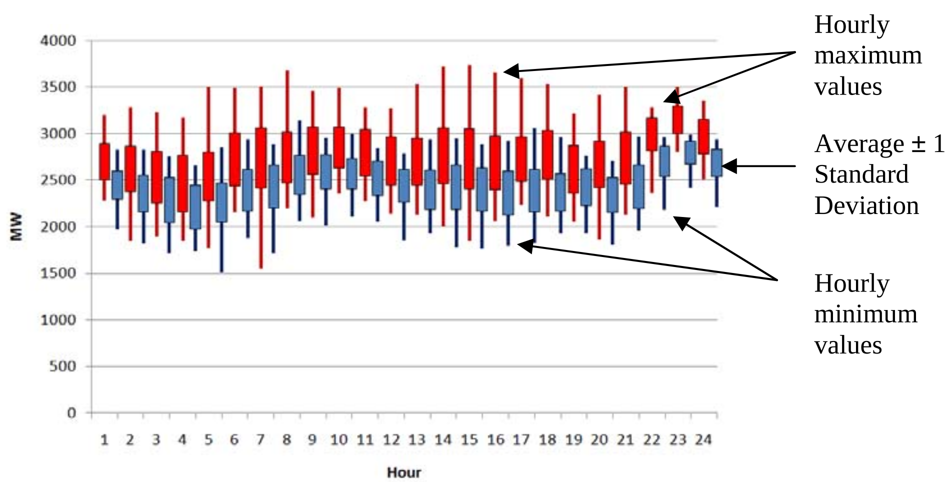
Preliminary Notes and Key to Figures

1. A number of the technical terms in this report refer to market products and market scheduling or operational procedures used by the ISO. Typically, such references are capitalized in ISO papers and reports to indicate that they are a defined term in the ISO Tariff. In this report, most technical terms are not capitalized and the use of acronyms is minimized to facilitate reading. For example, Regulation Up and Regulation Down are ancillary service products procured in the ISO markets, but are not capitalized in the report.

2. Many of the figures in the report represent data in the format of a "stock chart" or "whisker chart" that shows certain distribution statistics for a sample of simulated values or actual market results, typically shown by hour of season. In the example below, the top of the red or blue lines is the maximum data point in a sample, while the bottom of the red or blue lines is the minimum data point. The red and blue bars represent two standard deviations: the average plus one (1) standard deviation and the average minus one (1) standard deviation. Many of the figures, such as the one below, show these results for two simulated years that are being compared, in which case the results for each year are in different colors.



3. The figures in the report that use the format shown above are either measuring operational requirements in the upwards (positive) direction, which represent "incremental" energy or reserves, or in the downwards (negative) direction, which represents "decremental" energy or reserves. The figure above is for incremental energy, hence the vertical axis (or y-axis) is measuring positive values. For figures that show decremental energy or reserves, the y-axis shows negative values and the maximum and minimum of the sample data is reversed (i.e., the maximum requirement is the most negative).

4. In several sections of the report, readers need to distinguish between simulated results and actual results for the same or similar years. For certain simulations, the study benchmarks the results in the 20 percent RPS target year, assumed to be 2012, by simulation of prior years without the additional renewables, which in this study is 2006 and 2007. The study also includes analysis of actual ISO market and system conditions for selected periods up to 2010. The simulations of prior years, such as 2006, have been validated by comparison to actual conditions in those years, but there are differences due to modeling assumptions, as noted in the report.

Acronyms and Selected Definitions

ACE	Area Control Error
ADS	Automatic Dispatch Signal
AGC	Automatic Generation Control
BAA	Balancing Authority Area
BPM	Business Practice Manual
CEC	California Energy Commission
CPS	Control Performance Standard
CPUC	California Public Utilities Commission
DA	Day Ahead
EMS	Energy Management System
FERC	Federal Energy Regulatory Commission
FNM	Full Network Model
GW, GWh	Gigawatt, Gigawatt-hour (GW = 1,000 MW)
HA	Hour Ahead
HASP	Hour Ahead Scheduling Process
IFM	Integrated Forward Market
ISO	Independent System Operator
MW, MWh	Megawatt, Megawatt-hour (MW = 1,000 kW)
NERC	North American Electric Reliability Corporation
OTC	Once Through Cooling
PIRP	Participating Intermittent Resource Program
Pmin; Pmax	minimum and maximum operating level of a generator
PNNL	Pacific Northwest National Lab
PV	photovoltaic
QF	Qualifying Facility
RPS	Renewables Portfolio Standard
RT	Real Time
RTUC	Real Time Unit Commitment
WECC	Western Electricity Coordinating Council

Executive Summary

Under California's existing Renewables Portfolio Standard (RPS), utilities must supply 20 percent of all electricity retail sales from eligible renewable resources by 2010, with compliance expected in the 2011-2012 timeframe.[1] Much of the additional renewable generation to meet the RPS goal will be wind and solar technologies with variable operating characteristics that complicate electric system operations. As the entity responsible for the reliable operation of the bulk electric power system for most of the state, the California Independent System Operator Corporation (ISO) is focused on ensuring that the electric system is able to operate reliably with these additional renewable resources. This report represents an essential step in that effort. It describes the technical effects on system operations and wholesale markets of increases in wind and solar generation to achieve the 20 percent RPS target and evaluates the capability of the current generation fleet to maintain reliability under these changed conditions.

The chart below (Figure ES-1) shows the expected technology mix of renewable resource capacity assuming the 20 percent RPS is achieved in 2012 and compares it to the renewable resources in 2006, which is the year used to benchmark a number of study results.[2] Much of the expansion in renewable energy will come from variable energy resources, namely wind and solar technologies. The integration of variable energy resources will require increased operational flexibility—notably capability to provide load-following and regulation in wider operating ranges and at ramp rates that are faster and of longer sustained duration than are currently experienced. Forecast uncertainty associated with wind and solar production will increase the need for reservation of resource capacity to ensure that these requirements are met in real-time operations. There is also the likelihood of increased occurrence and magnitude of overgeneration, a condition where there is more supply from non-dispatchable resources, than there is demand. In providing these capabilities, the existing and planned generation fleet will likely need to operate longer at lower minimum operating levels and provide more frequent starts, stops and cycling over the operating day. Against this backdrop, certain conventional generators will also be operating at lower capacity factors due to the increased output from renewable energy generation.

To understand the extent of these impacts at 20 percent RPS, the ISO has conducted several analyses, both collaboratively and independently, over the past several years, including a study released in 2007 that focused on the operational and transmission

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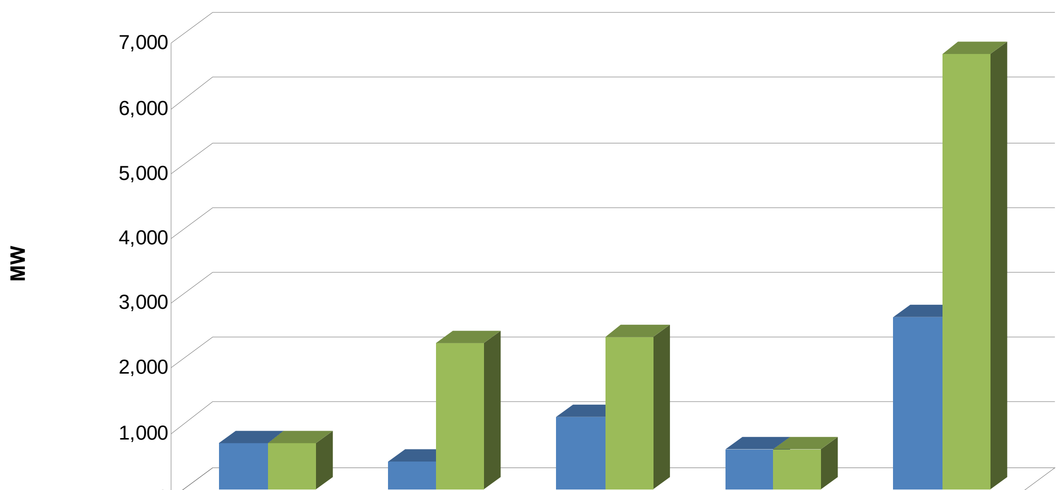
[1] California Public Utilities Commission, "Renewables Portfolio Standard, Quarterly Report, 2nd Quarter 2010", at http://www.cpuc.ca.gov/NR/rdonlyres/66FBACA7-173F-47FF-A5F4-BE8F9D70DD59/0/Q22010RPSReporttotheLegislature.pdf.

[2] The year 2006 was chosen as the benchmark year to facilitate easier comparison with prior ISO studies. This year was both a high hydro year—hence is useful as a base-year to examine the interaction of hydro and higher levels of wind production in overgeneration conditions—and had the highest annual peak load to date.

requirements of wind integration ("2007 Report").[3] This study builds on those prior efforts. The purpose of this study is to assess the operational impacts of an updated renewable resource portfolio that includes 2,246 MW of solar and to evaluate in more detail the operational capabilities of the existing generation fleet, as well as changes to their energy market revenues. The study utilizes several analytical methods, including a statistical model to evaluate operational requirements, empirical analysis of historical market results and operational capabilities, and production simulation of the full ISO generation fleet.

The results presented in this report have significant operational and market implications. From an operational perspective, the ISO is concerned with the extremes of potential impacts—in particular large, fast ramps that are difficult to forecast. A key purpose of the simulations in this study is to estimate the operational capabilities and clarify possible changes to market and operational practices to ensure that the system can perform as needed under these conditions, even if they rarely occur. Hence, the study identifies the maximum values of simulated operating requirements, such as load-following and regulation, by operating hour and by season. In addition, to clarify how more typical daily operations may change, distribution statistics are provided for most of the simulated requirements and capabilities to facilitate both operational and market preparedness.



	Biomass/BioGass	Solar	Geothermal	Small Hydro	Wind
2006	701	420	1,101	614	2,648
2012 (expected)	701	2,246	2,341	614	6,688

Figure ES-1: Renewable Resource Capacity (MW) in 2006 and 2012 (expected)

[3] California ISO, *Integration of Renewable Resources – Transmission and Operating Issues and Recommendations for Integrating Renewable Resources on the ISO-Controlled Grid* (Nov. 2007), available at http://www.caiso.com/1ca5/1ca5a7a026270.pdf.

Key Findings and Results

- The modeling of 2,246 MW of solar resources under the 20 percent RPS changes the operational requirements, compared to the incremental wind-only results presented in the ISO's 2007 Report.

- The changes to the operational requirements due to additional solar resources take place in the mid-morning and early evening hours. The ramp up in solar generation in the mid-morning can increase the load-following down and regulation down requirements compared to the case with wind generation alone that was studied in 2007. Similarly, the solar ramp down in early evening can increase the load-following up and regulation up requirements compared to the case with wind alone.

- In other hours, the combination of solar and wind resources can lessen operational requirements, because solar resources are ramping up when wind resources are ramping down, and vice-versa.

- The combination of increased production of wind and solar energy will lead to displacement of energy from thermal (gas-fired) generation in both the daily off-peak and on-peak hours. Due to this displacement and to simultaneous reduction in market clearing prices, there may be significant reductions in energy market revenues to thermal generation across the operating day in all seasons.

Load-following Impacts

A core operational and market function of the ISO is to forecast system load and renewable production day-ahead and in real-time, and then to ensure that sufficient generation and non-generation resources are committed such that intra-hourly deviations from hourly schedules can be accommodated by those resources under ISO dispatch control. These deviations can take place in the upward or downward direction. Currently, the intra-hourly deviations are largely caused by changes in load, hence the term "load-following." With additional variable energy resource production, the *net* load-following requirement—i.e., the requirement due to load schedule deviations plus wind and solar schedule deviations—could increase substantially in certain hours due both to the variability of wind and solar production and forecast uncertainty. Unless otherwise indicated, all results on load-following requirements in this report are of net load following.

- The simulated maximum load-following up and load-following down ramp rates for 2012, by season in which they occur, are 194 MW/min (summer) and -198 MW/min (winter), respectively.[4] These represent possible increases at times in the range of ± 30-40 MW/min over the ramp rates simulated for the year 2006.

[4] The load-following ramp rate measures the change in energy requirements between 1-minute intervals within the 5-minute dispatch intervals in an operating hour. The details behind the calculation of load-following ramp rate can be found in Section 3.

- While the system must be capable of delivering these capabilities, such ramp rates will not be experienced in every operational hour, nor sustained over the entire hour.

- One measure of the upper bound on the duration of the increased ramp rates is the hourly load-following capacity requirement.[5] The maximum hourly load following up and load-following down capacity requirements for 2012 are 3737 MW and -3962 MW (both summer season requirements), respectively. For the summer months, the maximum increase in the hourly capacity requirement when 2012 is compared to 2006 is 845 MW for load-following up and -930 MW for load-following down. As shown in Figures ES-2 and ES-3, in the summer, the highest requirements are typically in the morning and evening wind and solar ramp periods.

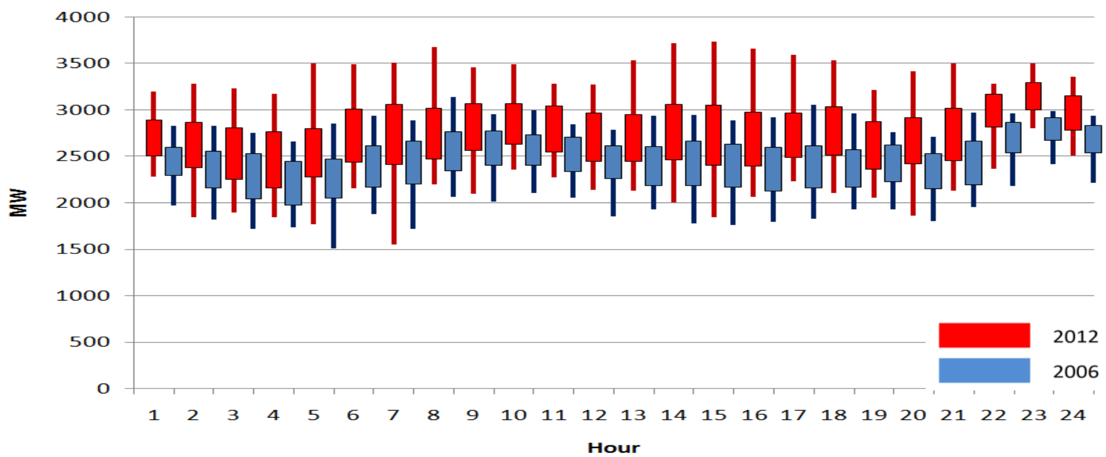


Figure ES-2: Simulated Load-following Up Capacity Requirement by Operating Hour, Summer, 2006 and 2012

[5] The hourly load-following capacity requirement is defined as the maximum difference between each hour-ahead schedule and the 5-minute real-time schedules within that hour. This can be measured in the upward or downward direction from the hourly schedule.

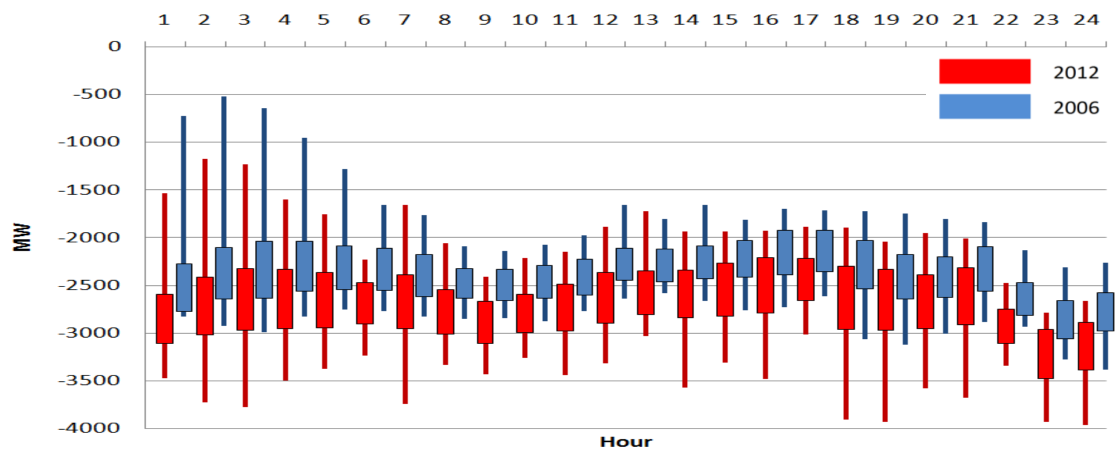


Figure ES-3: Simulated Load-following Down Capacity Requirement by Operating Hour, Summer, 2006 and 2012

- When the simulated maximum requirements for all hours in the season are taken into account, the percentage increase in total load-following capacity requirements in the summer season between 2012 and 2006 is estimated at 12 percent for load-following up and 14 percent for load-following down; the results for all seasons are shown in Table ES-1.[6]

Table ES-1: Percentage Increase in Total Seasonal Simulated Operational Capacity Requirements, 2012 vs. 2006

	Spring	Summer	Fall	Winter
Total maximum load-following up	27.0 %	11.9 %	19.2 %	19.7 %
Total maximum load-following down	29.5 %	14.0 %	21.2 %	21.3 %
Total maximum regulation up	35.3 %	37.3 %	29.6 %	27.5 %
Total maximum regulation down	12.9 %	11.0 %	14.2 %	16.2 %

- The historical 5-minute load-following capability[7] of the generation fleet, was measured for the period between April 1, 2009, and June 30, 2010. Figures ES-4 and ES-5 show the 5-minute load-following up and load-following down capability for units on 5-minute dispatch in the summer months during that period.[8] The results show that the ISO dispatch in recent months appears, for the majority of intervals analyzed, to be able to meet the load-following up

[6] The total is defined as the sum of the maximum simulated load-following capacity requirement in each hour of the season (2160 hours = 90 days × 24 hrs./day for a 90 day season); see Section 3 for details.

[7] The 5-minute load-following up (down) capability for a dispatch interval is the *maximum* capability that is available in the up (down) direction in 5-minutes, subject to the ramp rates and operational constraints of the dispatched resources.

[8] In the figures, each bar corresponding to an operating hour represents 1080 measurements for a 90 day season; e.g., for hour 1, each 5-minute interval of that hour for each of the 90 hour 1s in the season.

requirements simulated for 20 percent RPS within 20 minutes or less.[9] This is simply due to the ramp capacity remaining on units not dispatched to their maximum operating levels, and not to any preparations made by the ISO to address renewable integration.

- The simulated maximum load-following down ramp rate for summer in 2012 was -169 MW/min, which is -845 MW/5 min. These high load-following down requirements are often for the mid-morning hours. Under the current practice of self-scheduling generation rather than allowing them to be operated through economic dispatch, the 5-minute downward ramp capability as shown in Figure ES-5 could be well below the requirement of -845 MW during some of the mid-morning hours.

- Figures ES-5 and ES-6 compare the 5-minute load-following down capability, limited and not limited by self-schedules, respectively. Figure ES-6 suggests that current load following down capability could be more than doubled in many hours if all thermal generation were fully dispatchable. The implication is that to accommodate the increased variability at 20 percent renewable energy, the level of self-schedules will have to decrease.

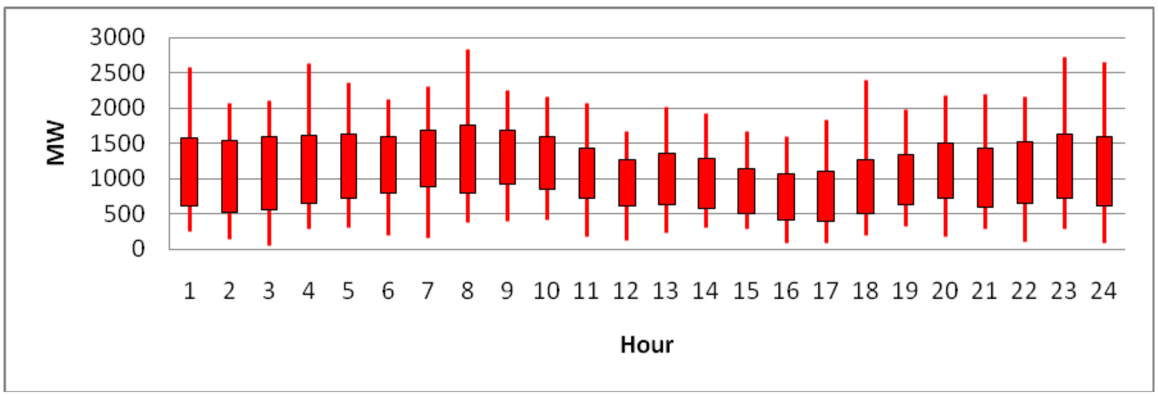


Figure ES-4: Summer 5-Minute Load-following Up Capability: June 2009-August 2009, June 2010

[9] For example, if the 3,737 MW maximum load-following up capacity has to be met within 20 minutes of the start of the hour, the results suggest that in most hours, the current system ramp could on average in most hours sustain 1000 MW/5-minutes or more, meaning that the requirement could be met and slightly exceeded in 4 such intervals.

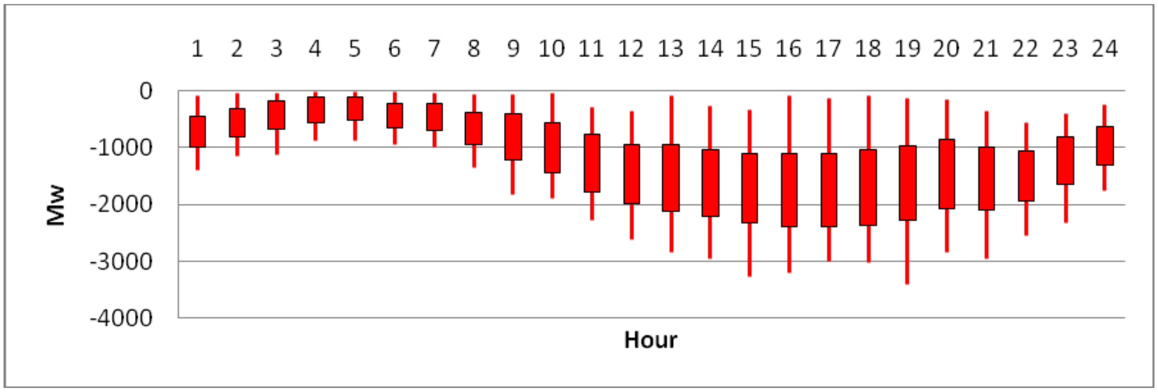


Figure ES-5: Summer 5-Min Load-following Down Capability (Limited by Self Schedules): June 2009-August 2009, June 2010

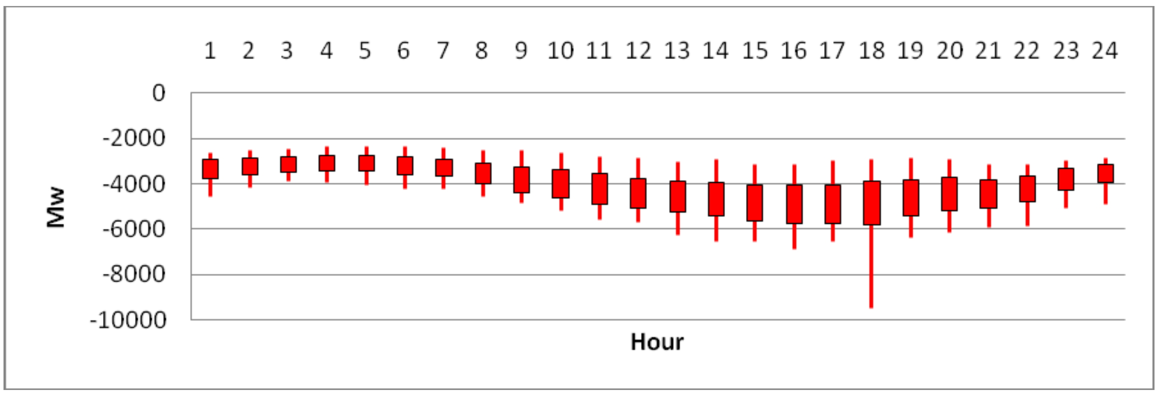


Figure ES-6: Summer 5-Minute Load-following Down Capability (not limited by Self-Schedules): June 2009-August 2009, June 2010

To further evaluate the load-following up and down capabilities of the ISO generation resources, the ISO also conducted production simulations for selected days that included simulation of 5-minute dispatch. The production simulation assumed that all thermal generation were fully dispatchable (i.e., maximum operational flexibility), but that all other classes of generation were following fixed schedules.

- Figure ES-7 shows the load-following capability over one such simulated day, May 28, 2012. This figure shows the capability of the dispatchable generators to move from one 5-minute dispatch to the next, subject to ramp and other operational constraints.[10] The 5-minute load-following down capability is at or

[10] It should be noted that Figure ES-7 shows the simulated load-following capability for each 5-minute period in the day, whereas Figure ES-5 shows the historical hourly distribution of 5-minute load-following capability.

close to zero during the morning hours from 4 a.m. to 10 a.m.[11] as shown. If current scheduling practices continue, this simulated capability would be further diminished due to self-scheduling. Production simulation results for additional days can be found in Section 5 and Appendix C.

- Figure ES-8 then shows the simulated overgeneration on May 28, 2012 due to the shortage of load-following down capability. Insufficient capability to ramp down manifests itself as overgeneration in the production simulations.[12] This figure also shows the regulation down procurement (green line) and the CPS2[13] violation threshold (yellow line) for the same period. While there is significant, sustained overgeneration for a few hours from 5 a.m. to 8 a.m., for the other hours in the day, the overgeneration can be covered by the procured regulation down or allowed to result in an Area Control Error (ACE) violation, if it is not sustained. Only significant overgeneration sustained over 10 minutes is likely to result in the curtailment of generation.

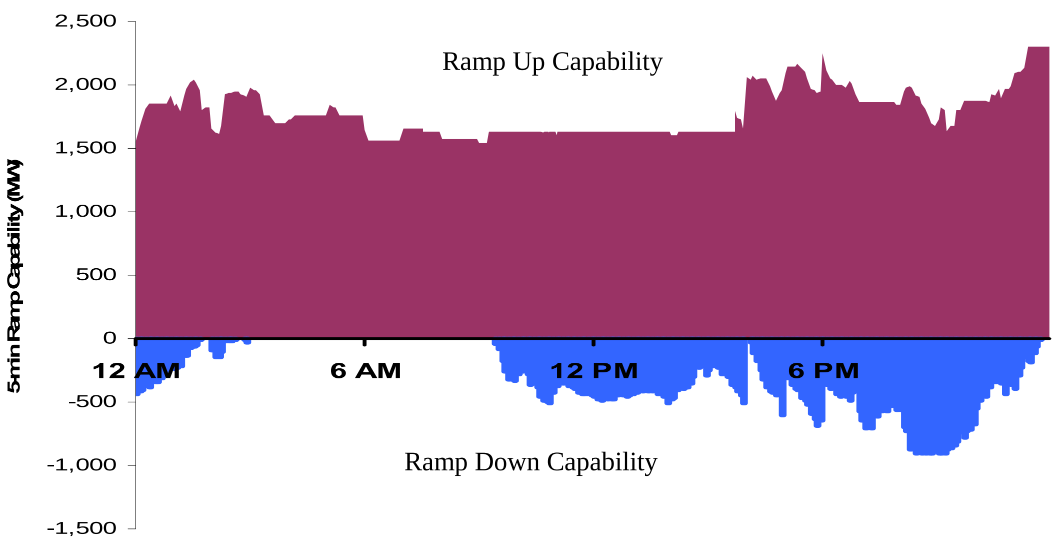


Figure ES-7: 5-minute ramp up and down capability for May 28, 2012

[11] The low load-following down capability in the simulation is because very few dispatchable generators are online and most are already operating at or close to their minimum load point. When operators can no longer dispatch resources downwards, the operating condition called overgeneration exists and is managed through additional measures, including curtailments of renewable resources.

[12] As discussed further in Sections 2 and 5, there were further constraints in the model that affected the overgeneration result.

[13] NERC Control Performance Standard 2.

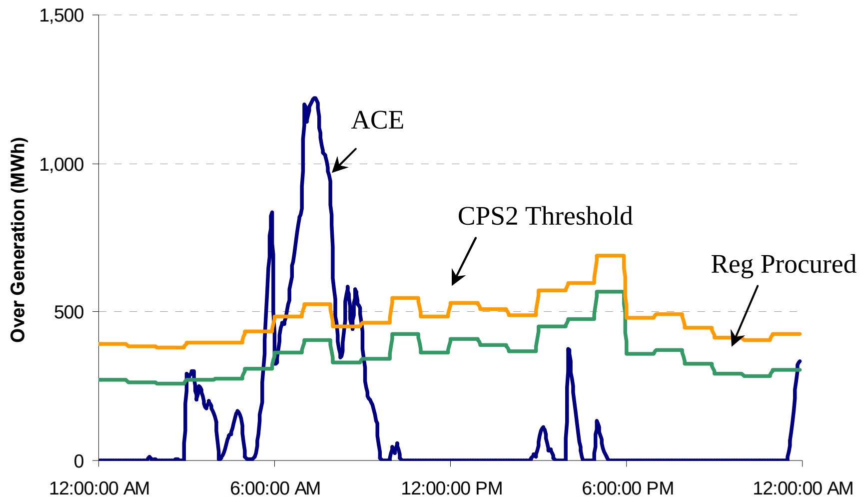


Figure ES-8: Detailed overgeneration analysis of May 28, 2012

- For the year, production simulations show that load-following down shortages will result in less than 0.02 percent of renewable generation (approx. 10 GWh) potentially needing to be curtailed under assumed conditions. The production simulations did not identify any load-following up shortages.

Regulation Impacts

In real-time, the ISO operators issue dispatch instructions to generators every 5 minutes based on forecasts of demand and supply that are available in the prior minutes. The second-by-second variability of load, net of wind and solar production, within those 5-minute intervals is balanced by units on automatic generation control (AGC) that can provide regulation as needed in the upwards or downwards direction.

- The maximum hourly regulation up and regulation down capacity requirements in 2012, which take place in different seasons, are 502 MW (spring) and -763 MW (summer), respectively. The largest increases in these requirements between the 2012 and 2006 simulations are 270 MW (spring) and -457 MW (summer). These results are found in Appendix A-1, tables A-1 to A-8.

- As shown in Figures ES-9 and ES-10 for the summer 2012 season, the highest regulation up requirements are typically in the morning and evening wind and solar ramp periods, while regulation down requirements are concentrated in the mid-afternoon hours. Hour 18 consistently results in very high regulation down requirements in the summer simulations, due largely to the consistently fast wind ramp up experienced in that hour.

- The maximum hourly simulated regulation up and regulation down ramp rates in 2012 are 122 MW/min (spring) and -97 MW/min (summer), respectively, compared to 75 MW/min and -79 MW/min, respectively, for simulated 2006 levels.

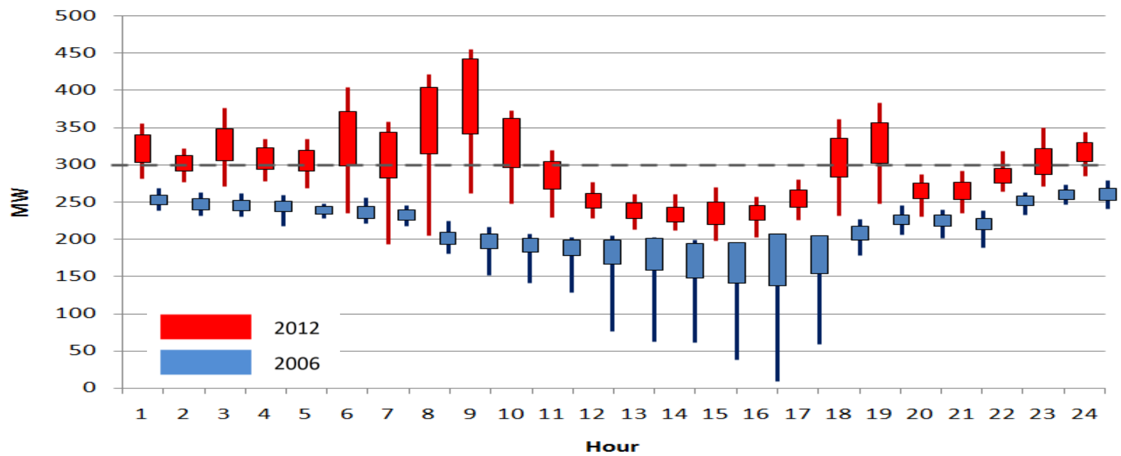


Figure ES-9: Simulated Regulation Up Capacity Requirement by Operating Hour, Summer, 2006 and 2012

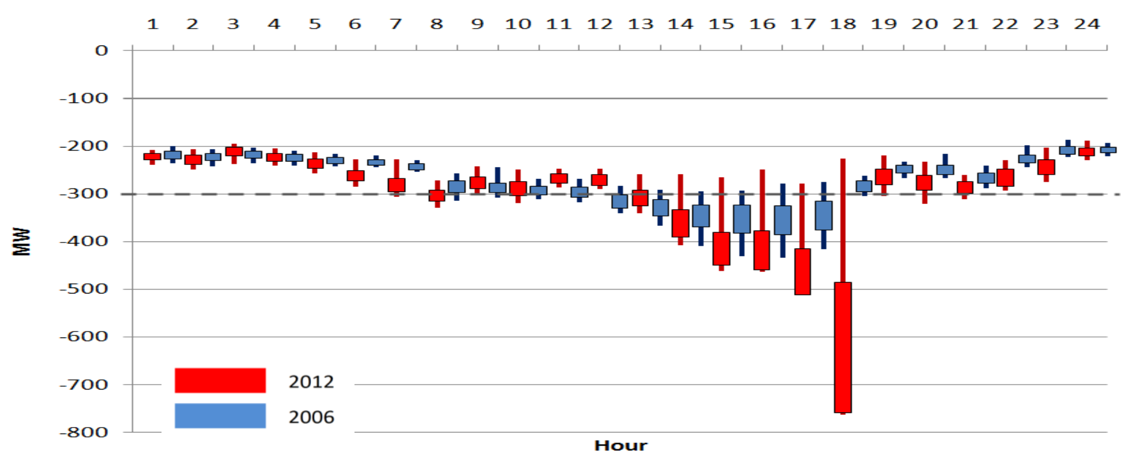


Figure ES-10: Simulated Regulation Down Capacity Requirement by Operating Hour, Summer, 2006 and 2012

- The simulated percentage change in total regulation capacity requirements in the summer season between the 2012 and 2006 simulations is estimated at 37 percent for regulation up and 11 percent for regulation down (as shown in Figure ES-10, most of the regulation down increased requirement is concentrated in three afternoon hours); the results for other seasons are shown in Table ES-1.[14]

- The regulation results require several important clarifications. First, the ISO currently procures 100 percent of its regulation requirement in the day-ahead

[14] The total is defined as the sum of the maximum simulated regulation capacity requirement in each hour of the season; see Section 3 for details.

market, with a minimum requirement in the range of 300 MW in the upwards and downwards direction. First, the simulation does not consider the effect of day-ahead wind and solar production forecast errors on determining the forecast next day regulation need. Second, there are other uncertainties factored into regulation procurement, such as actual uninstructed deviations from dispatch instructions that are not considered in the simulation. Hence, the simulated results shown here may understate the ISO's actual regulation needs, but are indicative of future increases in regulation procurement.

- The additional regulation requirements appear to be well within the capabilities of the existing generation fleet. The ISO regulation markets have procured levels of regulation up and regulation down since April 1, 2009, in the range of 600-700 MW in each hour of the operating day, with these high procurements largely taking place during the first month of market implementation to ensure reliability. These procurement levels provide one test of the ISO's ability to meet the higher regulation requirements that could be experienced under 20 percent RPS.

- Moreover, as another indicator of current regulation capability, the 5-minute regulation ramp capability of the generation resources committed and dispatched in each hour of the day since April 1, 2009, has been measured and determined to be above the calculated regulation requirements under 20 percent RPS for most hours.[15] Hence, the empirical analysis suggests that deficiency of regulation capability should not be a problem except in the hours of overgeneration, when regulation down may be in shortage.

Overgeneration Impacts

- The production simulations analyzed both a high hydro year (based on 2006 hydro production) and a low hydro year (based on 2007 hydro production), as well as sensitivities to assumptions about load growth and firm imports, to evaluate their effect on overgeneration. The maximum overgeneration occurred in a scenario that assumed no load growth between 2006 and 2012. The overgeneration in this case was approximately 0.3% (150 GWh) of annual renewable generation.

- Most of the overgeneration occurs in late spring (April-May), due to combination of high generation from hydro and variable energy resources, and low loads. In general, overgeneration was found to be directly correlated to the amount of non-dispatchable generation in the system. There appears to be sufficient dispatchable generation available to operate if the ISO is not prevented from doing so due to an excess of non-dispatchable generation, including imports.

[15] This is a rough measure of how much additional regulation capacity could be procured if units were converted from providing energy or other ancillary services to regulation.

Fleet Operations and Economic Impacts

- The increased supply variability associated with the 20 percent RPS results in the dispatched gas-fired generators starting and stopping more frequently. In an hourly simulation of 2012, combined cycle generator starts increase by 35 percent compared to a reference 2012 case[16] that assumes no new renewable capacity additions beyond 2006 levels. Also, the energy from the combined cycle units reduces by roughly 9 percent on an average, with more reduction occurring during off-peak hours when there wind production is highest, indicating more cycling in the dispatchable fleet.

- The lower capacity factors combined with the reduced energy prices under 20 percent RPS may result in a significant drop in energy market revenues for the gas fleet in all hours of the day and in all seasons. Tables ES-2 to ES-4 show the change in simulated annual energy revenues for three types of gas resources: combined cycle units, simple cycle gas turbines, and gas-fired steam turbines. These simulated revenue results, based on marginal production costs, are provided to illustrate potential changes in energy market revenues rather than as a forecast; actual market prices will reflect factors not considered, or only partially considered, in the model, such as congestion and the effect on prices of market bids. Also, revenues from ancillary services are not included in the annual revenues.

Table ES-2: Aggregate Operational, Emissions and Revenue Changes for Combined Cycle Units, 2012

	20% RPS case	2012 Reference case	Percent change
Number of starts	3,362	2,492	35 %
On-peak Energy (MWh)	32,421,142	36,258,580	-11 %
Off-peak Energy (MWh)	26,146,347	31,055,863	-16 %
CO2 Emissions (tons)	24,266,005	27,969,588	-13 %
Revenue ($,000)	3,455,290	4,103,959	-16 %

Table ES-3: Aggregate Operational, Emissions and Revenue Changes for Simple Cycle Gas Turbines, 2012

	20% RPS case	2012 Reference case	Percent change
Number of starts	9,618	12,123	-21 %
On-peak Energy (MWh)	6,223,446	10,244,121	-39 %
Off-peak Energy (MWh)	3,359,432	5,034,037	-33 %
CO2 Emissions (tons)	5,591,607	8,660,370	-35 %
Revenue ($,000)	605,167	996,017	-39 %

[16] The only difference between the 2012 reference case and the 20% RPS case is the amount of renewable energy. Both cases use the same load and other assumptions.

Table ES-4: Aggregate Operational, Emissions and Revenue Changes for Gas-fired Steam Turbines, 2012

	20% RPS case	2012 Reference case	Percent change
Number of starts	2,653	3,392	-22 %
On-peak Energy (MWh)	5,109,377	7,179,751	-29 %
Off-peak Energy (MWh)	3,396,360	4,125,934	-18 %
CO2 Emissions (tons)	3,654,106	4,598,358	-21 %
Revenue ($,000)	522,329	735,255	-29 %

Study Recommendations

Based on the study results, the following recommendations are made.

- **Evaluate market and operational mechanisms to improve utilization of existing generation fleet operational flexibility.** The study confirmed that the generation fleet possesses sufficient overall operational flexibility to reliably integrate 20 percent RPS in over 99 percent of the hours studied. However, the current markets do not reveal that full capability due to self-scheduling. In particular, the empirical analysis demonstrated the shortage of the 5-minute load-following capability in the downward direction when resources are self-scheduled, as compared to offering their actual physical capabilities for economic dispatch. These results were further substantiated using production simulation. Hence, the study makes clear that the ISO should pursue incentives or mechanisms to reduce the level of self-scheduled resources and/or increase the operating flexibility of otherwise dispatchable resources.

- **Evaluate means to obtain additional operational flexibility from wind and solar resources.** The simulations demonstrated the need for additional dispatchable capacity in the morning hours under certain conditions. The ISO should explore market rules and incentives intended to encourage greater participation by wind and solar resources in the economic dispatch. Greater economic dispatch control, including curtailment and ramp rate limitations, can be used in targeted circumstances to mitigate overgeneration or shortfalls in regulation and load-following capability generally.

- **Improve day-ahead and real-time forecasting of operational needs: (a) Develop a regulation prediction tool.** The analysis demonstrated that regulation needs will vary substantially from hour to hour depending on the expected production from wind and solar resources. The development of a tool to forecast the next day's hourly regulation needs based on probabilities of expected renewable resource output would enhance market efficiency.

- **Improve day-ahead and real-time forecasting of operational needs: (b) Develop a ramp/load-following requirement prediction tool.** The ISO should accelerate the development of improved forecasting of operational ramps generally and load-following requirements on different intra-hourly time frames. This capability could be complemented by evaluation of whether to modify unit commitment algorithms and procedures to reflect those forecast ramp requirements.

- **Further analysis to quantify operational and economic impacts on fleet at higher levels of RPS.** Although this study was not focused on the impact of renewable integration on the revenues of existing generation, it has provided some indications of possible changes in such revenues, primarily through changes in energy market prices. Further analysis is needed to clarify the net revenue impact from changes in procurement and prices for wholesale energy and ancillary services as well as the implications for payments through resource adequacy contracts.

1 Introduction

California's existing Renewables Portfolio Standard (RPS) requires utilities to achieve their statutory obligation to supply 20 percent of all consumed electricity from eligible renewable resources by 2010. Compliance with this level is now anticipated in the 2011-2012 timeframe and will likely depend on load growth, contract implementation, and other factors.[17] The California Independent System Operator Corporation (ISO), along with the California state agencies and the electric power industry, is conducting the substantial planning, along with the operational, technological and market changes, needed in the power sector to accommodate this higher level of renewables.

The majority of new renewable generation capacity needed to realize the state's 20 percent RPS goal likely will come from additional variable energy resources, primarily wind and solar technologies.[18] The key operational characteristics of such resources are the variability of their generation over different operational time-frames (seconds, minutes, hours) and the uncertainty associated with forecasting their production (i.e., forecast error). As such, the integration of variable energy resources will require increased operational flexibility—notably capability to provide load-following and regulation in wider operating ranges and at ramp rates that are faster and of longer sustained duration than are currently experienced. Forecast uncertainty associated with wind and solar production will increase the need for reservation of resource capacity to ensure that these requirements are met in real-time operations. There is also the likelihood of increased occurrence and magnitude of overgeneration, a condition where there is more supply from non-dispatchable resources than there is demand. In providing these capabilities, the existing and planned generation fleet will likely need to operate longer at lower minimum operating levels and provide more frequent starts, stops and cycling over the operating day. Against this backdrop, certain conventional generators will also be operating at lower capacity factors due to the increased output from renewable energy generation.

The ISO provides open access to the transmission system under its control while simultaneously operating the grid and markets for energy, ancillary services and

[17] California Public Utilities Code Section 399 requires that the RPS objectives be achieved by 2010, with some accommodation for deferred compliance under specified circumstances. In 2009, the California investor-owned utilities served 15.4 percent of their load with renewable energy eligible under the RPS. In late 2009, the California Public Utilities Commission (CPUC) estimated that the 2010 deadline would not be met and that 2013-14 was more realistic. However, in mid-2010, based on declines in electricity consumption, rapid growth in RPS contract approvals (including short-term contracts for out-of-state wind energy), and other factors, the CPUC estimated that the 20 percent target could be reached in 2011. In this study, the ISO models 20 percent renewable energy in 2012. See CPUC, Renewables Portfolio Standard, Quarterly Report (Q4 2009), at p.4, and CPUC, Renewables Portfolio Standard, Quarterly Report (2nd Quarter 2010), at p. 3, both available at http://www.cpuc.ca.gov/PUC/energy/Renewables/documents.htm.

[18] "Variable energy resources" is the term being used by the Federal Energy Regulatory Commission to describe renewable resources that have variable or intermittent production. Variable energy resources is thus used here as an equivalent term to "intermittent resources". Not all renewable resources eligible under renewable portfolio standards are variable energy resources. For example, geothermal, biogas and biomass resources generally follow fixed hourly schedules.

congestion revenue rights. The design of the ISO's integrated wholesale market and system operations has the capability to significantly facilitate renewable integration. There are both day-ahead and real-time markets that optimize the utilization of system resources using state-of-the-art software, while accounting for key constraints on electric power production such as generation unit operating characteristics and transmission congestion and losses. During the operating day, the ISO now has more accurate procedures to adjust market resources in response to changing real-time conditions, with dispatch instructions sent every five minutes. This allows for more efficient use of system resources in following the output of variable energy resources, like wind and solar. As a result, the redesigned market will allow more renewable energy to be integrated into the system.

As the entity with primary responsibility for the continued reliable operation of the electric transmission, the ISO needs to evaluate the effects on system and market operations of integrating 20 percent RPS. If necessary, the ISO will take action to facilitate renewable integration and address any adverse effects on market functioning and reliability. In this regard, the ISO has conducted several analyses, both collaboratively and independently, over the past several years, including a study in 2007 focused on the operational and transmission requirements of wind integration ("2007 Report").[19] This report builds on those efforts. The study utilizes several analytical methods, including a statistical model to evaluate operational requirements, empirical analysis of historical market results and operational capabilities, and production simulation of the full ISO generation fleet.

1.1 Report Organization

The report is organized as follows. The remainder of this section provides background on the impacts of generation from variable energy resources on operations and market functions and identifies the specific objectives of this study. Section 1.2 reviews the mix of resources projected to fulfill California RPS requirements by 2012. Section 1.3 discusses the characteristics of generation from variable energy resources and how they impact system operations. Section 1.4 sets forth the specific objectives of this study and also discusses how this study builds upon prior work.

Section 2 then provides an overview of the simulation methodologies and the scenarios that were modeled in this study. Section 3 discusses the results of the simulations that were used to determine the operational requirements, i.e., regulation and load-following requirements, under 20 percent RPS. Section 4 describes the results of the empirical analysis performed to assess the historical capability of the fleet and how it compares

[19] California ISO, *Integration of Renewable Resources – Transmission and Operating Issues and Recommendations for Integrating Renewable Resources on the ISO-Controlled Grid* (Nov. 2007) at http://www.caiso.com/1ca5/1ca5a7a026270.pdf. Another recent report on renewable integration using ISO data by KEMA titled, "*Research Evaluation of Wind Generation, Solar Generation, and Storage Impact on the California Grid* (June 2010)" can be found at http://www.energy.ca.gov/2010publications/CEC-500-2010-010/CEC-500-2010-010.PDF.

with the future operational requirements. Section 5 presents the results of the production simulations used to test the capability of the fleet to meet the operational requirements with and without the 20 percent RPS in 2012. Finally, Section 6 provides recommendations.

Similar to the 2007 Report, this report includes a set of appendices that provide additional results and selected discussion of methodology. There is also a separate technical appendix that provides mathematical formulations of the models and other information on how renewable production profiles and forecast errors were developed.

1.2 California Renewable Portfolio Standards

After several years of fairly static energy production from renewable resources, the next few years could see a significant increase in production each year, with the great majority from variable energy resources. In 2009, California investor-owned utilities collectively served 15.4 percent of their load with renewable energy. In late 2009, the California Public Utilities Commission (CPUC) forecast that 20 percent RPS would be achieved by 2013-2014. More recently, the CPUC estimates that utilities are expected to have procured approximately 18 percent renewable energy in 2010 and over 20 percent by 2011 based on signed renewable resource contracts.[20]

Much of the incremental renewable deliveries anticipated over the next couple of years to achieve the RPS target will be from operational out-of-state resources, many of which have signed short-term contracts with California utilities. Under current scheduling practices, the Balancing Area Authority (BAA) exporting the renewable energy to California will be largely responsible for managing the variability and uncertainty of the renewable resources interconnected to its system. This has the potential to mitigate the integration requirements confronting the ISO in the near-term. However, as those short-term out-of-state contracts expire, they will generally be replaced by power purchase agreements with in-state renewable resources.[21] Existing out-of-state resources may also seek dynamic transfer arrangements with the ISO. Both of these circumstances will shift the integration requirements to the ISO.

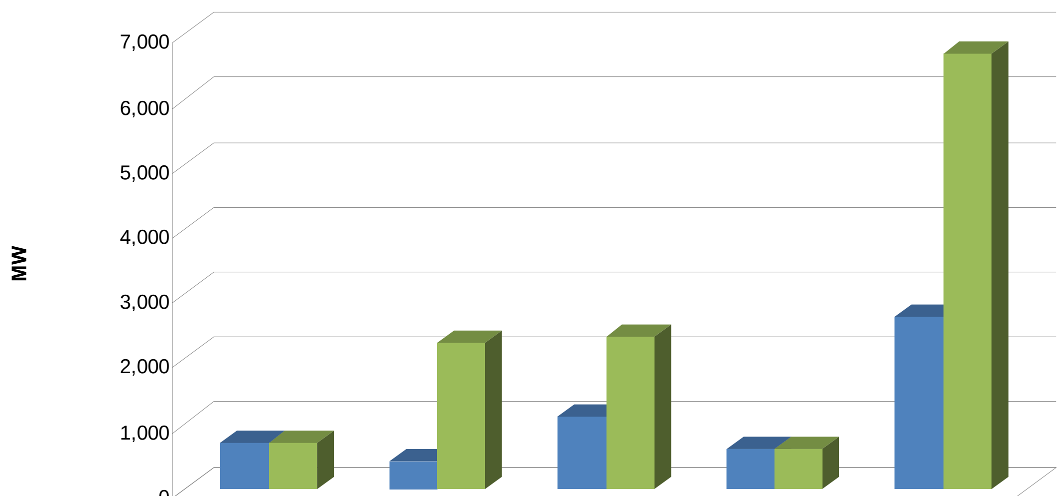
This study assumes that most of the renewable generation is in-state and within the ISO BAA – or equivalently that a high proportion of the in-state and out-of-state resources located outside the ISO BAA are dynamically transferred into the ISO. Such an assumption is not only consistent with the longer-term trend of the utility contracts, but also comports with the ISO's objective in this study to test the capability of the existing fleet to provide the integration requirements within the ISO BAA at 20 percent RPS.

The renewable resource portfolio includes a wind resource forecast developed by the ISO and consultants, and adapts a forecast of expected solar and geothermal capacity

[20] California Public Utilities Commission, "Renewables Portfolio Standard, Quarterly Report, 2nd Quarter 2010", at http://www.cpuc.ca.gov/NR/rdonlyres/66FBACA7-173F-47FF-A5F4-BE8F9D70DD59/0/Q22010RPSReporttotheLegislature.pdf.

[21] For information on the status of RPS procurement activity by California's investor-owned utilities see the CPUC website at http://www.cpuc.ca.gov/PUC/energy/Renewables.

developed by the CPUC in 2009.[22] The renewable resource capacity (MW) and associated expected energy production (MWh) were adjusted, based on 2012 load forecasts, to provide approximately 20 percent energy from RPS-eligible resources. Figure 1-1 shows the renewable capacity modeled. The figure also shows the renewable generation portfolio modeled in the base-year of the study (2006). The year 2006 was chosen as the base year to facilitate easier comparison with the 2007 Report. Compared to the 2007 Report, this study evaluates an additional 1,826 MW of solar generation, comprised of 830 MW of solar photovoltaic (PV) and 996 MW of solar thermal resources, for a total of 2,246 MW of solar resources. Both the 2007 Report and this study assume 6,686 MW of wind resources by 2012.



	Biomass/BioGass	Solar	Geothermal	Small Hydro	Wind
2006	701	420	1,101	614	2,648
2012 (expected)	701	2,246	2,341	614	6,688

Figure 1-1: Renewable Resources in the Base Case and under 20 percent RPS scenarios

1.3 *Potential Impacts in System Operations*

As noted above, the majority of new renewable generation capacity needed to realize the state's 20 percent RPS goal likely will come from additional variable energy resources, primarily wind and solar technologies. This section discusses the impact of the generation variability and forecast uncertainty on power system operations.

[22] The portfolio was the CPUC 20 percent RPS reference case developed for its 33 percent RPS Implementation Analysis. See http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf.

1.3.1 Variability of Wind and Solar Generation

The variability of wind and solar generation is measured over different time-scales. Beginning on the time-scale of minutes, Figure 1-2 shows the variability in wind and solar PV generation on a minute-by-minute basis over the full day. Figure 1-3 then shows those variations more closely on a sub-hourly basis. The implications for system operations are that, unless the variability is smoothed by the variable energy resource itself, other resources have to increment or decrement their generation on similar time frames (seconds, minutes, hours) to compensate for the supply variability. The ISO operational time frames and procedures by which this is done are discussed in the next section.

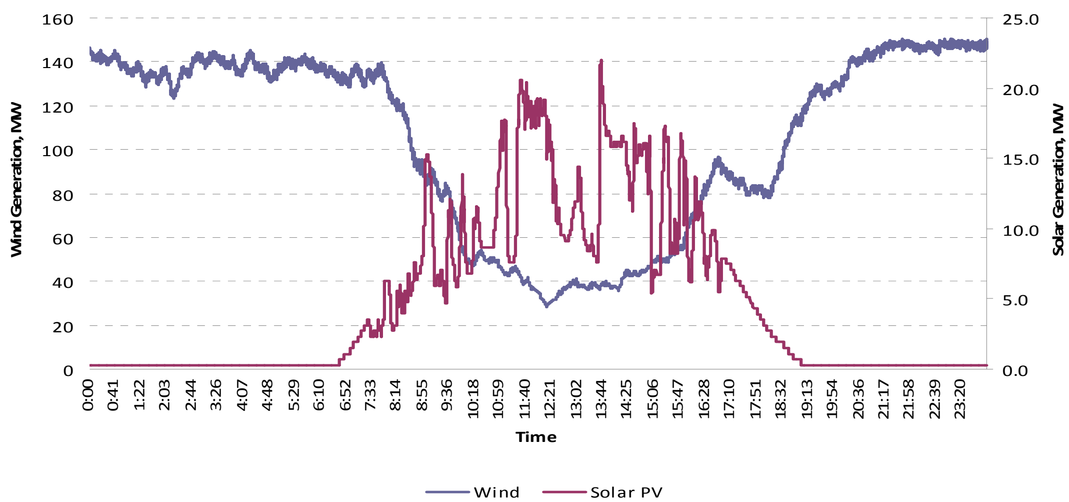


Figure 1-2: Sub-hourly wind and solar generation for a day for a 150 MW wind generator and a 24 MW Solar PV plant

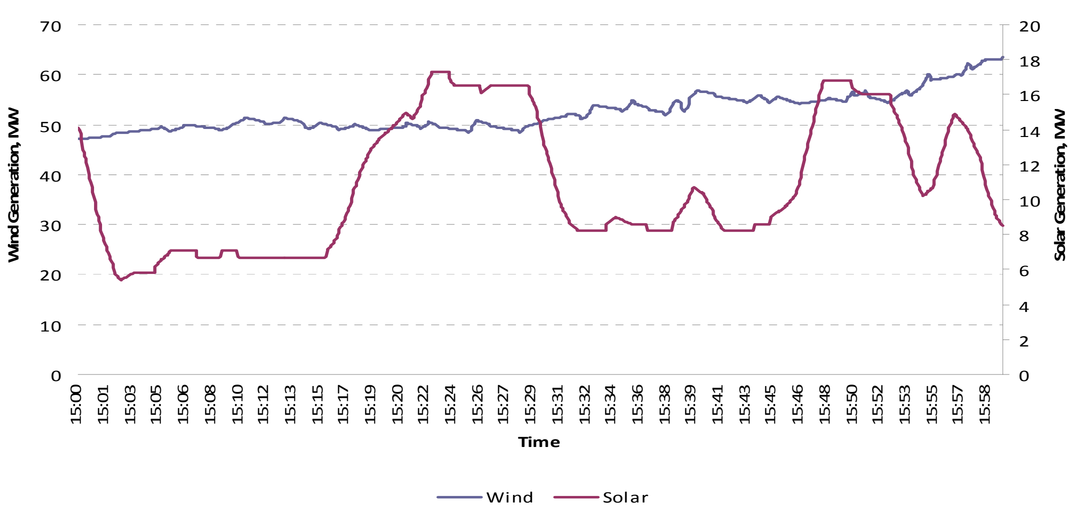


Figure 1-3: Sub-hourly wind and solar generation profiles for an hour

On any particular day, the multi-hour ramps associated with wind production, and the range of that production, can vary significantly. Figures 1-4 to 1-7 illustrate simulated high ramp days in every season in 2012 based on data on historical wind performance in California, in which total state-wide wind production can vary from almost full output to very low output in a few hours, and vice-versa. The simulated load and renewable energy production shown in these and subsequent figures are based on assumptions, data and methods described in Section 3.

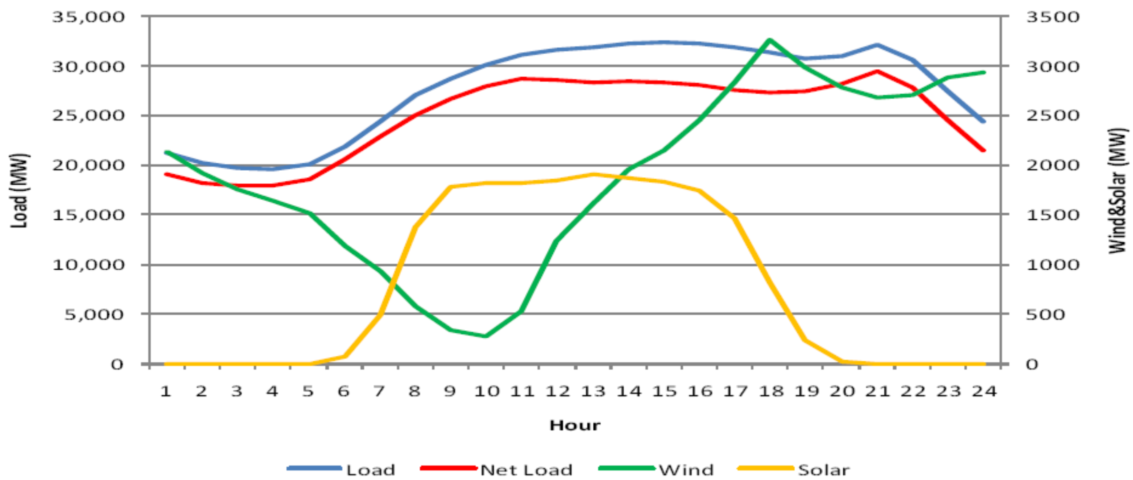


Figure 1-4: Simulated May 8, 2012

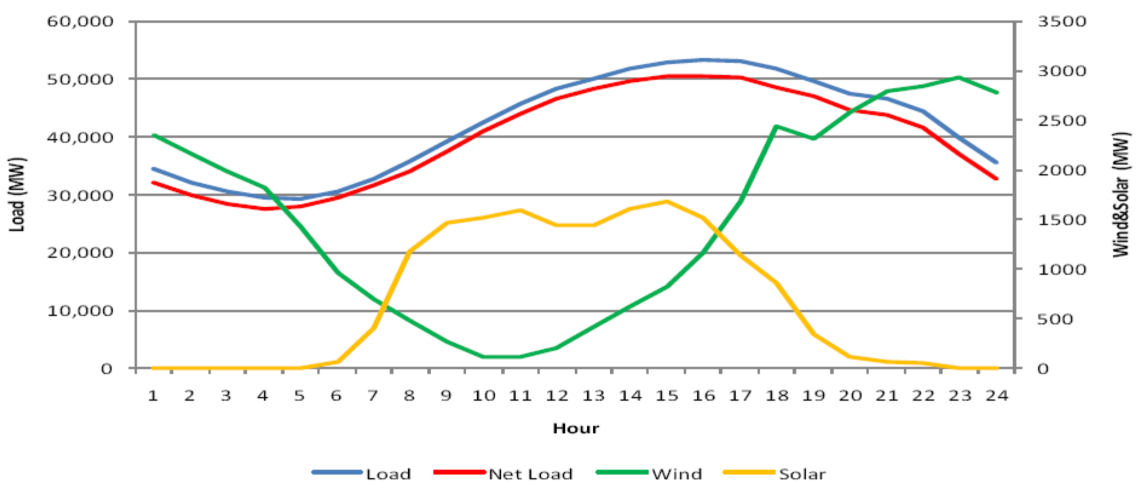


Figure 1-5: Simulated July 25, 2012

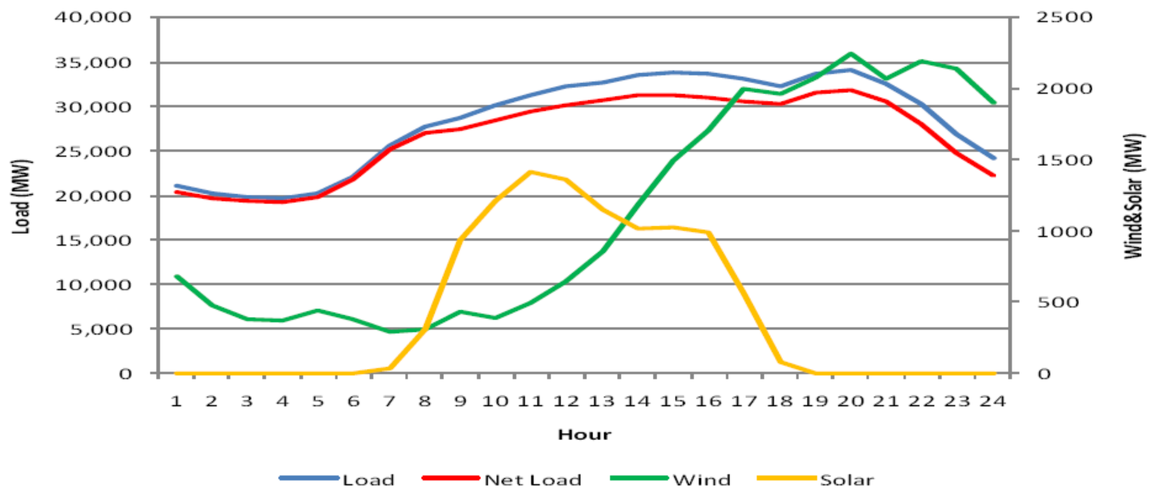


Figure 1-6: Simulated October 23, 2012

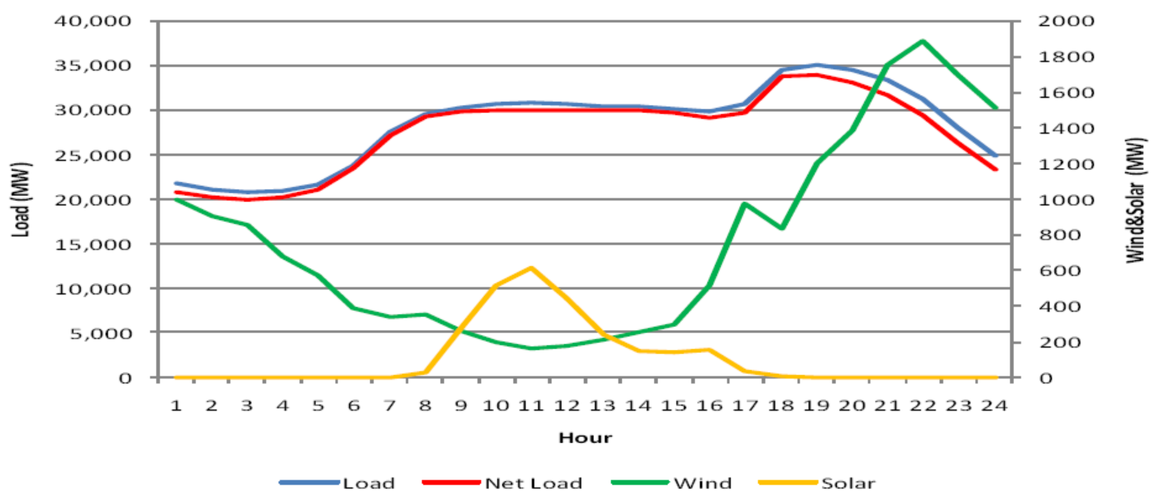


Figure 1-7: Simulated December 4, 2012

On the time-scale of multiple days, wind production will vary substantially across each day, regardless of the season. Figure 1-8 shows the daily wind pattern for May 2012 analyzed in this study. Each line of a different color represents a different day in the month. The monthly average hourly production shown by the thicker red line thus represents a wide range of actual daily production. Figures 1-9 to 1-12 show the dispersion of simulated wind production by operating hour in each season in 2012. These figures show that in almost every operating hour, wind could be producing across the full range of its potential production, from close to zero to almost maximum output.

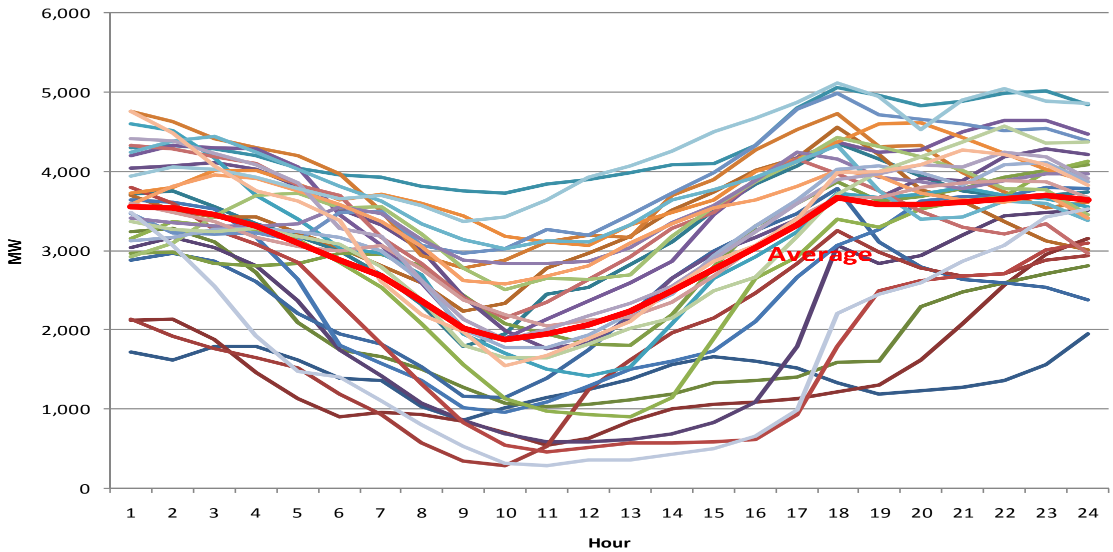


Figure 1-8: Wind Production in May 2012 based on 2005 production patterns

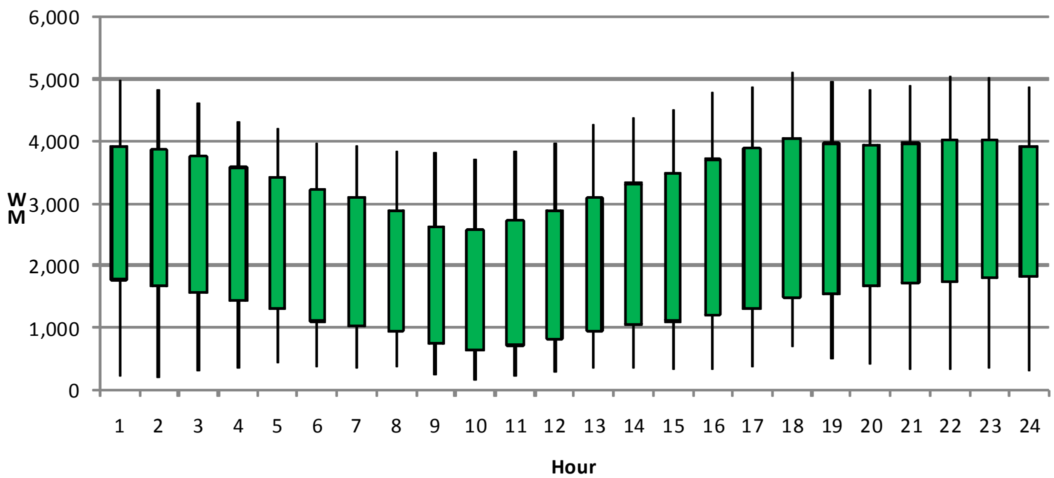


Figure 1-9: Spring 2012 Simulated Wind Production by Hour

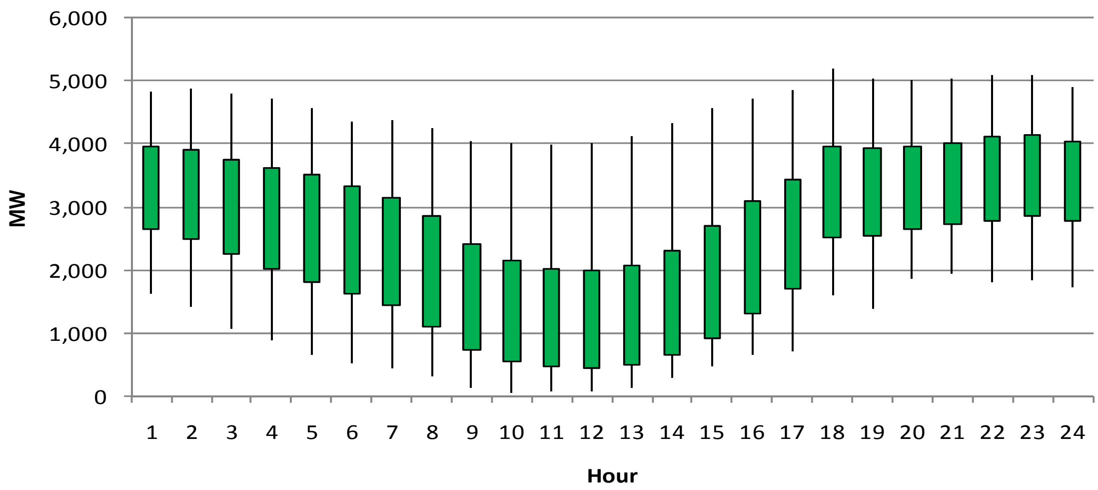


Figure 1-10: Summer 2012 Simulated Wind Production by Hour

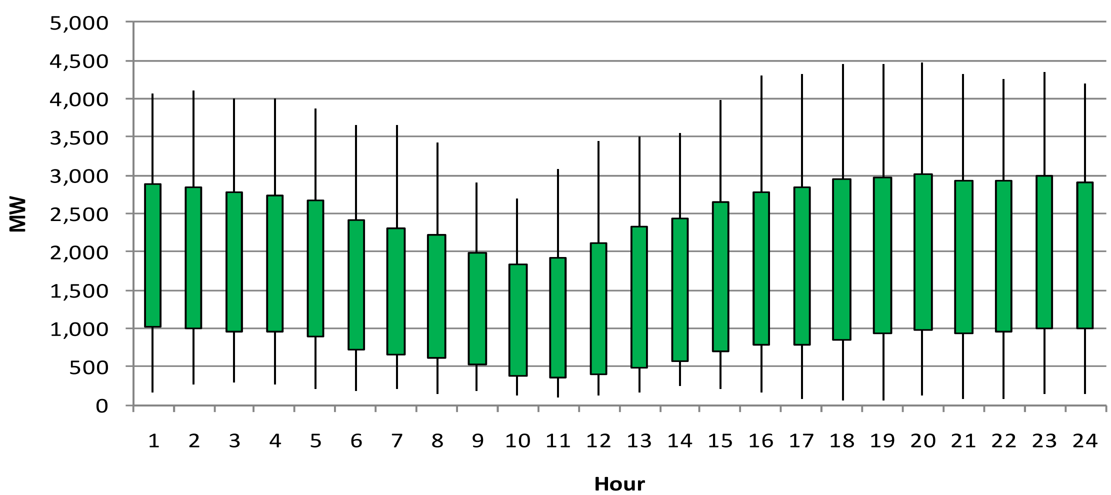


Figure 1-11: Fall 2012 Simulated Wind Production by Hour

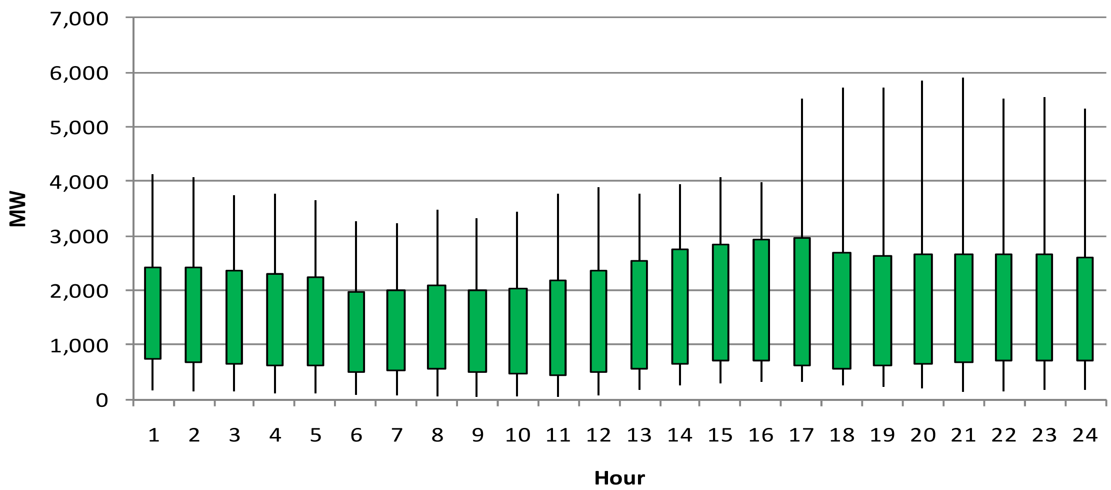


Figure 1-12: Winter 2012 Simulated Wind Production by Hour

Another important characteristic of wind generation is that it may operate at low capacity during peak hours, particularly the annual summer peak demands. Figure 1-13 shows wind generation production during the historical peak hours in the July 2006 heat wave. The red dots indicate peak hours, showing that average hourly production during those hours was close to the daily minimum wind production. Of note, 2006 is one of the benchmark years for the simulations in this study. In other years, there will be different patterns of summer peak hour wind energy production. For example, Figure 1-14 shows that in July 2010, wind production was higher during peak hours than in 2006, but still below maximum production, while Figure 1-15 shows that in August 2010, peak load production varied substantially.

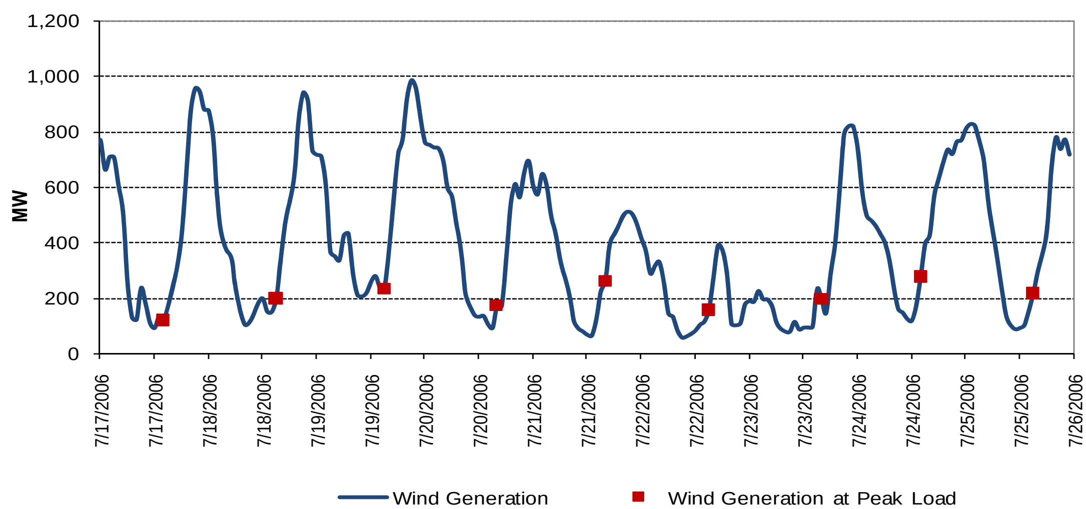


Figure 1-13: Wind Production during Summer Peak Hours in 2006

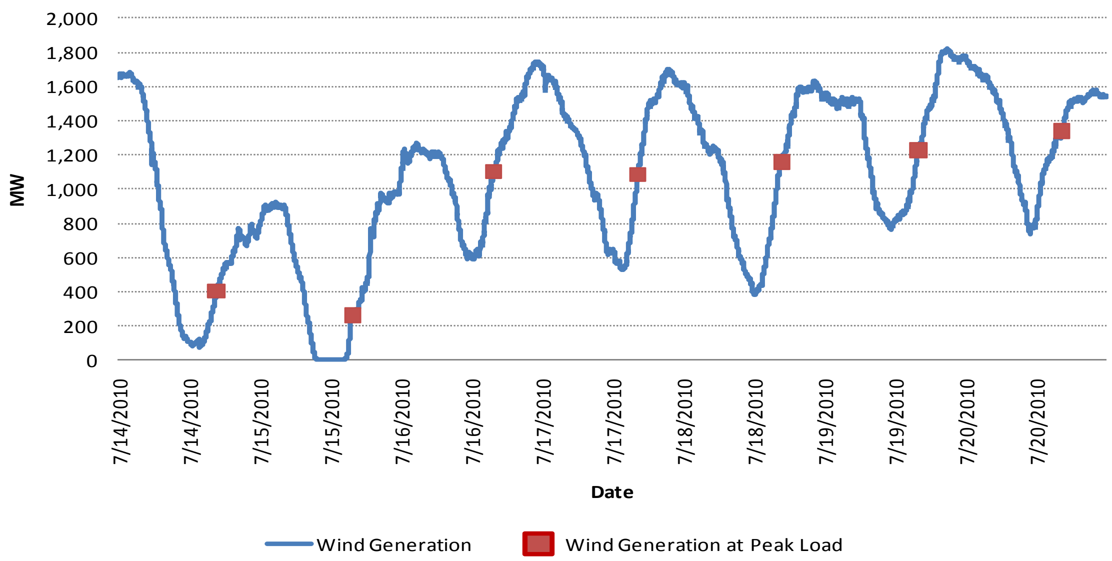


Figure 1-14: Wind Production during July Peak Hours in 2010

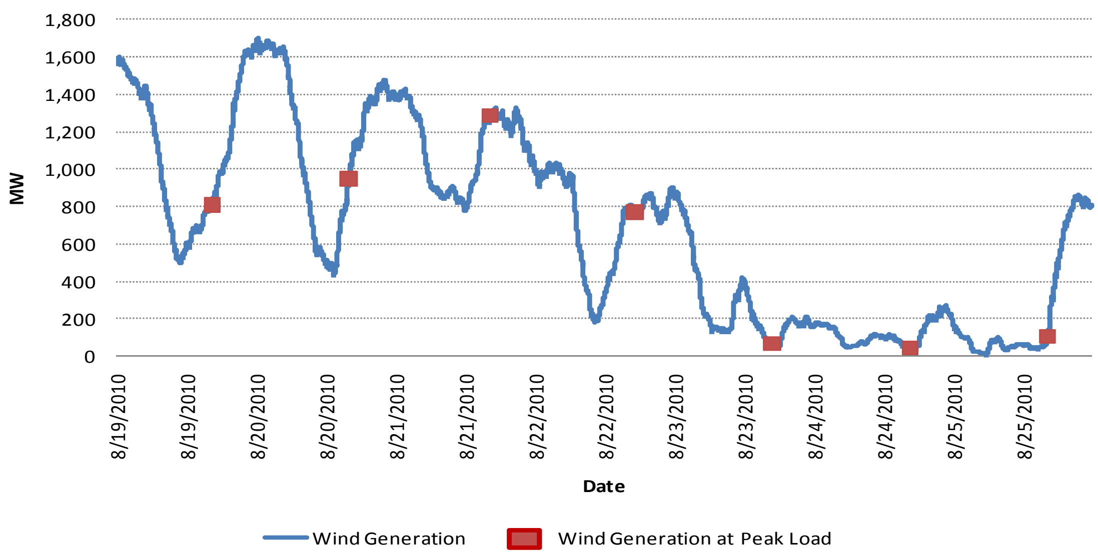


Figure 1-15: Wind Production during August Peak Hours in 2010

Even on the time-scale of months or seasons, when average production is measured, total wind generation can vary fairly substantially by hour and season. For much of the year, wind generation is on average inversely related to load, but in some seasons, notably spring, there can be a higher correlation on average between peak wind production and peak daily load.[23] Within any particular season, as noted above, the average wind

[23] As shown in Figure 2-1, in the spring months, the total wind generation on average starts decreasing after midnight and reaches its minimum production level around midday, just as the system experiences the first peak of the day. Beginning around Hour 13, the wind generation starts to increase while system load

production shown here does not reflect the significant differences in wind production on any particular day. Solar production is clearly well correlated with the daily load cycle, but seasonal weather patterns can result in different average solar generation. Moreover, in the winter, solar production can diminish before the daily peak hours.

1.3.2 Wind and Solar Forecast Uncertainty

The second important operational characteristic of variable energy resources is the uncertainty about their production, due to the current accuracy of weather forecasting, in particular of wind speed and cloud formations. Historically, given its variable nature, wind generation has been taken on an as-available (or "must take") basis, and grid operators compensate by incrementing or decrementing the output of other committed generation. At low wind penetrations, such actions do not significantly affect system operations. At higher levels of wind penetration, however, forecast uncertainty becomes more challenging. Figure 1-16 shows actual wind generation and the forecasted wind generation in the hour-ahead time frame.

Improvements in forecasts will facilitate renewable integration by allowing operators to ensure that the right resources are committed and on dispatch to address actual variability. The ISO is undertaking a number of initiatives to improve forecasting and the integration of forecasts into its market and system procedures.[24] This study does not focus on improvements in forecasts, but does conduct sensitivity analysis in the simulations to examine the impact of such improvements on operational requirements (see Appendix A-2).

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typically drops off. As system load increases towards the second peak of the day (which occurs in the spring), the pick-up in wind generation offsets some of the energy required to meet the increase in load. As system load begins dropping after the daily peak, wind is typically at its highest generation level. In the summer and fall months, average wind production peaks around Hour 24 and then decreases over the morning until reaching a minimum in the middle hours of the day, when load is at or close to its maximum. Wind production picks up in the early evening hours when load is typically decreasing. The winter months have a slightly different average pattern, in which average wind production is less variable over the day.

[24] The ISO aims to achieve continuous improvements as they become available by both public and commercial weather forecasting systems as well as innovative technology vendors (such as laser-based short-term wind forecast technologies). In this regard, during 2008-09, the ISO undertook an evaluation of three commercial wind forecasters that demonstrated improvements in both day-ahead and hour-ahead forecasts and examined the impact on wind forecast errors of geographic diversity of wind resources and different load levels, among other factors. The results are available in California ISO, *Revised Analysis of June 2008 – June 2009 Forecast Service Provider RFB Performance*, March 25, 2010, available at http://www.caiso.com/2765/2765e6ad327c0.pdf.

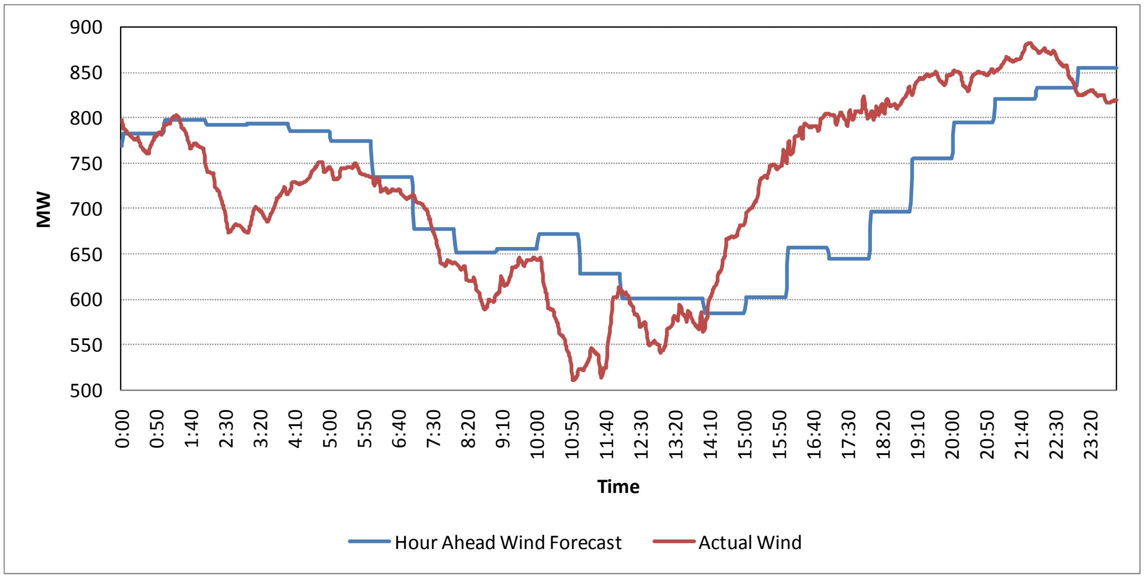

Figure 1-16: Hour-ahead forecast and actual generation profile for wind production, June 24, 2010

1.3.3 Impact of Variability and Uncertainty on Market and System Operations

Variable energy resources schedule and operate within the sequence of day-ahead to real-time market and system operational procedures that the ISO conducts on various intervals over the day. The ISO markets are a specialized type of wholesale commodity market in that any scheduling and trading must be consistent with: (a) the physical laws that govern power flows, (b) the need to balance the system second-by-second, and (c) physical and reliability constraints that affect the operation of both generation and transmission facilities—particularly the congestion and losses associated with transmission use. The ISO markets are in fact designed around reliable system operations, and the prices generated in those markets provide information relevant to future operational needs. More information on the markets and system operations can be found in the ISO's business practice manuals (BPMs), tariff, and other technical documents; this section focuses on a few key features applicable to renewable integration.[25]

Because generation resources have different start-up times (ranging from more than 24 hours for large steam units to under 10 minutes for gas turbines), system operators must begin the process of scheduling generation based on forecasts of next day system conditions. This is the function of the ISO day-ahead market, which takes place in the

[25] On market and system operations, see in particular the BPM for market instruments and the BPM for market operations. These are available at http://www.caiso.com/17ba/17baa8bc1ce20.html. More detail on the ISO's market and system operations and renewable integration can be found in the ISO's comments to the Federal Energy Regulatory Commission (FERC) in its recent notice of inquiry on variable energy resources, available here: http://www.caiso.com/2777/2777ac8636f20.pdf. In addition, the ISO will be undertaking a detailed review of market design changes needed to facilitate renewable integration, with documents and schedules provided here: http://www.caiso.com/27be/27beb7931d800.html.

afternoon of the day prior to the operating day. The day-ahead market consists of an integrated forward market that clears on the basis of schedules and market bids submitted by both suppliers and load. The integrated forward market is also where the ISO aims to procure one hundred percent of its ancillary service requirements for the next day, including regulation, spinning reserves and non-spinning reserves.[26] The ISO then makes adjustments to the day-ahead schedule using its own load forecasts and forecasts of renewable production in a process called the residual unit commitment. This sequence of markets and procedures is collectively called the day-ahead market.

Wind and solar resources can schedule voluntarily in the day-ahead market. However, there is currently little incentive for them to do so prior to the hour-ahead scheduling process, as discussed next. Moreover, day-ahead forecast errors for variable energy resources are not insignificant. From an operational perspective, the failure to schedule renewable resources day-ahead can result in additional commitment of conventional resources. In the event that the day-ahead market significantly underestimates the next day's renewable production, there could be situations in which the ISO has difficulty committing the right conventional units to provide integration capabilities in real-time.[27] The simulations described in Section 3 and Section 5 attempt to test for this outcome.

The day-ahead market schedules are in one-hour blocks; that is, there are no schedules for expected load or wind and solar production at intervals within the hour. When the operating day begins, the real-time market serves to adjust day-ahead schedules to account for imbalances, because of forecast error, changes in system conditions, actual intra-hourly load and renewable energy production, and any other factors. It does so through a sequence of procedures, including an hour-ahead scheduling process for changes to intertie schedules, rolling intra-hourly unit commitment procedures, and 5-minute economic dispatch intervals in which system operators send instructions to increment or decrement the output of generators under dispatch.

Scheduling of wind and solar resources under the ISO's Participating Intermittent Resource Program (PIRP) is conducted through a special process. Prior to the hour-

[26] Ancillary services are additional services provided by generation and, increasingly, non-generation resources, such as demand response and storage, that are needed for power system reliability. As discussed elsewhere in this report, ancillary service procurement may increase with additional renewables. Two types of ancillary services are procured by the ISO through the wholesale markets: operating reserves and regulation. Operating reserves are essentially capacity retained on generators that can be converted to energy in a short period of time in order to responds to contingencies such as the loss of a generating resource or a transmission line. There are two types of operating reserves in the ISO markets: ten-minute spinning reserves, provided by resources that are synchronized to the grid, and ten-minute non-spinning reserves, provided by resources that are not synchronized but can start and provide energy within ten minutes. Regulation is energy provided on a second-by-second basis for system balancing by resources equipped with automatic controls. Currently provided by thermal generators and hydro systems, regulation could be supplied also by demand response and storage technologies. The ISO also meets other ancillary services requirements that are not procured through the markets, such as voltage support and black-start.

[27] If the integrated forward market fails to forecast renewable energy production adequately, the ISO can also adjust its residual unit commitment to account for forecast renewable production. However, as this residual unit commitment takes place day-ahead, it is also subject to forecast errors.

ahead scheduling process, data is collected from wind resources and transferred to a forecast service provider, which develops an hour-ahead wind forecast. This forecast is then returned to the ISO via the scheduling coordinators for the participating resources. Deviations from the hour-ahead schedules are followed by the ISO's dispatch functions (every five minutes) and regulation (second-by-second) in real-time. Resources in the PIRP are settled financially using a formula that nets their imbalances over the month and applies an averaged monthly locational marginal price for energy. Generally, because of their contracts, production incentives, and technology, wind and solar resources do not respond to price-based dispatch instructions, but only to reliability-based dispatches when they are needed to decrement output to address congestion or overgeneration. If such resources become more price-responsive, they could reduce the ISO's need for additional operational capabilities discussed in this report.

1.3.3.1 Impact on Load-following and Regulation

To further explore the operational and market impact of variability and forecast uncertainty in real-time requires additional detail on how the ISO markets follow load and renewable resource schedule deviations over the operating hour. Secondary frequency control mechanisms such as load-following and regulation are the key mechanisms by which the ISO maintains the balance between generation and load in the time frame of seconds to minutes.

The demand and generation are constantly changing within the ISO balancing authority area (BAA). This means that the ISO will have some unintentional outflow or inflow of energy at any given instant. The mismatch in meeting a balancing authority's internal obligations, along with a small obligation to maintain frequency, is measured via an instantaneous value called Area Control Error (ACE), measured in MW. The North American Electric Reliability Corporation (NERC) control performance standards are intended to be the indicator of sufficiency of secondary control. Overgeneration makes ACE go positive and the frequency increases. A large negative ACE causes frequency to drop. NERC Control Performance Standards (CPS1 and CPS2) capture these relationships. In simple terms, CPS1 assigns each balancing area a slice of the responsibility for control of the interconnection frequency. The amount of responsibility is directly related to the size of the BAA. CPS2 is a statistical measure of ACE over all 10-minute periods in a month. Under CPS2, ACE is limited to a regulating range whose width is proportional to the BAA's size.

The ISO monitors ACE and attempts to keep the value within specified limits. This is accomplished through a combination of automatic generator adjustments, manual dispatch and sales and purchases from neighboring balancing authorities. The ISO maintains sufficient generating capacity, both in the up and down direction, under automatic generation control (AGC) within the energy management systems (EMS) to continuously balance generation and interchange schedules with real time load.[28] Although the regulation dispatch is done every four seconds, the regulation margin has to

[28] The WECC defines AGC as equipment that automatically adjusts a control area's generation from a central location to maintain its interchange schedule plus frequency bias.

be adequate to meet deviations within a 5-minute dispatch interval. The capacity under AGC is referred to as regulating reserve or regulation.[29] Figure 1-17 pictorially depicts the regulation capacity requirement—that is, the MW range that regulating resources must be able to provide—as the area shaded in red: the area between actual load and the 5-minute dispatch.

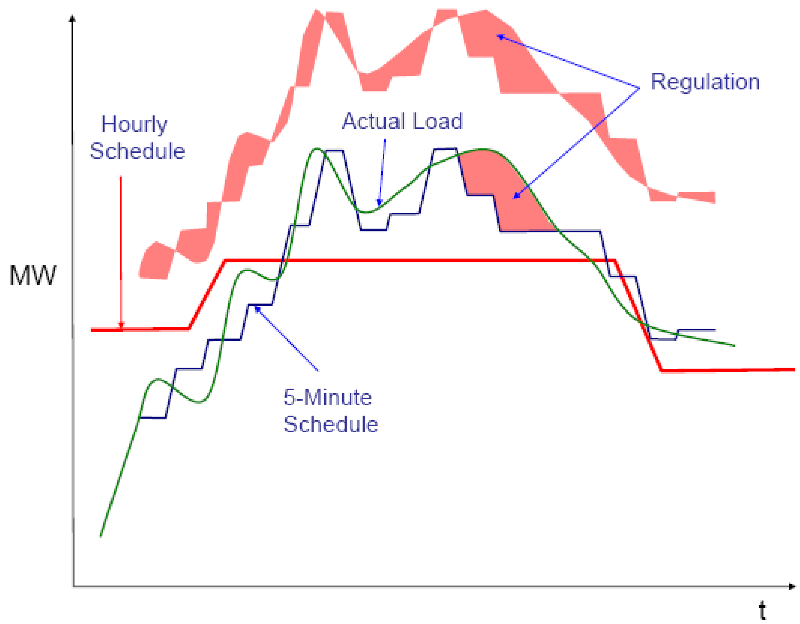

Figure 1-17: Regulation Requirement shown as the red shaded area

Load-following is the use of online generation on economic dispatch or quick start generation to meet the intra- and inter-hour changes in loads. While regulation is needed to balance the minute-by-minute changes in the system and keep ACE with limits, load-following is required to ensure that the system has enough capacity on economic dispatch to move from one 5-minute dispatch interval to the next. Load-following is not an ancillary service like regulation and is not explicitly procured by the ISO in its day-ahead and real-time markets; rather, it is a function of the generation committed and dispatched in the day-ahead to real-time market and operational sequence and is met as long as the optimization algorithms used in those processes are appropriately specified. Similar to regulation, load-following is defined in both the up and down directions.

In this study, several measures of load-following requirements are presented, including capacity and ramps over various time frames needed to fill the gap between the difference between the day-ahead hourly schedule for an operating hour and the real-time 5-minute dispatch schedule. In Figure 1-18, load-following capacity—that is, the incremental and decremental energy that resources on economic dispatch have to be able to provide

[29] The WECC defines Regulating Reserve as sufficient spinning reserve, immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the control area to meet NERC's Control Performance Criteria.

within the operating hour to meet load—is depicted graphically as the blue shaded area. Load-following ramp rate, expressed in MW/min, is the rate at which this capacity can ramp from one 5-minute dispatch point to the next.

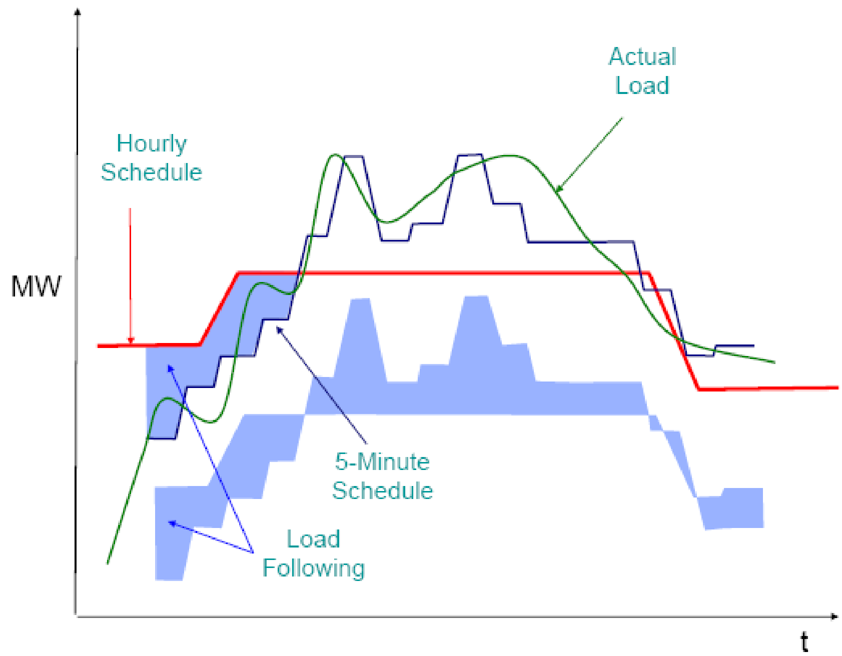

Figure 1-18: Depiction of hourly load-following capacity requirement

As seen in Figure 1-2 and Figure 1-3, wind and solar generation vary on a minute-by-minute basis. The variability in wind and solar generation, coupled with the variability in load, will have an impact both on regulation and load-following requirements. The uncertainty in wind and solar generation increases the system operator's need to reserve capacity for wider ranges of regulation and load-following capability than would otherwise be needed if they had full certainty about the actual variability. Uncertainty in the day-ahead timeframe may lead to a unit commitment with inadequate regulation and load-following capability that is required in real-time. The lack of regulation and load-following capability may have an impact on ACE, and if sustained, result in a CPS2 violation. Under extreme cases, the lack of regulation and load-following down capability might require the curtailment of generation to keep ACE within specified limits.

1.3.4 Overgeneration due to Variable Energy Resources

Overgeneration occurs whenever there is more generation than load and the operators cannot move generators to a lower level of production. In California, overgeneration is most likely to occur under the confluence of some or all of the following conditions: light spring load conditions (historically with loads around 22,000 MW or less), all the nuclear plants on-line and at maximum production, hydro generation at high production levels due to snow melt in the mountains, long-start thermal units on-line and operating at their minimum levels because they are required for future operating hours, other generation in a regulatory "must take" status or required to be on-line for local reliability reasons, and wind generation at high production levels. At higher levels of RPS, solar production may also be a factor in overgeneration conditions, particularly in the morning solar ramp hours.

All other things equal, the increased generation from variable energy resources under a 20 percent RPS is expected to lead to higher frequency and magnitude of overgeneration conditions than exist today. Even if renewable resources were perfectly predictable and constant (i.e., no uncertainty and variability in generation), the amount of wind and solar generation that can be accommodated into the system will depend on the extent to which the existing fleet can be dispatched downwards to accommodate the renewable energy. Inability to dispatch the existing fleet will lead to overgeneration conditions and could possibly result in the curtailment of renewable generation.

To illustrate overgeneration conditions, Figure 1-19 shows the load for one week (red trace) and the generation from non-dispatchable resources. Non-dispatchable resources in this figure include the following generation resources: nuclear, biomass, geothermal, Qualifying Facilities (QFs), hydro and imports. Non-dispatchable resources also include wind and solar generation. Some of the resources are dispatchable, but a portion of their generation is treated as fixed due to contractual and other reasons. During some periods, the total generation from the non-dispatchable resources approaches the load that needs to be served. These periods will likely see overgeneration, especially if thermal generation needs to be dispatched at their minimum operating level. Importantly, overgeneration in this case has very little to do with the variability and uncertainty of generation from variable energy resources. Rather, it strictly depends on whether the rest of the fleet can be dispatched down to accommodate the energy from variable energy resources.

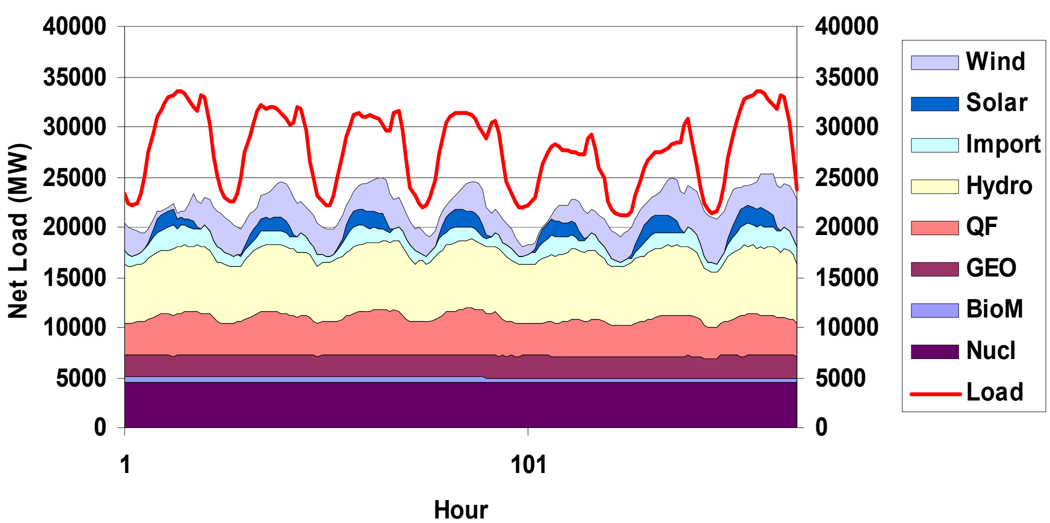

Figure 1-19: Load and Non-dispatchable generation for one week

1.4 Objectives of this Study

The ISO and California state agencies have undertaken several analyses that attempt to estimate the requirements on the power system to integrate higher levels of variable energy resources, including the ISO's 2007 Report.[30] The 2007 Report concluded provisionally that integrating 20 percent renewable energy into the California electric power system is operationally feasible, subject to changes to operating practices. Based on a high-level survey of existing resources, the report also concluded that ISO generation and pumped storage was adequately flexible to meet the anticipated ramping requirements for load-following and regulation. The report noted the potential for renewable energy to cause an increase in overgeneration conditions, but did not attempt to quantify that increase.

This study addresses some of the recommendations of the 2007 Report and fills some of the gaps in the prior analysis. Because that report focused only on the impact of wind generation on system operations, one of its recommendations was for a future study to analyze the impact on integration requirements of solar power variability and forecast error. Another recommendation was to study changes in the commitment and dispatch of thermal resources due to renewable integration, in particular to quantify the impact of additional cycling (additional start-ups) and associated wear-and tear on conventional generation. This study addresses these recommendations and undertakes other analysis. Other recommendations are being addressed through various other ISO operational and market initiatives.

The starting point for the present analysis is that while there is substantial interest in storage and demand response to provide integration capabilities, at least during the next few years, support for integration of renewable resources during normal operating conditions will need to be provided largely through the flexibility of existing, re-powered, and new thermal generation. This generation fleet will also need to have the ability to provide sufficient ancillary services, particularly regulation up and regulation down and possibly some additional operating reserves.

Given this background, this study focuses on the operational requirements and assessment of generation fleet capability, along with measurement of generator operations and economic impacts, under the most recent estimate of the conventional and renewable resource mix under a 20 percent RPS. The core objectives of the present study are:

- to forecast the operational requirements and extreme conditions—specifically operational ramps, load-following, regulation, and overgeneration—under a 20 percent RPS that includes over 2000 MW of solar;

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[30] California Energy Commission, "Intermittency Analysis Project" (2007), CEC-500-2007-081 at http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF; California ISO, *Integration of Renewable Resources – Transmission and Operating Issues and Recommendations for Integrating Renewable Resources on the ISO-Controlled Grid*; KEMA, *Research Evaluation of Wind Generation, Solar Generation, and Storage Impact on the California Grid*.

- to further assess and verify—through analysis of historical operational data, as well as simulations of future conditions—that the existing fleet is sufficiently capable of satisfying the forecasted system operational requirements; and

- to provide insight on expected changes to generation fleet operations and market revenues.

The analysis and conclusions presented here will be augmented by the ISO's forthcoming scenario-based 33 percent RPS operational and market study, which is similar in structure and methodology to this study. As the renewable portfolios in 2020 and interim years become better defined, the ISO will also extend this analysis to renewable cases between 20 percent and 33 percent RPS.

2 Study Methodology and Assumptions

To provide the level of detail on operational requirements and capabilities needed to enable adequate system and market preparations, the ISO has worked intensively, including through collaboration with a number of organizations, to develop a suite of simulation models and to conduct extensive analysis of empirical data. A further objective is to standardize elements of these analyses to support periodic updating of the results as the mix and location of future renewable resource portfolios changes. This study utilizes several of these analytical methods to assess both the operational requirements associated with renewable integration and the capability of the generation fleet to meet those requirements.

The study evaluates a subset of key *operational requirements* that include (1) operational ramp rates at different time scales, (2) regulation capacity and ramp rate, and (3) load-following up and down capacity and ramp rates. These requirements are estimated using a statistical simulation methodology initially developed for the ISO's 2007 Report; for this study, that methodology has been updated to evaluate the impact of solar production forecast error and variability on these requirements.

Operational capability refers to the ability of the ISO's existing and planned generation and non-generation resources to address the incremental operational requirements as a result of variable energy resources. For this study, operational capabilities were evaluated on two separate tracks:

- First, the ISO reviewed data on the certified operational characteristics of the existing generation and pumped storage resources to gain insight into capacity with different ranges of start-up times, ramp rates and regulation capacity and ramp rates. The ISO also analyzed historical operational and market data to evaluate what additional operational flexibility might be available in current operations to accommodate renewable integration (i.e., without requiring changes to market operations or procurement of additional reserves).

- Second, the ISO has used both deterministic and stochastic production simulations to estimate whether the generation fleet possesses the capability to meet load in both hourly and sub-hourly time frames and supply the required ancillary services, under 20 percent RPS.

This section is organized as follows. Common data and assumptions for the simulations are described first, along with some further characterization of net load in 2012. The statistical methodology used for determining the regulation and load-following requirements is described generally in Section 2.4. The production simulation methodology and description of data and assumptions specific to those simulations are provided in Section 2.5.

2.1 Study Scenario Data and Assumptions

This section describes the common assumptions and data used in development of the scenarios for 20 percent RPS.

2.1.1 Load

As noted, the year 2012 was selected as the target year for the 20 percent RPS. The load profiles for 2012 were developed by scaling actual 1-minute ISO Balancing Area load data from two base years – 2006 and 2007 – using an annual load growth factor of 1.5 percent. The years 2006 and 2007 were selected to permit an assessment of the effects on fleet capability under distinct hydro conditions, with 2006 being a high-hydro year and 2007 being a low-hydro year. The use of base year 2006 is further consistent with the decision to apply conservative, i.e., stressful, assumptions in the analysis whenever appropriate since 2006 represents a greater than average ISO coincident peak load condition.

The application of a linear annual load growth factor of 1.5 percent from 2006 and 2007 may result in an overestimate of demand and peak in 2012 when compared against the California Energy Commission's (CEC) revised 2012 forecast included in its December 2009 California Energy Demand Forecast 2010-2020.[31] Table 2.1 sets forth the annual net energy and the coincident peak growth rates assumed by the CEC for the ISO Balancing Areas for the 2009 revised forecast, which reflected the impact of reduced economic activity during 2008-2010 and from a prior 2007 forecast. Table 2.2 reflects the load data used in the study and includes a comparison to both the prior 2007 CEC demand forecast and the revised 2009 CEC estimate. The total demand used in the study for 2012 (2006 base year) is approximately 10 percent greater than the CEC's current estimate of 2012 demand, while the non-coincident peak load for 2012 (2006 base year) is approximately 5 percent higher than currently anticipated by the CEC. However, in order to assess the impact of the potential additional load, the ISO has performed production simulations based on 2006 demand without the 1.5 percent annual load growth factor. The demand in this sensitivity exceeds the 2009 CEC demand forecast by approximately 2 percent.

The use of the higher demand assumption is consistent with study's primary objective of assessing the capability of the thermal generation fleet to reliably integrate a 20 percent RPS renewable resource portfolio. The effect of potentially overestimating demand is to more severely test the ability of the existing generation fleet to account for both greater than average load conditions and the integration of a concomitantly higher level of renewable resources (adjusted to meet the 20 percent RPS at the higher load). Relatively higher levels of renewable resources will increase the overall system variability and uncertainty and need for operational flexibility.

[31] See CEC, California Energy Demand 2010-2020 Adopted Forecast available at http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF.

Table 2.1: CEC Average Annual Net Energy[32] and Average Peak Growth Rates[33]

Year	Annual Average Net Energy		Average Annual Peak Growth Rates	
	CEC Forecast 2007 – Statewide	CEC Forecast 2009 – ISO Balancing Area	CEC 2007 Forecast – Statewide	CEC 2009 Forecast – ISO Balancing Area
2008 – 2010	1.39 percent	-0.99 percent	1.43 percent	0.82 percent
2011 – 2015	1.21 percent	1.22 percent	1.31 percent	1.50 percent
Avg.	1.28 percent	0.39 percent	1.36 percent	1.25 percent

Table 2.2: Demand Assumptions in 2012[34]

Service Territory		Base Year 2006	Base Year 2007	CEC 2007 Forecast	CEC 2009 Forecast Adopted
PG&E	Base Year Energy (GWh)	107143	108290		
	Base Year Peak (MW)	22635	21196		
	2012 Energy (GWh)	117155	116659	113238	111113
	2012 Peak (MW)	24750	22834	24699	24112
SCE	Base Year Energy (GWh)	111560	112507		
	Base Year Peak (MW)	23340	23830		
	2012 Energy (GWh)	121985	121202	111562	102408
	2012 Peak (MW)	25521	25672	24805	23522
SDG&E	Base Year Energy (GWh)	21498	21513		
	Base Year Peak (MW)	4476	4602		
	2012 Energy (GWh)	23507	23176	22606	21682
	2012 Peak (MW)	4894	4958	4842	4640
ISO Total	Base Year Energy (GWh)	240201	242310		
	Base Year Peak (MW)	50451	49628		
	2012 Energy (GWh)	262646	261037	247406	235203
	2012 Peak (MW)	55165	53463	54346	52274
Note:	Total Peaks are non-coincident				

32 *Id.* at P. 13 (Table 3) and 16 (Table 4).

33 *Id.* at P. 13 (Table 3) and 20 (Table 5), Statewide peak growth rates apply to a non-coincident peak, while the ISO annual peak growth rates apply to a coincident peak.

34 *Id.* at P. 55 (Table 10), 89 (Table 14) and 123 (Table 18),

2.1.2 Renewable Resource Portfolios by Capacity

The study models two renewable resource portfolios:

- a “20 percent RPS” portfolio that models 20 percent renewable energy in 2012 based on data developed by the California Public Utility Commission (CPUC); and

- a “2006 Reference” portfolio which includes only renewable resources on-line in 2006 to provide a reference to the 20 percent RPS results.

In both cases, the remainder of the generation fleet consists of resources that were on-line through 2006 within the ISO’s footprint and the addition of 3,263 MW of new thermal generation facilities expected to be on-line by 2012.

The 20 percent RPS portfolio being modeled has some significant differences from the one modeled in the 2007 Report. In 2006, when the prior study assumptions were developed, the prevailing view based on Load Serving Entity (LSE) contracts and ISO generation interconnection queue positions was that wind would constitute the predominant incremental in-state renewable technology to achieve 20 percent RPS. Wind resource capacity *additions* consisted of a total of 4,040 MW: 3,540 MW located at Tehachapi and 500 MW located at Solano. Although the 2007 Report also assumed a significant amount of new geothermal and biomass resources, it noted that those types of resources are not variable and hence their integration into the ISO is not anticipated to cause material operational issues. Moreover, the 2007 Report assumed that the interconnection of less than 1000 MW of central station solar power by 2010, as estimated at the time, would not result in significant integration requirements. As a result, the analysis of operational requirements in the 2007 Report focused exclusively on the impact of wind resources.

Since 2007, solar projects have become a significantly higher percentage of the portfolio of renewable resources under contract with investor owned utilities as well as of those supply resources generally seeking to interconnect by 2012. Much of the anticipated solar capacity consists of photovoltaic (PV) technologies that have demonstrated substantial variability due to their potential for rapid fluctuations in output.[35] Hence, the ISO determined to examine more explicitly the impact of solar resources on the statistical analysis of operational requirements, as well as in the production simulations. The solar resources are modeled in Barstow, Riverside East 1, Riverside East 2, Mountain Pass/Tehachapi, and include some distributed generation at multiple locations.

[35] E.g., as noted by NERC, “PV systems can experience variations in output of +/- 50 percent in the 30 to 90 second time frame and +/- 70 percent in a five to ten minute time frame. Furthermore, the ramps of this magnitude can be experienced many times in a single day during certain weather conditions. This phenomenon has been observed on some of the largest PV arrays (ranging from 3-10 MW) deployed in the U.S. located in Arizona and Nevada.” See NERC, “Special Report: Accommodating High Levels of Variable Generation” at p. 27, available at http://www.nerc.com/files/IVGTF_Report_041609.pdf.

To provide a reference for changes on the power system, the ISO also modeled a "2006 Reference" scenario in which only renewable resources in operation in 2006 are considered in the simulations. This case is analyzed to measure the incremental impact of renewables in the production simulation. In the statistical analysis of operational requirements, this 2006 scenario is also modeled using 2006 loads to show the increase in requirements arising from the change in load from 2006 to 2012. Table 2.3 summarizes the installed capacity (MW) in each of the scenarios, including both renewable and conventional generation technologies.

Table 2.3: Installed Capacity (MW) of the 2012 Cases by Generation Type

	2006 Reference Case	2012 20 Percent RPS Case
Biomass/BioGas	701	701
Solar	420	2,246
Geothermal	1,101	2,341
Small Hydro	614	614
Wind	2,648	6,688
Total ISO Installed Renewable Capacity	5,484	12,590
Thermal	32,308	32,308
Large Hydro	7,166	7,166
QF	3,555	3,555
Nuclear	4,550	4,550
Total ISO Installed Conventional Capacity	47,579	47,579
Total ISO Installed Capacity	53,063	60,169
ISO Planning Reserve 17 Percent	64,543	64,543
Import Contribution to Capacity	12,711	12,711
Total Resources	65,774	72,880

The incremental renewable portfolio used in the study is intended to be consistent with assumptions made by state agencies and, in particular, the CPUC on the resource mix by technology and location (including in-state and out-of-state). As such, the expected wind capacity remains essentially the same as in 2007 Report, but the incremental geothermal and solar capacity is patterned after the 20 percent RPS reference case developed by the CPUC as part of its 33 percent RPS Implementation Analysis conducted in 2009.[36]

[36] See, CPUC, 33 percent Renewables Portfolio Standard, Implementation Analysis, Preliminary Results (June 2009), available at http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf.

2.1.3 Aggregate Energy Production by Renewable Resources

The renewable resource capacity (MW) requirements shown above are determined by a combination of specific projects and the renewable energy requirements under 20 percent RPS. In turn, the total annual energy production by resource type is then converted into energy production profiles, based on the capacity factors of each technology by location, for each time interval being analyzed. Table 2.4 shows the annual energy production (GWh) associated with the mix of renewable resource capacity shown in Table 2.3.

Table 2.4: Renewable Energy Production (GWh) in the 20 percent RPS Scenario

Resources	Energy (GWh)
Wind (ISO)	17,886
Solar	4,907
Small Hydro	1,047
Biomass/Biogas	4,753
Geothermal	19,225
Wind (Out-of-State)	6,062
Total Renewable Resources	53,879
Total of All Resources	263,646
Renewables as a percentage of total resources	***20.4 %***

2.2 Development of Wind and Solar Production Profiles

The study uses a wind production profile for 2012 that was developed by AWS Truepower for the 2007 Report[37] and which located the incremental wind additions at Tehachapi and Solano. The expected wind production data was simulated using actual production data from January 2002 to December 2004 combined with atmospheric simulation models to create wind speeds for the resource areas. The maximum wind production level in the data set is 6,000 MW at times. Additional information on the development of the wind production data can be found in the technical appendix.

For both solar thermal and solar PV resources, production profiles by plant were also developed and were located at five CREZs and some distributed locations. A method

[37] This data was also used in the CEC IAP Study (http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF).

was developed to simulate locational variability in production due to changes in irradiance and the operating characteristics of each technology type.[38]

The final wind and solar production profiles used in the "2006 Reference" case and "20 Percent RPS" case were developed on a 1-minute time-step, corresponding chronologically to the load data for each period studied. Similarly to the graphs shown in Figure 1-2 and Figure 1-3 in Section 1, these profiles reflect the inherent variability of the wind and solar production for the target year (as well as load variability). Figures 1-9 through 1-12 in Section 1 plot the average hourly 2012 production data for wind in each season by operating hour.

2.3 Load Net of Renewable Energy by Season in 2012

Because both the renewable energy profiles and the load are fixed inputs into the models, the net load in each hour – load minus renewable energy production – can be calculated ex ante. This section shows the net load by season in 2012 as background to some of the subsequent simulation results.

Figure 2-1 toFigure 2-4 illustrate the *average hourly* load, net load and wind and solar generation in California for each of the four seasons in 2012 (as noted in Section 1, the average hourly production is not reflective of the actual hourly variability of wind and solar resources).[39] Load and net load MW are measured on the left horizontal axis (or y-axis), while wind and solar generation are measured on the right horizontal axis (or y-axis). The figures show that due to solar production, the net load now decreases in the daily peak hours in all seasons. This results in more displacement of daily peak hour thermal generation than the incremental wind-only scenario modeled in the 2007 Report. Section 5 discusses the exact energy displacement (GWh) by season as well as price and revenue impacts.

[38] The existing solar resources were modeled using ISO 1 minute production data. For the new plants, a different production profile data set was constructed for each technology type – solar PV with tracking, solar PV without tracking and solar thermal which used the trough model – at each location that captured differences in hourly solar irradiance, the time delay in how particular technologies respond to irradiance, and the effect of cloud cover on locations with multiple plants. The methodology is explained in detail in the technical appendix.

[39] That is, the hourly average production across all similar hours in the season using the data sets for the production profiles in the simulation models discussed in Sections 2-5. The averaging is why wind production appears much lower than its full rated capacity in 2012.

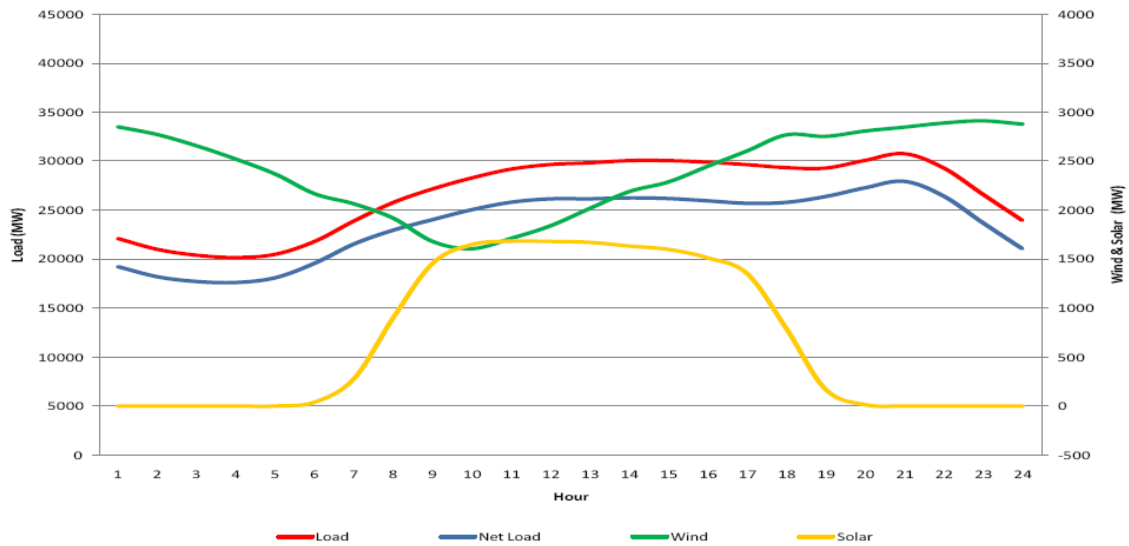

Figure 2-1: Simulated average hourly load, net load and wind and solar generation, Spring 2012

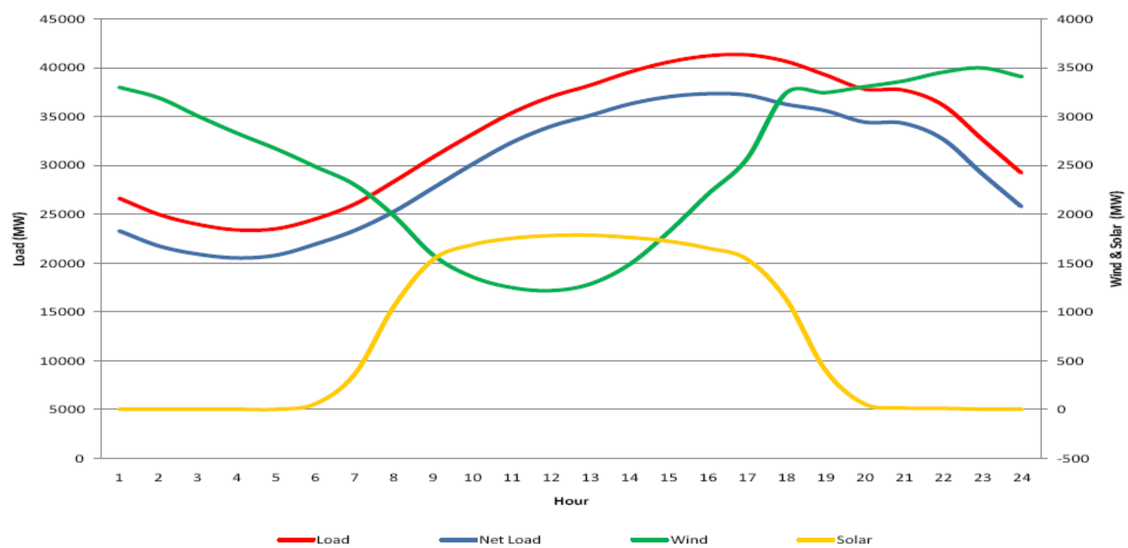

Figure 2-2: Simulated average hourly load, net load and wind and solar generation, Summer 2012

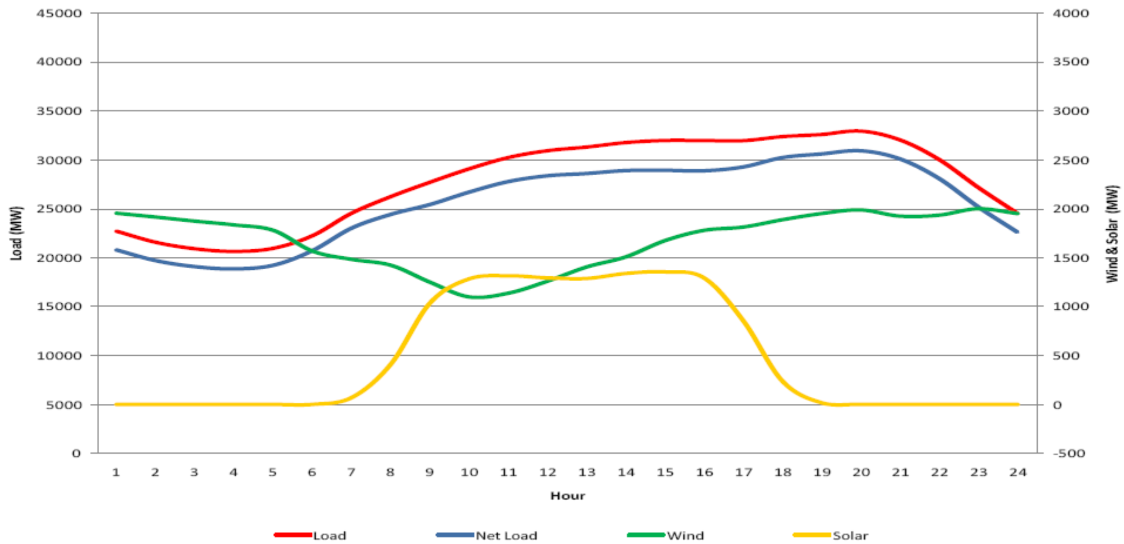

Figure 2-3: Simulated average hourly load, net load and wind and solar generation, Fall 2012

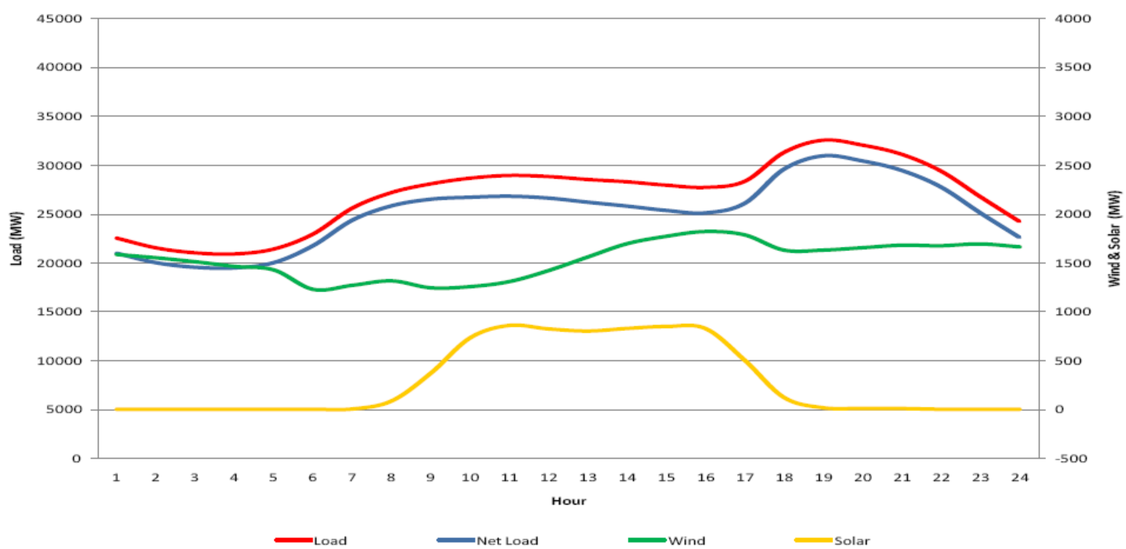

Figure 2-4: Simulated average hourly load, net load and wind and solar generation, Winter 2012

2.4 Methodology for Determining Operational Requirements

A key component of renewable integration studies is statistical analysis, including simulation through stochastic processes, of the potential deviations in wind and solar generation over various operational and market time frames – e.g., day-ahead to hour-ahead; hour-ahead to 5-minute; 5-minute to one-minute – due both to variability and forecast error. These deviations are measured in terms of operational ramping (various time frames), load-following capacity (typically deviations within the operating hour on a 5-minute basis) and regulation capacity (typically deviations from 5-minute schedules to

1-minute actual generation), and can then be evaluated against the operating characteristics and capabilities of system resources, as discussed in subsequent sections. This section begins with an overview of the statistical methodology used in this study, followed by more detailed discussion of how the regulation and load-following requirements are calculated.

2.4.1 Overview of the Operational Requirements Simulation Methodology

There are several statistical methodologies that have been used in renewable integration studies to determine hourly and sub-hourly operational requirements and, by inference, integration costs.[40] This study uses a stochastic process developed by the ISO and Pacific Northwest National Laboratory (PNNL)[41] that employs Monte Carlo simulation, which uses random sampling over multiple trials or iterations to estimate the statistical characteristics of a mathematical system. The simulation is designed to model aspects of the daily sequence of ISO operations and markets in detail, from hour-ahead to real-time dispatch. The objective is to measure changes in operations at the aggregate power system level, rather than at any particular location in the system. The model provides realistic representations of the interaction of load, wind and solar forecast errors and variability in those time frames and evaluates their possible impact on operational requirements through a very large number of iterations. The model also incorporates some representation of system ramps between hours to improve accuracy.

A detailed description of the statistical analysis methodology is found in the technical appendix issued separately from this document. The basic method is as follows. First, the load and renewable production data is aggregated from the 1-minute data set to create averaged hour-ahead and 5-minute dispatch schedules for each hour of the year.

Second, the probability distributions of forecast errors, and other statistical properties, such as autocorrelation, for load, and wind and solar production in the hour-ahead and 5-minute-ahead timeframes are constructed. These distributions were developed from various sources, including the ISO and AWS Truepower data on wind forecast errors by location in California, and available data and additional modeling of solar forecast errors. Solar forecast error data is not yet widely available, so a detailed model to estimate those errors was developed that took into consideration the annual and daily patterns of solar irradiance, an hour-to-hour clearness index,[42] dynamic patterns of the cloud systems, types of solar generators, geographical location and spatial distribution of solar power plants, and other factors. Both wind and solar forecast errors are used in the hour-ahead random draws. However, in the 5-minute time frame, the ISO uses a wind persistence

[40] Earlier studies of California operational requirements using alternative statistical methods include the California Energy Commission, "Intermittency Analysis Project" (2007), CEC-500-2007-081 at http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF (hereafter "CEC IAP Study"). The ISO's 2007 Report adopted a different statistical method, which is developed further in the present study.

[41] See Makarov, et al., "Operational Impacts of Wind Generation on California Power Systems," *IEEE Transactions on Power Systems*, Vol. 24, No. 2, (May 2009) at 1039.

[42] The clearness index is a measure of the actual solar irradiance divided by the maximum solar irradiance; see the technical appendix.

forecast, which is the basis for the simulation. Hence, in the 5-minute sampling, the wind variability is preserved but the forecast error is static for the period of the persistence model. For the solar resources, the 5-minute persistence forecast is based on the clearness index, but the morning and evening ramp periods for solar are also modeled explicitly, during which persistence would not be an appropriate assumption.

Third, the Monte Carlo sampling then conducts random draws from the load, wind and solar forecast errors, with consideration of autocorrelations between the errors, to vary the initial hour-ahead and 5-minute schedules. The Monte Carlo sampling is done on each hour in the sequence individually.[43]

To facilitate analysis, the values generated from the sequence of hours being modeled are evaluated on a seasonal basis and the results for each hour are presented at that level of granularity (i.e., by season, by hour of day). These hourly results by season are shown in Section 4 and Appendix A. The seasonal time frame for presenting results was considered to provide sufficient information on changes in operational requirements over the season, and to capture sufficient variation among the seasons.

Each simulation of a seasonal case includes 100 iterations over all hours in the season to capture a large number of randomly generated values. Of these simulated values, five percent are eliminated as extreme points, using a methodology that considers all dimensions being measured in the analysis (capacity, ramp and ramp duration).[44] In the discussion that follows in Section 4, the ninety-fifth (95th) percentile value is called the "maximum".

Fourth, the remaining values from each full set of iterations are then evaluated using different measures. For example, the 2007 Report showed the maximum value for each operating day hour (i.e., Hour 1 through Hour 24) across the season, to highlight the maximum operational stress likely to be experienced. This study also shows the distribution (maximum, minimum, and average ± one standard deviation) of the maximum values for all hours in the seasonal simulation, to provide more information on the frequency of particular values across the season. [45] However, the basic methodology is the same in both studies.

The specific application of this methodology to evaluate load-following and regulation requirements is discussed in the next sections.

[43] However, the twenty (20) minute ramps that characterize the boundary between actual hourly schedules are represented in the model to ensure that in those periods, deviations between the underlying schedules and the random draws do not exaggerate the result.

[44] See discussion in the 2007 Report and the technical appendix to this report.

[45] That is, assuming a 90 day season, each of the 100 iterations runs through all hours of the season – day 1, hour 1, hour 2, …, day 2, hour 1, hour 2, …, day 90, hour 1, hour 2. This results in 100 values for each hour in the season. Of these 100 values, the maximum value is selected. Then all the hour 1s are grouped, as are all the hour 2s, hour 3s and so on. That results in 24 sets of 90 values, since there are 90 hour 1s, 90 hour 2s, and so on.

2.4.2 Determination of simulated load-following requirements

The statistical methodology described above can be used to evaluate operational requirements that correspond to the time-steps in which the data is sampled. The furthest forward in time that this study evaluates is the transition from hour-ahead schedules to intra-hour schedules and dispatch, which is called load-following. In the context of this analysis and the ISO market, load-following is defined as the intra-hour energy deviations from the hourly schedule, whether in the upward or downward direction. Such deviations can be measured in different ways and on different time-scales within the hour (e.g., 5 minute, 10 minute); generally, in this report, it refers to deviations in the ISO's 5-minute economic dispatch intervals.

Table 2.5 shows four different ways in which this study has measured and evaluated load-following requirements and capabilities, both through simulation and empirical analysis. The methods described in this section are listed as the first two in the table.

As noted above, the underlying data for the Monte Carlo simulation is based on 1-minute data that is then averaged to establish hourly schedules and 5-minute dispatch schedules for each hour. The objective of this approach to the simulation was to model data on time frames that correspond to the ISO's hour-ahead scheduling process and real-time unit commitment process, although the simulation itself does not "connect" each interval that it models through an optimization, as do the actual market processes. The hour-ahead scheduling process runs 75 minutes prior to each operating hour using the wind schedules and load forecasts available at that time. The hour-ahead wind schedule for about half of the wind resources currently on the system is constructed through a centralized forecast and made available to the ISO through the arrangements in the Participating Intermittent Resource Program (described in Section 2). The real-time unit commitment runs on a much shorter time horizon, and creates a schedule for economic dispatch of generators on a 5-minute basis. To restate the methodology in ISO scheduling and market terms, the operational requirements simulation defines load-following as the amount of incremental and decremental energy required to serve the MW difference between the hour-ahead scheduling process schedule and the real-time unit commitment and dispatch schedules for each 5-minute interval in the hour, as discussed next.

As noted above, the random draws of forecast errors then generate one value for each hour of the season and twelve values corresponding to each 5-minute interval within each hour, for each of 100 iterations. The method then calculates two quantities that are relevant to load-following. The first is called "load-following capacity" (MW); the second is called "load-following ramp rate" (MW/5 minutes). Load-following capacity is defined as the maximum difference between the hourly "schedule" MW calculated by the simulation and any 5-minute interval MW within that hour. That is, the largest *potential* movement upward and downward over the hour from the hourly schedule. The load-following ramp rate is defined as the difference between the MW in any two contiguous 1-minute intervals within the dispatch intervals in the hour. The maximum load-following ramp rate is thus the largest of these, and the duration of the ramp rate is also measured ex post. These results are presented in Section 4 to show the distribution statistics or simply the maximum value for each hour of the day by season.

Figure 2-5 shows the analytical flow of the load-following calculation. The full mathematical model is presented in the technical appendix.

Table 2.5: Comparison of definitions of "load-following" in study analysis

Analysis	Term	Description/Definition
Operational requirements simulation (Section 3)	Load-following capacity requirement	The maximum difference between the simulated hourly block schedule and any positive deviation from that schedule in the simulated 5 minute schedules (load-following up) or negative deviation (load-following down)
Operational requirements simulation (Section 3)	Load-following ramp rate	The maximum change between the MW level in any two consecutive simulated 1 minute intervals within an hour; can also be calculated for other intervals within the hour or over multiple hours
Operational capability based on actual market analysis (Section 4)	Actual 5-minute load-following capability	The estimated upward and downward capability of the generation committed and dispatched in actual five minute intervals, based on ramp rates and maximum and minimum operating limits
Operation capability based on production simulation (Section 5)	5-minute Load-following capacity	The cumulative capability of the units dispatched in the simulation to move in 5-minutes, subject to their ramp rates

2.4.3 Determination of simulated regulation requirements

The calculation of the regulation requirements proceeds similarly to the load-following analysis, but measuring deviations between the 5-minute dispatch intervals and the 1-minute data that underlies the analysis. In this case, the method measures the largest 1-minute deviation within the 5-minute period to give the regulation result. The “regulation capacity” requirement is defined as the largest such deviation within an hour. The “regulation ramp rate” is defined as the largest sampled change from minute-to-minute within the 5-minute interval.

Figure 2-6 shows the analytical flow of the regulation calculation, with additional detail available in the separate technical appendix.

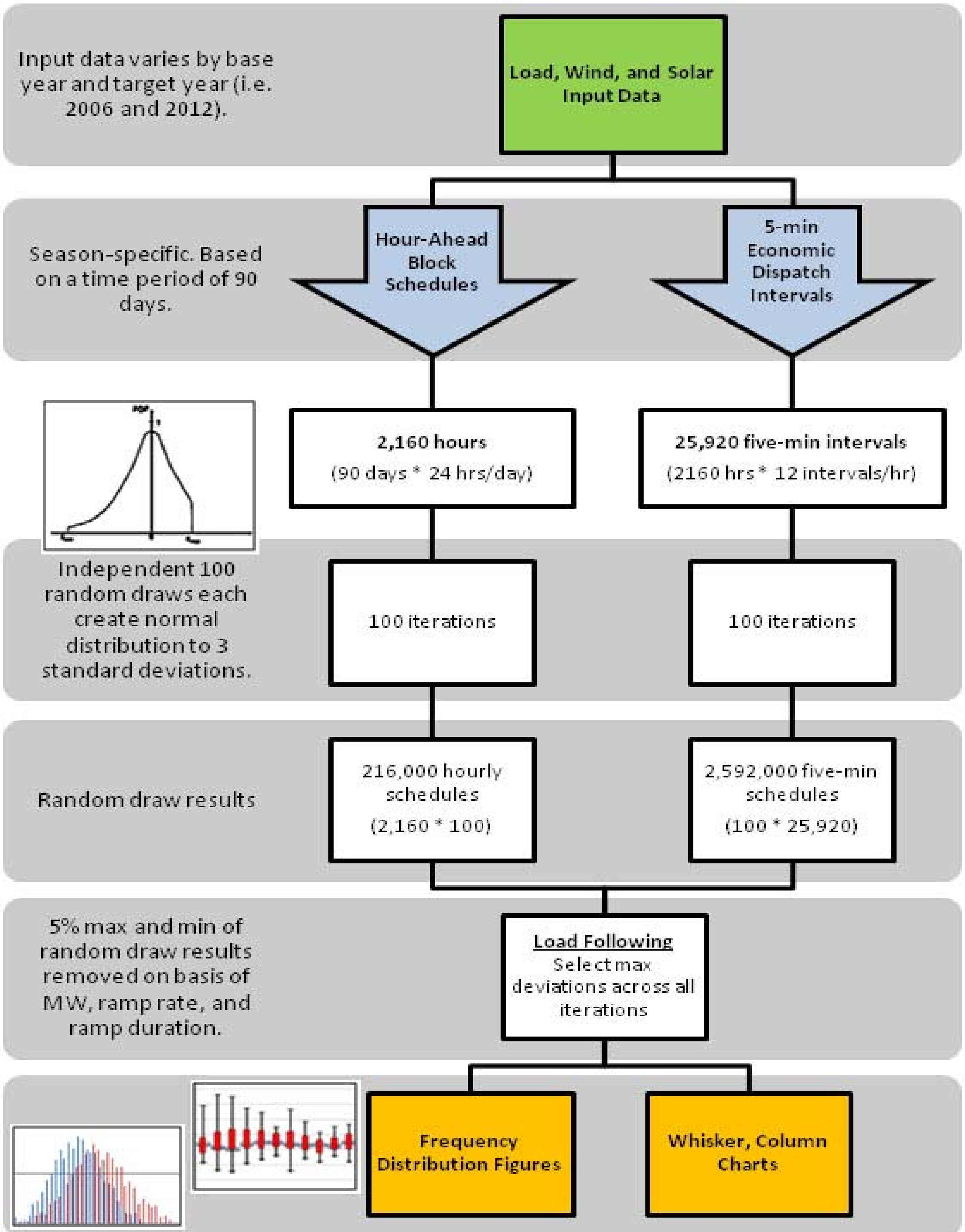

Figure 2-5: Analytical Flow Chart for Calculating Load-following Capacity Requirements

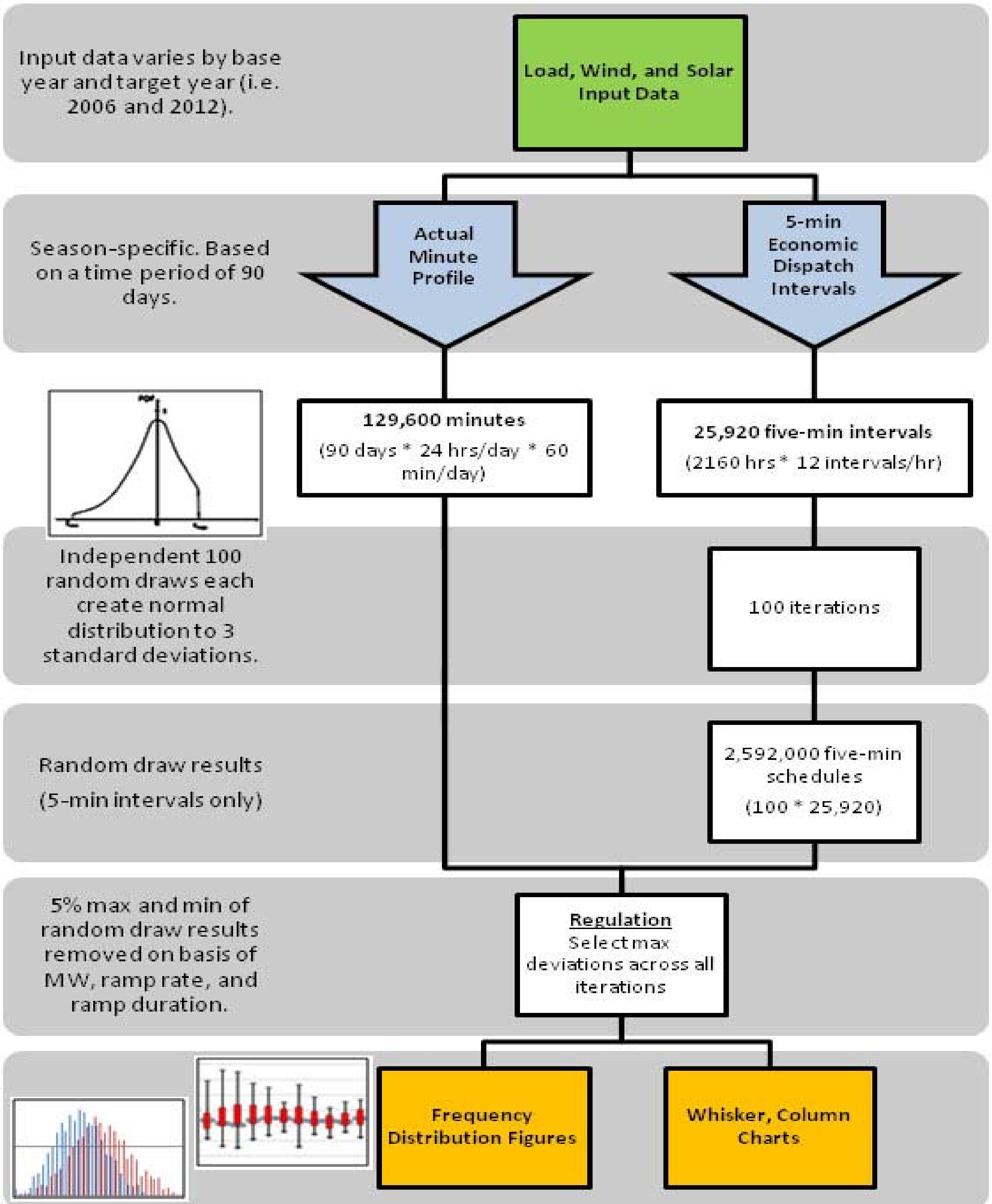

Figure 2-6: Analytical Flow Chart for Calculating Regulation Capacity Requirements

2.5 Production Simulation Methodology for Evaluation of Fleet Capability

One limitation of the operational requirements methodology is that it does not represent the supply side of the power system explicitly. That is, while estimating operational requirements, the statistical analysis does not address the capability of the ISO generation fleet to meet those requirements during market and system operations.

The analysis of generation fleet characteristics, historical bids and the historical dispatch described in Section 4 evaluates whether sufficient regulation and load-following capability exists to meet the integration requirements, based on historical operations. By juxtaposing the historical capability with the future operational requirements, it is possible to arrive at some conclusions regarding the capability of ISO generation fleet to meet the integration requirements with 20 percent renewable generation.

However, to analyze in detail the capability of the fleet to meet the integration requirements, it is necessary to conduct simulations of both hourly and minute-by-minute operations under future load and generation scenarios. The production simulation models developed for this study sought to replicate with a reasonable degree of accuracy the operational and market processes used in the commitment and dispatch of generation. It incorporated all the physical characteristics of the generators, such as ramp rate, start-up costs and time, minimum up-time, minimum down-time, etc. However, it did not include certain generator operating constraints, such as forbidden regions.

Production simulation (or production cost modeling) refers to the use of large-scale computer-based models that incorporate a detailed representation of generation, demand and transmission over a wide region to simulate least cost commitment and dispatch of generators subject to operational constraints and determine marginal prices at different locations in the system. Due to their scale, these types of models are typically used for planning purposes and not for market or operational evaluation. However, over recent years, many models have incorporated sufficient detail on generation and transmission network parameters, as well as updated their optimization algorithms for efficient unit commitment solutions, such that they are now also used to evaluate shorter-term market and operational conditions. Typically conducted on an hourly time-step, current state-of-the-art production simulation models can represent both unit commitment – the decision whether to start (commit) or stop (decommit) a particular resource in a particular period – and dispatch – the actual output from a particular resource in a particular period. They also explicitly represent key generation operating characteristics, such as start-up times, ramp rates and minimum up and down times.

Most of the large-scale regional wind integration studies to date have employed production simulation models to evaluate the capability of generation and non-generation resources to meet energy and ancillary services requirements under different future conditions.[46] These production simulations have used an hourly time interval for

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[46] For a recent survey, see M. Milligan, et al., Large-Scale Wind Integration Studies in the United States: Preliminary Results, Conference Paper, NREL/CP-550-46527, September 2009; See also California Energy Commission, "Intermittency Analysis Project" (2007), CEC-500-2007-081 at http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF; See also several

dynamic optimization, with the capability of the system to meet the sub-hourly requirements such as load-following evaluated heuristically based on the results of the hourly simulation and not explicitly determined via sub-hourly optimization. Also, most of the prior studies have employed deterministic production simulation, which does not adequately model the impact of uncertainties in load and variable generation. The stochastic, sequential simulation methodology employed in this study was designed to overcome the above-mentioned problems. This methodology is described below in Section 2.5.2 in detail. The data and assumptions used in the production simulation model are described next.

2.5.1 Data and Assumptions

The major objective of production simulation is to model the least cost operation of a power system while ensuring that the system's security constraints are not violated. Security constraints include the operating limits and capabilities of generation sources, constraints and contingencies imposed by the transmission system and the operational limits such as minimum operating reserve levels. The primary inputs are hourly loads, generator capacity and characteristics, fuel prices and transmission constraints that need to be monitored. This section provides the data and assumptions for the production simulation model used in this study.

2.5.1.1 General data and categorizations

The source for the identity and operating characteristics of the conventional resources incorporated into the production simulation model was the full network model used for allocation of ISO congestion revenue rights, and the ISO Master File, respectively. The ISO's Master File data includes all key generator confidential operating characteristics such as Pmin, Pmax, minimum up and down times, ramp rates, start times, heat rates, and ancillary service certified ranges. Table 2.6 describes how classes of resources are modeled in the production simulations. In this analysis, the generation from certain resources such as biomass, geothermal, and Qualifying Facilities (QFs) are assumed to be fixed based on historical operations. Hydro generation, although dispatchable, is assumed to be fixed based on either 2006 or 2007 hydro data, in order to study two different extremes in hydro generation. Similarly, a portion of imports is assumed to be fixed to reflect historical operations. Only gas-fired units are dispatchable in this analysis. These assumptions are further explained in the sections below.

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studies conducted by GE Consulting, including New York State Energy Research and Development Authority's "The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations, " available at http://www.nyserda.org/publications/wind_integration_report.pdf ; Ontario Power Authority, Independent Electricity System Operator, Canadian Wind Energy Association, "Ontario Wind Integration Study," available at
http://www.powerauthority.on.ca/Storage/28/2321_OPA_Report_final.pdf ; Electrical Reliability Council of Texas, "Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements," available at http://www.ercot.com/news/presentations/2008/Wind_Generation_Impact_on_Ancillary_Services_-_GE_Study.zip.

Table 2.6: Modeling assumptions about production profiles and flexibility by generation resource type and imports

Generation Type	Production Simulation -- Assumptions about Commitment and Dispatch
Solar	Simulated production profiles based on solar irradiance data; variable over the day (on both an hourly and intra-hourly basis); not dispatchable
Wind	Simulated production profiles from historic production data; variable over the day (on both an hourly and intra-hourly basis); not dispatchable
Biomass	Scaled historic production profile; constant over the day; not dispatchable
Geothermal	Fixed production profile; constant over the day; not dispatchable
Thermal	Dispatchable in each time-period within generation operating parameters
Hydro	Historical production and ancillary service profile (2006 and 2007); typically constant over the day; not dispatchable
Nuclear	Fixed production profile; constant over the day; not dispatchable
QF	Historic production profile; constant over the day; not dispatchable
Imports	Historic injection for 2006 and 2007; varies by hour; not dispatchable (but varied in sensitivity analysis)

2.5.1.2 Existing Conventional Gas Resources

Thermal resources in the study provide about 32,308 MW of the capacity within the ISO BAA, which would account for approximately 54 percent of the ISO's total resource mix in 2012. Gas plants are particularly important because they currently provide most of the ramping and ancillary service capability for the ISO. In this study, the gas-fired generation is assumed to be dispatchable; i.e., self-schedules of gas-fired generation are not modeled.

Tables 2.7 through 2.9 provide summaries of the various technology types and some of their operational characteristics.

Table 2.7: Ramp rates of ISO generation fleet

Generation Type		Ramp Rate (MW/min) by Category						
		RR < 0.5	0.5 ≤ RR < 1	1 ≤ RR < 5	5 ≤ RR < 10	10 ≤ RR < 20	20 ≤ RR	Total MW
Non-OTC Units	Combined Cycle			4,885	4,630	3,617		13,132
	Dynamic Schedule				552	1,746	2,379	4,676
	Gas Turbine	32	68	1,040	4,635	1,601	553	7,929
	Hydro	99	157	427	1,135	1,927	3,671	7,416
	Other	5	4	14	1,633		4	1,660
	Pump/Storage				440		1,792	2,232
	Recovery	61	17	115	13			206
	Steam	357	355	1,328	747	59		2,847
	Not specified	5	6	42	1,568	20	525	2,165
Non-OTC Unit Total		559	607	7,851	15,353	8,970	8,924	42,263
OTC units	Combined Cycle			600				600
	Gas Turbine			15				15
	Steam		354	8,542	5,650	1,516	1,510	17,573
OTC Unit total		0	354	9,158	5,650	1,516	1,510	18,188
All Units Total		559	961	17,008	21,003	10,486	10,434	60,451

Table 2.8: Definitions and characteristics of units based on start-times

Attribute	Fast-Start	Short-Start	Medium-Start	Long-Start	Extremely Long-Start
Start-up Time	Less than or equal to 10 minutes	Less than 2 hours	Between 2 & 5 hours	Between 5 & 18 hours	Greater than 18 hours
Cycle time		Less than 5 hours	Less than 5 hours		

Table 2.9: Start up times of ISO generation fleet

Generation Type		Start-up Times (minutes) by Category: ST < 10	10 ≤ ST < 120	120 ≤ RR < 300	300 ≤ RR < 10,800	unknown	Total MW
Non-OTC Units	Combined Cycle		174	1,241	11,717		13,132
	Dynamic Schedule				3,650	1,026	4,676
	Gas Turbine	1,261	2,161	191		4,317	7,929
	Hydro	4,908	1,382	486		640	7,416
	Other	352	294	377		636	1,660
	Pump/Storage	2,232					2,232
	Recovery	19	35	114		37	206
	Steam	267	169	221	1,760	430	2,847
	Not specified	360	114	19		1,672	2,165
Non-OTC Unit Total		9,400	4,329	2,649	17,127	8,759	42,263
OTC units	Combined Cycle			109	491		600
	Gas Turbine					15	15
	Steam				15,127	2,446	17,573
OTC Unit total				109	15,618	2,461	18,188
All Units Total		9,400	4,329	2,758	32,745	11,220	60,451

2.5.1.3 Expected Additional Conventional Gas Resources by 2012

Table 2.10 shows the new and planned thermal resources that were included in the analysis. These resources were included as they are currently under construction and have little or no risk of not being available in the 2012 timeframe. No resource retirements were modeled, nor were sensitivities conducted for the status of once-through cooling (OTC) plants. OTC plants are slated to be retrofitted or shut down after 2013 and are not expected to affect the 20 percent RPS integration. However, they could affect renewable integration after 2013, and hence are being examined in the ISO's 33 percent RPS operational study.

Table 2.10: New Resource Additions by 2012

	New Resources	Max. Cap. (MW)	Location	Commission Date
1	EIF_Panoche_2_PL1X2	400	Fresno, NP15	August 2009
2	GateWay_2_PL1X4	530	Contra Costa, NP15	May 2009
3	Humboldt_1_PL1X2	163	Humboldt, NP15	April 2010
4	Inland_Emp_2_PL1X4	800	Riverside, SP15	Unit 1: Nov. 2008 Unit 2: July 2009
5	Otay_Mesa_2_PL1X2	590	San Diego, SP15	October, 2009
6	Starwood_1_PL1X2	120	Fresno, NP15	May 2009
7	Colusa Generating Station	660	Colusa, NP15	October, 2010
Total		3,263		

2.5.1.4 Imports of Energy and Ancillary Services

To simplify the analysis, and to keep it focused on the operational capabilities of the generation fleet under ISO dispatch control, the production simulation used fixed imports of energy based on historical import data. The ISO is a net importer of energy and this is not likely to decrease in the near future. The 2012 import levels used in this study were based on the actual import profiles for 2006 and 2007. As discussed further in the next section, during high hydro years within the ISO's footprint, imports are significantly lower than they are during low hydro years. Thus, the combination of the hydro patterns and imports for 2006 and 2007 are a useful starting point for examining the sensitivity of renewable integration to alternative system conditions.

During the off-peak hours in 2006, the average imports exceeded 5,100 MW in the spring and 5,500 MW in the summer months. During the off-peak hours in 2007, the average imports were 7,000 MW in the spring and 6,900 MW in the summer. Some of the reasons for high import levels during the off-peak hours are jointly owned units that are dynamically scheduled into the ISO, load-serving entity contracts to purchase base-loaded energy from out-of-state coal plants, and external resources that are needed to serve the ISO's peak demand but cannot be shut down by the host balancing authorities due to their long start up times and shut down times between starts. In cases where the ISO needs the peak energy from an external resource it may have to also take the minimum generation from that resource during the off-peak hours because the host balancing authority may not need the off-peak generation.

In the model, ancillary services imports over the interties were assumed to be zero, in part due to the limitations of the model to represent dispatch of external resources and also because the analysis was focused on the renewable integration capability of the existing in-state generation fleet.

It is expected that the energy import levels modeled here will be available in 2012; the study did not scale up the imports (i.e., assume that there will be additional surplus generation outside the ISO) on the assumption that in other regions, generation additions will at least keep up with expected load growth.

To examine the sensitivity of the results to import assumptions, the production simulation analysis included several alternative cases that varied the level of imports considered fixed and the level considered dispatchable. Subsequent studies, notably the forthcoming 33 percent RPS operational study, will use a WECC-wide model that can examine regional energy trade balances and ancillary service provision.

2.5.1.5 Hydro Resources

The off-peak hydro production levels could average 3,822 MW (49 percent) of total capacity during the spring, about 2,707 MW (35 percent) in the summer and 2,337 MW (30 percent) during the winter months. Also in the spring, high temperatures can result in early snow melt and high hydro production levels, which can result in overgeneration conditions because the off-peak loads in the spring is typically about 2,000 MW lower than the off-peak loads in the summer. Since the hydro capacity is expected to remain about the same in the 2012 timeframe, the realized hydro production levels can greatly influence the amount of wind generation that can be accommodated into the resource mix.

The study used two sensitivities for hydro production: a high hydro case based on actual production in 2006; and a low hydro case based on actual production in 2007. The ancillary services (spinning reserve, non spinning reserve and regulation) awarded to hydro resources were assumed to be the same as 2006 and 2007.

Table 2.11: Comparison of Hydro and Imports in 2006 and 2007 (GWh/yr)

	2006	2007	percent diff.
CA hydro	48,876	26,958	-45 %
CA net imports:			
From NW	19,808	24,669	25 %
From SW	44,959	67,547	50 %
Total	**64,767**	**92,216**	**42 %**

The hydro profiles used in the simulation were actual production for 2006 and 2007. 2006 was declared a high hydro year due to the higher than normal rainfall, snowpack and reservoir storage levels. By comparison, 2007 was declared a normal hydro year.

Overall, hydro production was 48,876 GWh in 2006 and 26,958 GWh in 2007, a reduction of 45 percent. The ancillary services modeled in the production simulation studies were assumed to be the same as was provided by the hydro resources in 2006 and 2007.[47] Typically, during high hydro years in California, the ISO imports are significantly lower than during dry hydro years. As shown in Table 2.11, a high hydro year has a significant impact on imports.

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[47] Availability of hydroelectric production is a major influence on the availability of regulation. Hydroelectric resources typically provide a large fraction of the regulation utilized by the ISO, and are among the most flexible resources available, so anything that impacts their ability to provide the service has a noticeable impact on the market. Water conditions can directly affect the capability of hydro resources to provide regulation. In 2006, hydro generation was at high capacity, such that hydro generators were forced to either generate at maximum capacity or allow water to go over spillways. Under these circumstances, hydro units had no spare capacity to provide for regulation and other resource types were used to make up for reduced hydro availability. In the spring of 2006, there was insufficient upward regulation capacity in the market a total of 104 hours, distributed fairly evenly across all hours of the day. Upward regulation from hydro resources hovered in the 150 MW range in 2006, but was in the 200 MW range in the comparatively lean water year of 2007. In the spring of 2007, hydro units were not producing energy at their maximum capacity, and were therefore able to offer regulation capacity to the market. By comparison, insufficiency occurred in only 5 hours during January through May 2007 period, when water levels were much lower.

2.5.1.6 Modeling of Other Generation Resources

In 2006, of the four nuclear units within the ISO area, two units were off-line for some time in the spring and one unit was off-line for a period of time during the fall and winter months. In subsequent years, it is highly likely that all four units would be on-line and generating at their maximum capacity during off-peak hours. Therefore, all four nuclear units were modeled at a combined full output of 4,550 MW.

Qualifying Facilities (QFs) were modeled at their historic production profiles in 2006 and 2007; actual QF production does not vary much from one hour to the next and is not modeled as dispatchable (typically, QFs are only given dispatch instructions when the ISO declares an emergency). Although geothermal and biomass resources are classified as QFs, for accounting purposes, their actual production was not included in the QF total but instead counted as renewable energy to meet the RPS.

2.5.1.7 Renewable Resource Operational Characteristics

All RPS-eligible renewable resources, including variable generation renewables, were modeled as fixed output (or “must-take”) generation. Wind and solar production profiles were discussed above in Section 2.2. Geothermal, biomass and small hydro facilities were modeled based on their historic production profiles realized in 2006 and 2007 and incremented to 2012 production levels as appropriate.

2.5.1.8 Load Forecasts and Assumptions

Load forecast assumptions were discussed in Section 2.1. The minute-by-minute load data for 2012 was averaged to obtain the 5-minute and hourly load for the production simulations. The methodology used for simulating day-ahead and hour-ahead loads using forecast error is described in the technical appendix.

2.5.1.9 Network Representation

The ISO service territory was modeled as three transmission regions—PG&E, SCE and SDG&E—but transmission limits were only enforced on Path 26. As noted above, hourly net interchange for NP26 and SP26 were fixed based on 2006 or 2007 actual data. A full network representation was not employed since it would have greatly increased the solution times of the stochastic simulations.

2.5.1.10 Ancillary Service Requirements

The production simulation model co-optimizes energy and ancillary services, such as regulation, spinning and non-spinning reserves. The ancillary service requirements used in the simulations are listed in Table 2.12. As noted above, they include the seasonal maximum regulation requirements by operating hour calculated in the operational requirements simulations. Those actual requirements are shown in Section 3 and Appendix A-1. However, the model did not represent ancillary service procurement requirements on a regional and sub-regional basis.

Table 2.12: Ancillary Service Requirements

Ancillary Service	2007 Report Requirements for Incremental Wind Case	Requirements for Incremental Wind plus Solar Case
Regulation-Down	350-750 *	350-775 *
Regulation-Up	350-530 *	350-525 *
Spinning	0.5 × (3 percent × Load + 3 percent × Generation)	0.5 × (3 percent × Load + 3 percent × Generation)
Non-Spinning	0.5 × (3 percent × Load + 3 percent × Generation)	0.5 × (3 percent × Load + 3 percent × Generation)

* Regulation requirements vary by time of day and season.

2.5.2 Stochastic Sequential Production Simulation Methodology

For this study, the ISO developed a more detailed modeling approach to production simulation than most prior renewable integration studies. A stochastic, sequential production simulation with the capability to simulate both hourly commitment and dispatch and 5-minute real-time dispatch was developed for this study. The methodology considered the impact of day-ahead and hour-ahead wind and load forecast errors on unit commitment and dispatch, thereby replicating to some degree the actual sequence of those forward markets and procedures. As discussed below, the hour-ahead commitment is then frozen and the units dispatched to serve net load across 5-minute "real-time" intervals. This process is repeated for 100 iterations to test the impact of multiple possible forecast errors that need to be resolved in the actual dispatch. The technical appendix provides the mathematical details on the methodology.

2.5.2.1 Generation of stochastic load and wind generation forecasts

The further forward in time, the greater the uncertainty about actual (real-time) wind and load due to forecast error. A stochastic process using Brownian motion with mean reversion was developed to generate a random sequence of day-ahead and hour-ahead load and wind forecasts errors for each hourly interval in 2012. The stochastic process was specified using the statistical properties—mean, standard deviation, autocorrelation, and cross-correlation—of the actual day-ahead and hour-ahead load and wind forecast errors. The cross-correlations are composed of the inter-regional correlation of load forecast errors, wind inter-zonal correlations, load-wind correlations and day-ahead and hour-ahead correlations. The statistical properties are derived for four seasons: spring, summer, fall and winter. However, the random process did not include solar forecast errors, although the solar profiles with their actual variability were used to establish the hourly and 5-minute net loads.

The stochastic process was used to generate 100 different day-ahead and hour-ahead load and wind generation forecasts for evaluation of alternative unit commitment and dispatch realizations. These were then used in the process described next.

2.5.2.2 Sequential day-ahead to real-time simulations

The analytical flow of the stochastic, sequential production simulation methodology is depicted in Figure 2-7. The first step in this methodology is the simulation of the day-ahead market with a day-ahead load and wind forecast. The model did not include a day-ahead solar forecast, but rather modeled solar production as a fixed hourly profile. The day-ahead market simulation is an hourly simulation for the entire study year (8760) hours. This simulation is performed 100 times using the day-ahead load and wind generation forecast errors described in the previous section. This simulation uses a 24-hour optimization window, with a 24-hour look-ahead to account for long-start units.

The next step in the sequential simulation is the "hour-ahead" simulation which lines up in time with the ISO's hour-ahead scheduling procedure and with the submission of wind schedules in the Participating Intermittent Resource Program. The commitment status for the extremely long- and long-start generators are passed from the day-ahead simulation and frozen in the hour-ahead simulation. As in the case of the day-ahead simulation, the hour-ahead simulation is an hourly simulation for the entire study year (8760) hours. This simulation is performed 100 times using the hour-ahead load and wind generation forecast errors. The day-ahead and hour-ahead load and wind generation forecast errors are correlated. This simulation uses a 6-hour optimization window. The hourly unit commitment status for the extremely long-, long-, medium-, and quick-start generators are queried by iteration from the solution and passed to the "real-time" 5-minute simulations, which are described next.

In the real-time simulation unit commitment and dispatch, the resource and network data are the same as that in the day-ahead and hour-ahead simulations. The loads and variable energy resource generation are the "actual" data prior to the introduction of forecast errors, and averaged from the underlying 1-minute data to the 5-minute intervals. The solution is the co-optimization of energy and ancillary services with generation unit commitment and dispatch.

To reduce the computational burden, a selected number of days that exhibited interesting operational challenges were selected for this detailed simulation process to examine the impact on load-following and overgeneration. To identify these days or hours, the ISO undertook a variant on what is called "importance sampling."[48] This is a method for choosing most likely scenarios, or in this case, most likely periods for ramp violations, ancillary service shortfalls, or overgeneration events. The procedure used to identify interesting days for real-time simulations is described in Appendix C-1.

[48] See, e.g., description as applied to the ISO's Transmission Economic Assessment Methodology (TEAM), (2004), pg. 5-8.

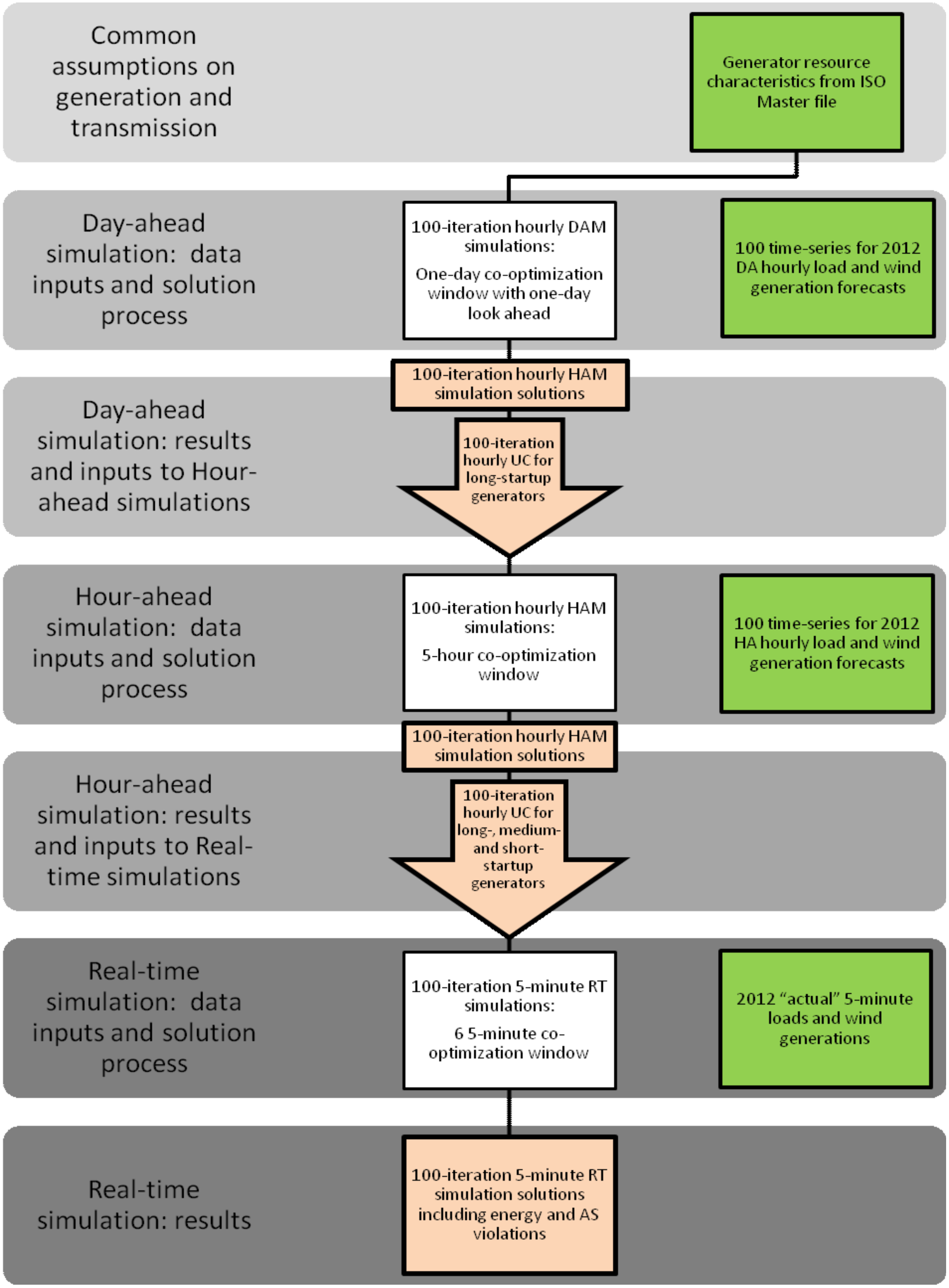

Figure 2-7: Flowchart of the Stochastic, Sequential Production Simulation Methodology

3 Analysis of Operational Requirements

This section and appendices A-1 and A-2 present the updated estimates of operational requirements under a 20 percent RPS, along with a comparison to analogous results from the ISO's 2007 Report and other relevant studies. This section focuses on results from the Summer 2012 simulation; results for other seasons are in Appendix A-1. In addition, Appendix A-2 shows additional sensitivity results for Summer 2012.

The simulation results provide information on a number of operational and market relevant questions, including the simulated seasonal maximum requirements by hour of day[49] and other distribution statistics – average, range (maximum, minimum), frequency of the requirement – over each hour of the season based on different subsets of the simulation results.[50] The seasonal maximum hourly requirement is important information for operational reasons, to provide the ISO with the largest magnitudes of potential requirements. The other statistics are to provide both the ISO and market participants with information about the expected frequency and magnitudes of the operational requirements over the course of each season. This is particularly true for wind production as the input data set to the simulations captures variations in wind production over the entire target year (2012) based on historical production data.

In the 2007 Report, only the seasonal maximum hourly operational requirements by hour of day were reported.[51] At the time, the objective of the analysis was solely to provide results for system operational preparations. In addition, the study used only one wind production profile for the year (based on average capacity factors from historical data), and thus there was concern that additional statistics on the results could be misleading, given that other annual wind profiles could have generated different results, although the maximum requirement results would probably not change substantially.

Moreover, as noted in Section 2.2, the statistical simulations of regulation requirements do not consider the effect of other real-time considerations, such as generator uninstructed deviations in real-time dispatch, as well as day-ahead forecast errors of wind and solar production that could affect day-ahead procurement of regulation and possibly other ancillary services at higher levels of variable energy production. Currently the ISO procures a minimum of 300 MW of Regulation Up and Regulation Down in the day-ahead market to cover peak hour load requirements and those other considerations. The ISO expects that this will remain a minimum requirement, even for hours in which the simulation results shown here suggest a possible "real-time" requirement of less than 300 MW. The ISO believes that the simulation results are a better indicator of the potential need for procurement of above 300 MW of Regulation in certain hours due to forecast

[49] i.e., the maximum seasonal requirement for each hour of the day from the 100 iterations of the simulation of the 90 days of the season

[50] Section 3 describes the results yielded from the 100 iterations of each season. The other statistics are generated from this underlying data set.

[51] See 2007 Report, sections 5.8.3 and 5.10.1 as well as Appendix A; available at http://www.caiso.com/1ca5/1ca5a7a026270.pdf.

variable energy resource production. Further simulations of different wind production profiles and consideration of other factors, such as day-ahead (rather than hour-ahead) forecast errors, could thus improve understanding of the relationship between operational requirements in real-time and market procurement forecasts day-ahead.

However, the ISO believes that there is market value to providing some of the other statistics on the simulation results. In particular, these additional statistics clarify that the average ± one standard deviation of the simulated values for operational requirements for particular hours of the day over the season can be substantially less than the maximum seasonal requirements for those hours, particularly for the daily peak hours when wind production is typically at a low capacity factor. Moreover, in actual operations, the ISO uses daily and hourly forecasts of load and renewable energy production, and has continuously improved its wind and ramp forecasting capabilities. Hence the ISO will not, in practice, commit resources day-ahead to meet a simulated seasonal maximum operating requirement for a particular hour in which that maximum requirement is not forecast.

As noted in Section 3, the statistical method for calculating these requirements does not evaluate whether the existing generation fleet can meet them. To provide that evaluation, the regulation requirements presented in this section are then compared in Section 4 with historical ISO procurement of regulation and are also explicitly incorporated into the production simulations to further test the capability of the generation fleet to meet them. The load-following requirements are also compared in Section 4 to ISO historical data, but are not explicitly incorporated into the production simulations, which instead attempt to replicate load-following for selected days by conducting sequential day-ahead to real-time unit commitment and dispatch simulations.

Organization of results

The discussion of the simulated load-following and regulation requirements is organized into three categories of results that are found in this section and appendices A-1 and A-2:

1. Portfolio results with all forecast errors, in which the analysis is of the combined wind and solar portfolio and there is no evaluation of changes in forecast error [Section 4 and Appendix A-1];

2. Requirements by renewable technology, in which the simulations are re-run with and without particular technologies to distinguish the impact of incremental solar resources only, incremental wind resources only, and the full renewable portfolio [Appendix A-2]; and the

3. Impact of forecast error and variability, in which the simulations are re-run to distinguish the differential effect of these factors [Appendix A-2].

In all instances, references to the operational requirements in 2006 refer to the *simulated* operational requirements for the reference year. Like the 2007 Report, the results reported in the following tables and figures as maximums are the 95th percentile occurrence for a particular hour.[52]

3.1 Summary of Findings

The simulation results are summarized as follows.

Load-following

- The maximum hourly simulated load-following up and load-following down capacity requirements in 2012 are 3737 MW and -3962 MW, respectively, compared to 3140 MW and -3365 MW for simulated 2006 levels.

- The maximum hourly simulated load-following up and load-following down ramp rates in 2012 are forecast as 194 MW/min and -198 MW/min, respectively, compared to 166 MW/min and -158 MW/min, respectively, for simulated 2006 levels.

- Because most of the renewable production being modeled in 2012 is from wind resources, they are the primary cause of the increased load-following requirements; at the levels modeled, solar resources only slightly alter the load-following requirements in the morning ramp up hours and evening ramp down hours. Obviously, wind is the sole contributor to the incremental load-following requirements in the night-time hours.

- The largest changes in load-following up capacity are in hours 8-9, corresponding to the morning wind ramp down. The changes in load-following down capacity are less concentrated in particular hours, but the average requirements increase in the hours 6-8 corresponding to the morning solar ramp up and the late afternoon or early evening hours, corresponding in part to the wind ramp up. Seasonal results differ, as shown in Appendix A-1.

- The maximum requirements will not be needed in all hours; for example, the percentage increase in aggregate load-following capacity requirements in the summer season between the 2012 and 2006 simulations is estimated at 20 percent for load-following up and 23 percent for load-following down.

- Because the wind and solar ramps are typically inversely correlated in the morning and evening hours, in some of those hours the combination of the two resources slightly reduces the load-following requirements compared to wind resources alone (see Appendix A-2).

[52] That is, excluding the 5 percent highest results from the simulations.

- The effect of forecast error (load, wind and solar) on the load-following requirement is approximately four times the effect of the inherent variability of load, wind and solar (see Appendix A-2).

Regulation

- The maximum hourly simulated Regulation Up and Regulation Down capacity requirements in 2012 are 502 MW and -763 MW, respectively, compared to 278 MW and -440 MW for simulated 2006 levels.

- The maximum hourly simulated Regulation Up and Regulation Down ramp rates in 2012 are 122 MW/min and -97 MW/min, respectively, compared to 75 MW/min and -79 MW/min, respectively, for simulated 2006 levels.

- However, these requirements will not be needed in all hours; for example, the percentage change in aggregate regulation capacity requirements between the 2012 and 2006 simulations of the summer season is estimated at 43 percent for regulation up and 12 percent for regulation down. An important caveat is that there are drivers of regulation procurement not considered in the simulation; however, the changes in the procurement between the two cases are indicative of future increases of procurement.

- The incremental requirements due to solar are greater during the peak hours of the day than those due to wind, due to the greater production of solar energy in those peak hours. Obviously, wind is the sole contributor to the incremental regulation requirements in the off-peak hours.

- Because the wind and solar ramps are typically inversely correlated in the morning and evening hours, the combination of the two resources slightly reduces the regulation requirements compared to wind resources alone.

3.2 Comparison of Seasonal Results

The seasonal maximum results across all hours from the operational requirements simulations for all four seasons are shown in Table 3.1 and Table 3.2, with a comparison of the base-year simulation result (2006), the 20 percent RPS result (2012), and a 33 percent portfolio RPS (2020) result.[53] The remainder of Section 3 focuses on detailed results for one season: summer. The corresponding results for all seasons are found in

[53] The 33 percent RPS result is from one of the renewable portfolios being studied by the ISO and other entities in a subsequent operational study. The particular portfolio is the CPUC's 2009 "Reference Case" portfolio, which includes an additional 9,700 MW of solar resources (PV and solar thermal) and an additional 8,350 MW of wind resources over the base case. Thirty-three (33) percent RPS portfolios with other technology mixes will produce different results. For the source portfolio, see http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf.

Appendix A-1. Before turning to the summer results, a brief discussion is provided here on seasonal differences and their implications for operational requirements.

As shown in Sections 1 and 2, the typical production profiles for variable energy resources, particularly wind, as well as load profiles vary by season, and the simulation results reflect the differences in average seasonal production and actual variability. Appendix A-1 shows the seasonal results side by side. With respect to load-following, the simulations show higher results in the summer than in the lower load seasons. However, this increase is due more to load variability and forecast error than to changes in the variability and forecast errors associated with the renewable resources.

For regulation up, spring has the highest hourly seasonal maximum value in hour 18. The daily maximums for regulation up tend to be at different times in the different seasons, although all seasons have high values in hour 6 and 18, generally corresponding to the morning wind ramp down and the afternoon solar ramp down. For regulation down, the summer season provides the highest seasonal maximum value in hour 18; however, all seasons have spikes in the regulation down requirement in hour 18. These results are due to the higher wind production in the spring months.

Table 3.1: Change in Simulated Maximum Regulation and Load-Following Capacity (MW) Requirements by Season

	Spring			Summer			Fall			Winter		
	2006	2012	2020	2006	2012	2020	2006	2012	2020	2006	2012	2020
Max Regulation Up Requirement (MW)	277	502	1135	278	455	1444	275	428	1308	274	474	1286
Max Regulation Down Requirement (MW)	-382	-569	-1,097	-434	-763	-1,034	-440	-515	-1,264	-353	-442	-1076
Max Load-following Up Requirement (MW)	2,292	3,207	4,423	3,140	3,737	4,841	2,680	3,326	4,565	2,624	3,063	4,880
Max Load-following Down Requirement (MW)	-2,246	-3,275	-5,283	-3,365	-3,962	-5,235	-2,509	-3,247	-5,579	-2,424	-3,094	-5,176

Table 3.2: Change in Simulated Maximum Regulation and Load-Following Ramp Rate (MW/Min) Requirements

	Spring			Summer			Fall			Winter		
	2006	2012	2020	2006	2012	2020	2006	2012	2020	2006	2012	2020
Max Regulation Ramp Up Rate (MW)	67	122	447	75	118	528	70	114	472	73	107	344
Max Regulation Ramp Down Rate (MW)	-66	-90	-310	-76	-97	-300	-72	-90	-301	-79	-90	-303
Max Load-following Ramp Up Rate (MW)	150	168	325	166	194	313	147	181	324	143	165	296
Max Load-following Ramp Down Rate (MW)	-138	-162	-451	-145	-169	-434	-134	-167	-438	-158	-198	-427

Table 3.3 shows the percentage increase between 2012 and 2006 in the total simulated requirements for load-following and regulation capacity requirements.

Table 3.3: 2012 vs. 2006, Percentage Increase in Total Simulated Operational Capacity Requirements

	Spring	Summer	Fall	Winter
Total maximum load-following up	27.0 %	11.9 %	19.2 %	19.7 %
Total maximum load-following down	29.5 %	14.0 %	21.2 %	21.3 %
Total maximum regulation up	35.3 %	37.3 %	29.6 %	27.5 %
Total maximum regulation down	12.9 %	11.0 %	14.2 %	16.2 %

3.3 *Load-following Requirements for Summer 2012*

This section shows the simulation results for the full 20 percent RPS portfolio assuming all forecast errors (for load, wind and solar) remain within historical experience.

As described in Section 2, load-following capacity in the statistical simulation is defined as the largest deviation between the hourly schedule and any 5-minute interval schedule within the hour. Figures Figure 3-1 and Figure 3-2 show distribution statistics for the set of values that include the *maximum* load-following capacity result for each hour in the season drawn from all 100 iterations of the simulation. The hourly bars are a modification of a typical “stock” chart. The colored line represents the range (minimum, maximum) of the results and the bar shows the average ± one standard deviation. Red bars show the results of the 2012 simulation, while blue bars show the 2006 simulation.

The subset of hours shown in the 2012 result is comprised of the 90 maximum values for each of the 24 hours of the days.[54] Hence, while the distribution of results shown here reflects higher forecast errors drawn across the iterations (although it is also affected by the variability reflected in that hour), it also preserves the actual variable energy resource production profiles such that hours with low production are on average shown to have smaller impacts on the simulated requirements than hours with high production. That is, the results reflect that, e.g., a 10 percent hour-ahead forecast error on wind production at 6000 MW in one Hour 14 results in a higher load-following requirement than a 10 percent error on wind production at 600 MW in another Hour 14. Hence, this distribution is reflective of the actual requirements over the season.

The *maximum* hourly values in these figures – the top of the ranges – are analogous to the results that were shown in the 2007 Report, although the simulations conducted in this study have used a different load profile reflecting the different target year (2012 compared to 2010 in the 2007 Report) and include the effect of production, forecast error and variability also for solar production.[55]

As shown in the figures, the maximum seasonal hourly load-following up requirement (for summer 2012) is 3737 MW (Hour 15), which is an 854 MW increase over the requirement estimated for that hour in the 2006 simulation. The maximum seasonal hourly load-following down requirement for 2012 is 3,962 MW (Hour 24), a 597 MW increase over the requirement estimated for that hour in the 2006 simulation. These maximum increases in requirements are almost entirely driven by the additional wind on the system (some further analysis into the relative impact of load, wind and solar is shown in Appendix A-2).

The figures show that the maximum load-following up and down capacity requirements in 2012, and the biggest changes from the 2006 results, are concentrated in the morning and evening ramp hours, as would be expected. The maximums for the top 4 load-following up hours are in hours 8, 14, 15 and 16; the maximums for load-following down are in hours 18, 19, 23 and 24. Notably, the highest average values for load-following requirements in both the upwards and downwards directions are in hours 22-24, corresponding to maximum wind production, showing that it is in these hours that the requirements will increase most substantially overall over the season. This can be seen from the red bars corresponding to those hours in Figure 3-1 and Figure 3-2.

[54] That is, assuming a 90 day season, each of the 100 iterations runs through all hours of the season – day 1, hour 1, day 1, hour 2, … day 2, hour 1, day 2, hour 2, …, day 90, hour 1, hour 2. This results in 100 values for each hour. Of these 100 values, the maximum value is selected. Then all the hour 1s are grouped, as are all the hour 2s, hour 3s and so on. That results in 24 sets of 90 values, since there are 90 hour 1s, 90 hour 2s, etc. The distributions shown here is of those 90 values for each hour.

[55] The range shown in each red arrow is the minimum and maximum of the *highest* hourly seasonal values for each of the 100 iterations in the simulation. The maximum is thus the highest of those values.

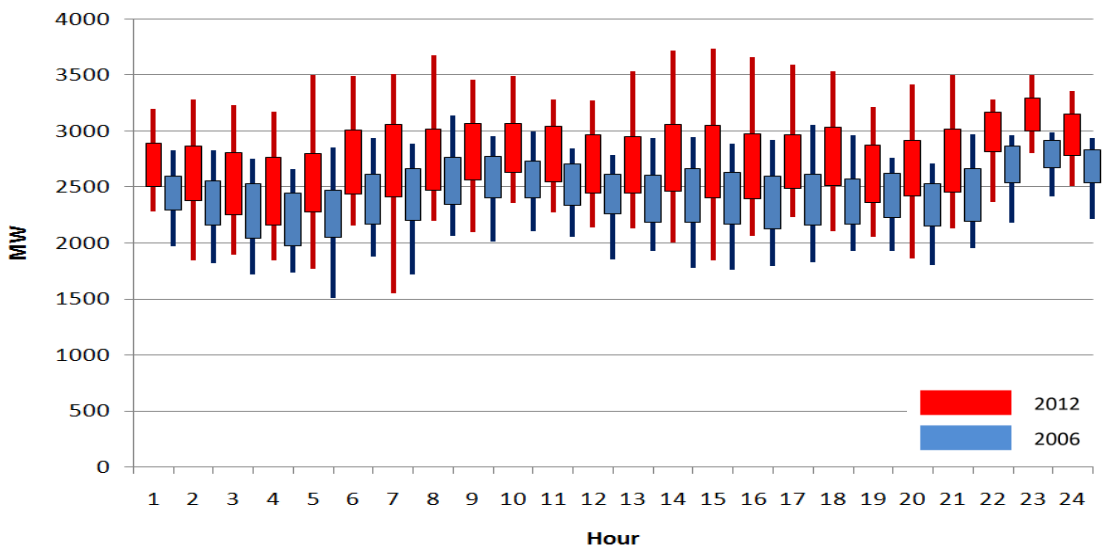

Figure 3-1: Load-following Up Capacity by Hour, Summer (2006 and 2012)

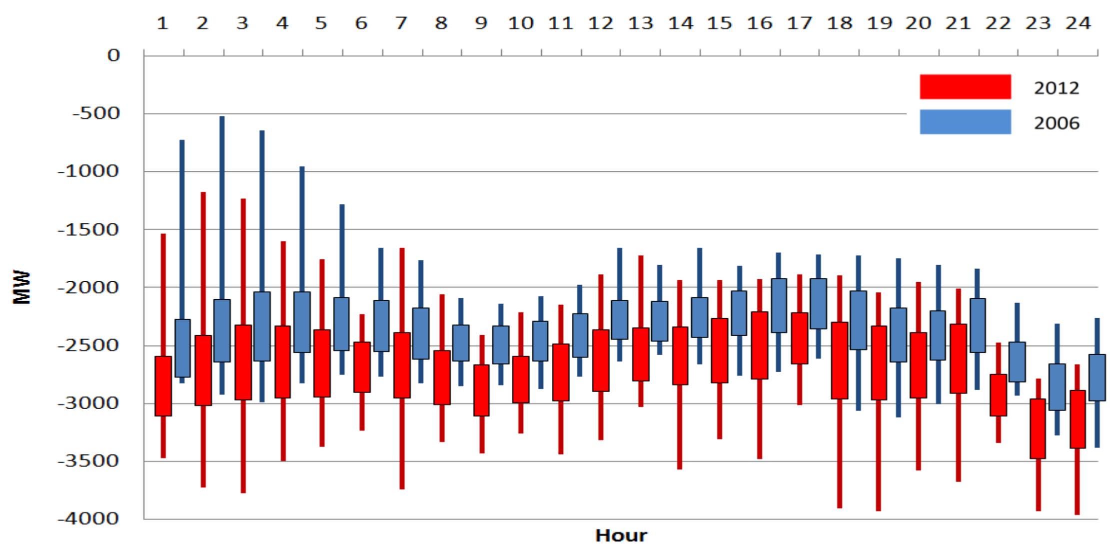

Figure 3-2: Load-following Down Capacity by Hour, Summer (2006 and 2012)

Figure 3-3 and Figure 3-4 show the frequency distribution of the maximum load-following capacity requirements in 2012 and 2006 by MW range and percentage of the total hours in the season.[56] These figures show more explicitly that the highest seasonal load-following capacity requirements are expected to be infrequent, but that the overall increase in this requirement remains significant. For the summer season, the total simulated requirement of load-following up in 2012 (the total MW of the values in the frequency distribution) is about 12 percent greater than the corresponding total for 2006; the simulated requirement for load-following down in 2012 is 14 percent greater than that

[56] This frequency distribution is drawn from the same data shown in Figure 3-1 and 3-2.

for 2006.[57] This provides a measure of the increasing volume of the real-time market between the baseline and the target year.

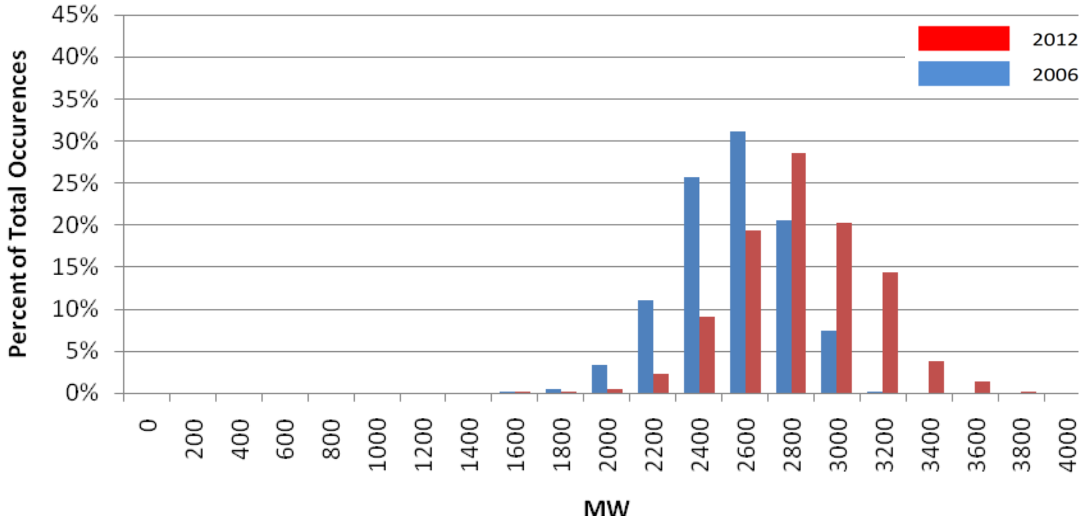

Figure 3-3: Frequency Distribution of Load-following Up Capacity Requirements, Summer (2006 and 2012)

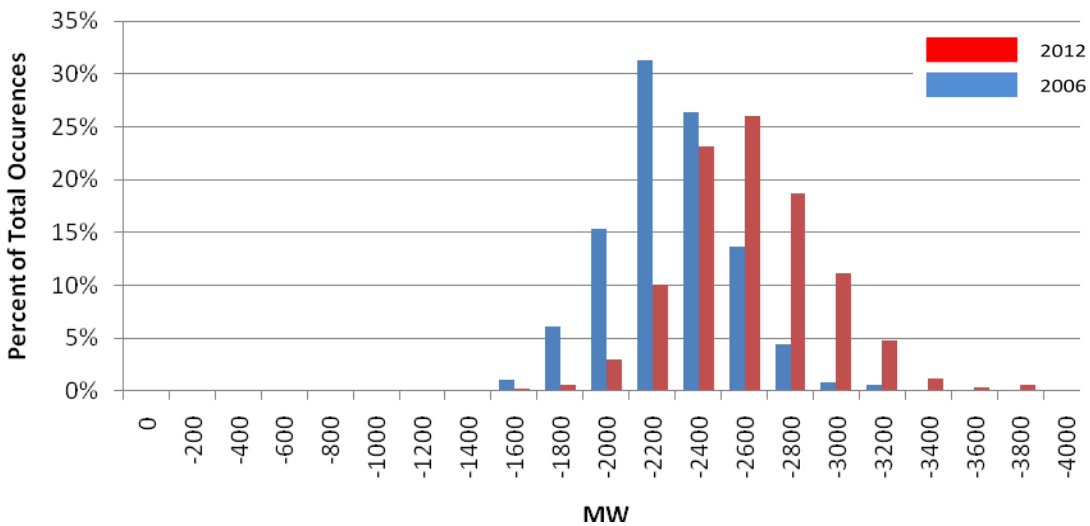

Figure 3-4: Frequency Distribution of Load-following Down Capacity Requirements, Summer (2006 and 2012)

[57] That is, the total MW calculated as "load-following" capacity for each hour in the 2012 simulations divided by the total MW calculated for 2006.

As discussed in Section 2, the simulated load-following *ramp rate* is defined as the maximum increase or decrease in the estimated capacity requirement between any two contiguous 5-minute intervals within the hour being simulated. Figure 3-5 shows that the maximum load-following up ramp rates across the season for the full portfolio are located in the off-peak hours, where they correspond to variability and forecast error in wind production.

Figure 3-6 shows that the maximum requirements in load-following down ramp rate occur between Hour 7 and Hour 10, when solar production ramps up and wind production is decreasing. Again, the actual system net ramp rate can be high in these hours when the wind and solar ramps are not well correlated with the morning load ramp up.

In the high load-following ramp hours, the duration of the ramps may be sustained for a large number of intervals. The statistical methodology tracks duration of the simulated ramp rate using a specialized algorithm (see Section 2).[58] Figures 3-7 and 3-8 show the ramp requirement by minute (MW/min) plotted for the longest number of minute intervals that the algorithm identified in the morning and evening hours, respectively. As shown in Figure 3-7, the upward ramp duration in the morning is required for approximately 30 minutes (as shown on the figure's x-axis), while the downward ramp will be required for approximately 20 minutes. Resources on dispatch should be able to ramp up at a rate of about 100 MW/min. (as shown on the figure's x-axis) for most of the 30 minutes. Similarly, in the downward direction, the resources on dispatch should be able to ramp down at a rate of approximately -175 MW/min. for at least 20 minutes. Figure 3-8 can be interpreted similarly for the evening ramps, in which the ramp duration and magnitudes are roughly reversed compared to the morning hours.

[58] Called the "swinging door" algorithm, which tracks and measures sequences of random draws to infer changes in ramp rates and durations.

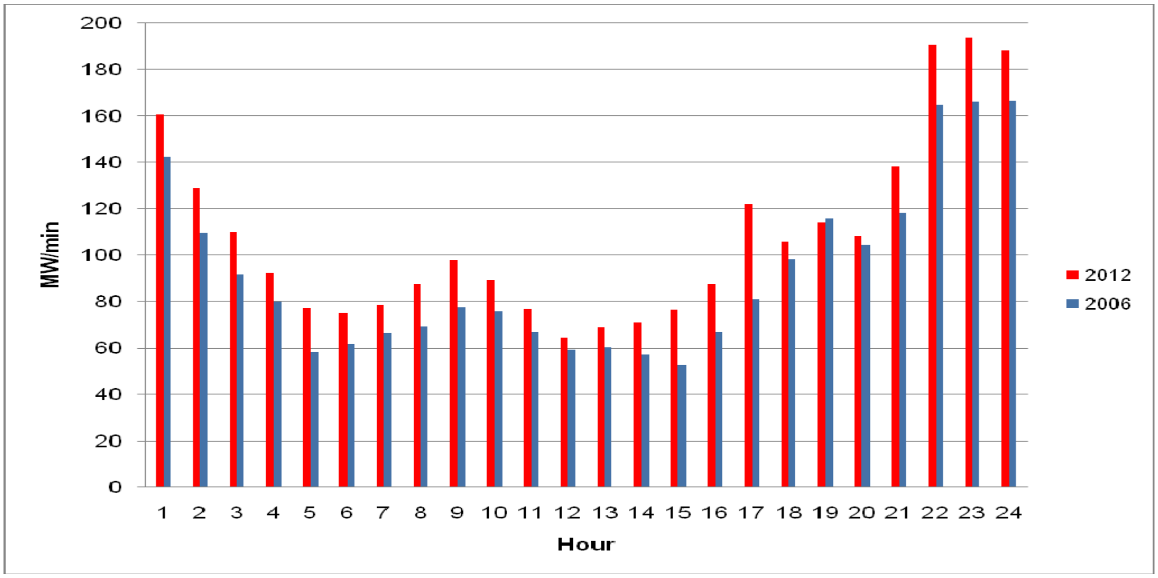

Figure 3-5: Load-following Up Ramp Rate, Summer (2006 and 2012)

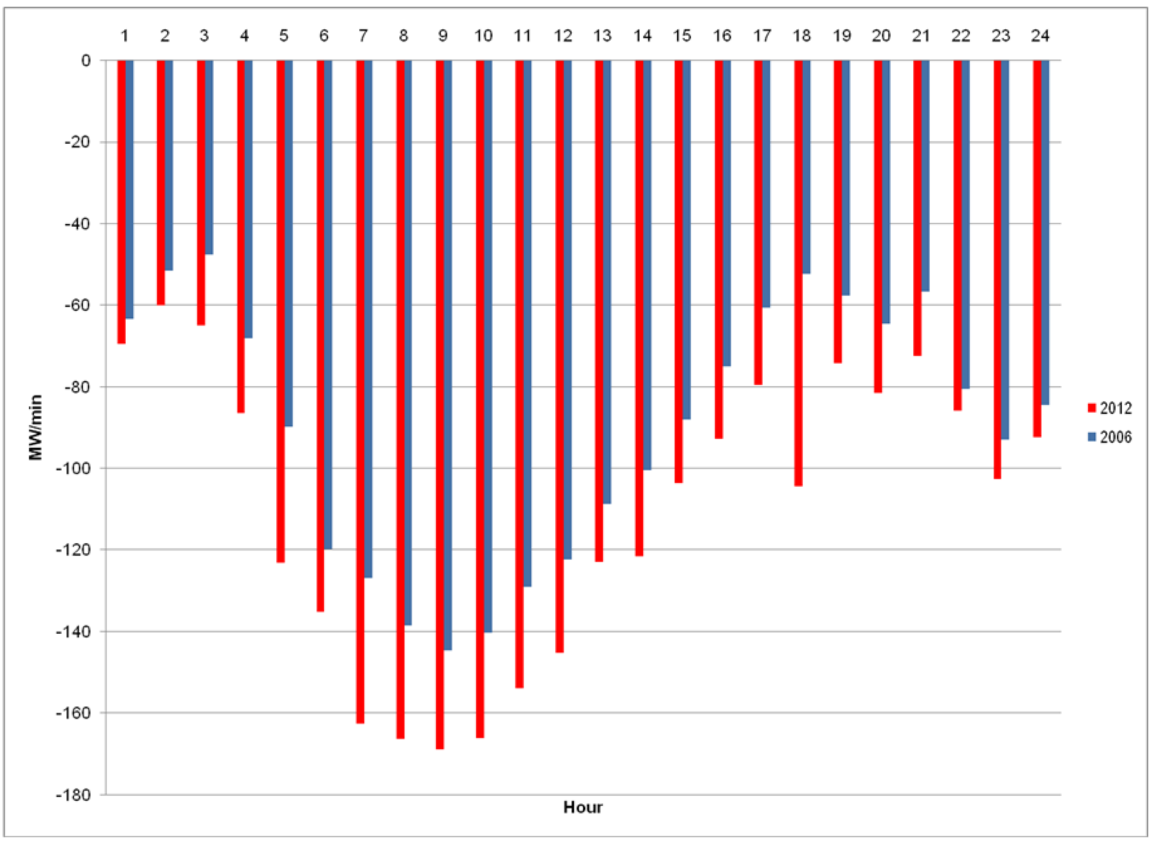

Figure 3-6: Load-following Down Ramp Rate, Summer (2006 and 2012)

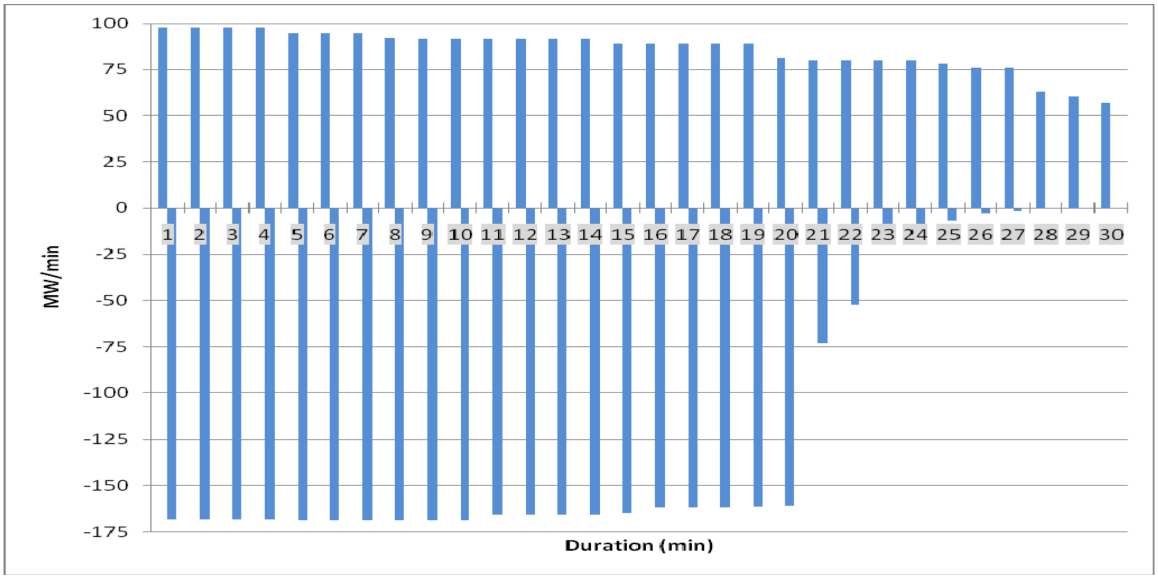

Figure 3-7: Seasonal Load-following Up and Down Ramp Duration for Morning Hours, Summer 2012

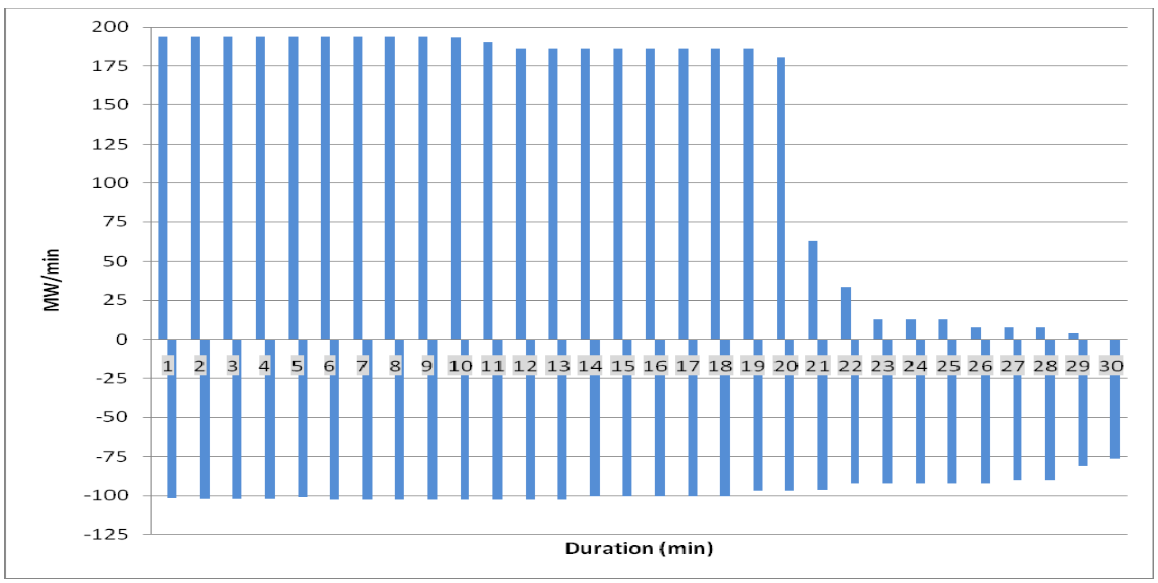

Figure 3-8: Seasonal Load-following Up and Down Ramp Duration for Evening Hours, Summer 2012

In general, the maximum simulated load-following capacity and ramp requirements increase substantially for almost every hour of the day. Section 4 compares the load-following requirements determined here with the historical load-following capability. Section 5 simulates the capability of the fleet to meet the load-following requirements in 2012 under different conditions.

3.4 Regulation Requirements for Summer 2012

This section shows the simulated regulation requirement results for the full 20 percent RPS portfolio assuming all forecast errors (for load, wind and solar) remain within historical results. The results presented here are organized in parallel to the results shown for load-following, with some differences noted. Figures Figure 3-9 and Figure 3-10 show distribution statistics for the set of values that include the *maximum* regulation capacity result for each hour in the season drawn from all 100 iterations of the simulation. As with the load-following results, the hourly bars are a modification of a typical "stock" chart. The black line represents the range (minimum, maximum) of the results and the red box shows the standard deviation. The arrow points towards the maximum of the range. The maximum of the baseline 2006 simulation for each hour is shown in blue.

As with the load-following results, the subset of hours shown in the 2012 result is comprised of the 90 maximum values for each of the 24 hours of the days. [59] Hence, while the distribution of results shown here reflects higher forecast errors drawn across the iterations (although it is also affected by the variability reflected in that hour), it also preserves the actual variable energy resource production profiles such that hours with low (or no) production are on average shown to have smaller impacts on the simulated regulation requirements than hours with high production.[60]

The *maximum* hourly values in these figures – the top of the ranges – are analogous to the results that were shown in the 2007 Report, although the simulations conducted in this study have used a different load profile reflecting the different target year (2012 compared to 2010 in the 2007 Report) and include the effect of production, forecast error and variability also for solar production.

The figures show that similarly to load-following, the incremental regulation capacity requirements are concentrated in the morning and evening ramp hours, as would be expected. The maximums for the top 4 regulation up hourly requirements are in hours 9, 8, 6 and 19; the maximums for regulation down are in hours 15-18. Solar production variability has the strongest effect on the simulated regulation up requirements in the late afternoon hours, while also having a strong effect on the regulation down requirements in Hour 8 (see figures in Appendix A-2). Wind production variability is the predominant driver of the increased requirements in the other hours. In particular, the spike in regulation down requirements in Hour 18 is due to the consistent fast ramp in wind production in that hour found in the underlying wind production data set for 2012.

[59] That is, assuming a 90 day season, each of the 100 iterations runs through all hours of the season – day 1, hour 1, hour 2, …, day 2, hour 1, hour 2, …, day 90, hour 1, hour 2. This results in 100 values for each hour. Of these 100 values, the maximum value is selected. Then all the hour 1s are grouped, as are all the hour 2s, hour 3s and so on. That results in 24 sets of 90 values, since there are 90 hour 1s, 90 hour 2s, etc. The distributions shown here is of those 90 values for each hour.

[60] That is, the regulation results reflect that, e.g., variability on wind production at 6000 MW in one Hour 14 results in a higher regulation requirement than variability on wind production at 600 MW in another Hour 14. Hence, this distribution is reflective of the actual requirements over the season, as modeled.

Notably, the distribution statistics show that not only the maximums for regulation up are in the mid-morning hours, but also the highest averages. These hours correspond to the maximum wind ramp down periods, showing that it is in these hours that the requirements will increase most substantially overall. Similarly, not only the maximums but also the average increase in regulation down requirements take place in the late afternoon hours.

In a few hours of the regulation down results, the simulation with the incremental wind and solar shows a lower maximum result than the 2006 simulation. This result is due to the correlation of wind, solar and load in those hours, which has the effect of lowering the regulation requirement. For example, in the early morning, load is ramping up, while wind is ramping down and solar is ramping up. The net effect can be very little downward requirements in the regulation time frame. However, as noted above, the ISO typically procures a minimum quantity of 300 MW of regulation up and 300 MW of regulation down in the day-ahead time frame to account for uncertainties that are not captured in the simulation.

As noted above, the maximums are not an indication of the change in regulation procurement across all hours and all system conditions. Figures Figure 3-11 and Figure 3-12 show the frequency distribution of the maximum regulation capacity requirements in 2012 and 2006 by MW range and percentage of the total hours in the season.[61] These figures show more explicitly that the highest seasonal regulation capacity requirements are expected to be infrequent, but that the overall increase in this requirement remains significant. For the summer season, the total simulated requirement of regulation up in 2012 (the total MW of the values plotted in the frequency distribution for 2012) is approximately 37 percent greater than the corresponding total for 2006; the simulated requirement for regulation down in 2012 is only 11 percent greater than that for 2006, and much of that increase is concentrated in one or two late afternoon hours.[62] This provides a measure of the possible increasing aggregate procurement of regulation between the baseline and the target year.

[61] This frequency distribution is drawn from the same data shown in Figure 3-9 and Figure 3-10.

[62] That is, the total MW calculated as “load-following” capacity in the 2012 simulations divided by the total MW calculated for 2006.

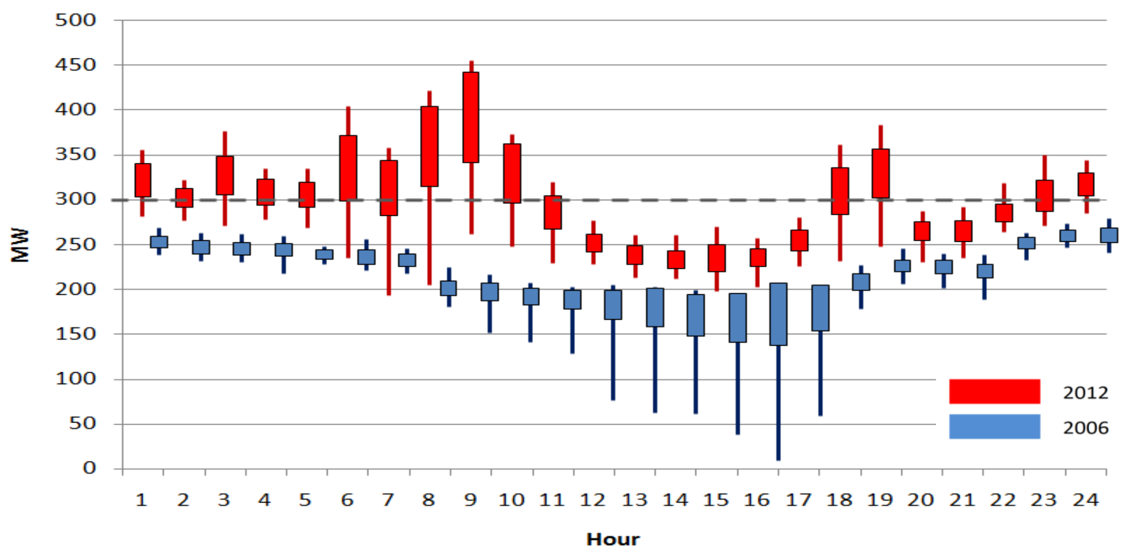

Figure 3-9: Regulation Up Capacity Requirement by Hour, Summer (2006 and 2012)

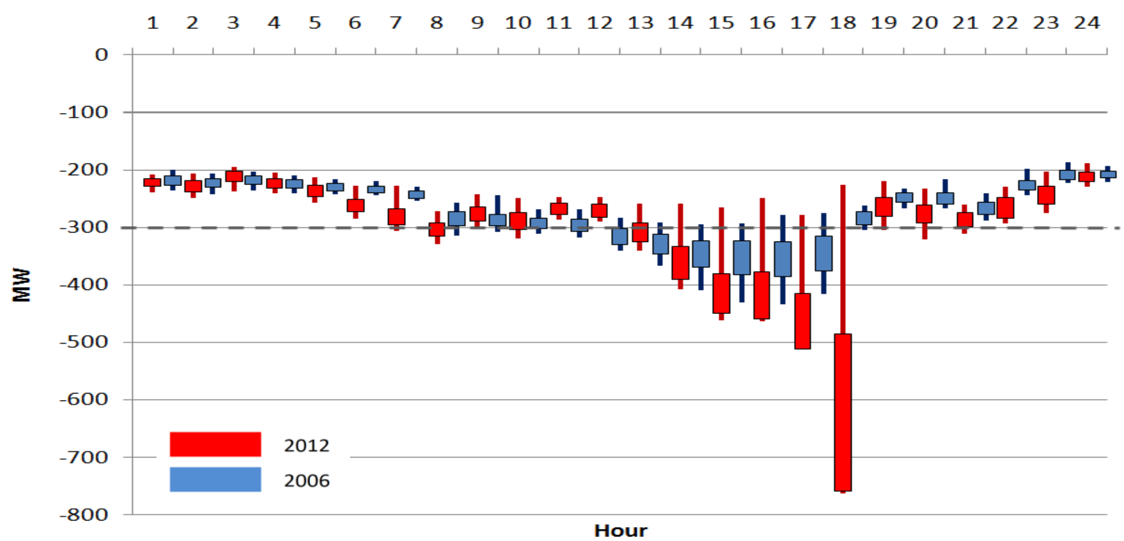

Figure 3-10: Regulation Down Capacity Requirement by Hour, Summer (2006 and 2012)

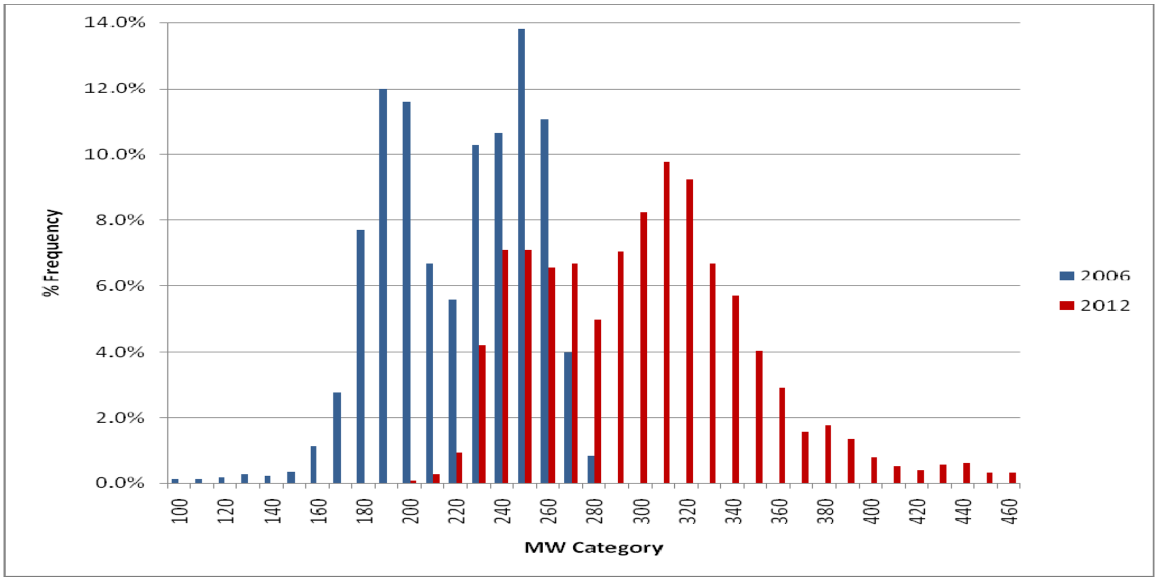

Figure 3-11: Frequency Distribution of Regulation Up Capacity Requirements, Summer (2006 and 2012)

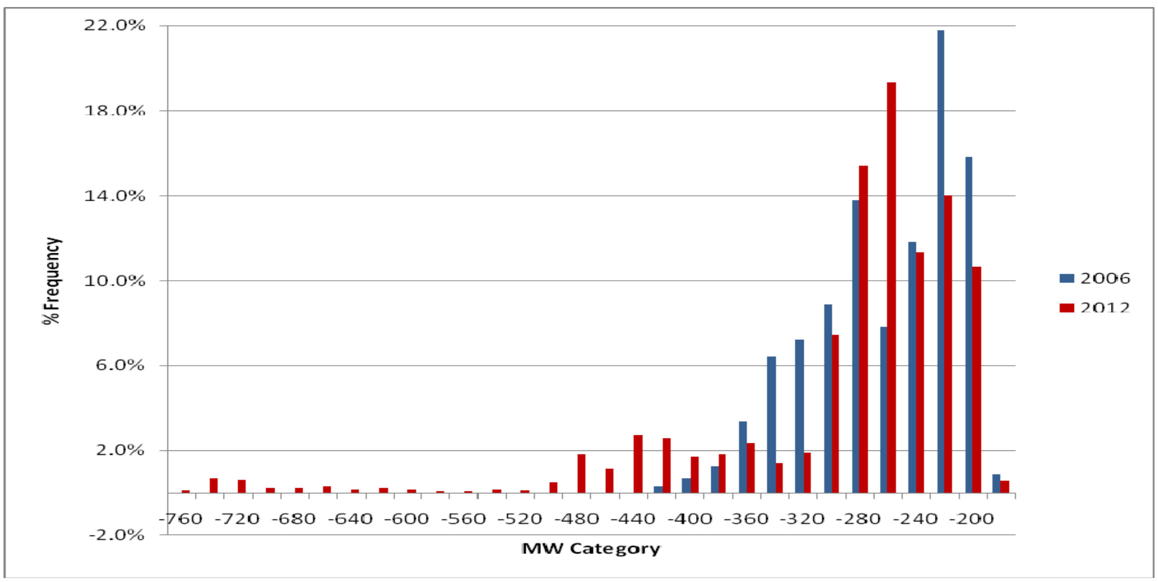

Figure 3-12: Frequency Distribution of Regulation Down Capacity Requirements, Summer (2006 and 2012)

As discussed in Section 2, the simulated regulation *ramp rate* is defined as the largest minute-to-minute change within a 5-minute dispatch interval. Figure 3-13 shows that the maximum regulation up ramp rates across the season (for the full portfolio) are located in the afternoon hours. Figure 3-14 shows that the maximum requirements in regulation down ramp rate occur between Hour 6 and Hour 9, when solar production ramps up and wind production is decreasing, and again in the late afternoon in Hours 16 to 18.

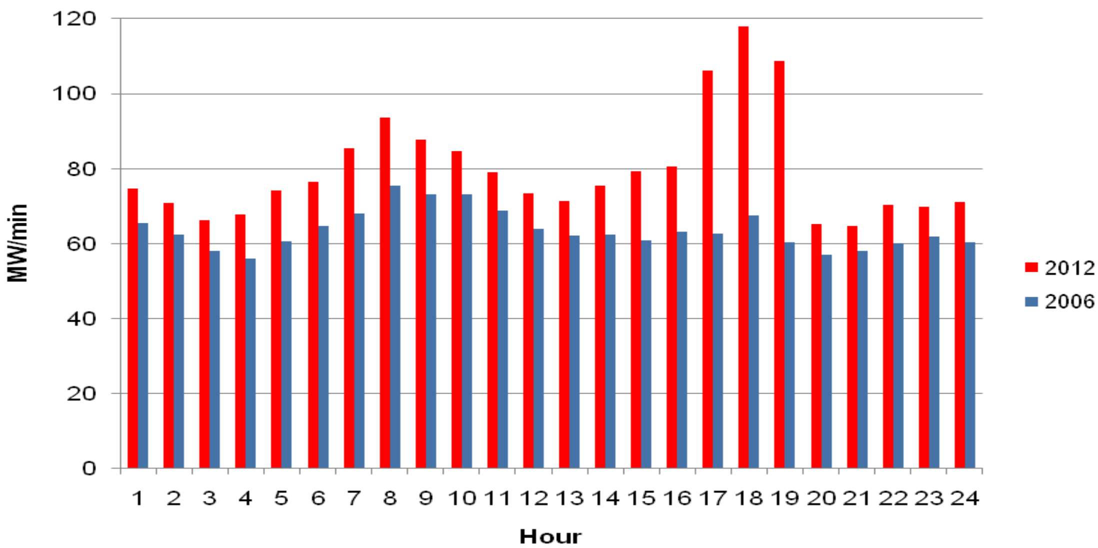

Figure 3-13: Summer Regulation Up Ramp Rate by Hour (2006 and 2012

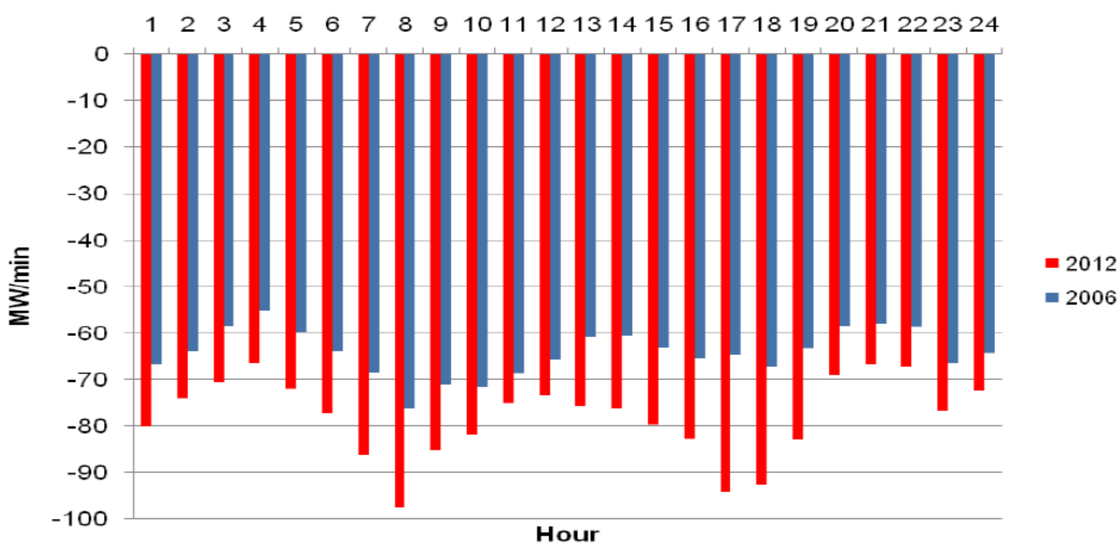

Figure 3-14: Summer Regulation Down Ramp Rate by Hour: 2006 and 2012

4 Analysis of Historical Fleet Capability

This section presents analysis of selected measures of generation fleet capability for the period from April 1, 2009 to June 30, 2010. The objective is to provide insight into the ability of the current generation fleet to provide sufficient regulation and load-following capacity to meet the operational requirements under 20 percent RPS determined in Section 3. Section 4.1 provides a summary of the findings of this analysis. Section 4.2 presents an inventory of the physical characteristics of the ISO generation fleet. Section 4.3 compares historical, seasonal load-following capacity with the corresponding requirements discussed in Section 3.3. Similarly, Section 4.4 compares historical, seasonal bid-in and committed regulation capacity with the additional regulation capacity requirements discussed in Section 3.4.

4.1 Summary of Findings

- The historical 5-minute load-following capability of the generation fleet, defined as the upward and downward ramp capability in each 5-minute interval, has been measured from April 1, 2009, to June 30, 2010. This analysis shows that the fleet inherently has the 5-minute load-following capability required under 20 percent RPS. However, much of the downward capability is currently provided to the ISO with limited inflexibly due to submitted self-schedules. To successfully integrate 20 percent RPS, the level of self-schedules will have to decrease.

- The ISO regulation markets have procured levels of regulation up and regulation down since April 1, 2009, in the range of 600-700 MW in each hour of the operating day, with these high procurements largely taking place during the first month of market implementation to ensure reliability. These procurement levels provide one test of the ISO's ability to meet the higher regulation requirements that could be experienced at the 20 percent RPS.

- In addition, the 5-minute regulation capability of the generation resources bid-in and committed in each hour of the day since April 1, 2009, has been measured and shown potentially to be the source in most hours of sufficient capability over and above the calculated additional regulation requirements under 20 percent RPS.

4.2 Physical Characteristics of the Existing Generation Fleet

Table 2.7 in Section 2 provides a breakdown of the generation fleet capacity organized by ramp rate segment (MW/min). For example, there is a total of 21,003 MW of capacity under the ISO's control with a ramp rate of 5 to 10 MW/min. Individual generation units will have different ramp rates over their range of output, so may have capacity in several of the columns. The table also divides the generation fleet into once-through cooling (OTC) units and those that are not once-through cooling units. Although replacement and repowering of once-through cooling units will begin after the study date of 2012, the table helps to characterize the flexibility characteristics of those units, which must be considered in the context of renewable integration capabilities.

4.3 Load-following Capability

Physical characteristics give important insight into fleet capabilities, but operational flexibility is a function of which units are committed in each time interval and also their availability for dispatch. Generation that is self-scheduled at levels greater than a resource's physical minimum operating level (Pmin) through the ISO markets is essentially unavailable to ISO dispatchers within the hour except through non-market dispatch instructions that can distort market prices. To gain insight into the historical upward and downward capability of the committed resources, the ISO has examined the resources on the system from April 1, 2009 - June 30, 2010, to quantify both their load-following and regulation capability.

This section discusses load-following capability for the summer season. The examination for the remaining seasons can be found in Appendix B. Figure 4-1 provides the 5-minute Load-following up capability, measured as the maximum dispatch that can be achieved in the upward direction based on submitted energy bids within 5 minutes, subject to the ramp rates and other operational constraints of the dispatched units. Figure 4-2 provides the 5-minute load-following down capability, limited by self-schedule, measured as the maximum dispatch that can be achieved in the downward direction within 5 minutes, subject to the ramp rates and other operational constraints of the dispatched units. As used throughout this report, the stock charts show the range and standard deviation of the upward and downward 5-minute load-following capability. The upper and lower dispatch limit are internally calculated and reflect a resource's ramping capability, operating limits, derates, regulation limits (when on regulation). The load-following capability is a measure of the capability to follow load from one 5-minute dispatch to the next.

The results show that the ISO dispatch in recent months appears on average to meet the expected load-following upwards capability for even the extreme ramps reflected in the statistical simulations. The simulated *maximum* load-following up ramp rate for summer in 2012 as shown in Table 3-2 was 194 MW/min, which is 980 MW/5 min. From Figure 3-5 in Section 3, it can be observed that the high ramps are during hours 22 through 24. The historical summer 5-minute load-following capability in 2009-2010 is shown in Figure 4-1. Historically, anywhere between 0 and 3000MW of load-following capacity is available during these hours with an average of approximately 1200MW. Therefore, on an average, based on committed resources with existing solution constraint, sufficient 5-minute load-following capacity would be available to meet the requirements. The production simulation discussed in Section 5 tests the load-following capability of the system for a few selected days in the future.

The results for downwards ramping appear more problematic. The simulated maximum load-following down ramp rate for summer in 2012 was -169 MW/min as shown in Table 3-2, which is -845 MW/5 min. These high downwards ramps are often in the mid-morning hours as shown in Figure 3.6 in Section 3. As discussed before, Figure 4-2 shows the summer 5-minute load-following down capability of only the units that are dispatchable. Figure 4-3 shows the summer 5-minute load-following down capability of thermal units, both self-scheduled and dispatchable. The 5-minute downward ramp capability without the self-scheduled units, ranges from 0 to -2000MW. During some hours, for example, hour 7 in Figure 4-2, the average 5-minute downward capacity could be as low as -500 MW, which is less that the requirement of -845 MW. The 5-minute downward ramp capability is much higher if the contribution from self-scheduled units is counted. This shows the need for the ISO to pursue incentives or mechanisms to reduce the level of self-scheduled resources and/or increase the operational flexibility of other dispatchable resources. The production simulation discussed in Section 5 will specifically test the downward load-following capability of the system for a few selected days when down ramp is expected to be a problem.

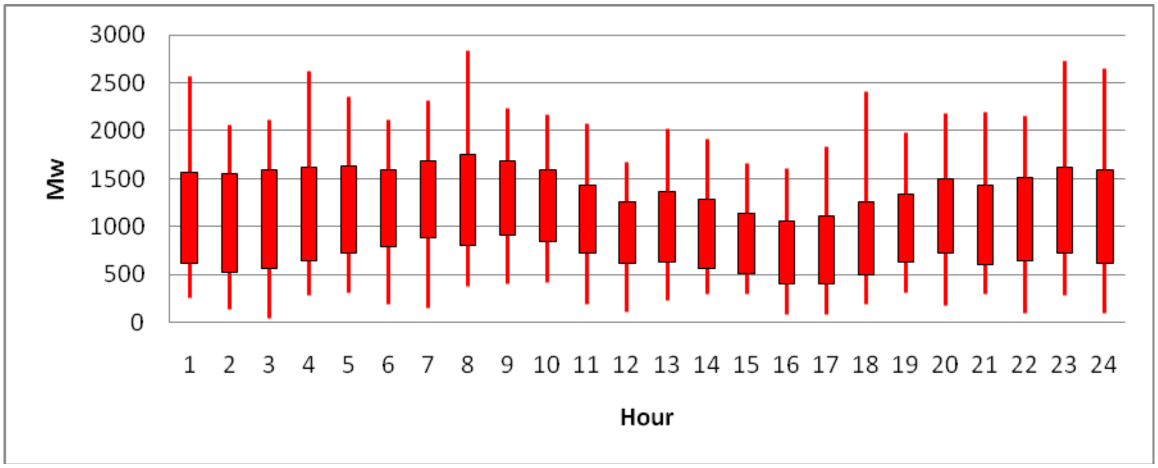

Figure 4-1:Summer Upward 5-minute Capability, 2009 and June 2010

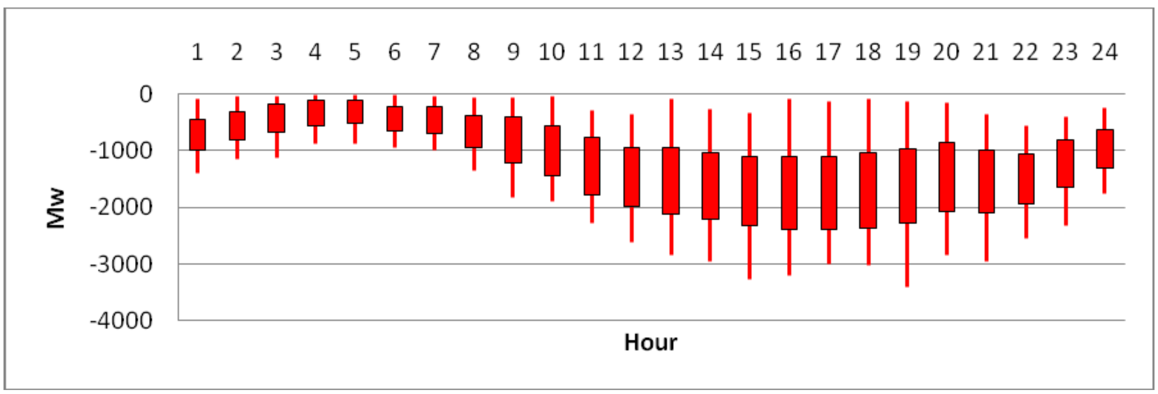

Figure 4-2: Summer Downward 5-minute Capability, limited by self-schedules, 2009 and June 2010

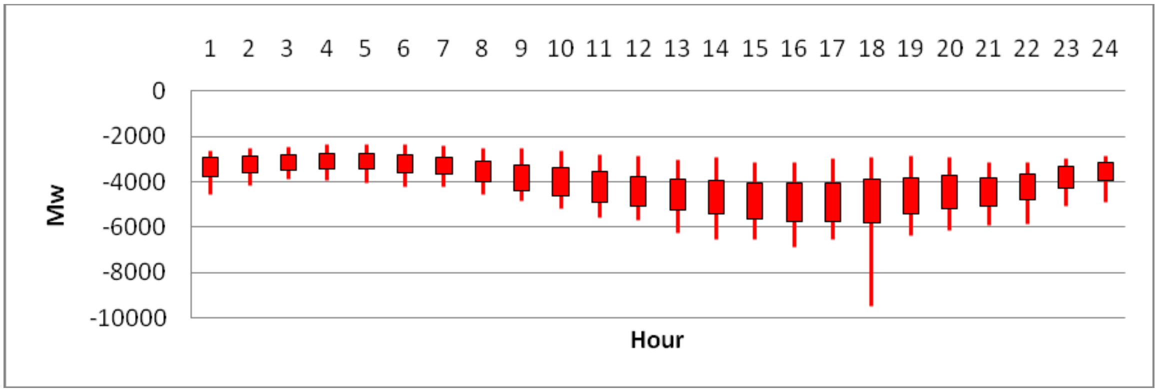

Figure 4-3:Summer Downward 5-minute Capability of Thermal Units, not limited by self-schedules, 2009 and June 2010

The above results show that the ISO dispatch in recent months appears, for the majority of intervals analyzed, to be able to meet the load-following up requirements simulated for 20 percent RPS within 20 minutes or less.[63] This is simply due to the ramp capacity remaining on units not dispatched to their maximum operating levels, and not to any preparations made by the ISO to address renewable integration.

A further measure of the frequency of downward ramp constraints and overgeneration is the occurrence of negative prices. Table 4.1 shows the number of real time 5-minute dispatch intervals which all Load Aggregation Points (LAP) had negative prices since April 1, 2009 (3,727 intervals in total). The chart shows that the highest frequency is concentrated in the early and mid-morning hours with heaviest occurrence in the spring months.

[63] For example, if the 3,737 MW maximum load-following up requirement determined in Section 3 has to be met within 20 minutes of the start of the hour, the results suggest that in most hours, the current system ramp could on average in most hours sustain 1000 MW/5-minutes or more, meaning that the requirement could be met and slightly exceeded in 4 such intervals.

Table 4.1: Frequency of Negative Prices in Real-Time Dispatch Intervals by Month and Hour, April 1, 2009 to June 30, 2010

	April 1, 2009-March 31, 2010												April 1, 2010-June 30, 2010		
	Apr (Out of 360int/ hr)	May (Out of 372int/ hr)	Jun (Out of 360int/ hr)	Jul (Out of 372int/ hr)	Aug (Out of 372int/ hr)	Sep (Out of 360int/ hr)	Oct (Out of 372int/ hr)	Nov (Out of 360int/ hr)	Dec (Out of 372int/ hr)	Jan (Out of 372int/ hr)	Feb (Out of 336int/ hr)	Mar (Out of 372int/ hr)	Apr (Out of 360int/ hr)	May (Out of 372int/ hr)	Jun (Out of 360int/ hr)
1	69	40	31	19	6	2	2	4	13	2	3	2	1	5	33
2	26	34	37	14	18	7	0	5	7	10	0	7	1	0	20
3	26	35	85	41	11	19	1	28	9	9	14	10	10	5	20
4	71	64	105	78	22	13	2	8	9	25	23	5	27	4	20
5	58	65	65	72	13	19	1	8	8	7	16	10	22	56	80
6	47	66	67	14	6	8	0	4	2	1	1	10	14	42	66
7	29	75	98	76	7	15	0	7	6	6	0	2	2	61	81
8	74	20	36	21	11	9	3	6	1	0	0	0	5	18	52
9	9	17	33	29	7	2	0	0	0	0	0	0	0	5	49
10	2	14	12	9	3	0	0	0	0	0	0	0	0	6	24
11	15	12	1	0	0	1	0	0	0	0	0	0	0	0	1
12	18	9	0	0	0	0	0	0	0	0	0	0	0	0	3
13	10	6	8	0	0	0	0	0	0	0	0	0	0	0	10
14	6	4	0	0	0	0	0	0	0	0	0	0	0	0	5
15	9	15	0	0	0	0	0	2	0	0	0	0	0	0	0
16	7	12	10	0	0	3	0	1	0	0	0	0	0	2	0
17	13	2	6	0	0	0	0	0	0	0	0	0	0	2	0
18	16	12	11	0	0	0	0	0	0	0	0	0	1	0	0
19	37	3	17	0	0	0	0	0	0	0	0	1	1	2	2
20	29	1	11	0	0	0	0	0	0	0	0	0	4	0	0
21	3	0	4	0	0	0	0	0	0	0	0	0	0	0	0
22	16	5	1	0	0	1	0	0	0	0	0	0	0	0	0
23	77	24	25	3	1	0	0	1	1	0	0	0	0	3	6
24	42	63	36	16	4	4	2	4	7	7	1	0	1	10	11

4.4 Regulation Capability

As one step to evaluate the ability to meet the sustained higher regulation requirements identified in Section 3, the ISO has examined the regulation capability of the fleet as well as regulation procurement quantities and the ranges of regulation capable units under dispatch since the start of the redesigned wholesale markets in April 2009. As shown in Table 4.2, the ISO has substantial regulation capacity, with almost 20,000 MW of regulation certified capacity and over 5,000 MW with regulation ramp rates of 20 MW/min or higher. Regulation deficiency when it occurs is thus primarily due to system conditions that restrict regulation capable units from being on dispatch. Historically, the ISO has been short of regulation down at times, especially during high hydro conditions such as occurred in 2006, which could be exacerbated with additional wind on the system.[64]

Table 4.2: Regulation Certified Capacity of the ISO Generation Fleet by Ramp Rate, 2010

Generation Type		Regulation Ramp Rates (RR) (MW/min) by Category				
		1 ≤ RR < 5	5 ≤ RR < 10	10 ≤ RR < 20	20 ≤ RR	Total MW
Non-OTC Units	Combined Cycle	719	1693	2171	347	4930
	Dynamic Schedule				775	775
	Gas Turbine	20	20	159		199
	Hydro	319	1020	891	1880	4110
	Other				4	4
	Pump/Storage				969	969
	Steam	316	100			416
	Not specified				525	525
Non-OTC Unit Total		1374	2833	3221	4500	11928
OTC units	Combined Cycle		370			370
	Steam	2442	3599	500	1060	7601
OTC Unit total		2442	3969	500	1060	7971
All Units Total		3816	6802	3721	5560	19899

Note: Some capacity numbers are rounded

Given the significant changes in market optimization and bidding incentives inherent in the redesigned markets, the ISO determined not to examine regulation procurement and market conditions prior to April 2009.[65] Since that date, while system conditions have not corresponded to the prior historical periods in which ancillary service bids were insufficient, the ISO has procured regulation up and regulation down quantities above the historical norm of 350 MW for the first few months of the redesigned market to ensure reliability of system operations. This has provided one natural test of the markets' ability

[64] Performance of the regulation down markets in the 2006 high hydro conditions is discussed in California ISO, Department of Market Monitoring, *Annual Report, Market Issues and Performance, 2006*, Chapter 4. Available at http://www.caiso.com/1b7e/1b7e71dc36130.html.

[65] The ISO market now procures all ancillary service requirements in the day-ahead market, where the market model simultaneously co-optimizes offers for energy, regulation and operating reserves. This procedure allows for the most efficient selection of bid-in generation capability to meet market and reliability requirements.

to procure higher levels of regulation capacity in all hours of the day, albeit under the system conditions in April 2009. Regulation procurement has been reduced in more recent months and is currently procured on a variable basis throughout the operating day, reflecting the impact of system conditions on regulation needs. Figure 4-4 shows that the ISO has procured 400 MW or more of both regulation up and regulation down for over 2500 hours from April 1, 2009 – June 30, 2010. Moreover, the maximum MW procurements of 600 MW or more took place in every hour of the operating day, confirming that at least under the conditions of that period, the market could mobilize as much regulation as the operational simulations of 20 percent RPS.

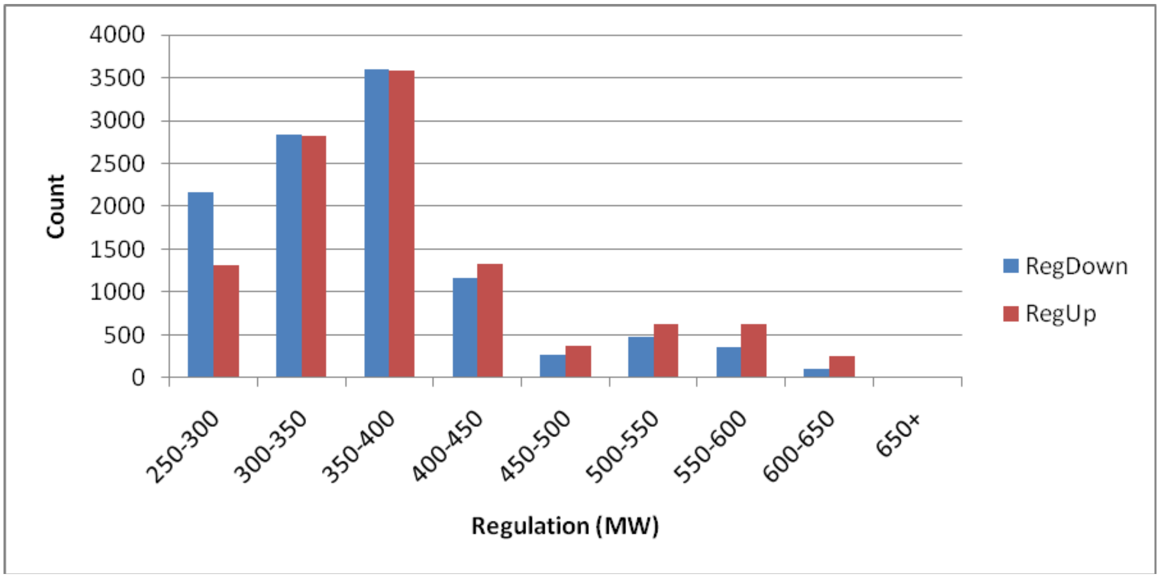

Figure 4-4: Frequency of Regulation procurement by MW (4/1/09 to 6/30/10)

Figure 4-5 and Figure 4-6 show the historical regulation up and down procurement. The values shown are the maximum of the day-ahead and real-time regulation procurements. These figures show that the ISO has been procuring at least 300 MW of regulation during all hours.

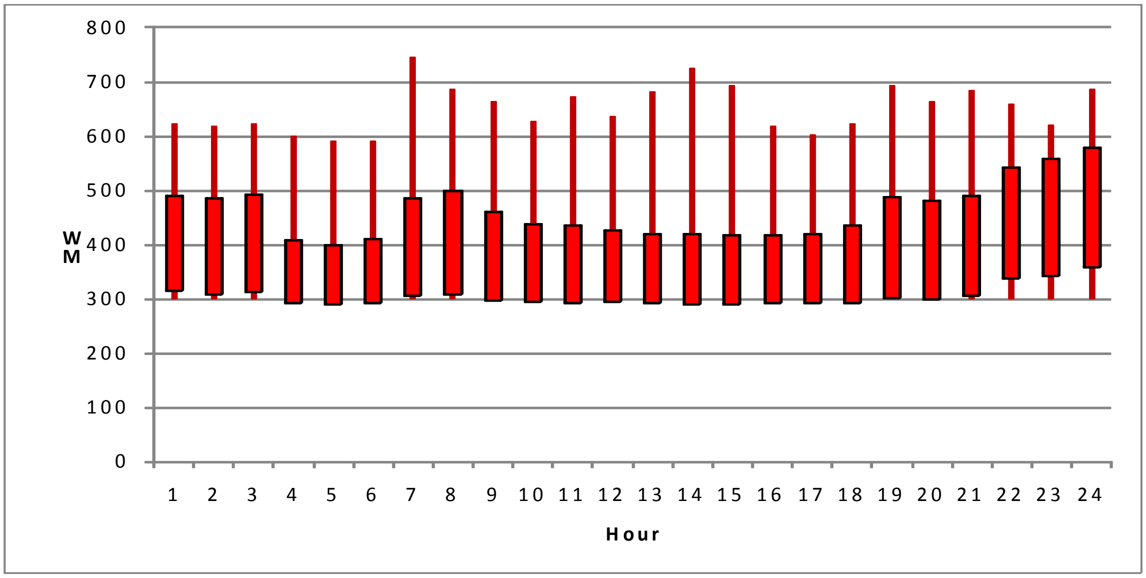

Figure 4-5: Regulation Up Procurement (Max of DA and RTPD Cleared Values)

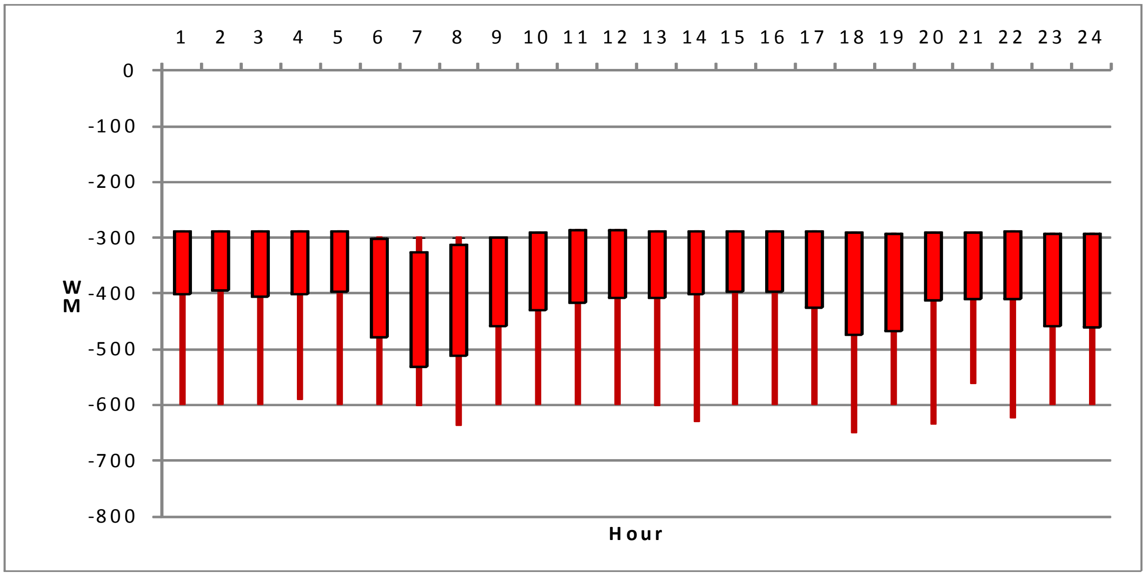

Figure 4-6: Regulation Down Procurement (Max of DA and RTPD Cleared Values)

Moreover, additional analysis of generation that bid into the regulation market, and was committed and dispatched in energy (i.e., on-line) but not necessarily selected to provide regulation, shows that there is a large reservoir of regulation certified capacity available at all hours of the day. When this on-line capacity is constrained to its 5-minute regulation ramp capacity (using the unit-specific regulation ramp rates shown in Table 4.2) there is typically potential coverage of between 1,000 – 2,000 MW of regulation up and regulation down requirement in that 5-minute interval, *if* all such on-line units could provide regulation and do so without creating overgeneration conditions.[66] Moreover, the measurements do not reflect the operational limitations of bid-in capacity due to resource awards of energy or other ancillary services.

This measurement is shown for the summer months in Figures 4-7 and 4-8 and for all seasons in Appendix B. However, particularly in spring and summer, this measure of potential regulation capacity falls below 1000 MW and close to 500 MW in some early morning hours, showing that capability does tighten reflecting fewer regulation capable units on-line.

The combination of the inventory of regulation capacity and ramp rates, the record of sustained regulation procurement at up to 600 MW of regulation up and regulation down, and the empirical analysis of on-line regulation ramp capability suggest that the ISO can meet the higher regulation requirements forecast for 20 percent renewable energy. A further test of the ability of the unit commitment and dispatch to meet the higher regulation requirements is conducted using production simulation that reserves such capacity, as discussed in Section 5. That analysis highlights the potential constraint on regulation down during spring high hydro, light load conditions.

[66] The ISO actually procures regulation based on the resource's 10-minute regulating ramp range. However, this measurement was conducted on a 5-minute basis to provide comparison with the operational simulation results in Section 3. Clearly, if the measurement was for 10-minute ramps, the capability shown here would be roughly doubled.

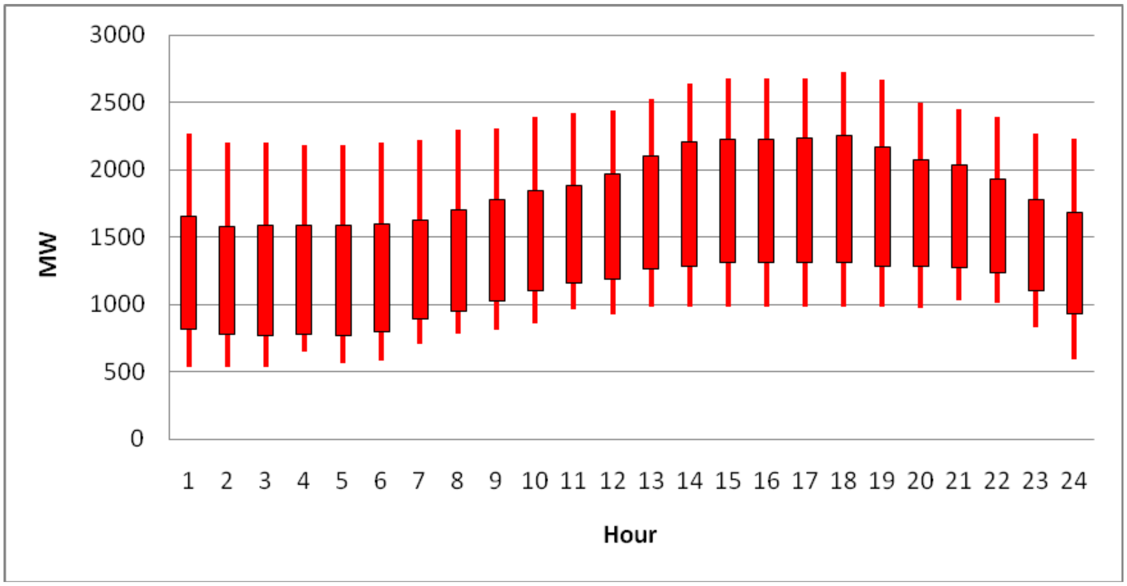

Figure 4-7: Regulation Up 5-Minute Ramp Capability of Bid-In Capacity (MW) by Dispatched Resources, Summer 2009, 2010

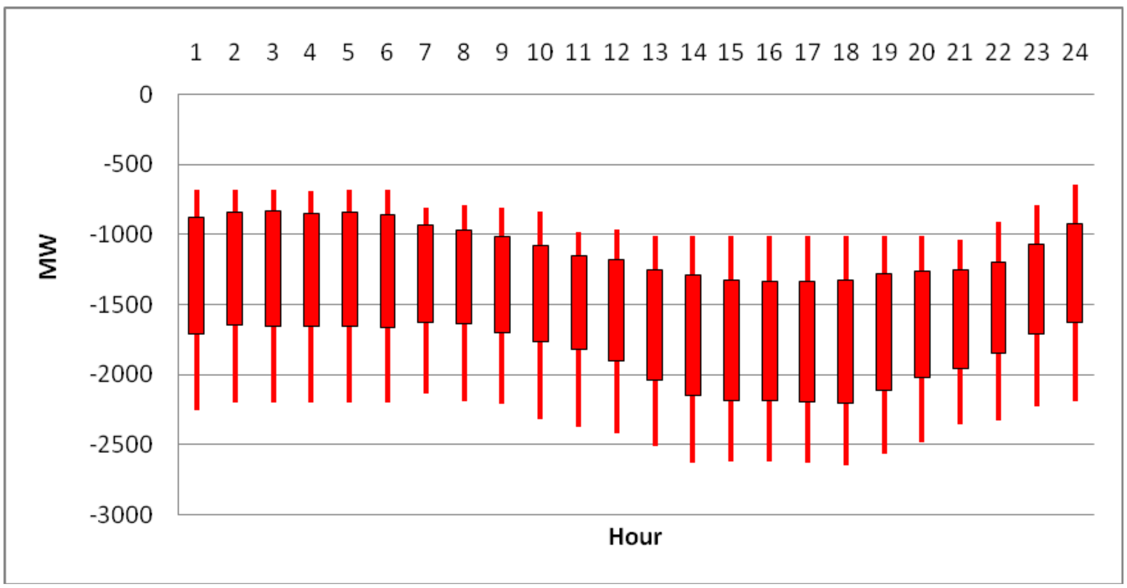

Figure 4-8: Regulation Down 5-Minute Ramp Capability of Bid-In Capacity (MW) by Dispatched Resources, Summer 2009, 2010

5 Analysis of Operational Capability under 20 percent RPS

This section presents the results of the production simulation modeling of the integration of 20 percent renewable energy. Section 5.1 provides a high-level summary of the findings. Sections 5.2 and 5.3 discuss the analysis of load-following and overgeneration impacts, respectively. Section 5.4 provides certain measures of changes in the operation of the thermal generation fleet (e.g., number of starts) as well as preliminary estimates of changes in energy market revenues by unit type.

5.1 Summary of Findings

- Production simulation results suggest that shortages in load-following down capability will result in less than 0.02 percent of renewable energy (approx. 10 GWh) potentially needing to be curtailed. No significant shortages of load-following up or regulation were found.
- Overgeneration was found to be directly correlated to the amount of non-dispatchable generation in the system. Overgeneration, under the worst-case scenario, which assumes no load growth between 2006 and 2012, was 0.32 percent (150 GWh) of annual energy from renewable resources. There is potential to further relieve these instances of overgeneration by increasing the commitment of dispatchable resources in place of inflexible resources, such as firm imports.
- With the 20 percent RPS, dispatchable generators will start and stop more frequently. In particular, combined cycle generators' starts increase by 35 percent. Also, the energy from the combined cycle units decreases by roughly 9 percent with more reduction occurring during off-peak hours with wind generation, indicating that there will be more cycling in the dispatchable fleet.
- The energy market revenues for all dispatchable thermal units were substantially lower by 2012 due to the compounding effect of lower capacity factors and suppressed energy prices due to the influx of renewable energy.

5.2 Load-following and Regulation Impacts

In general, variability in wind and solar generation impacts the regulation and load-following *requirements*, while uncertainty in their generation impacts the regulation and load-following *capability* of the system. Uncertainty in generation may lead to a unit commitment with inadequate regulation and load-following capability. The shortage of regulation and load-following capability may have an impact on Area Control Error (ACE), and if sustained, result in a CPS2 violation. Under extreme cases, the lack of regulation and load-following down capability might require curtailment of generation to resolve the problem.

The stochastic, sequential simulation methodology discussed in section 2.5.2 was used to evaluate the capability of the future system to meet the operational requirements with 20 percent renewable generation. The data and assumptions for the production simulation are discussed in Section 2.5.1. As summarized in Table 2.6, certain generation resources were assumed to be non-dispatchable in the production simulation. The generation profiles for these units, which included, Biomass, geothermal, QFs, hydro, and Imports, were based on either 2006 or 2007 actual operations as described in Section 2.5.1. It should be noted that the entire conventional gas fleet was assumed to be dispatchable in the production simulation. In other words, self-scheduling was not modeled in this analysis. The derivation of the generation profiles for variable energy resources and their day-ahead and hour-ahead forecasts is described in Section 2.5.2.1.

The simulations were targeted at selected days to examine the impact on load-following and regulation.[67] The procedure used for identifying interesting days for real-time simulations is described in Appendix C-1. This methodology identified a number of days in May 2012 with both high upward and downward load-following requirements as candidates for detailed real-time analysis. Table 5.1 shows the days selected for the sequential simulation, as well as the system conditions for each day. This section presents the results of the detailed analyses performed for two of the selected days (May 28, 2012 and May 17, 2012). The results for the remaining days are included as Appendix C.7.

Table 5.1: Characterization of System Conditions for the Days selected for Production Simulation

Date	Period	Load*	Non-Dispatchable Generation	Renewable Generation	Dispatchable Generation
May 28, 2012	6 a.m. – 10 a.m.	Ramp up	High import, High hydro	Solar ramp up, low wind	Low
May 27, 2012	6 a.m. – 10 a.m.	Ramp up	High import, High hydro	Solar ramp up, wind ramp down	Low
May 24, 2012	1 p.m.	High	High import, High hydro	Solar ramp down, wind ramp up	High
May 16, 2012	9 p.m.	High, ramping down	High import, High hydro	Solar very low, wind high	High
May 17, 2012	9 p.m.	High, ramping down	High import, High hydro	Solar very low, wind high	High

[67] It should be noted that the capability of the fleet to provide the regulation requirements determined in the operation analysis is studied using production simulation. However, this analysis does not attempt to identify the sufficiency of the regulation requirement since this would require sub-5-minute simulations that are beyond the scope of this analysis.

5.2.1 Load-following Capability under Low Dispatchability Conditions

Table 5.1 shows the simulated system condition for May 28, 2012. The screening process showed the need for high load-following down requirement on this day. This day also had very limited dispatchable generation online during the low load periods in the morning. This was due to a number of reasons: high hydro and imports from neighboring regions and high wind generation in the morning. This day was also characterized by a rapid increase in solar generation between 5.00 a.m. and 8.00 a.m.[68] Figure 5-1 shows the load (black line) and non-dispatchable generation[69] (red line) and the components of the non-dispatchable generation. The separation between the load and the non-dispatchable generation in Figure 5-1 is the amount of dispatchable generation available for load-following and regulation. Very few dispatchable resources are online during the morning hours, as is evident from the figure.

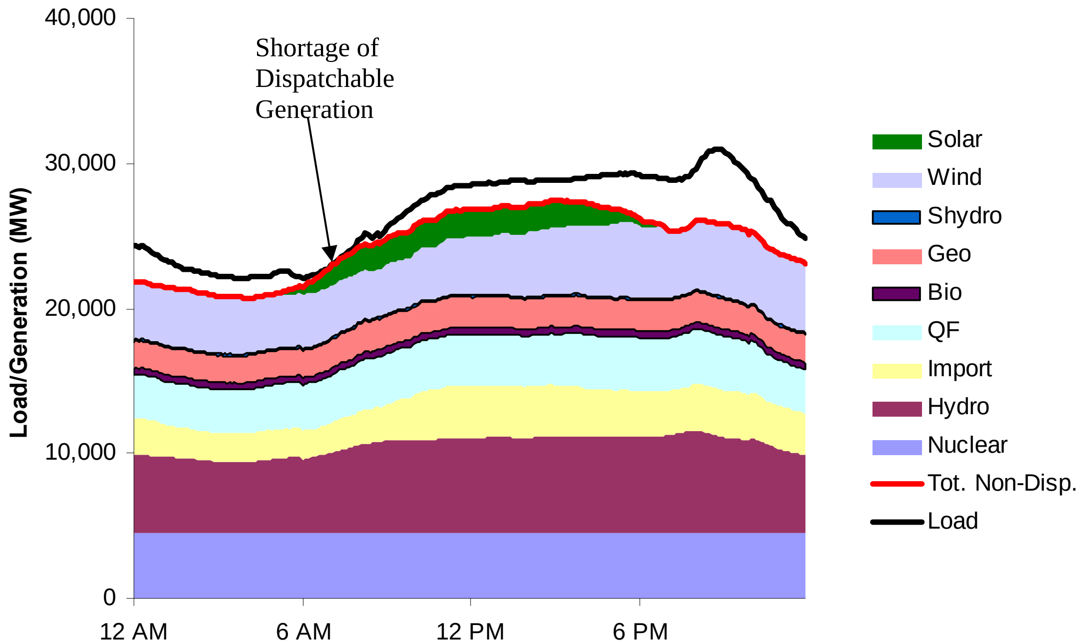

Figure 5-1: Load and Non-dispatchable Generation on May 28, 2010

Figure 5-2 shows the simulated 5-minute load-following up and down capabilities from dispatchable generators for May 28th, 2012. This is the capability of the dispatchable generators to move from one 5-minute dispatch to the next. The figure shows adequate 5-minute capability throughout the day and is comparable to the historical upward 5-

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[68] Unlike wind generation, zero forecast error is assumed for solar generation both in the day-ahead and hour-ahead time frame in the production simulations. Errors due to solar forecast will exacerbate load-following shortages.

[69] The non-dispatchable generation does not include the minimum generation of gas-fired generators that are also not dispatchable.

minute capability show in Figure 4-1 of Section 4. However, the figure shows low load-following down capability during the morning hours from 4 a.m. to 10 a.m. It should be noted that Figure 5-2 shows the 5-minute capability for the day whereas the corresponding figures in Section 4 show the historical hourly maximum 5-minute load-following up and down capability. The low load-following down capability is a direct consequence of the amount of dispatchable generation that is online. During the morning hours of May 28th 2012, as shown in Figure 5-1, very few dispatchable generators are online and most are already operating at or close to their minimum load point.

As discussed in Section 3-3, insufficient capability to ramp down manifests itself as overgeneration in the production simulations. Figure 5-3 shows the overgeneration for May 28, 2012 obtained from the production simulation. This figure also shows the regulation down procurement (green line) and the CPS2 violation threshold[70] (yellow line) for the same period. While there is significant, sustained overgeneration for a few hours from 5 a.m. to 8 a.m., the rest of the time the over generation can be covered by the procured regulation or allowed to result in an ACE error if it is not sustained. Only large overgeneration sustained over 10 minutes may result in the curtailment of generation.

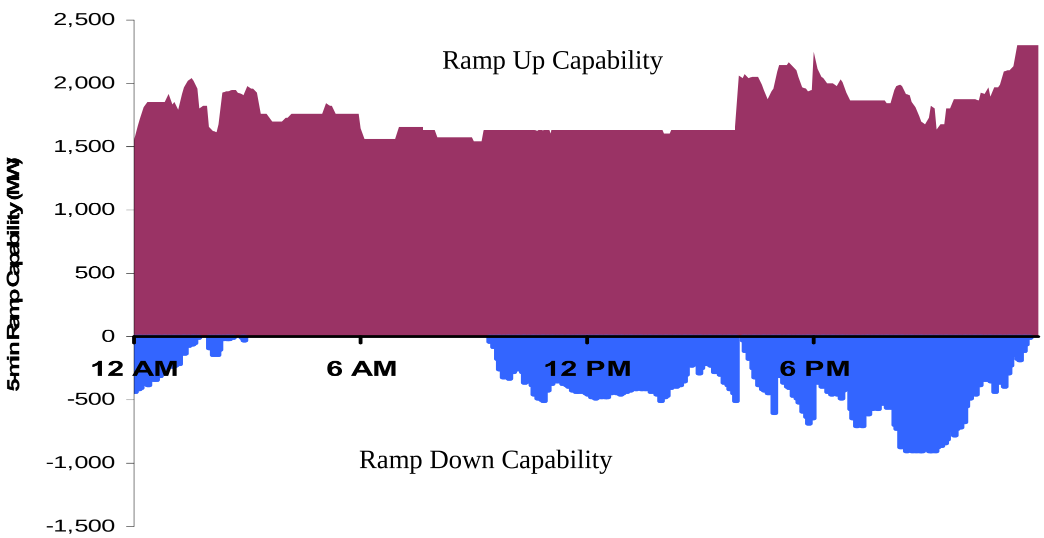

Figure 5-2: Upward and Downward 5-minute Load-Following capability for May 28th 2012

[70] CPS2 threshold is 110MW for ISO.

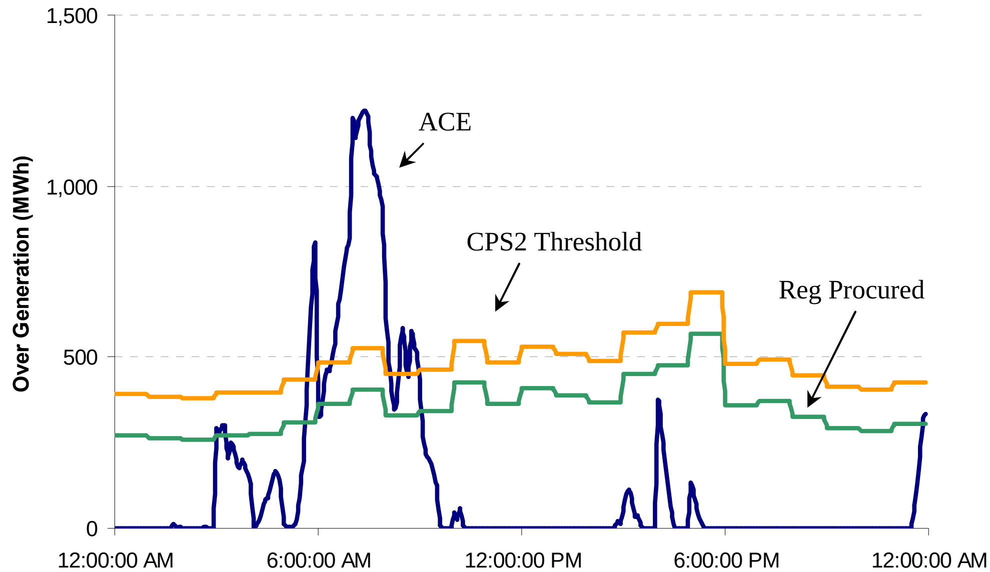

Figure 5-3: Detailed overgeneration analysis of May 28, 2012

Figure 5-4 shows the relationship between overgeneration and the amount of dispatchable generation during the hours between 4 a.m. and 10 a.m. The traces show that there is a direct correlation between overgeneration and lack of dispatchable generation. When the dispatchable generation is approaching zero, overgeneration is high. Under these conditions with very little dispatchable generation online, the fast ramp in solar generation results in an overgeneration condition. It should be noted that the solar generation ramp is not the cause of the overgeneration, rather it's the trigger. The cause for overgeneration is the lack of flexible or dispatchable resources during these hours.

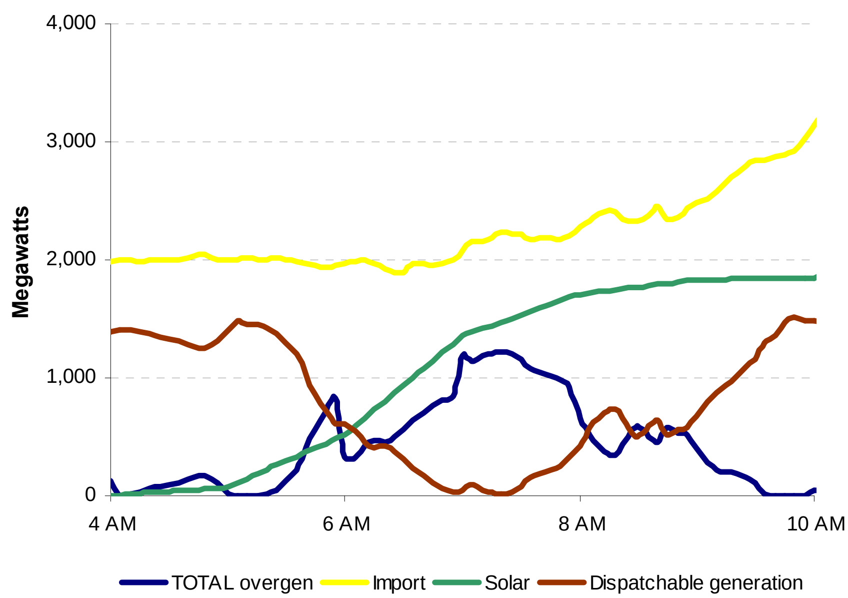

Figure 5-4: Dispatchable Generation and Overgeneration

5.2.2 Load-following Capability under High Dispatchability Conditions

Table 5.1 shows the simulated system condition for May 17, 2012. The main difference in system conditions between May 28 and May 17 is the amount of non-dispatchable resources that were online due to lower imports. Figure 5-5 shows the load (black line) and non-dispatchable generation[71] (red line) and the components of the non-dispatchable generation. The separation between the load and the non-dispatchable generation in Figure 5-5 is the amount of dispatchable generation available for load-following and regulation. More dispatchable resources are online during the morning hours, compared to May 28, 2012, as is evident from the figure.

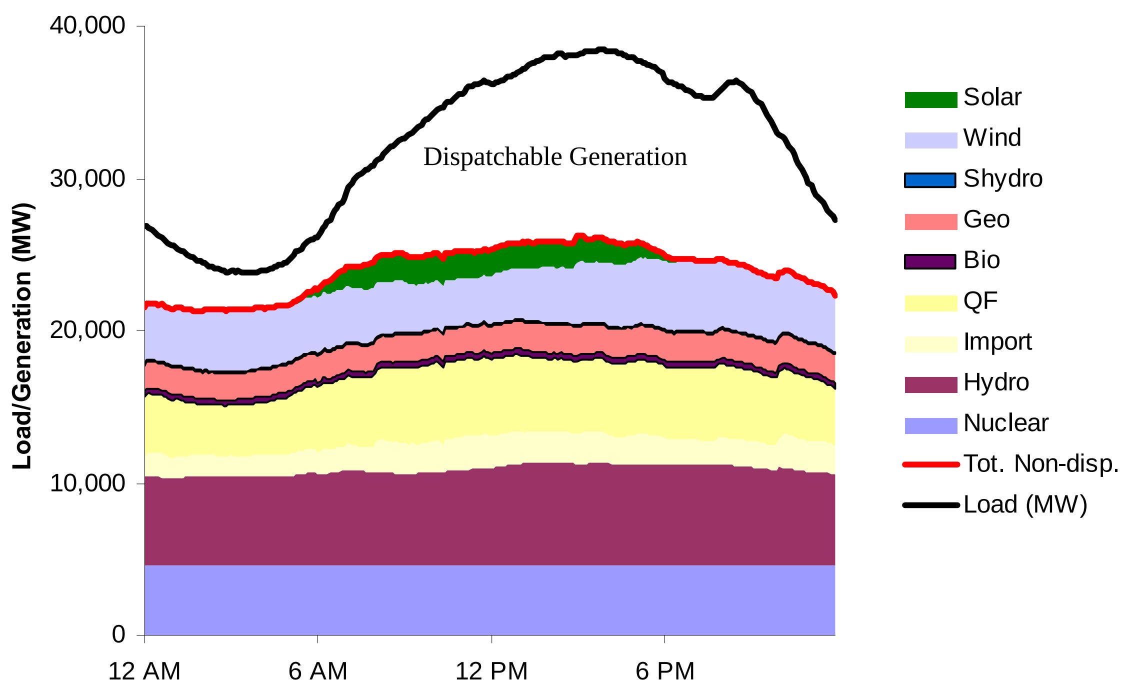

Figure 5-5: Load and Non-dispatchable Generation on May 17, 2010

Figure 5-6 shows the simulated 5-minute load-following up and down capabilities from dispatchable generators for May 17, 2012. The figure shows adequate capability throughout the day due to more dispatchable units being online.

[71] The non-dispatchable generation does not include the minimum generation of gas-fired generators that are also not dispatchable.

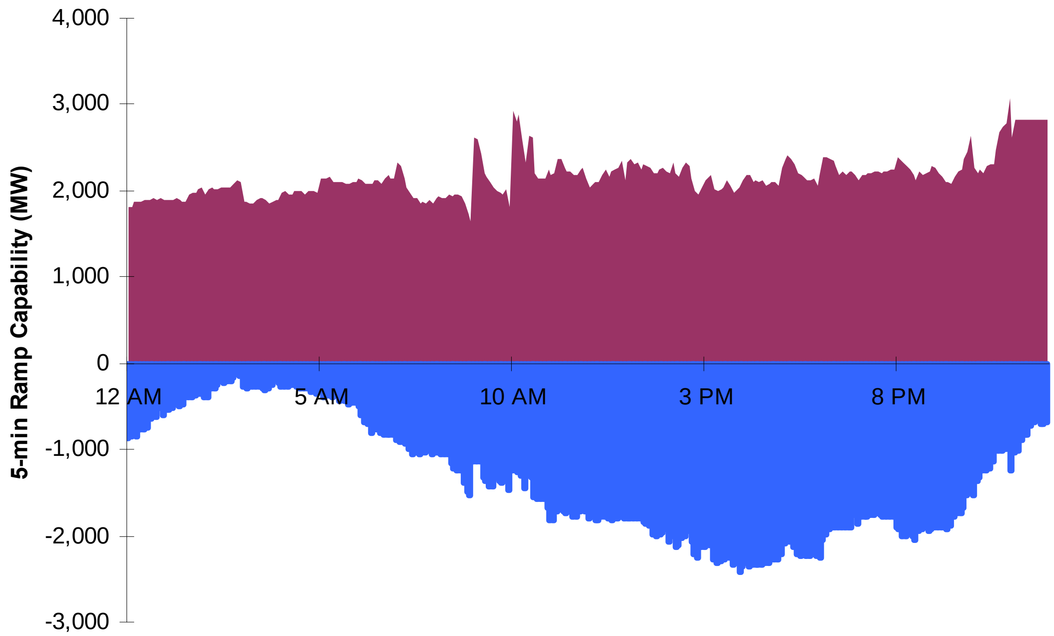

Figure 5-6: 5-minute ramp up and down capability for May 27, 2012

No overgeneration was observed in the 5-minute simulation of May 17, 2012. This reinforces the finding that load-following insufficiencies are primarily due to the lack of dispatchable generation resources. The results for the remaining days, summarized in Appendix C.7, also demonstrate that the lack of dispatchable resources causes the operational constraints. None of the detailed real-time simulations showed any significant upward load-following or regulation shortages indicating that the system has enough capability to meet load when there is a sudden decrease in variable energy resource generation.

To further analyze the impact of dispatchable gas-fired generation on overgeneration, a scatter plot of the two quantities was plotted. Figure 5-7 shows the plot of overgeneration (on the X axis) versus the amount of dispatchable gas-fired generation (on the Y axis) from a deterministic case[72] with all of the imports considered firm (100 percent firm import case). The deterministic cases that were simulated are discussed in Section 5.3. It can be observed that no overgeneration occurs when there is at least 1000 MW of dispatchable generation.

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[72] In a deterministic simulation, uncertainty in load and wind generation is ignored, unlike a stochastic simulation. Since the run-time is lower, deterministic simulations were used to study the impact of various study assumptions on the results.

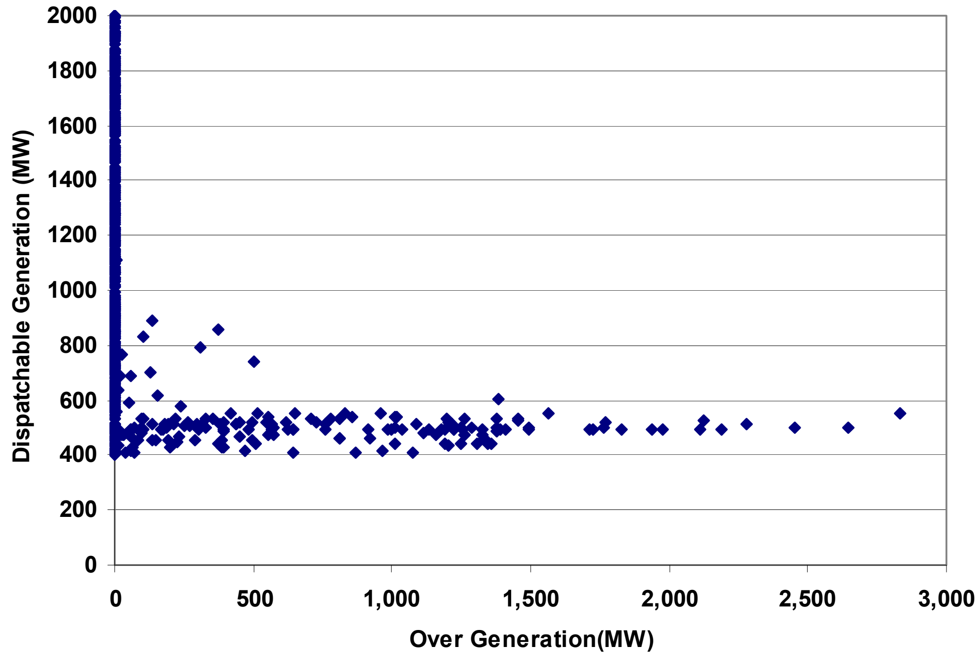


Figure 5-7: Overgeneration versus Dispatchable Generation

In contrast to the clear trend shown above, Figure 5-8 shows the overgeneration versus the system load. While no overgeneration occurs when the load is above 30,000 MW, the overgeneration occurs throughout the range of loads from 20,000 MW to 30,000 MW. These two figures again reinforce the finding that overgeneration is caused by shortages in downward dispatchable generation.

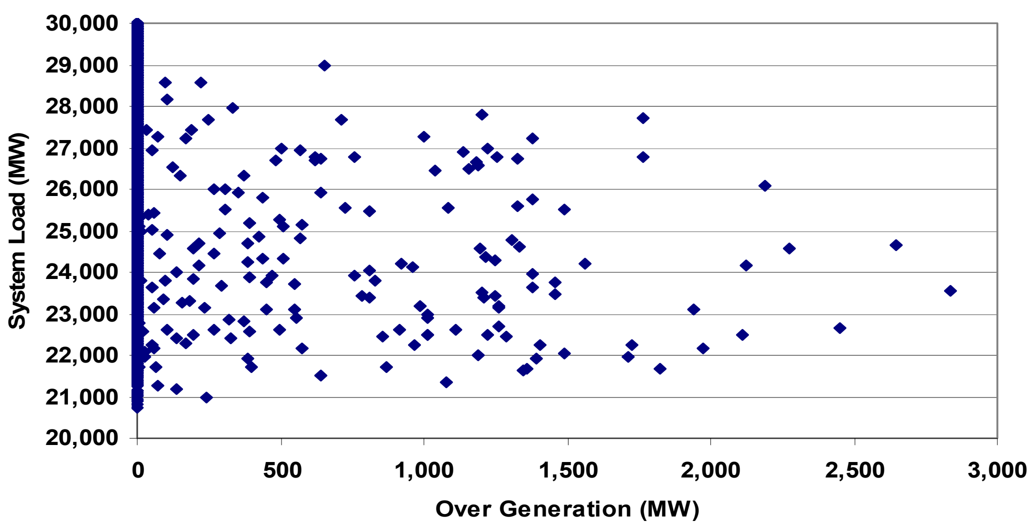


Figure 5-8: Overgeneration versus System Load

5.2.3 Quantification of Annual Load-following Shortages

The analysis shown in Section 5-2 is helpful in quantifying the shortages in load-following capability for a few selected days, and in understanding the factors that lead to the shortages. This section discusses the methodology that was used to estimate the shortage in load-following capability for the year.

Appendix C presents the results of the methodology that was used for identifying “interesting” days for stochastic, sequential simulations. The appendix discusses the approach for selecting the days for real-time simulation considering the impact of inflexibility in the existing fleet, and uncertainty and variability of load and variable energy resources on overgeneration. As shown by the hourly results in this appendix, most of the overgeneration is in the month of May, nearly 3.9 GWh. This month accounts for 80 percent of the annual overgeneration due to shortages of dispatchable generation, and uncertainty of load and generation from variable energy resources. Since this is an hourly simulation, it does not capture the impact of sub-hourly variability of load and generation from variable energy resources on the simulation.

Appendix C also quantifies the impact of intra-hour variability in load and generation from variable energy resources on overgeneration. The simulation of May 28, 2012 discussed in this appendix shows that variability increases overgeneration above and beyond what is caused by uncertainty alone. This is because variability imposes additional load-following constraints on the existing fleet, which might result in more overgeneration. Using May 28 as an example, variability doubles the overgeneration due to uncertainty of load and variable energy resources alone.

Table 5.2: Estimation of Annual Load-Following Shortages

Sensitivity Cases	GWh
(a) May overgeneration due to forecast uncertainty alone	3.90
(b) Estimated annual overgeneration due to uncertainty alone [1.20*(a)]	4.68
(c) Estimated annual overgeneration due to uncertainty and variability [2.2*(b)]	10.30

Using the information from the real-time hourly stochastic simulations, the regulation and load-following shortages for the year were estimated. Cumulative overgeneration for the high hydro case (based on 2006 loads and hydro) was roughly 10 GWh for 2012 as shown in Table 5.2. This is roughly 0.06 percent of the wind generation and 0.02 percent of the total renewable generation in 2012.

5.3 Impact of Non-dispatchability on Overgeneration

As mentioned previously, variability in wind and solar generation impacts the regulation and load-following *requirements*, while uncertainty in their generation impacts the regulation and load-following *capability* of the system. It was shown in Section 5.2 that shortages in dispatchable generation cause an inability to follow load, which in turn causes overgeneration. The preceding section quantified overgeneration due to the variability and uncertainty associated with load and variable energy resources to be 10 GWh for the year 2012. It should be pointed out that the overgeneration in this case is due to the inability of the fleet to follow net load changes in the sub-hourly time frame.

Even if the generation from wind and solar resources could be perfectly forecasted and were constant (i.e., no uncertainty and variability), the maximum generation that can be accommodated into the system will depend on the ability to dispatch the existing fleet. In this case, the overgeneration has nothing to do with the variability and uncertainty of variable energy resources. Rather, it strictly depends on whether the rest of the fleet can be dispatched down to accommodate the energy from variable energy resources.

The impact of dispatchability on overgeneration was studied both under high and low hydro conditions, under a range of assumptions regarding the dispatchable capability of generation resources and imports. This sensitivity analysis used a deterministic production simulation on an hourly basis. The intra-hourly variability and the forecast uncertainty associated with generation from variable energy resources were not modeled (but they were rather modeled as fixed, but variable by hour, production profiles). Certain portions of the generation fleet such as QFs, nuclear, biomass, hydro and imports were assumed to be non-dispatchable in this analysis. Historical hourly dispatches were assumed for these resources.

However, in reality, not all of these resources are always non-dispatchable. For example, based on an analysis of the bid data, 50 percent of the imports into California in 2006 were found to be bid into the market on an hourly basis, with the remaining being scheduled hourly as firm. The impact of increasing the dispatchable capacity on the system on the frequency and magnitude of overgeneration was studied by assuming various levels of firm imports (50 percent, 75 percent and 100 percent). Since overgeneration is more likely to occur at low loads, the impact of zero load growth from 2006 to 2012, but with the expected renewable generation additions, was also studied. A deterministic production simulation on an hourly time-step was conducted for all these cases. The assumptions for the deterministic cases are shown in Table 5.3.

Table 5.3: Assumptions for the Deterministic Production Simulations

Case	Load	Imports
50 % Import Case	2006 Load ×(1+0.015)^6	50% Fixed*, 50% Dispatchable
75 % Import Case	2006 Load ×(1+0.015)^6	100% Fixed
100 % Import Case	2006 Load ×(1+0.015)^6	50% Fixed*, 50% Dispatchable
No Load Growth Case	2006 Load	50% Fixed*, 50% Dispatchable

* Based on 2006 imports

Under the assumptions listed above, in the base case simulation, with 50 percent firm imports, no overgeneration was observed as a result of shortages in dispatchable generation. The most severe overgeneration was from the zero load growth case, as shown in Figure 5-9. Overgeneration in this case was roughly 150 GWh for the year, which is 0.84 percent of the expected wind energy and 0.32 percent of the total renewable generation in 2012. Most of the overgeneration occurs in late spring (April-May), due to combination of high generation from hydro and variable energy resources, and low loads. The 75 percent and 100 percent import cases also showed some overgeneration as shown in Figure 5-9. In general, there appears to be sufficient flexible generation available to operate, if the ISO is not blocked from doing so due to an excess of non-dispatchable generation, including imports.

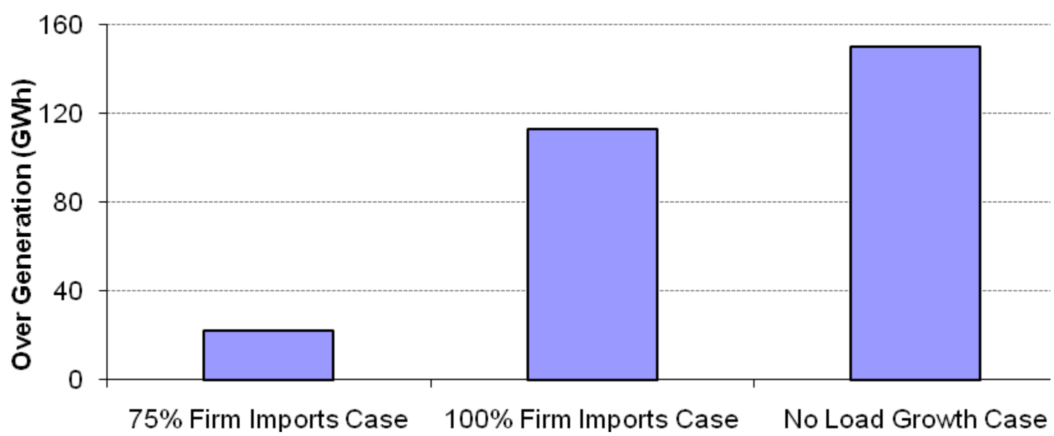


Figure 5-9: Volume of Annual Overgeneration (GWh) in Three Sensitivity Cases

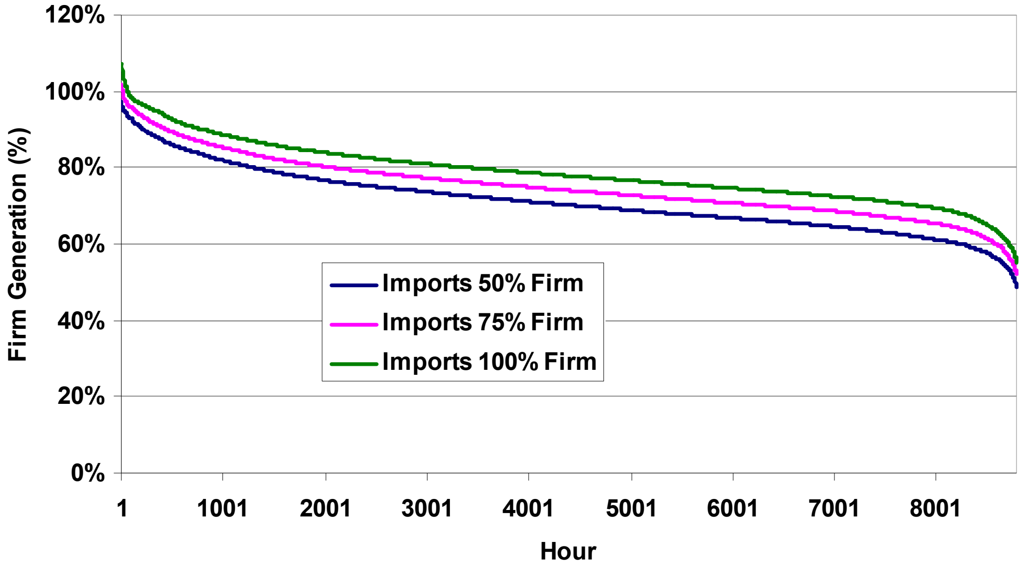


Figure 5-10: Duration curves for non-dispatchable generation with different levels of firm imports

Figure 5-10 shows the non-dispatchable generation in the three cases (50 percent, 75 percent and 100 percent import) as a percentage of the load. It can be observed that at higher percentages of firm imports, the total non-dispatchable generation is higher than load during a few hours, which results in overgeneration.

5.4 Fleet Operations and Economic Impacts

The production simulations results were also used to provide an initial evaluation of the impacts of 20 percent renewable energy production on the operations and revenues of the dispatchable thermal generation fleet. Table 5.4 shows the impact on the combined cycle fleet. This table shows the number of starts, on-peak and off-peak energy, CO2 emissions and revenues for the 20 percent RPS case, as well as the 2012 Reference case.[73] Tables 5.5 and 5.6 show the impacts on the simple cycle gas turbine and gas-fired steam turbine fleet, respectively. The 20 percent renewable energy modeled results in the combined cycle units starting and stopping more frequently. With the additional renewable production, combined cycle generator starts increase by 35 percent. Also, the energy from the combined cycle units reduces by roughly 9 percent, with more reduction occurring during off-peak hours, indicating increased cycling. The table also shows a reduction in CO_2 emissions from combined cycle generators due to the reduction in operations, although this was calculated using a single emissions factor multiplied by energy output, and did not consider the potential for higher emissions at less efficient levels of operations.

[73] The 2012 Reference case uses the same load and other assumptions as the 20 percent RPS case, except that the renewable portfolio includes only the renewable resources online in 2006.

Table 5.4: Aggregate Operational, Emissions and Revenue Changes for Combined Cycle Units

	20% RPS case	2012 Reference case	Percent change
Number of starts	3,362	2,492	35 %
On-peak Energy (MWh)	32,421,142	36,258,580	-11 %
Off-peak Energy (MWh)	26,146,347	31,055,863	-16 %
CO2 Emissions (tons)	24,266,005	27,969,588	-13 %
Revenue ($,000)	3,455,290	4,103,959	-16 %

Table 5.5: Aggregate Operational, Emissions and Revenue Changes for Simple Cycle Gas Turbines

	20% RPS case	2012 Reference case	Percent change
Number of starts	9,618	12,123	-21 %
On-peak Energy (MWh)	6,223,446	10,244,121	-39 %
Off-peak Energy (MWh)	3,359,432	5,034,037	-33 %
CO2 Emissions (tons)	5,591,607	8,660,370	-35 %
Revenue ($,000)	605,167	996,017	-39 %

Table 5.6: Aggregate Operational, Emissions and Revenue Changes for Gas-fired Steam Turbines

	20% RPS case	2012 Reference case	Percent change
Number of starts	2,653	3,392	-22 %
On-peak Energy (MWh)	5,109,377	7,179,751	-29 %
Off-peak Energy (MWh)	3,396,360	4,125,934	-18 %
CO2 Emissions (tons)	3,654,106	4,598,358	-21 %
Revenue ($,000)	522,329	735,255	-29 %

While the number of starts for combined cycle units increase with 20 percent renewable energy, the simulations show that the number of starts, along with energy produced, decrease quite substantially for simple cycle gas turbines and gas-fired steam turbines.

Figures 5-11 and 5-12 show the generation from combined cycle, simple cycle and gas-fired steam turbines for the same week in January, 2012, for the two cases. The combined cycle energy (area shown in blue) is smaller for the 20 percent RPS compared to the 2012 reference case. Also, the valleys in combined cycle generation are deeper indicating that more of these units either turn down and shutdown during off-peak hours.

Two conflicting impacts are at work here. On the one hand, the renewables decrease the overall amount of gas-fired generation required. The overall level of gas generation drops several thousand MW across the week, thereby decreasing the total energy and the number of starts. The average displacement by season and hour due to the renewable profiles being modeled can be seen in the gap between the load and net load in Figures 2-1 to 2-4. On the other hand, the uncertainty and variability tends to push up the number of starts. These simulation results likely underestimate production because intra-hourly load-following is not modeled.

Figures 5-13 and 5-14 show the seasonal on-peak and off-peak energy from combined cycle, simple cycle GT, gas-fired steam, wind and solar resources for the 20% RPS case and the 2012 reference case. From these two figures, it is clear that during on-peak hours, the incremental wind and solar generation displace the generation primarily from simple cycle and gas-fired steam generators. During off-peak hours, the generation from the incremental wind and solar generation has a bigger impact on the generation from combined cycle units.

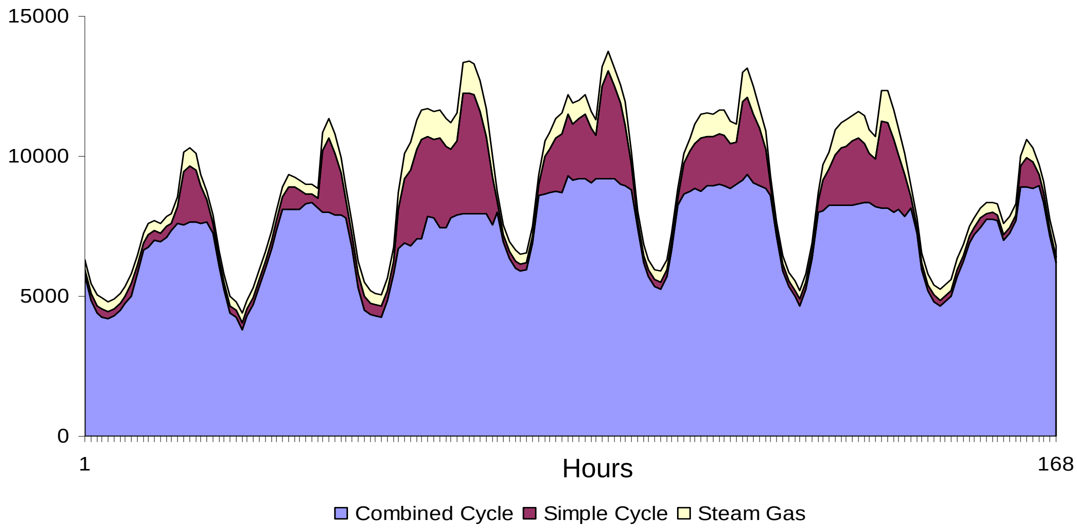


Figure 5-11: Weekly generation for gas units in the 2012 reference case

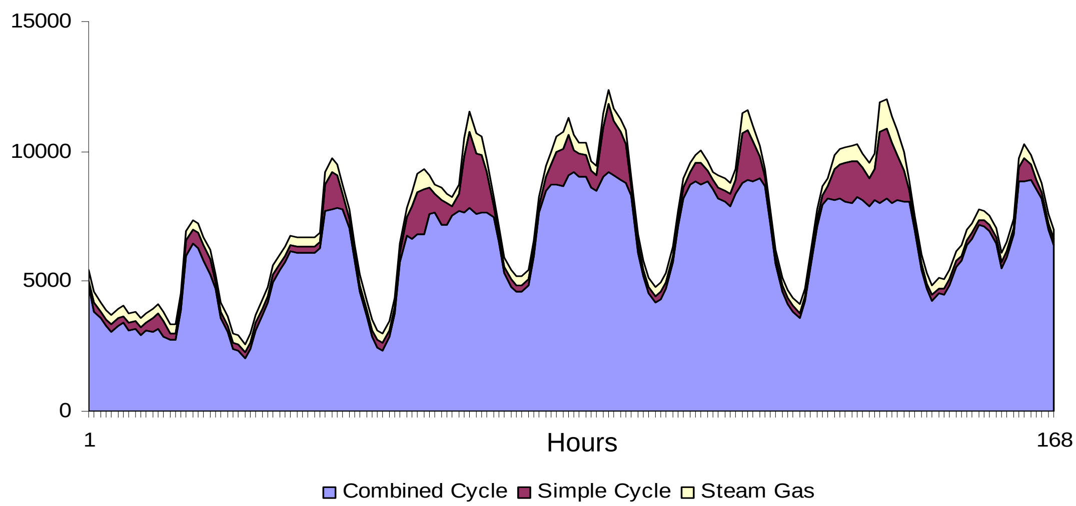


Figure 5-12: Weekly generation for gas units in the 20 percent RPS case

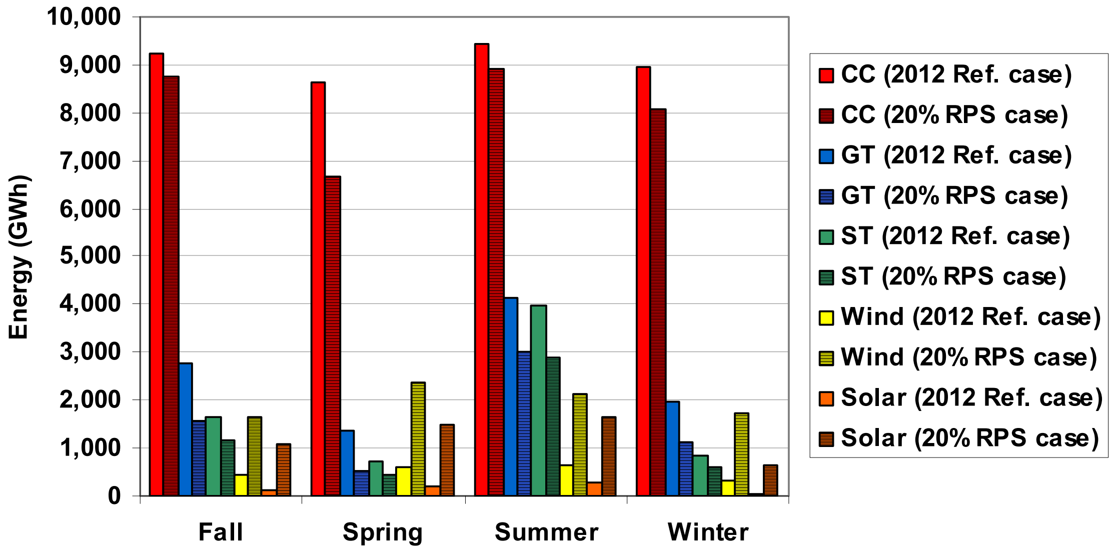


Figure 5-13: Seasonal on-peak energy by thermal and renewable technologies for (a) 2012 reference case (b) 20 percent RPS case

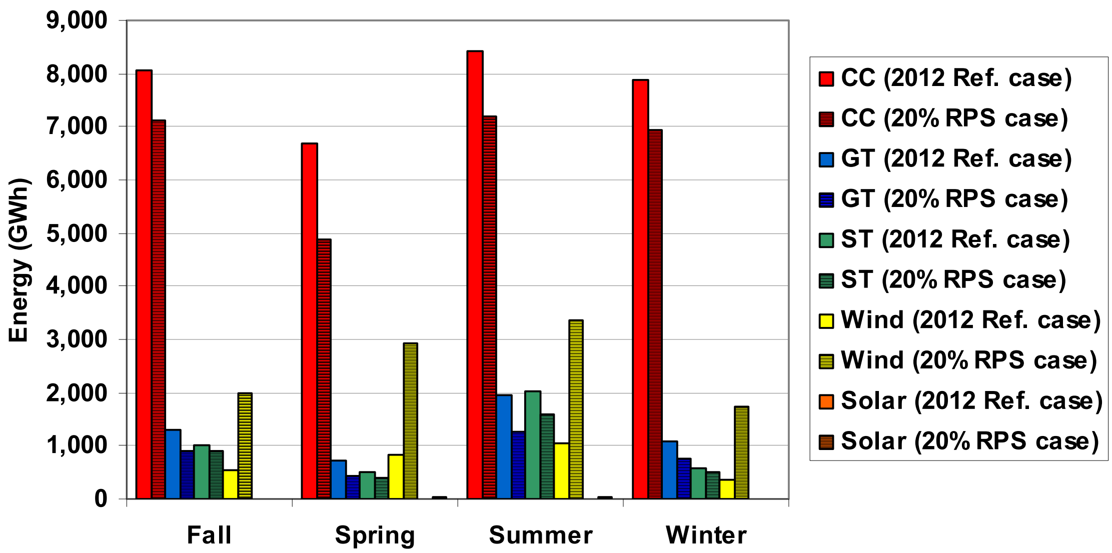


Figure 5-14: Seasonal off-peak energy by thermal and renewable technologies for (a) 2012 reference case (b) 20 percent RPS case

The energy market revenues for the combined cycle, simple cycle gas turbine and steam units are lower in the 20 percent RPS case, compared to the 2012 reference case, by 16 percent, 39 percent and 29 percent respectively. The revenues for combined cycle, simple cycle gas turbine and steam units are lower due to the compounding effect of lower dispatch and lower energy prices. Figure 5-15 and 5-16 show the energy prices in the summer and spring for the two cases. The figure shows the minimum, maximum and standard deviation of the seasonal average hourly spot prices. On an average, the energy prices in the 20 percent RPS case are lower by $2.50 /MWh compared to the 2012 reference case. The lower energy prices, combined with the lower capacity factor, have a negative impact on the revenues of thermal units. Peaking units such as simple cycle gas turbines and steam turbines are impacted more in the 20 percent RPS case because they operate less during the peak hours of the days when energy prices are higher.

Also, it can be observed that the price volatility is higher in the 20 percent RPS case. The spring plot shows few hours when the price is zero or negative due to overgeneration. These periods correspond to solar and wind ramp up periods discussed in other sections of the report. The price volatility in the negative direction also has an impact on generator revenues.

These simulated revenue results, based on marginal production costs, are provided to illustrate potential changes in energy market revenues rather than as a forecast; actual market prices will reflect factors not considered, or only partially considered, in the model, such as congestion and the effect on prices of market bids. Also, revenues from ancillary services are not included in the annual revenues. Further analysis to quantify operational and economic impacts on fleet is required, especially at higher levels of RPS.

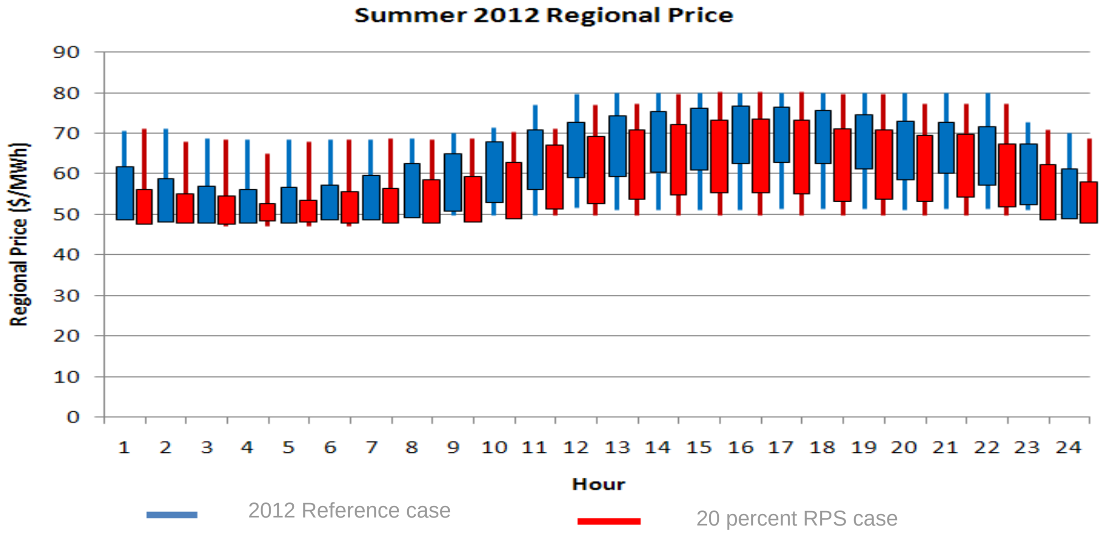


Figure 5-15: Summer 2012 Prices for the cases (a) 2012 reference case (b) 20 percent RPS case

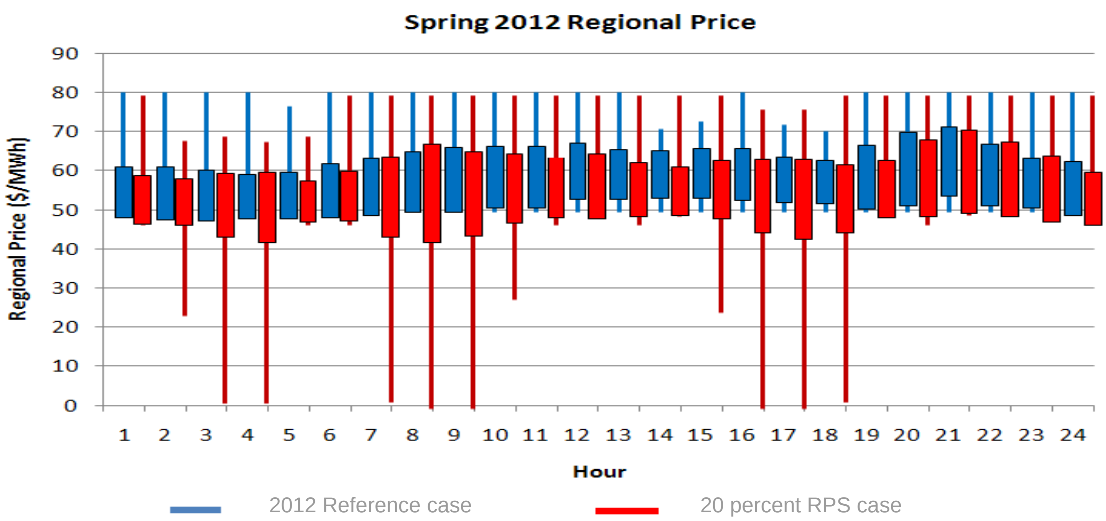


Figure 5-16: Spring 2012 Prices for the cases (a) 2012 reference case (b) 20 percent RPS case

6 Key Study Conclusions and Recommendations

The study shows that the generation fleet is capable of meeting the regulation up and down requirements, as well as the load-following ramp up requirements under the 20 percent RPS. Sufficient upward ramp capability was found both in the empirical analysis of the dispatch over the past 15 months (although there may be few intervals in the analysis where upwards capability is tight) and the production simulations.

The production simulation analysis showed that under certain conditions (for example, low load, high hydro and wind generation in May), the system may not have adequate flexible generation to meet the load-following down ramp requirement. In the methodology that was employed, the shortages in the ramp down capability are captured as overgeneration. The cumulative overgeneration for the high hydro case (based on 2006 loads and hydro) was roughly 10 GWh for 2012. This is roughly 0.02 percent of the expected renewable generation in 2012 and fairly insignificant. However, in the production simulations, the entire gas fleet was assumed to be dispatchable. The ramp down shortages can be exacerbated due to self-scheduling. Hence, the simulation result may be an under-estimate of actual overgeneration at 20 percent RPS.

Currently, a large portion of the generation fleet is self-scheduled and therefore not responding to 5-minute economic dispatch commands from the ISO. As a result, some periods may have insufficient dispatchable generation to follow load and variable energy production. The fleet capability analysis shows that due to self-schedules, the downward 5 minute capability of the generation fleet can be depleted. However, if no resource self-schedules, there is sufficient downward ramp capability inherent in the dispatch. This finding points to the significant negative impact that self-scheduling could have on efficient commitment and dispatch in high renewables scenarios. In fact, the ISO is already experiencing many hours of negative prices during off-peak hours in spring and summer, which is an indication that self-schedules are being violated to ensure reliable operations.

The study results indicate that the ISO should pursue incentives or mechanisms to reduce the level of self-scheduled resources during certain periods. The reduction in self-schedules will give the system the needed down ramp capability under certain conditions. The same outcome can also be achieved by reducing the amount of other non-dispatchable generation that are in the form of imports, hydro, QFs, geothermal etc. during these periods. There appears to be sufficient flexible generation available to operate with a 20 percent RPS if the ISO is not blocked from doing so due to an excess of non-dispatchable generation (including imports).The ISO is undertaking a large number of initiatives in system operations (notably improved wind and solar forecasting and visualization capabilities), grid planning and market design to prepare for renewable integration. These initiatives will not be reviewed here, but rather a few key recommendations that reflect the study findings are summarized.

- **Evaluate market and operational mechanisms to improve utilization of existing generation fleet operational flexibility**. As noted, the study confirmed that the generation fleet possesses sufficient overall operational flexibility to reliably integrate 20 percent RPS in over 99 percent of the hours studied. However, the current markets restrict ISO's access to that full capability due to self-scheduling. The empirical analysis provided information on the difference between load-following capabilities in the downward direction when resources are self-scheduled compared to their actual physical capabilities. Hence, the study makes clear that the ISO should pursue incentives or mechanisms to reduce the level of self-scheduled resources and/or increase the operating flexibility of otherwise dispatchable resources.

- **Evaluate means to obtain additional operational flexibility from wind and solar resources.** The simulations demonstrated the need for additional dispatchable capacity in the morning hours under certain conditions. The ISO should explore market rules and incentives intended to encourage greater participation by wind and solar resources in the economic dispatch or ancillary services. Greater economic dispatch control, including curtailment and ramp rate limitations, can be used in targeted circumstances to mitigate overgeneration or shortfall in regulation and load-following capability generally.

- **Improve day-ahead and real-time forecasting of operational needs: *(a) develop a regulation prediction tool.*** The analysis demonstrated that regulation needs will vary substantially from hour to hour depending on the expected production from wind and solar resources. The development of a means to forecast the next day's hourly regulation needs based on probabilities of expected renewable resource output would enhance the efficiency of regulation procurement in the day-ahead time frame.

- **Improve day-ahead and real-time forecasting of operational needs: *(b) develop a ramp/load-following requirement prediction tool.*** The study identified the potential for significant increases in load following capacity and ramp requirements at 20 percent RPS. While forecasts can identify the need in the day-ahead and hour-ahead time frame, they cannot currently identify the presence of ramp constraints that may limit the ability of generation to meet those requirements. The ISO should evaluate the development of improved forecasting of ramp requirements and whether to modify day-ahead and real-time unit commitment algorithms and processes to reflect those ramp requirements.

- **Further analysis to quantify operational and economic impacts on fleet at higher levels of RPS.** Although this study was not focused on the impact of renewable integration on the revenues of existing generation, it has provided some indications of possible changes in such revenues, primarily through changes in energy market prices. Further analysis is needed to clarify the net revenue impact over time from changes in energy and ancillary services procurement, as well as consideration of the implications for capacity payments.

APPENDIX A-1: Comparison of seasonal results for the operational requirements simulations

This appendix presents supplemental figures and tables for Section 3, showing all seasons. Definitions of the operational requirements shown in the figures and tables are the same as in Sections 2 and 3, as is discussion of the methodology used for the simulations

The figures and graphs in this appendix follow the conventions noted in Sections 2 and 3 of the report. In the figures, the hourly results are represented as typical "stock" or "whisker" charts. The two ends of the line represents the range (minimum, maximum) of the results and the bar shows the average ± one standard deviation. Red bars and lines refer to the 2012 simulations; Blue bars and lines refer to the 2006 simulations.

In all instances, references to the operational requirements in 2006 refer to the *simulated* operational requirements for the base year. Also, the results reported in the following tables and figures as *maximums* are the 95th percentile occurrence for a particular hour.[1]

[1] That is, excluding the 5% highest results from the simulations.

Figure A-1: Regulation Up Capacity Requirements by Hour of Day, All Seasons

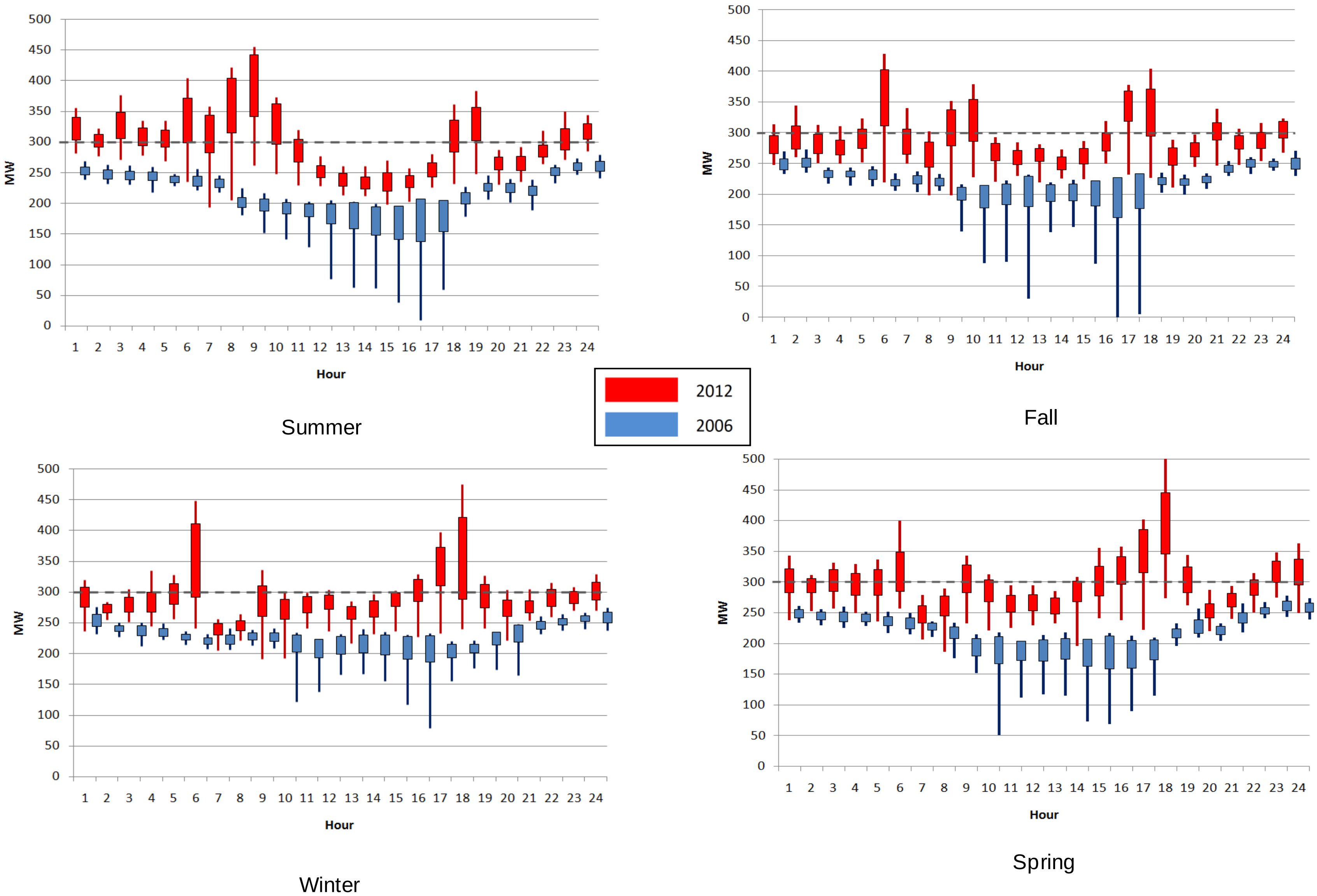


Figure A-2: Regulation Down Capacity Requirements by Hour of Day, All Seasons

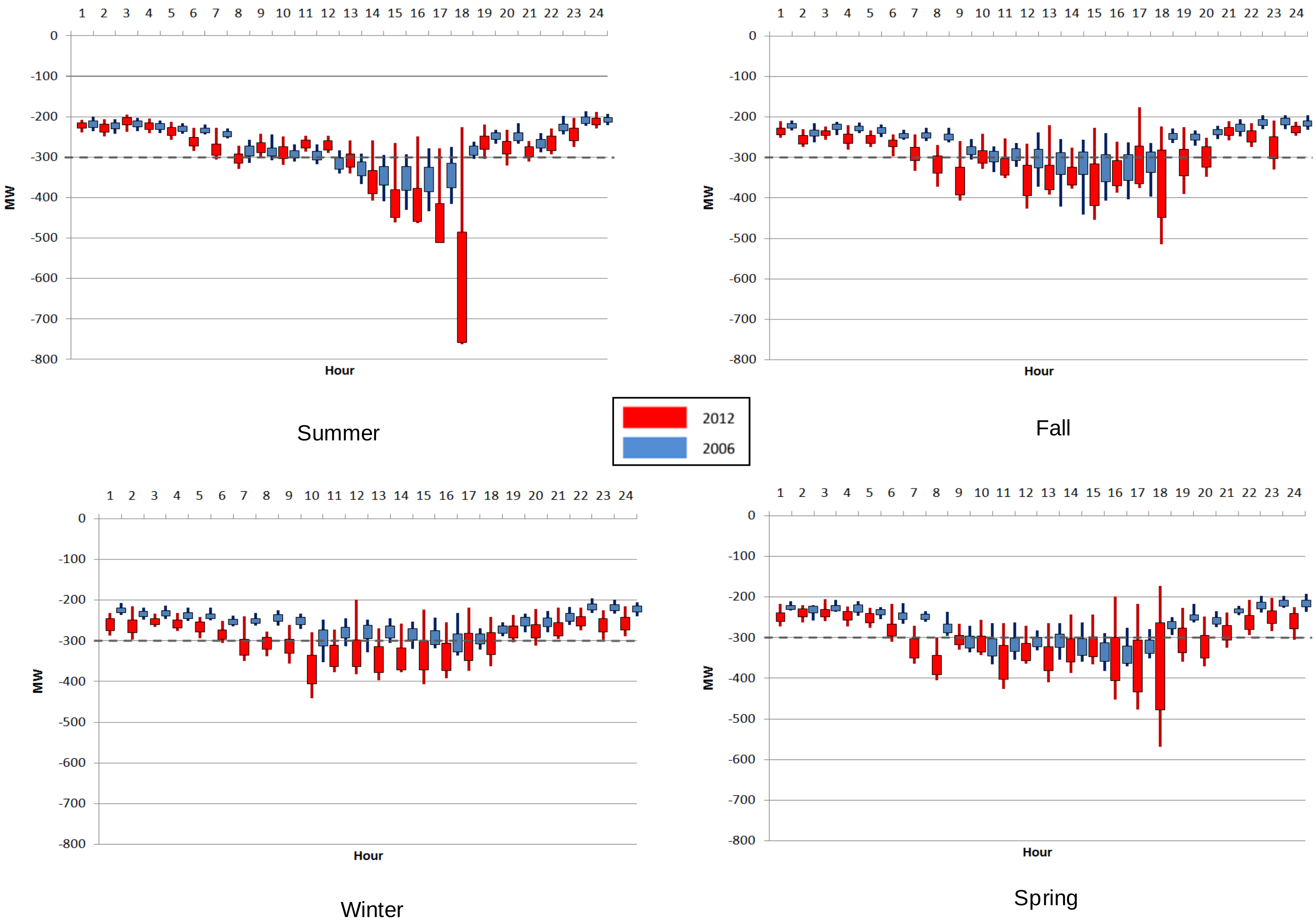


Figure A-3: Load Following Up Capacity Requirements by Hour of Day, All Seasons

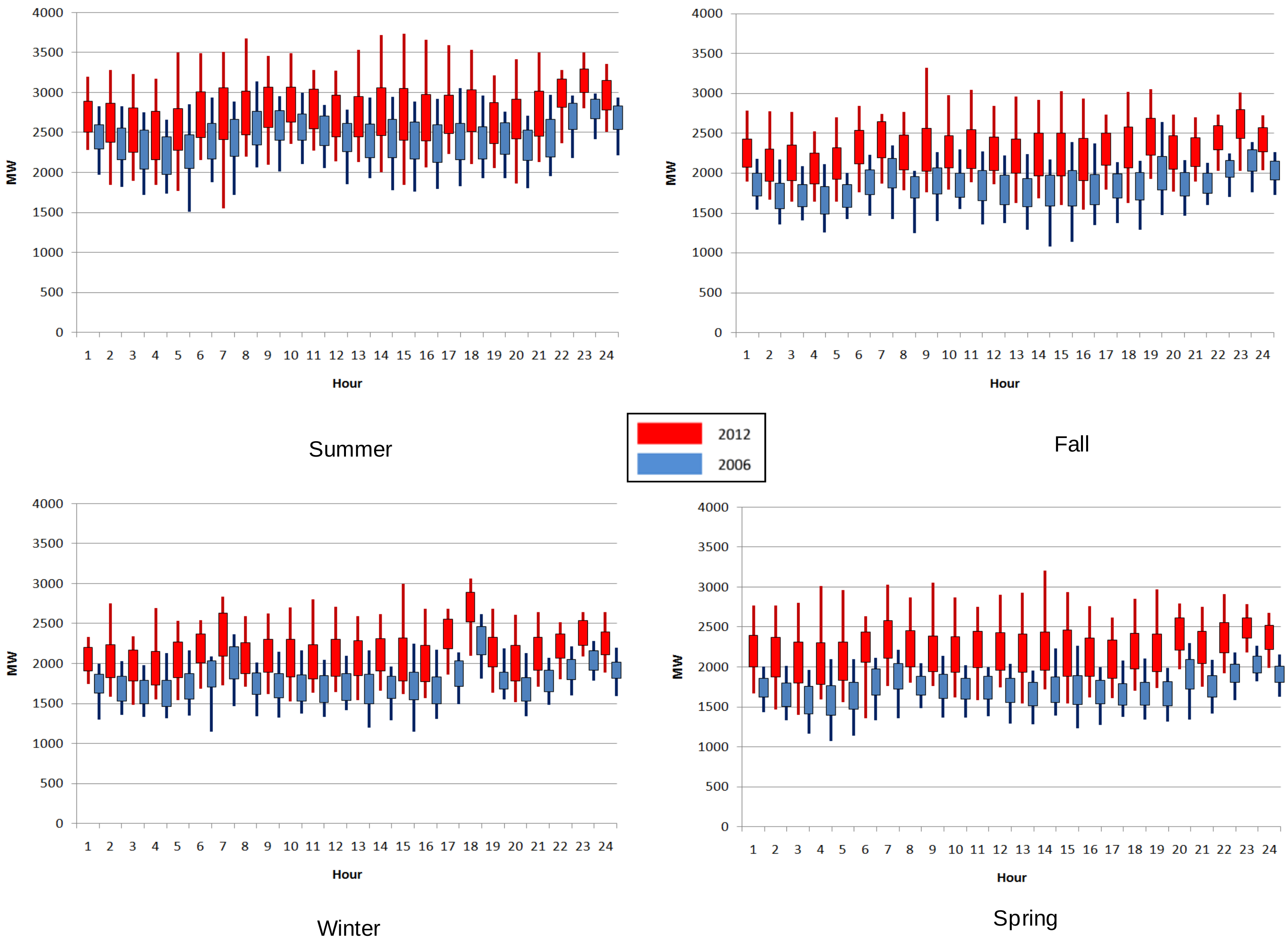


Figure A-4: Load Following Down Hourly Capacity Requirements by Hour of Day, All Seasons

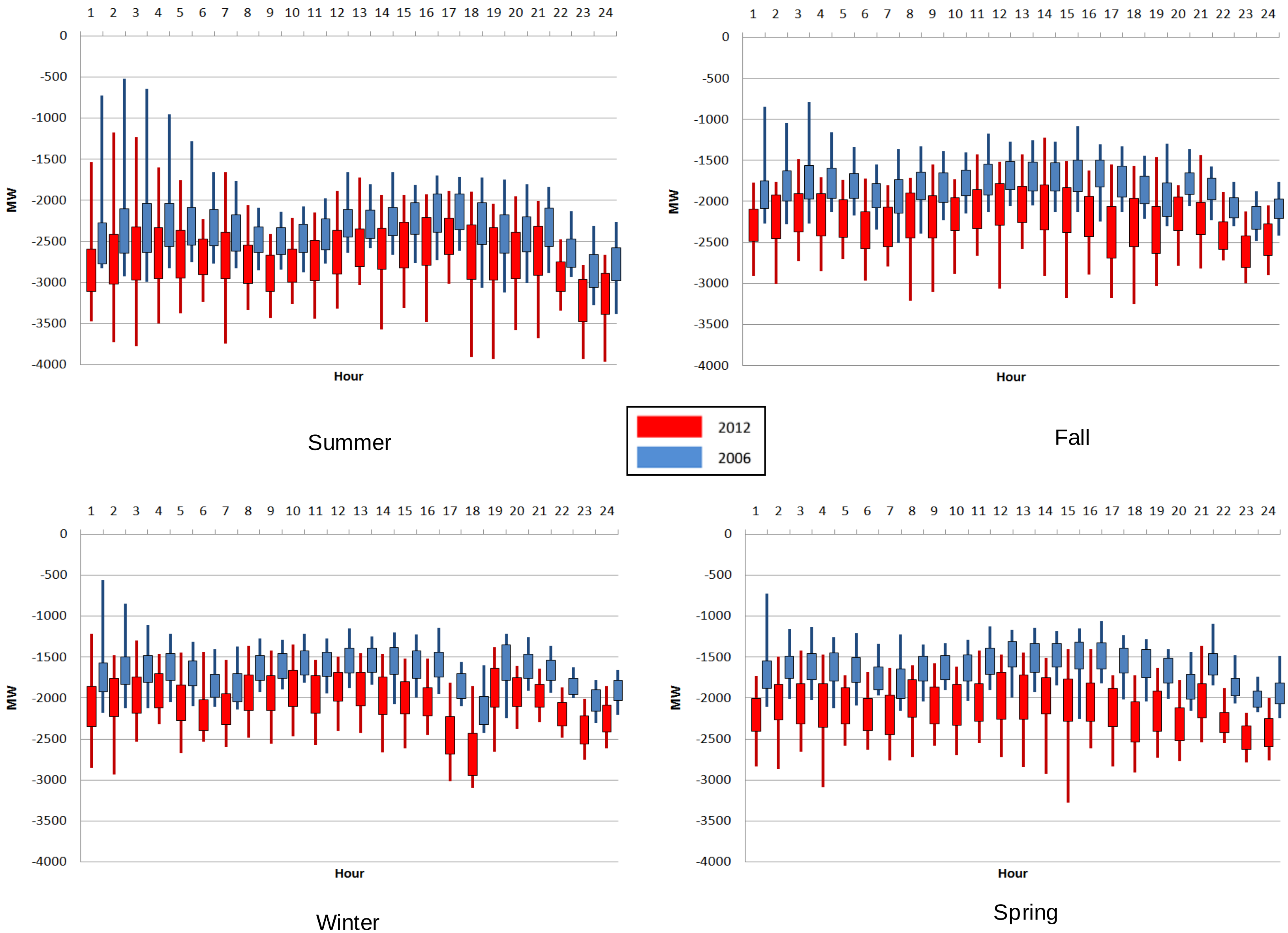


Figure A-5: Regulation Up Capacity, Frequency Distribution of Hourly Maximum Values across the Season, All Seasons

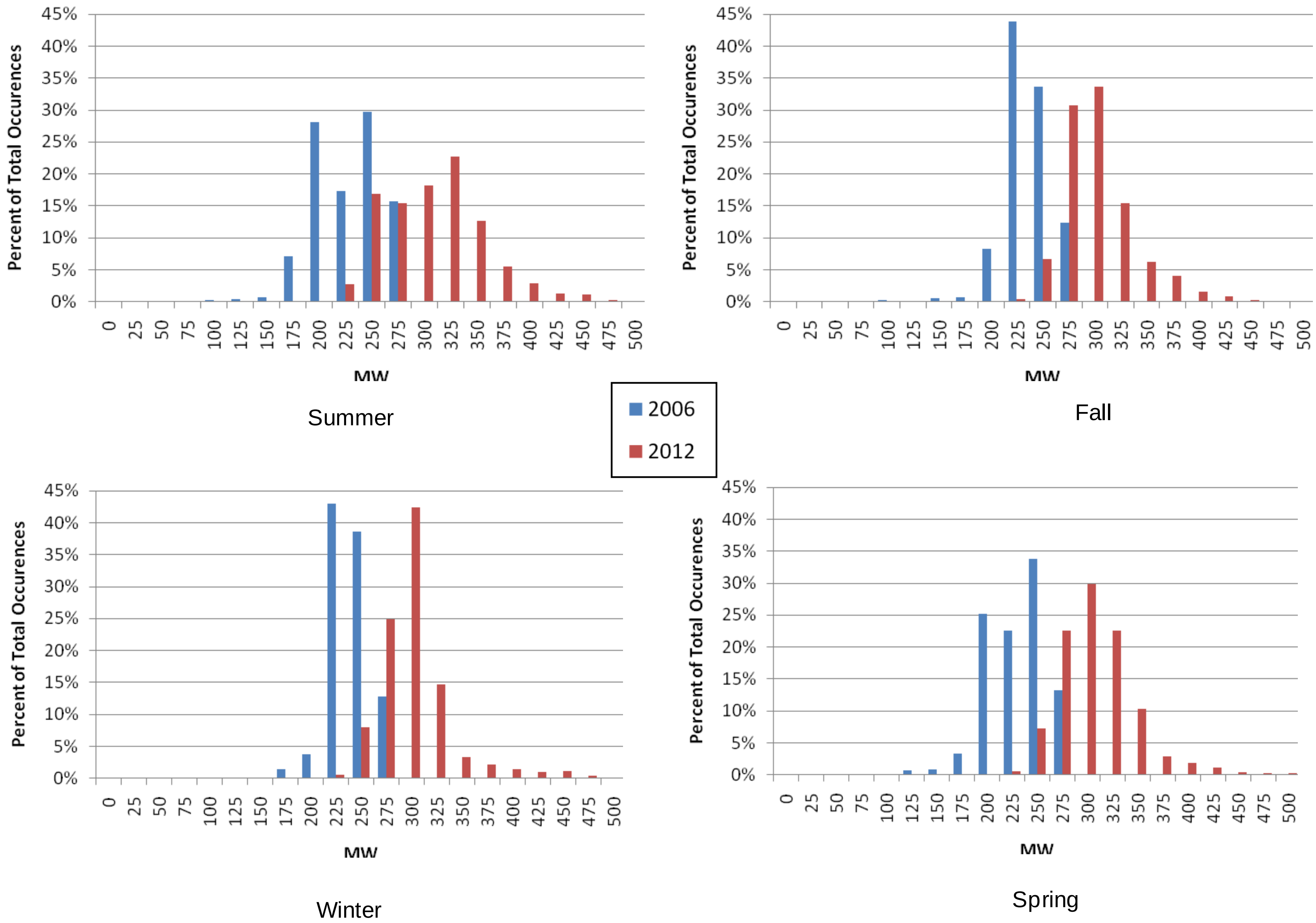


Figure A-6: Regulation Down Capacity, Frequency Distribution of Hourly Maximum Values across the Season, All Seasons

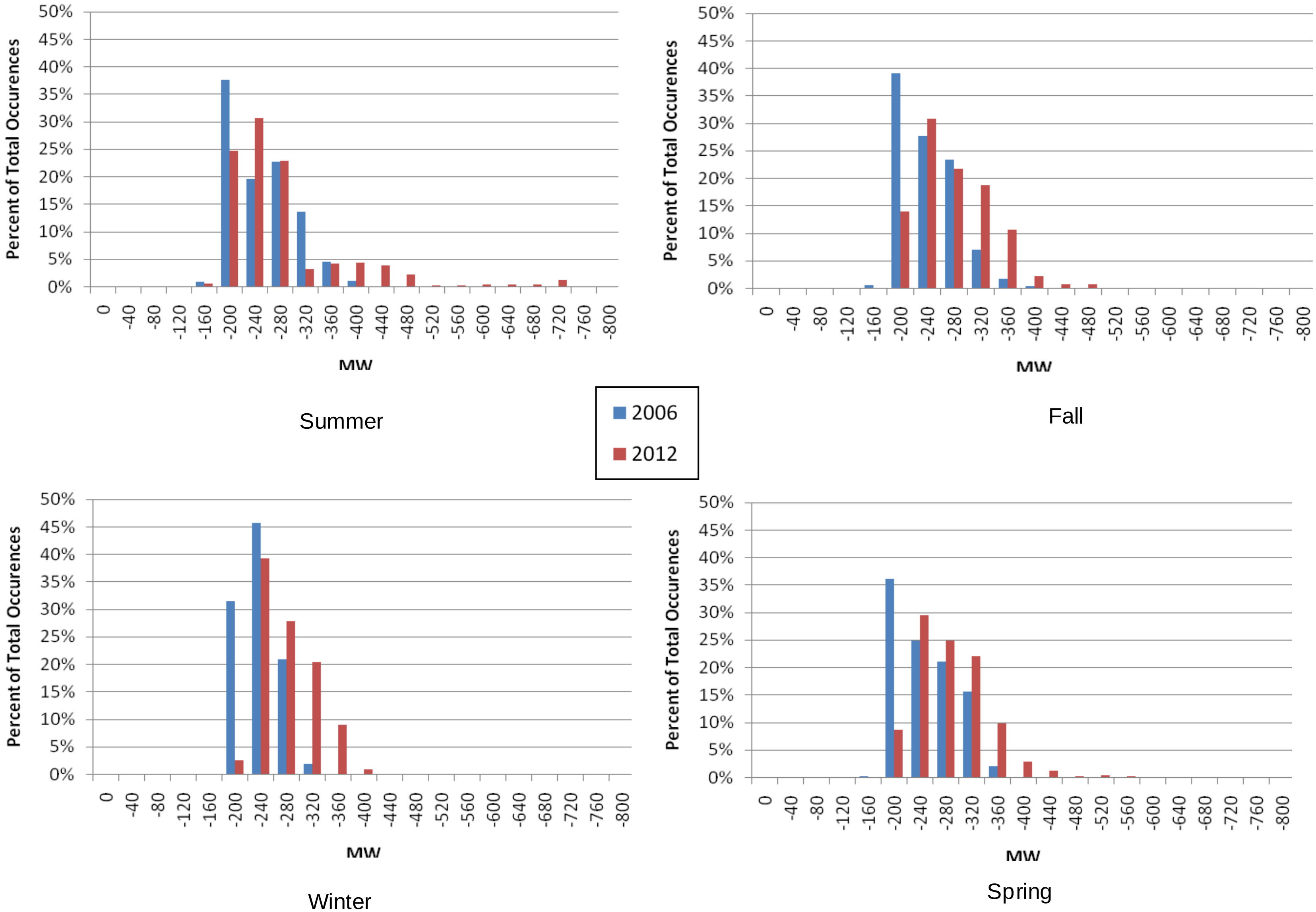


Figure A-7: Load Following Up Capacity, Frequency Distribution of Hourly Maximum Values across the Season, All Seasons

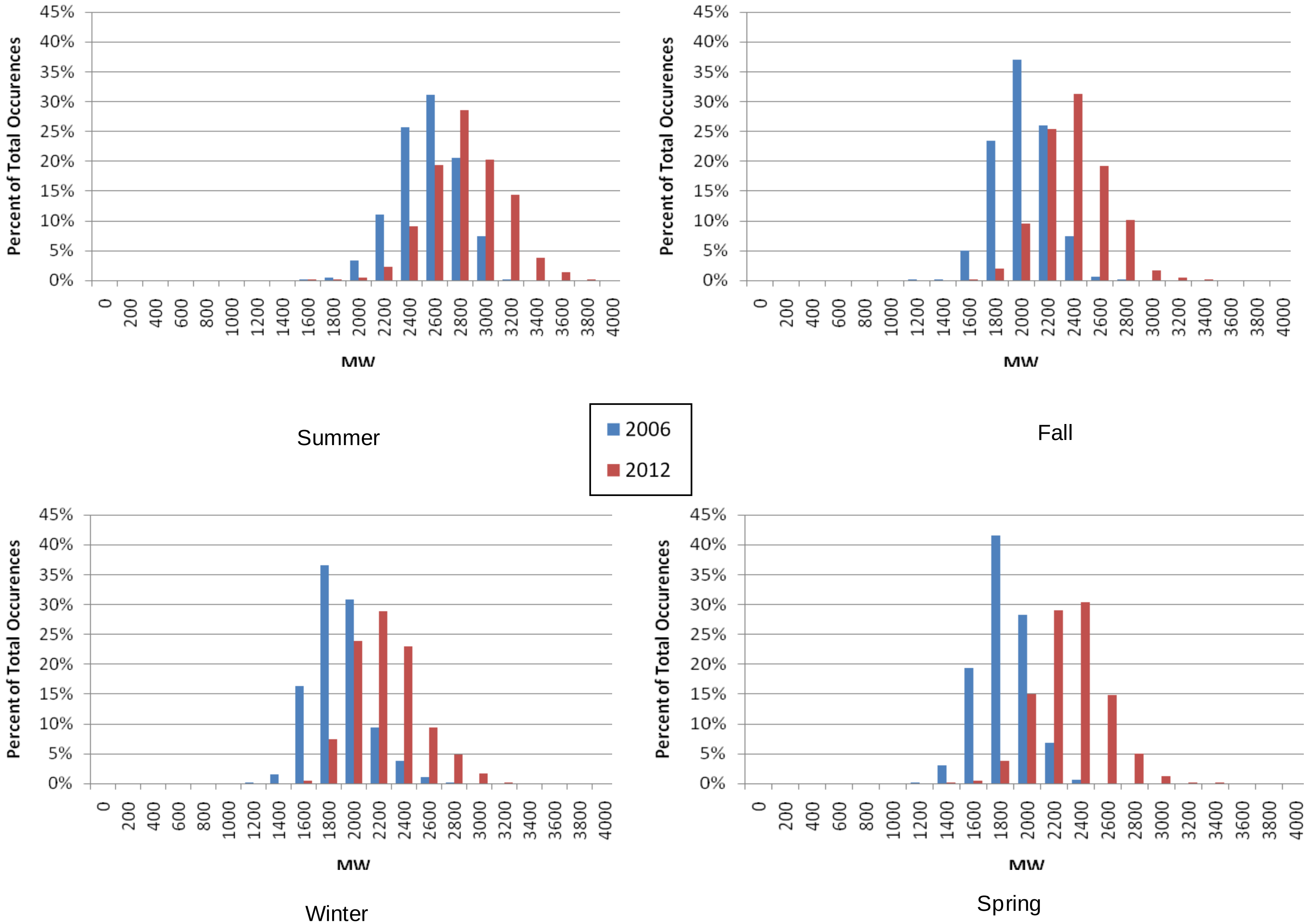


Figure A-8: Load Following Down Capacity, Frequency Distribution of Hourly Maximum Values across the Season, All Seasons

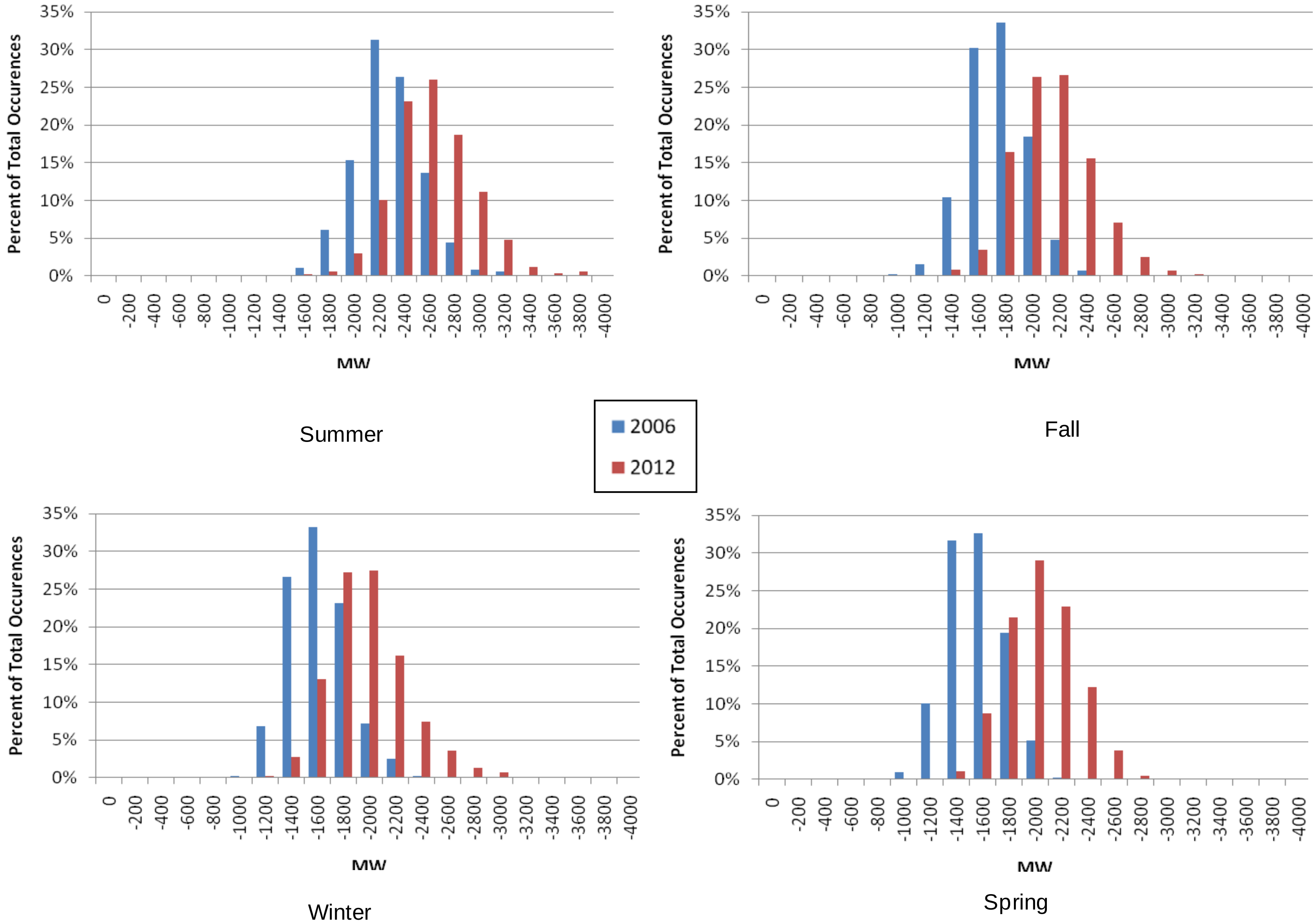


Table A-1: Spring Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 1-12

	1	2	3	4	5	6	7	8	9	10	11	12
Maximum load-following up capacity (MW) – 2012	2,767	2,773	2,801	3,012	2,968	2,639	3,030	2,871	3,055	2,873	2,755	2,901
Maximum load-following up capacity (MW) – 2006	1,999	2,008	1,963	2,091	2,093	2,109	2,207	2,046	2,132	2,013	1,991	2,036
Maximum load-following down capacity (MW) – 2012	(2,836)	(2,868)	(2,654)	(3,088)	(2,580)	(2,630)	(2,765)	(2,723)	(2,581)	(2,698)	(2,548)	(2,722)
Maximum load-following down capacity (MW) – 2006	(2,100)	(1,999)	(2,019)	(2,117)	(2,082)	(1,958)	(2,145)	(2,038)	(1,893)	(2,029)	(1,895)	(1,988)
Maximum Regulation Up capacity (MW) – 2012	343	311	331	329	336	399	279	289	342	312	294	294
Maximum Regulation Up capacity (MW) – 2006	260	255	259	251	251	249	234	233	214	217	202	213
Maximum Regulation Down capacity (MW) – 2012	(273)	(263)	(259)	(273)	(277)	(311)	(364)	(406)	(330)	(343)	(426)	(365)
Maximum Regulation Down capacity (MW) – 2006	(233)	(258)	(236)	(245)	(255)	(265)	(261)	(295)	(336)	(366)	(354)	(331)

Table A-2: Spring Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 13-24

	13	14	15	16	17	18	19	20	21	22	23	24
Maximum load-following up capacity (MW) – 2012	2,928	3,207	2,942	2,762	2,621	2,857	2,976	2,794	2,752	2,918	2,788	2,678
Maximum load-following up capacity (MW) – 2006	1,953	2,228	2,259	1,991	2,079	2,102	1,987	2,292	2,088	2,175	2,260	2,148
Maximum load-following down capacity (MW) – 2012	(2,845)	(2,926)	(3,275)	(2,614)	(2,838)	(2,910)	(2,731)	(2,771)	(2,542)	(2,548)	(2,782)	(2,761)
Maximum load-following down capacity (MW) – 2006	(1,922)	(1,840)	(2,246)	(1,816)	(2,012)	(2,030)	(2,004)	(2,148)	(1,834)	(2,061)	(2,166)	(2,239)
Maximum Regulation Up capacity (MW) – 2012	286	309	356	358	402	502	344	287	293	315	348	363
Maximum Regulation Up capacity (MW) – 2006	217	205	215	212	209	232	255	232	264	266	277	272
Maximum Regulation Down capacity (MW) – 2012	(410)	(387)	(366)	(452)	(476)	(569)	(359)	(371)	(325)	(294)	(284)	(305)
Maximum Regulation Down capacity (MW) – 2006	(353)	(359)	(382)	(371)	(350)	(293)	(263)	(273)	(245)	(237)	(226)	(236)

Table A-3: Summer Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 1-12

	1	2	3	4	5	6	7	8	9	10	11	12
Maximum load-following up capacity (MW) – 2012	3,198	3,285	3,234	3,174	3,500	3,496	3,507	3,675	3,461	3,491	3,281	3,278
Maximum load-following up capacity (MW) – 2006	2,826	2,823	2,752	2,663	2,854	2,933	2,888	3,140	2,948	2,993	2,845	2,782
Maximum load-following down capacity (MW) – 2012	(3,473)	(3,727)	(3,774)	(3,496)	(3,372)	(3,238)	(3,745)	(3,333)	(3,432)	(3,258)	(3,438)	(3,316)
Maximum load-following down capacity (MW) – 2006	(2,810)	(2,911)	(2,972)	(2,809)	(2,743)	(2,752)	(2,814)	(2,838)	(2,830)	(2,862)	(2,754)	(2,624)
Maximum Regulation Up capacity (MW) – 2012	355	321	376	334	334	404	357	421	455	373	319	276
Maximum Regulation Up capacity (MW) – 2006	268	263	261	259	248	256	245	224	216	207	202	204
Maximum Regulation Down capacity (MW) – 2012	(238)	(249)	(237)	(241)	(257)	(285)	(306)	(329)	(304)	(320)	(286)	(291)
Maximum Regulation Down capacity (MW) – 2006	(236)	(243)	(236)	(241)	(242)	(245)	(254)	(315)	(308)	(312)	(318)	(340)

Table A-4: Summer Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 13-24

	13	14	15	16	17	18	19	20	21	22	23	24
Maximum load-following up capacity (MW) – 2012	3,538	3,718	3,737	3,661	3,592	3,535	3,213	3,415	3,502	3,286	3,505	3,362
Maximum load-following up capacity (MW) – 2006	2,933	2,944	2,883	2,916	3,053	2,964	2,757	2,712	2,969	2,960	2,986	2,937
Maximum load-following down capacity (MW) – 2012	(3,031)	(3,570)	(3,308)	(3,479)	(3,013)	(3,908)	(3,927)	(3,579)	(3,675)	(3,338)	(3,934)	(3,962)
Maximum load-following down capacity (MW) – 2006	(2,567)	(2,649)	(2,751)	(2,718)	(2,601)	(3,046)	(3,107)	(2,989)	(2,866)	(2,918)	(3,262)	(3,365)
Maximum Regulation Up capacity (MW) – 2012	260	261	270	257	280	361	383	287	291	319	350	344
Maximum Regulation Up capacity (MW) – 2006	202	198	191	198	201	226	244	239	238	262	273	278
Maximum Regulation Down capacity (MW) – 2012	(341)	(408)	(461)	(463)	(506)	(763)	(305)	(321)	(312)	(294)	(275)	(229)
Maximum Regulation Down capacity (MW) – 2006	(367)	(408)	(430)	(434)	(416)	(305)	(267)	(268)	(289)	(245)	(223)	(222)

Table A-5: Fall Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 1-12

	1	2	3	4	5	6	7	8	9	10	11	12
Maximum load-following up capacity (MW) – 2012	2,782	2,777	2,765	2,522	2,701	2,843	2,746	2,773	3,326	2,976	3,050	2,846
Maximum load-following up capacity (MW) – 2006	2,232	2,221	2,138	2,165	2,060	2,276	2,389	2,084	2,310	2,345	2,316	2,269
Maximum load-following down capacity (MW) – 2012	(2,904)	(3,004)	(2,724)	(2,845)	(2,699)	(2,960)	(2,794)	(3,210)	(3,103)	(2,879)	(2,661)	(3,058)
Maximum load-following down capacity (MW) – 2006	(2,268)	(2,280)	(2,275)	(2,132)	(2,171)	(2,344)	(2,509)	(2,396)	(2,228)	(2,145)	(2,129)	(2,058)
Maximum Regulation Up capacity (MW) – 2012	314	345	313	311	323	428	340	303	351	378	293	285
Maximum Regulation Up capacity (MW) – 2006	271	275	245	245	248	235	239	235	217	214	224	234
Maximum Regulation Down capacity (MW) – 2012	(252)	(275)	(257)	(281)	(274)	(297)	(333)	(372)	(407)	(328)	(352)	(427)
Maximum Regulation Down capacity (MW) – 2006	(233)	(263)	(244)	(240)	(249)	(256)	(259)	(263)	(304)	(335)	(323)	(371)

Table A-6: Fall Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 13-24

	13	14	15	16	17	18	19	20	21	22	23	24
Maximum load-following up capacity (MW) – 2012	2,959	2,917	3,027	2,938	2,735	3,017	3,056	2,733	2,699	2,740	3,011	2,726
Maximum load-following up capacity (MW) – 2006	2,287	2,225	2,432	2,418	2,185	2,209	2,680	2,216	2,185	2,294	2,433	2,314
Maximum load-following down capacity (MW) – 2012	(2,579)	(2,904)	(3,176)	(2,890)	(3,172)	(3,247)	(3,031)	(2,787)	(2,820)	(2,720)	(2,992)	(2,894)
Maximum load-following down capacity (MW) – 2006	(2,048)	(2,132)	(2,133)	(2,249)	(2,131)	(2,217)	(2,307)	(2,060)	(2,232)	(2,305)	(2,482)	(2,420)
Maximum Regulation Up capacity (MW) – 2012	281	273	286	319	378	404	288	297	339	307	316	323
Maximum Regulation Up capacity (MW) – 2006	221	225	222	217	232	236	233	236	256	262	259	272
Maximum Regulation Down capacity (MW) – 2012	(392)	(377)	(454)	(388)	(376)	(515)	(390)	(347)	(257)	(275)	(329)	(247)
Maximum Regulation Down capacity (MW) – 2006	(420)	(440)	(406)	(402)	(395)	(263)	(270)	(254)	(248)	(230)	(230)	(232)

Table A-7: Winter Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 1-12

	1	2	3	4	5	6	7	8	9	10	11	12
Maximum load-following up capacity (MW) – 2012	2,338	2,753	2,344	2,698	2,532	2,541	2,838	2,598	2,631	2,700	2,803	2,710
Maximum load-following up capacity (MW) – 2006	1,999	2,037	1,984	2,132	2,171	2,095	2,370	2,015	2,153	2,168	2,048	2,097
Maximum load-following down capacity (MW) – 2012	(2,849)	(2,934)	(2,533)	(2,324)	(2,669)	(2,533)	(2,598)	(2,480)	(2,554)	(2,468)	(2,574)	(2,398)
Maximum load-following down capacity (MW) – 2006	(2,176)	(2,124)	(2,120)	(2,051)	(2,095)	(2,107)	(2,138)	(1,926)	(1,897)	(1,813)	(1,940)	(1,875)
Maximum Regulation Up capacity (MW) – 2012	319	284	304	334	327	448	255	263	335	300	298	302
Maximum Regulation Up capacity (MW) – 2006	274	249	249	248	235	230	240	237	240	233	222	231
Maximum Regulation Down capacity (MW) – 2012	(288)	(298)	(265)	(277)	(293)	(306)	(349)	(338)	(357)	(442)	(378)	(383)
Maximum Regulation Down capacity (MW) – 2006	(237)	(248)	(246)	(251)	(249)	(264)	(262)	(263)	(270)	(353)	(314)	(327)

Table A-8: Winter Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 13-24

	13	14	15	16	17	18	19	20	21	22	23	24
Maximum load-following up capacity (MW) – 2012	2,597	2,619	3,000	2,688	2,689	3,063	2,683	2,608	2,646	2,516	2,647	2,647
Maximum load-following up capacity (MW) – 2006	2,171	1,965	2,256	2,175	2,146	2,624	2,193	2,131	2,071	2,222	2,285	2,201
Maximum load-following down capacity (MW) – 2012	(2,424)	(2,666)	(2,613)	(2,448)	(3,013)	(3,094)	(2,655)	(2,380)	(2,298)	(2,482)	(2,754)	(2,612)
Maximum load-following down capacity (MW) – 2006	(1,837)	(2,069)	(1,989)	(1,947)	(2,097)	(2,424)	(2,244)	(1,907)	(1,934)	(1,998)	(2,303)	(2,204)
Maximum Regulation Up capacity (MW) – 2012	284	296	302	328	397	474	326	303	304	315	308	329
Maximum Regulation Up capacity (MW) – 2006	238	234	229	232	219	220	233	247	260	263	265	273
Maximum Regulation Down capacity (MW) – 2012	(397)	(377)	(407)	(391)	(374)	(363)	(304)	(313)	(296)	(274)	(297)	(289)
Maximum Regulation Down capacity (MW) – 2006	(306)	(320)	(319)	(336)	(322)	(289)	(280)	(279)	(261)	(232)	(233)	(240)

APPENDIX A-2: Additional sensitivity results from the operational requirements simulations

This appendix provides additional sensitivity results from the operational requirements simulations. As noted in Section 3, these include:

- Requirements by renewable technology, in which the simulations are re-run with and without particular technologies to distinguish the impact of incremental solar resources only, incremental wind resources only, and the full renewable portfolio; and the

- Impact of forecast error and variability, in which the simulations are re-run to distinguish the differential effect of these factors.

As with Section 3, the focus in this appendix is on Summer 2012 results; showing one season of such results is sufficient to characterize the relationships among the variables being analyzed.

The figures and graphs in this appendix follow the conventions noted in Sections 2 and 3 of the report. In all instances, references to the operational requirements in 2006 refer to the *simulated* operational requirements for the base year. Also, the results reported in the following tables and figures as *maximums* are the 95th percentile occurrence for a particular hour.[2]

A.1 Load Following Results for Summer 2012

A.1.1 Requirements by renewable technology

As noted in Section 2, the impact of variable energy resources can be differentiated by technology using the statistical simulation methodology. The results of such sensitivity analyses are presented here to show the relative impact of load and each renewable technology being modeled on load following by hour. The difference between wind and solar is in part a function of the capacity of each technology type in the portfolio (i.e., how much energy is being obtained in each hour from each technology), and also of their particular variability and forecast error characteristics. The results are not intended to be indicative of how to construct a renewable portfolio to minimize operational impacts; that is, there is not sufficient information in these results to determine how to isolate the relative impacts of wind and solar across all the operational requirements. As with the results shown above, the results here assume all forecast errors.

Figures A-9 and A-10 show the hourly maximum results due to (a) load, (b) load plus solar, (c) load plus wind, and (d) load plus wind plus solar. Obviously, in the off-peak hours, wind is the driver of the incremental operational requirements.

[2] That is, excluding the 5% highest results from the simulations.

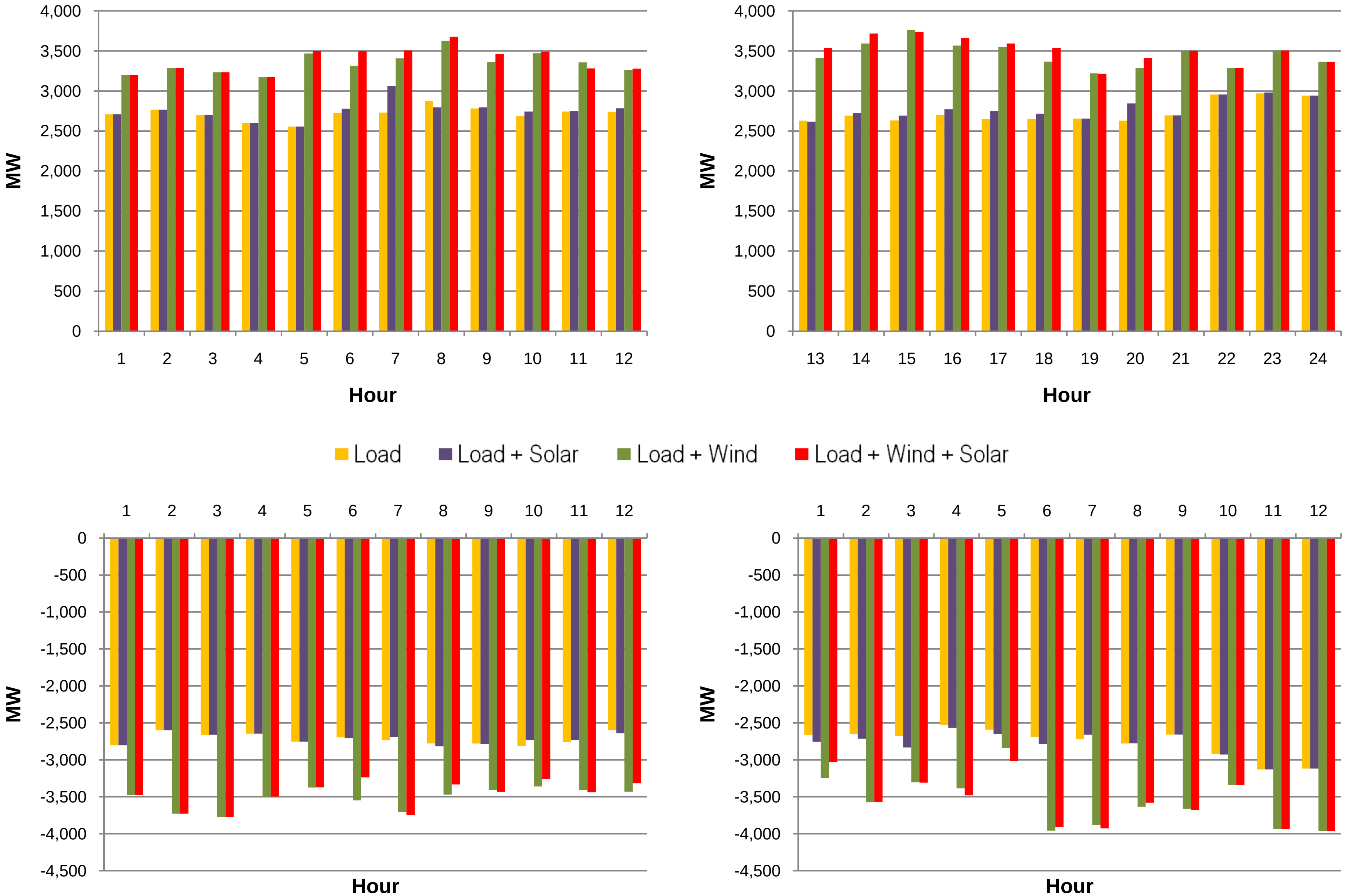


Figure A-9: 2012 Summer Load Following Maximum Hourly Requirement by Technology

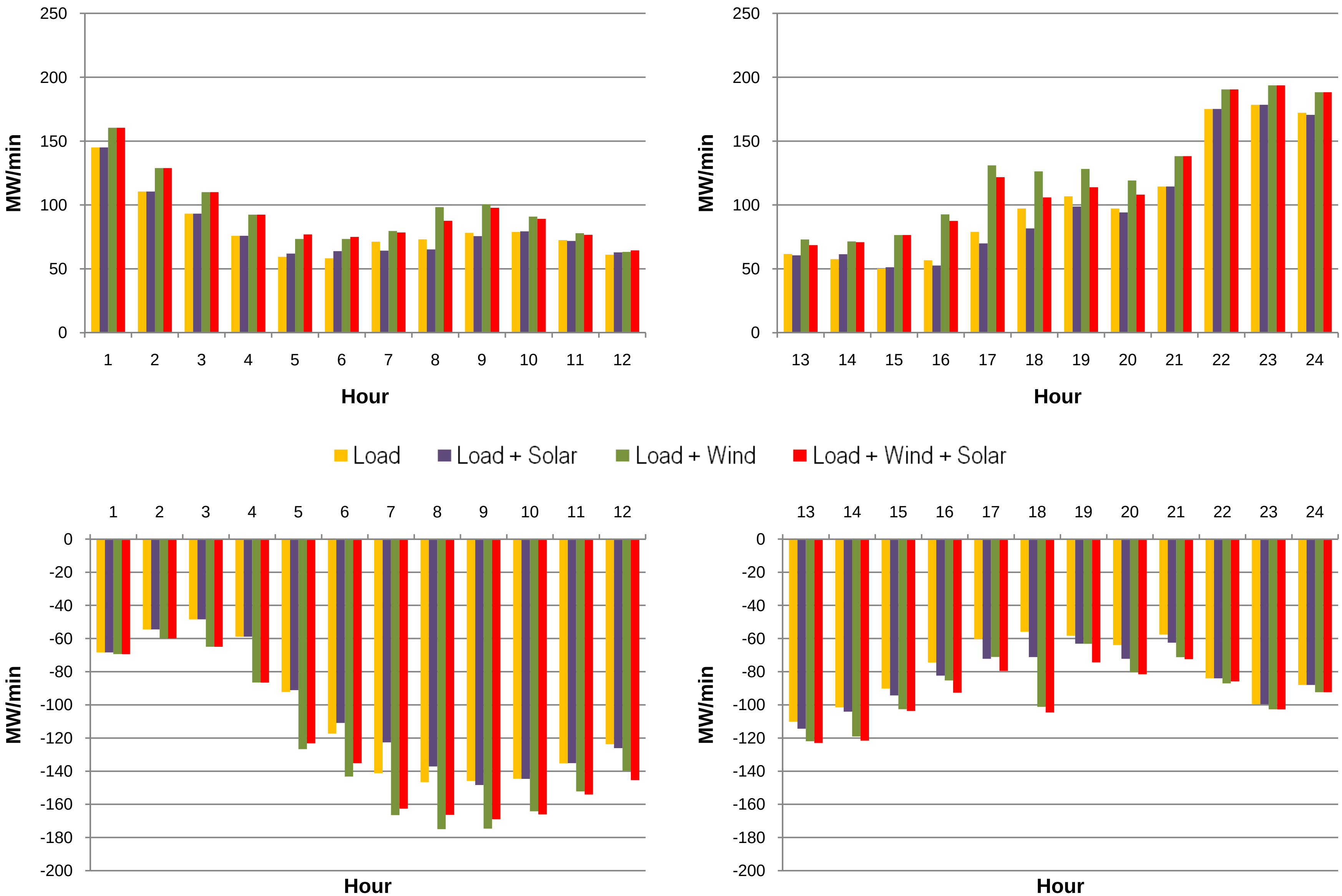


Figure A-10: 2012 Summer Load Following Up and Down Maximum Hourly Ramp Rate by Technology

A.1.2 Impact of forecast error and variability

In the hour-ahead time frame, forecast error is the more significant contributor to incremental load following requirements due to variable energy resources than their inherent variability. As noted, the simulation can take account of this difference by altering the statistical parameters of the distribution of forecast errors – including removing them altogether, at which point the residual impact on load following is due to variability alone. For comparison, this section compares the results of including all forecast errors and no errors; specific improvements in forecast errors were not evaluated in this study but will be explored in subsequent analysis.

The two components of Figure A-11shows an aggregate “all hours” result that compares the load following up and down MW calculated in each hour with and without errors for all hours in the season. The aggregate quantity without errors is presented as a proportion of the aggregate quantity with errors. As shown, in each case, variability contributes 19 percent of the total requirement, with forecast errors providing the remaining 81 percent. Figures A-12 and A-13 then show this result by operating hour. The hourly result shows in which hours improvements in forecasting are likely to provide the highest benefit.

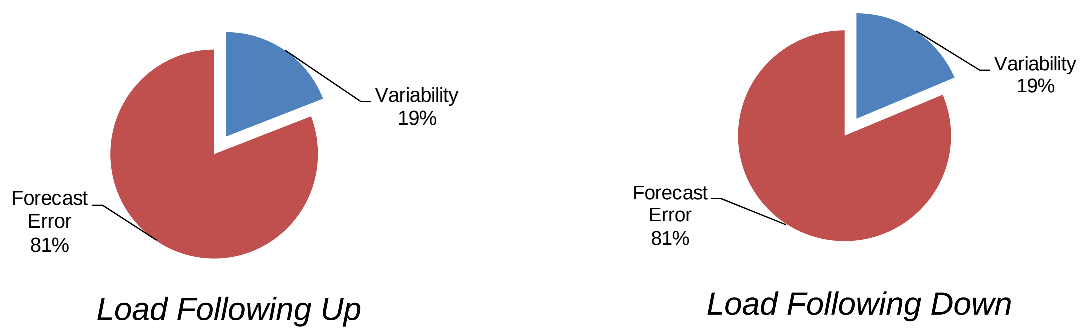


Figure A-11: Aggregate Contribution of Variability and Forecast Error to the Summer 2012 Load Following Requirement

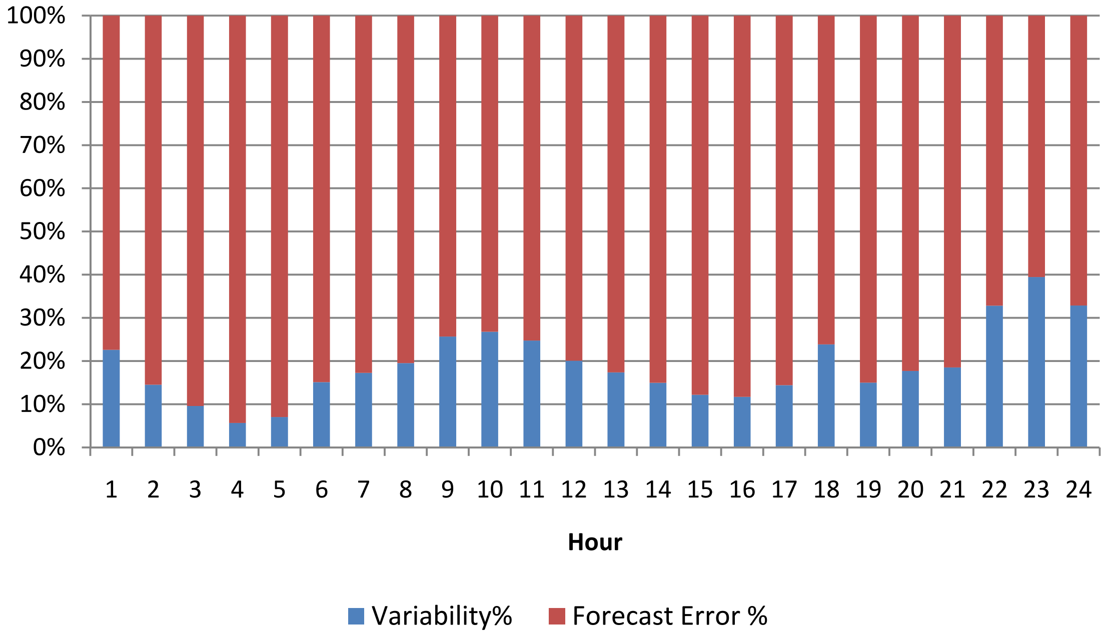


Figure A-12: Effect of Forecast Error and Variability on Load Following Up (Load & Wind & Solar) by Hour, Summer 2012

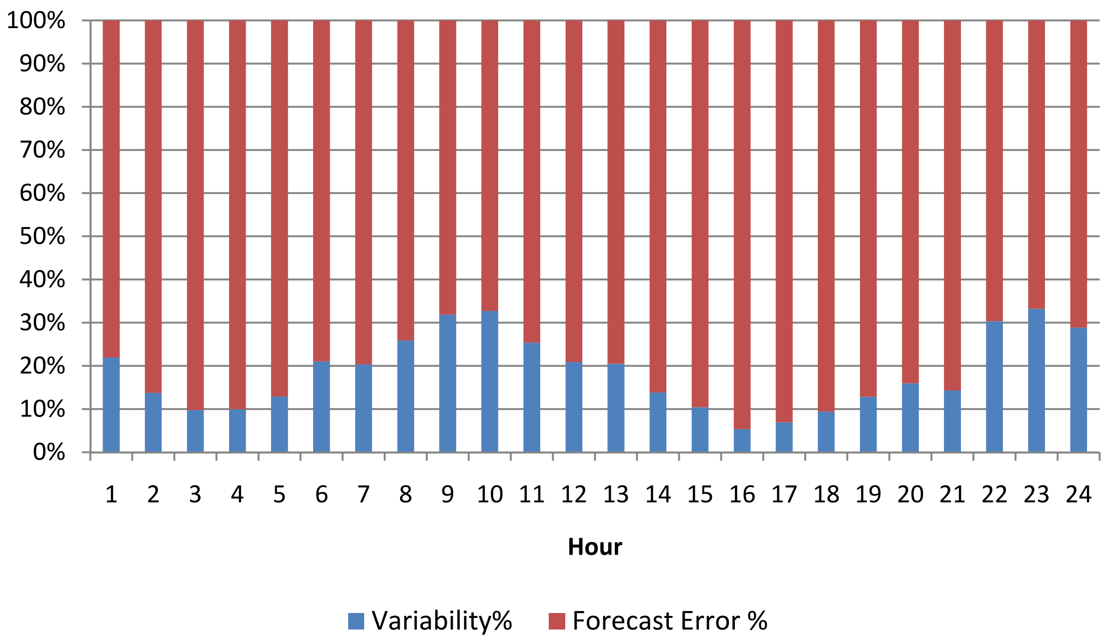


Figure A-14: Effect of Forecast Error and Variability on Load Following Down (Load & Wind & Solar) by Hour, Summer 2012

A further representation of this result is shown in Figure A-14, which compares the maximum load following capacity results for load-only requirements assuming all (load forecast) errors to portfolio requirements with wind and solar forecast errors eliminated and then to portfolio requirements with wind and solar forecast errors included.

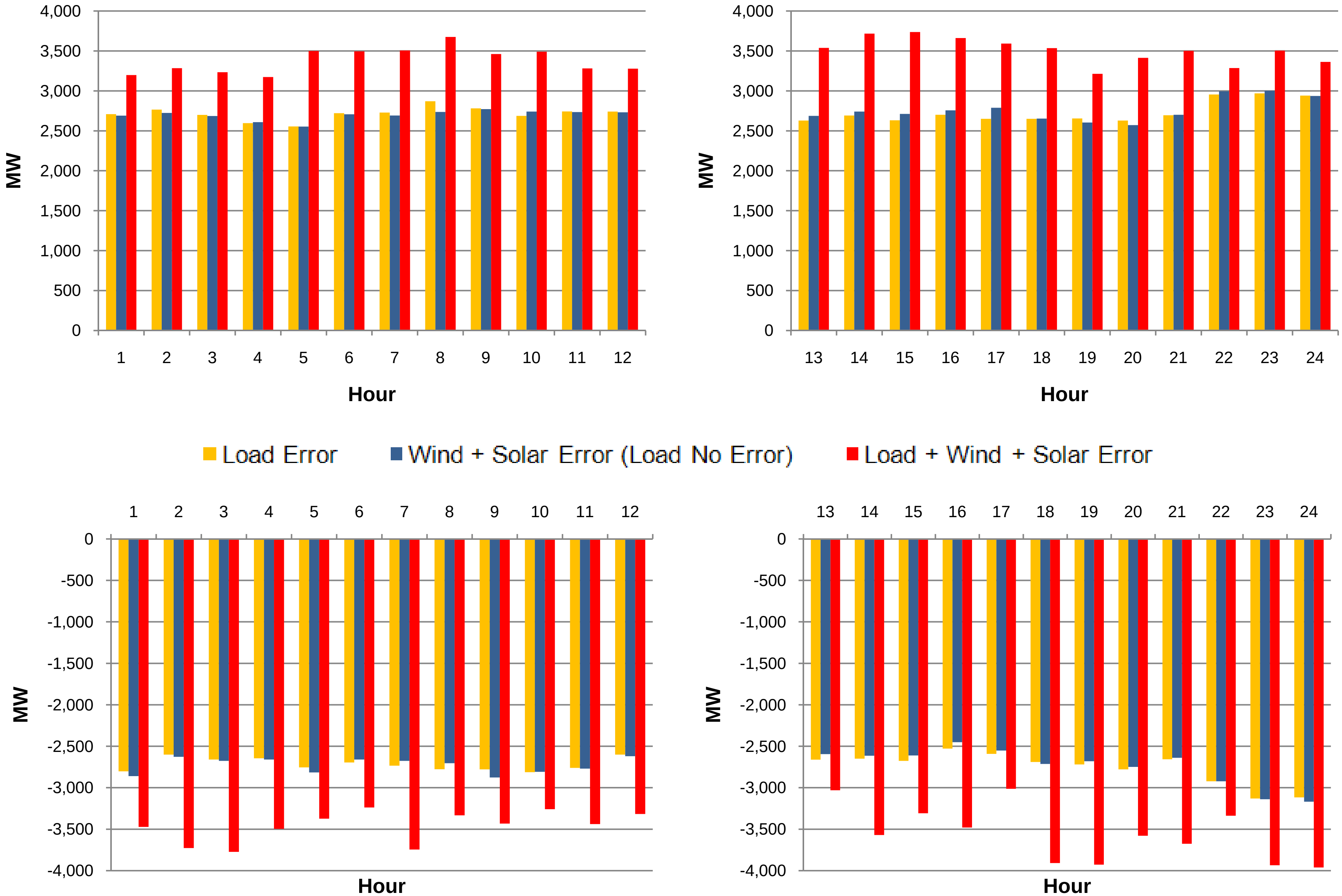


Figure A-13: Maximum Hourly Load-Following Capacity Requirement with Variations in Forecast Error Assumptions

The sensitivity analysis of forecast error provides a quantitative measure of how improvements in the hour-ahead forecast (and hence in periods further forward in time) can reduce the ramp range that the ISO will need to deploy within the hour. A 10 percent improvement in forecast error could result in a reduction in several hundred MW of load following capability in the upward and downward direction. The results point to the particular hours – morning and evening ramps – where such forecast improvements would have the most value. However, the ISO has not in this study quantified specific reductions in forecast error or the potential dispatch cost reductions. Subsequent studies may provide such information.

A.2 Regulation Results for Summer 2012

A.2.1 Requirements by renewable technology

As with load following, the impact of variable energy resources on regulation can be differentiated by technology using the statistical simulation methodology. These sensitivity results are presented here to show the relative impact of load and each renewable technology (at the capacity being modeled) on regulation by hour. Again, the results are not intended to be indicative of how to construct a renewable portfolio to minimize operational impacts. The results here assume all forecast errors and variability for load, but only the variability data captured for wind and solar. Hence, the results are not indicative of how variable energy resource forecast error affects the operational requirements in this time frame.

Figure A-15 shows the hourly maximum Regulation capacity results with sensitivity cases that model (a) load only for 2012, (b) load plus solar, (c) load plus wind, and, finally, (d) load plus wind plus solar, which is the case shown in Section 3. The results show that wind resources largely drive the increases in regulation up requirements in the morning hours, while solar resources barely increase those requirements compared to the load-only case. In the afternoon hours, solar resources drive additional requirements in the mid-afternoon hours, when wind is hardly creating any additional requirements until hours 18-19. For regulation down, solar has a more significant effect than wind in Hours 8-9, then wind significantly drives the maximum requirements in the mid-afternoon, with a peak in Hour 18. Figure A-16 shows these comparative results for the hourly maximum results for Regulation ramp rates.

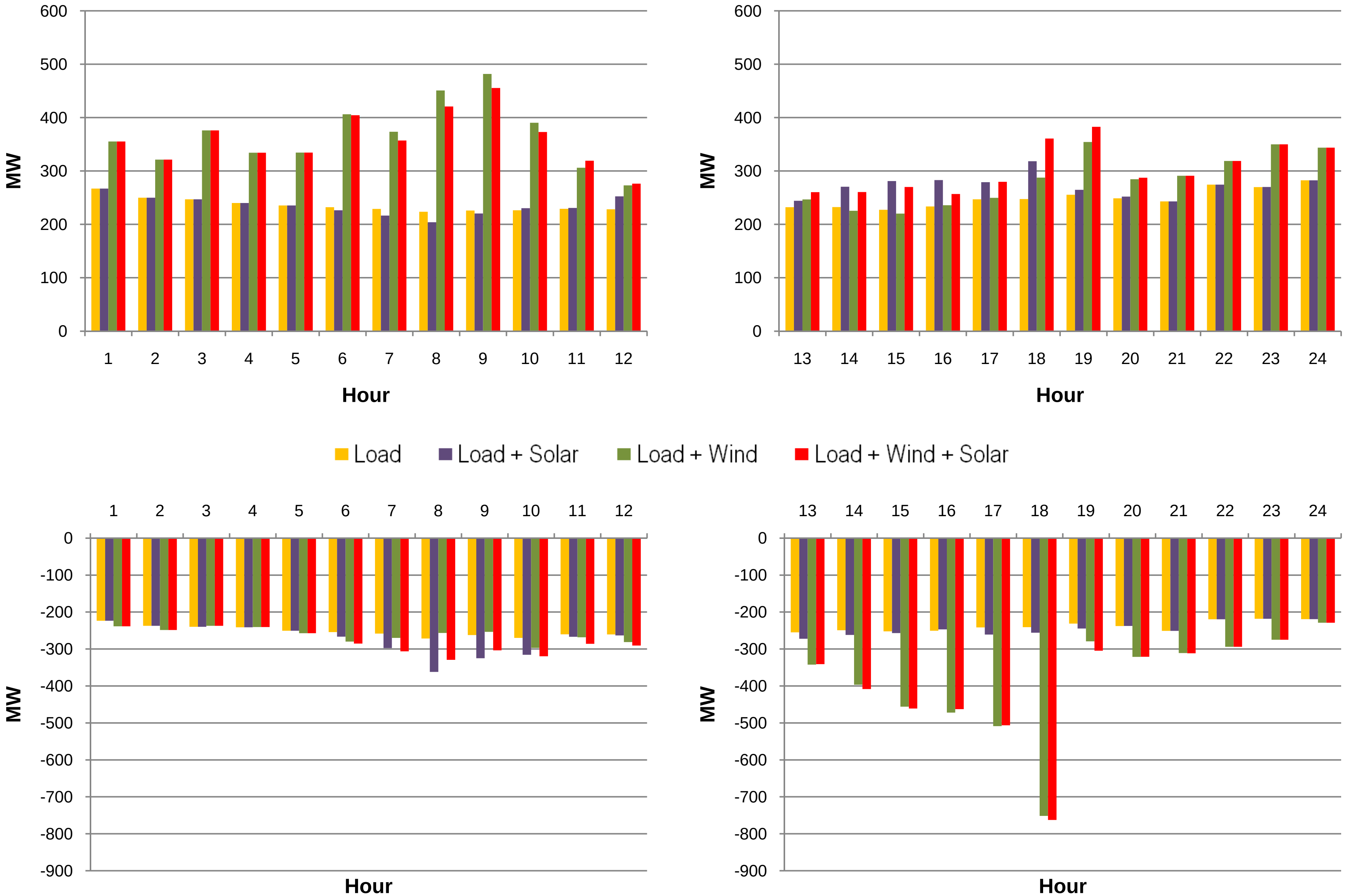


Figure A-14: Regulation Capacity Requirements by Technology by Hour, Summer 2012

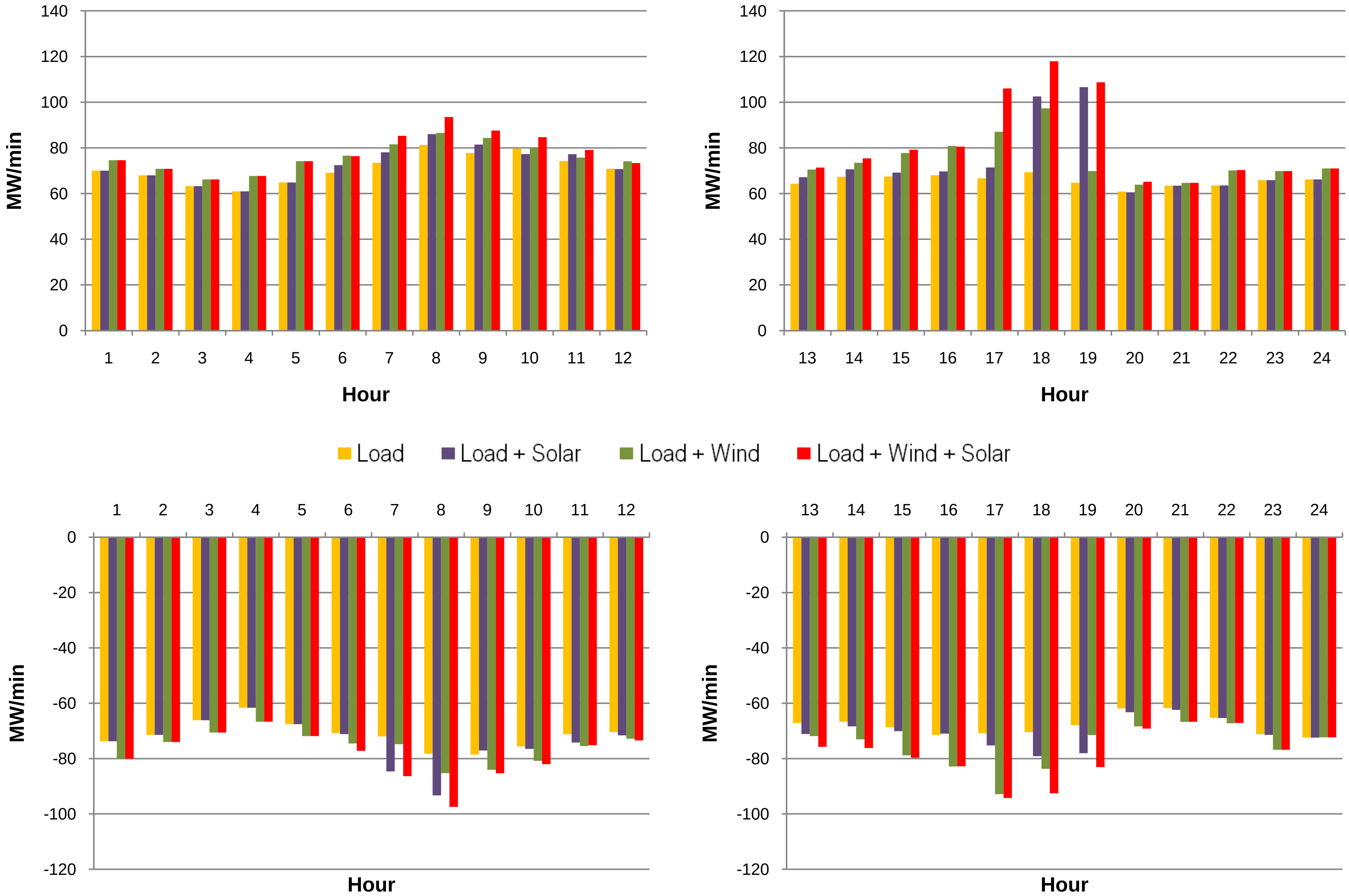


Figure A-15: Summer 2012 Regulation Ramp Rate by Technology

A.2.2 Impact of forecast error and variability

In the hour-ahead time frame, variability is the more significant contributor to the incremental regulation requirements due to variable energy resources than forecast error. However, unlike the load following simulation, the model does not include short-term forecast errors for wind and solar resources; in current practice, the ISO uses a persistence forecast for short-term dispatch, which was not sampled by the Monte Carlo simulation but rather held static in the analysis. Hence, only load forecast errors are evaluated when isolating forecast error from variability, and the impact of wind and solar resources on Regulation is based entirely on their variability within the five-minute dispatch interval.

Figure A-17 shows an aggregate "all hours" result that compares the regulation up and down MW calculated in each hour with and without errors for all hours in the season. The aggregate quantity without errors is presented as a proportion of the aggregate quantity with errors. As shown, in each case, variability contributes a little over 60 percent of the total requirement; with (load) forecast errors providing the remaining percent. Figure A-18 and Figure A-19 then shows this result by operating hour. The hourly results show which hours improvements in forecasting are likely to provide the highest benefit.

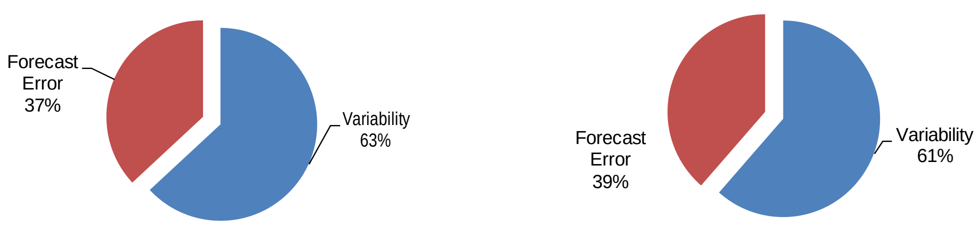


Figure A-16: Aggregate Contribution of Variability and Forecast Error to the Summer Regulation Requirement

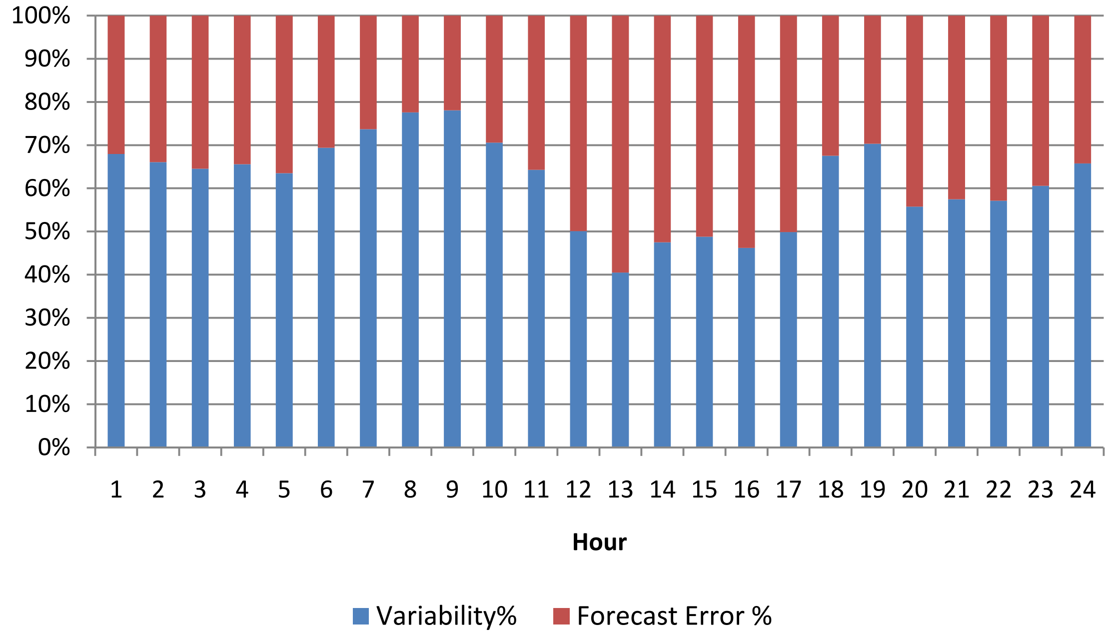


Figure A-17: Effect of Forecast Error and Variability on Regulation Up (Load & Wind & Solar) by Hour, Summer 2012

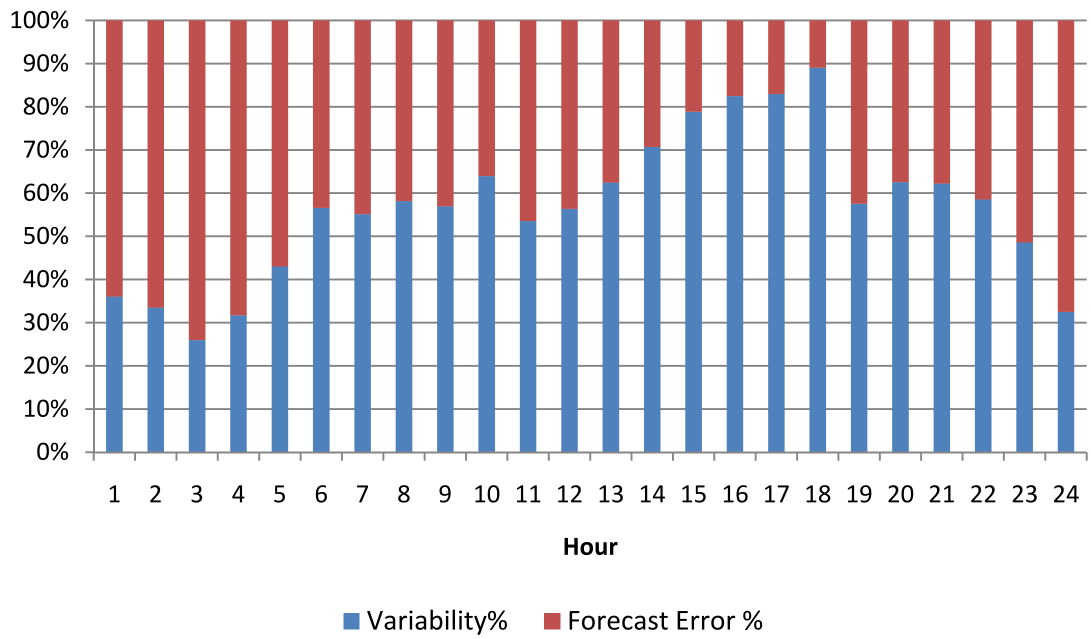


Figure A-18: Effect of Forecast Error and Variability on Regulation Down (Load & Wind & Solar) by Hour, Summer 2012

APPENDIX B Additional Fleet Capability Analysis Results

Section 4 discussed the load-following and regulation capability of the fleet for the summer season based on market data from April 1, 2009 to June 30, 2010. This appendix gives the historical capability for all the seasons.

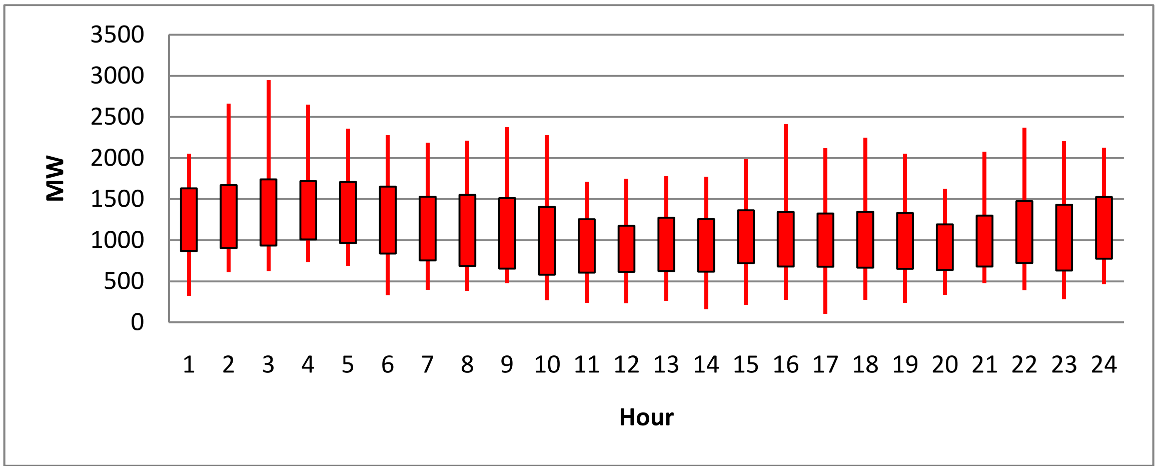


Figure B-1: Fall 5-Minute Load Following Up Capability: Sep2009-Nov2009

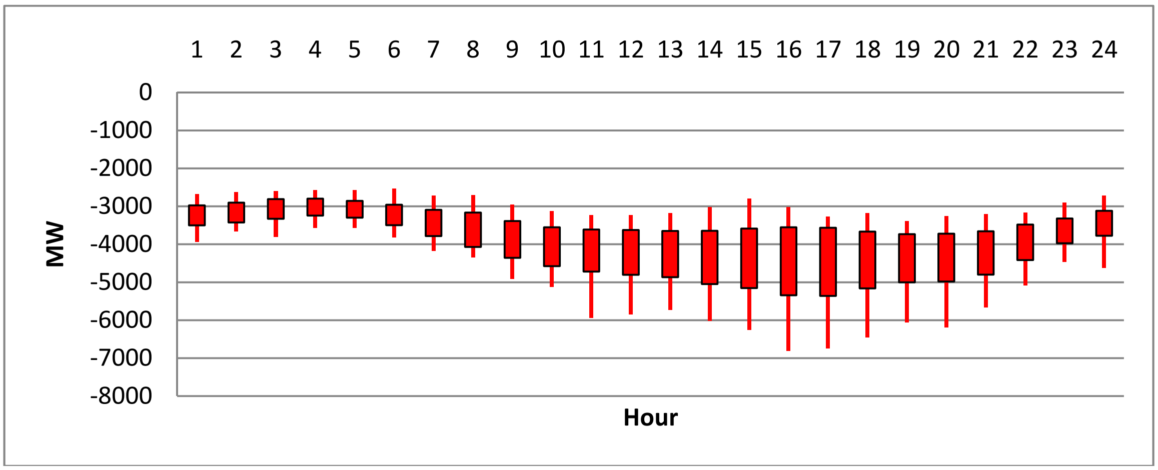


Figure B-2: Fall 5-Minute Load Following Down Capability: Sep2009-Nov2009

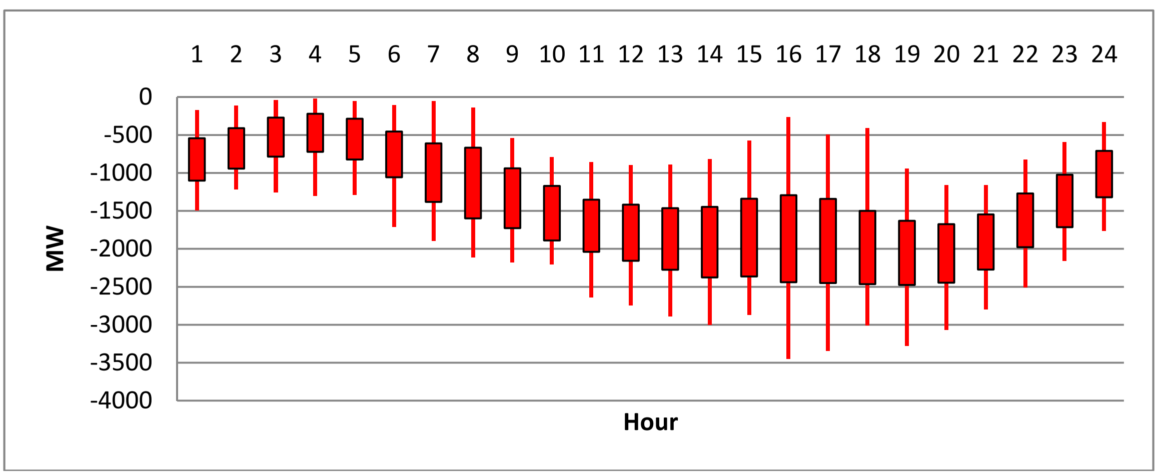


Figure B-3: Fall 5-Minute Load Following Down Capability (To Self Schedule): Sep2009-Nov2009

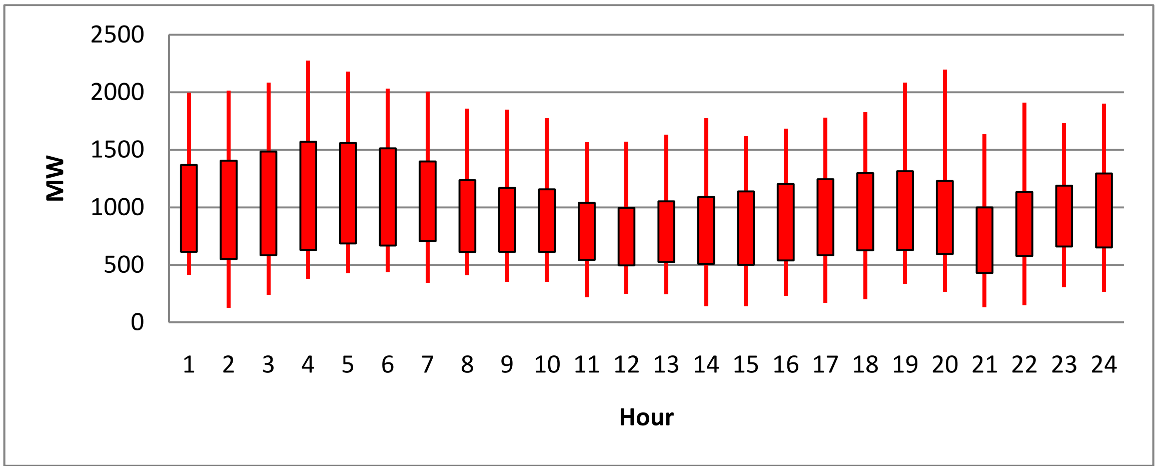


Figure B-4: Spring 5-Minute Load Following Up Capability: Mar-May, 2009-2010

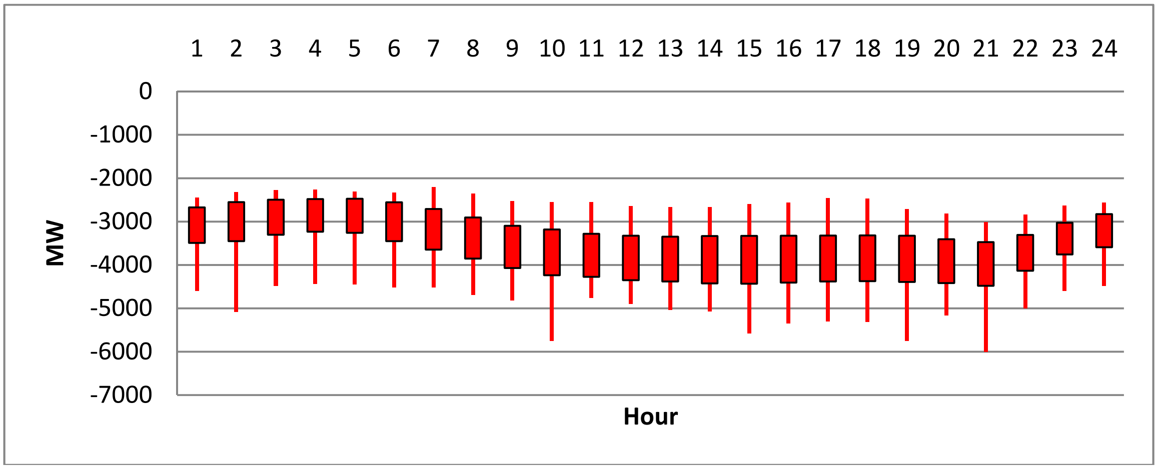


Figure B-5: Spring 5-Minute Load Following Down Capability: Mar-May, 2009-2010

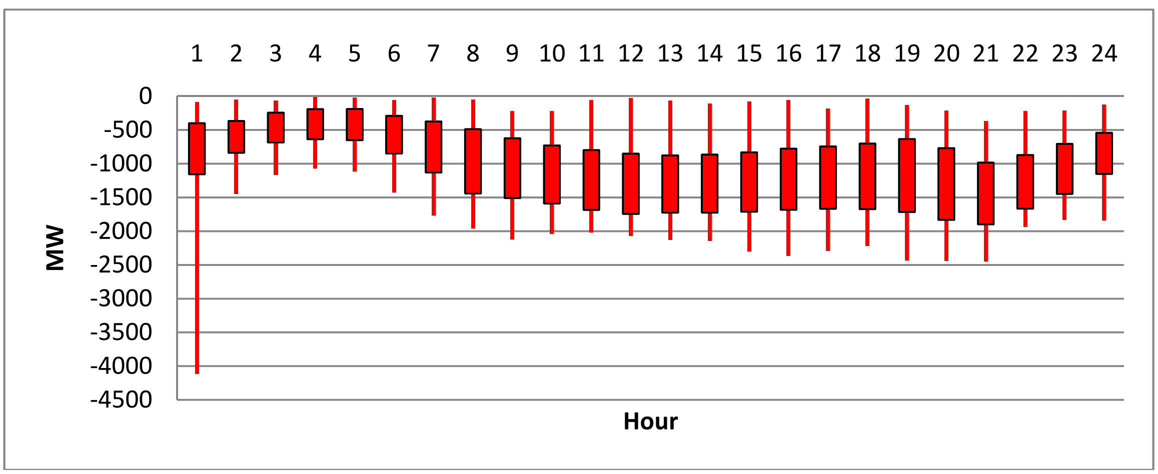


Figure B-6: Spring 5-Min Load Following Down Capability (To Self Schedule): Mar-May, 2009-2010

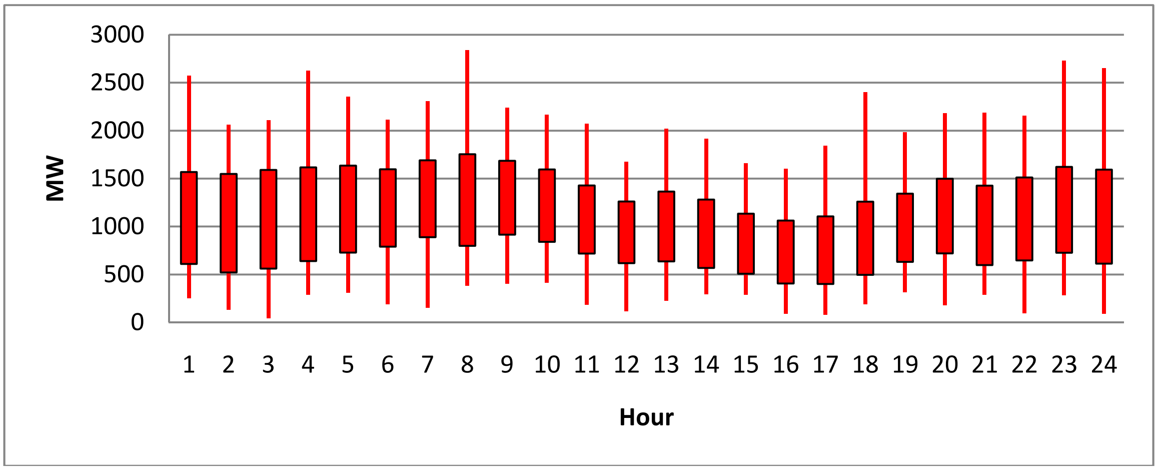


Figure B-7: Summer 5-Minute Load Following Up Capability: Jun2009-Aug2009, Jun2010

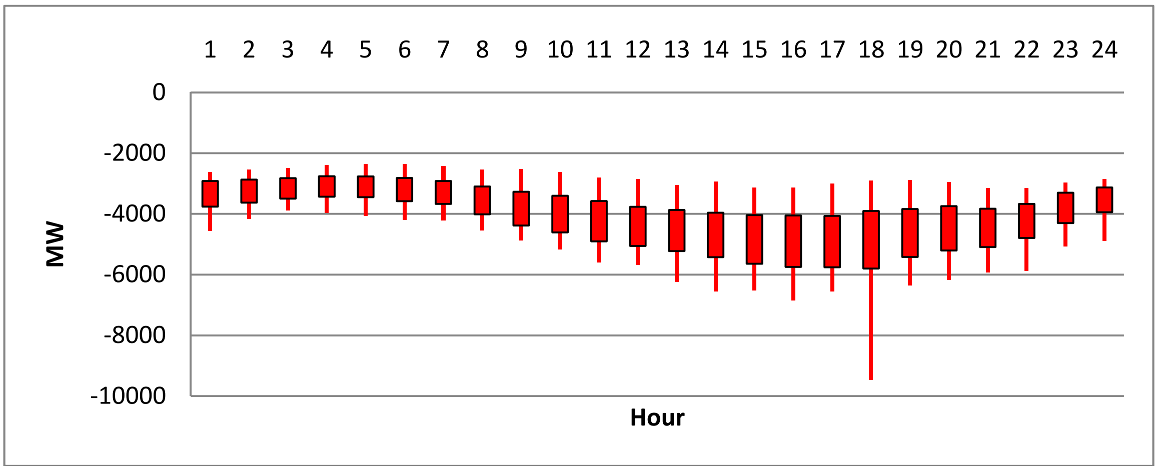


Figure B-8: Summer 5-Minute Load Following Down Capability: Jun2009-Aug2009, Jun2010

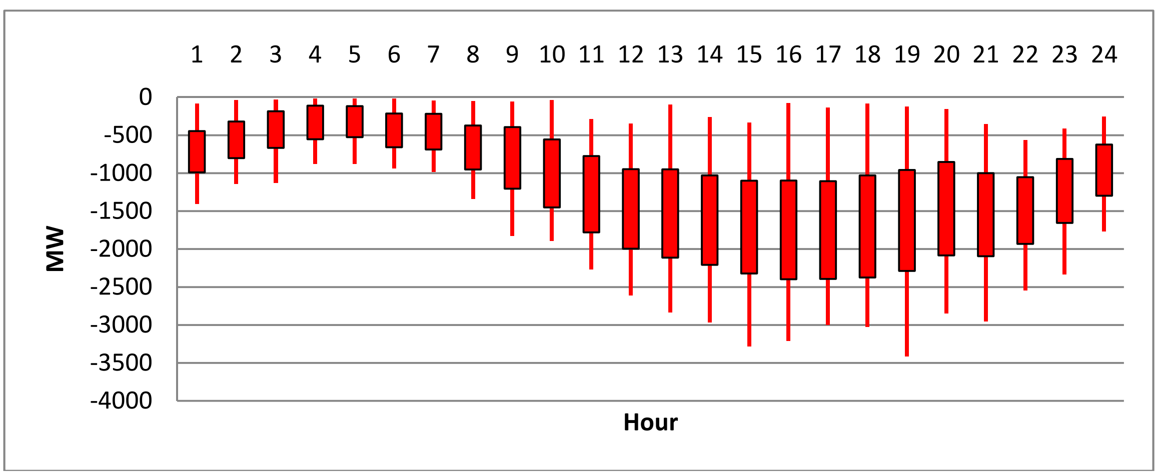


Figure B-9: Summer 5-Min Load Following Down Capability (To Self Schedule): Jun09-Aug09, Jun10

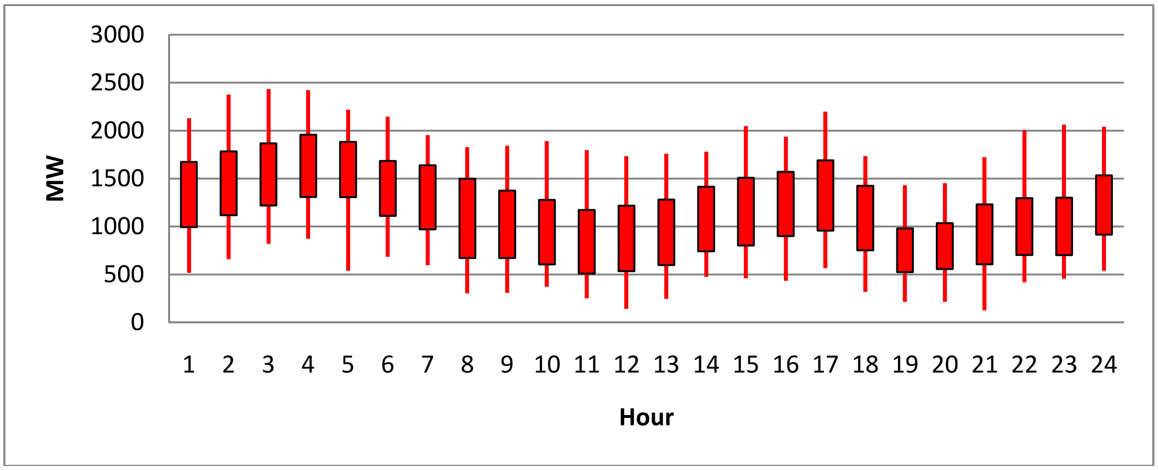


Figure B-10: Winter 5-Minute Load Following Up Capability: Dec2009-Feb2010

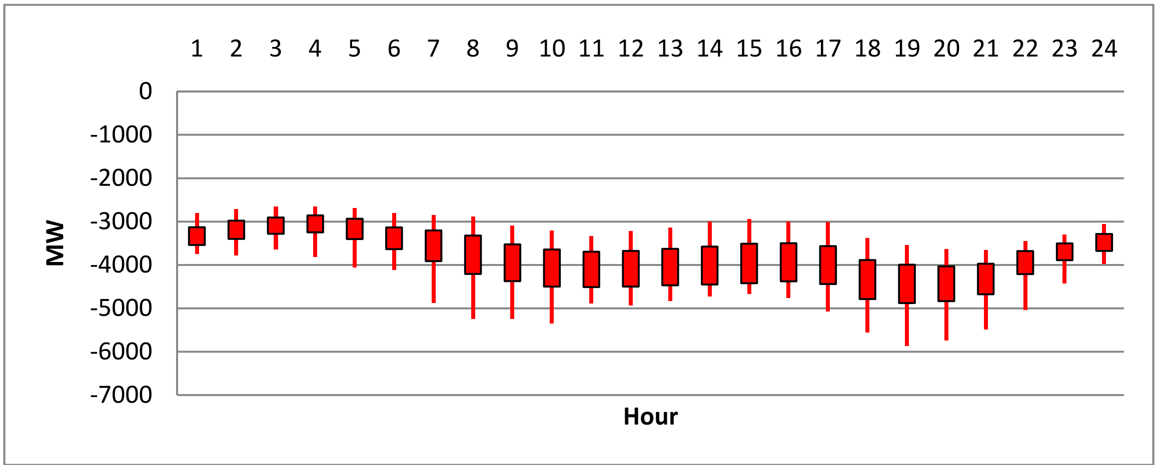


Figure B-11: Winter 5-Minute Load Following Down Capability: Dec2009-Feb2010

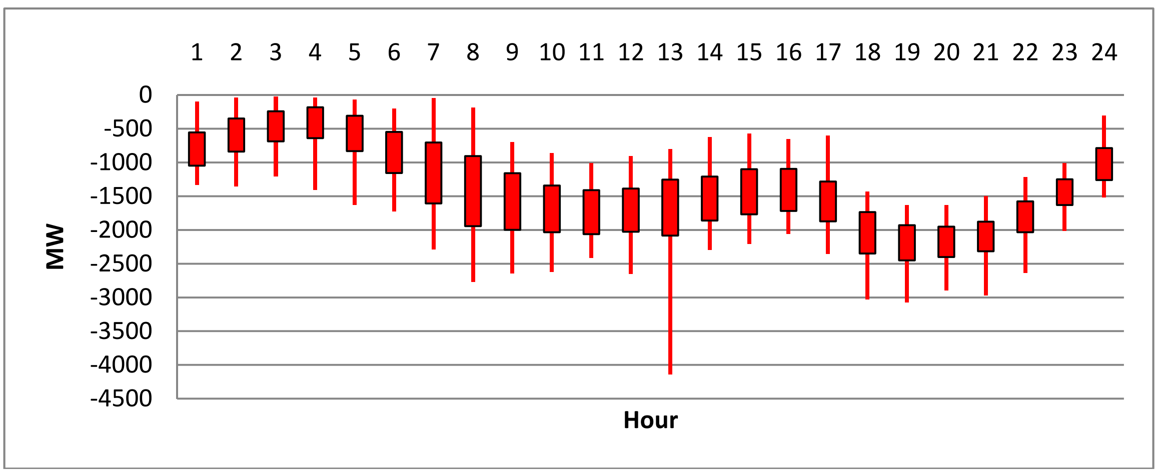


Figure B-12: Winter 5-Minute Load Following Down Capability (To Self Schedule): Dec2009-Feb2010

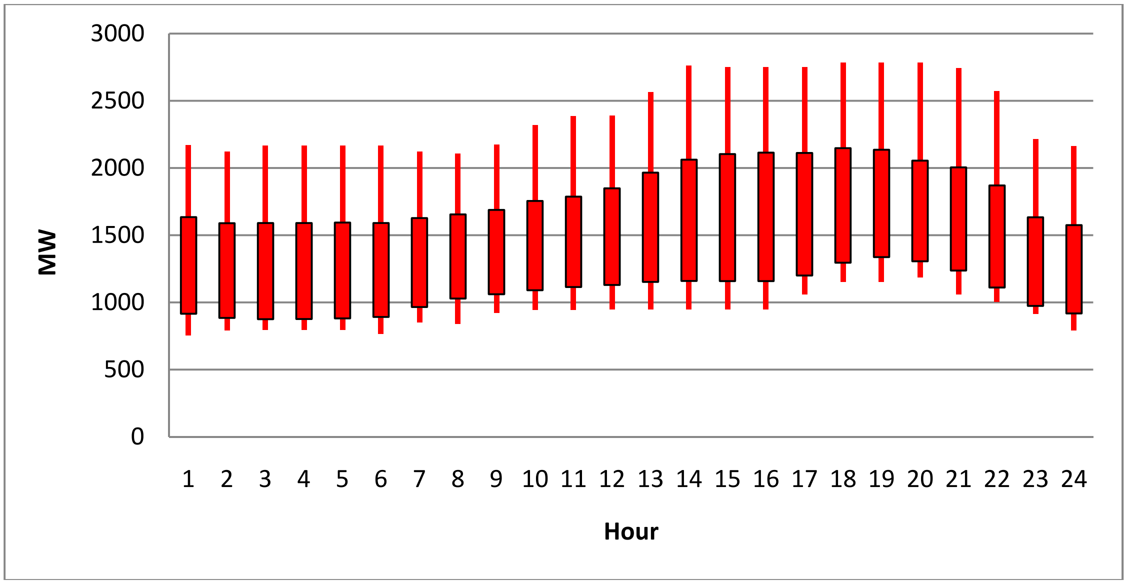


Figure B-13: Fall Regulation Up, 5-Min. Ramp Capability of Bid MW: Sep2009-Nov2009

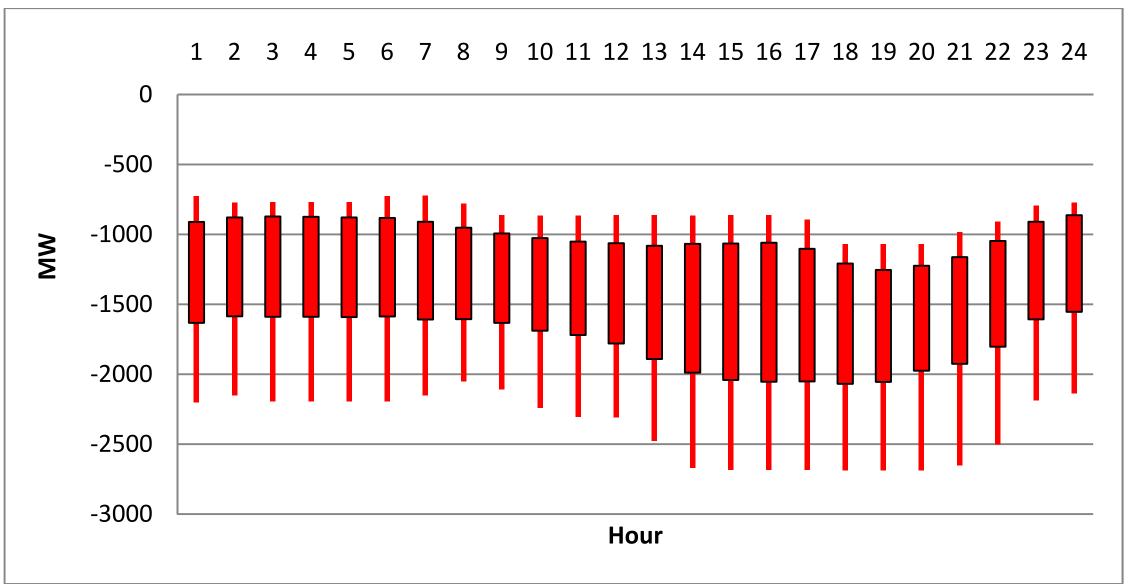


Figure B-14: Fall Regulation Down, 5-Min. Ramp Capability of Bid MW: Sep2009-Nov2009

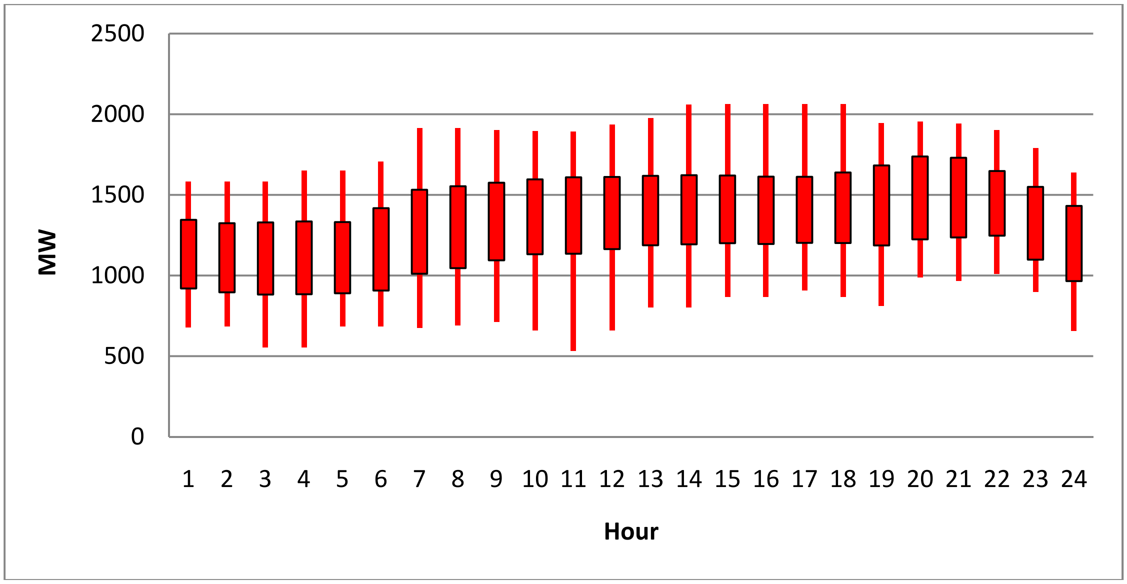


Figure B-15: Spring Regulation Up, 5-Min. Ramp Capability of Bid MW: Mar-May, 2009-2010

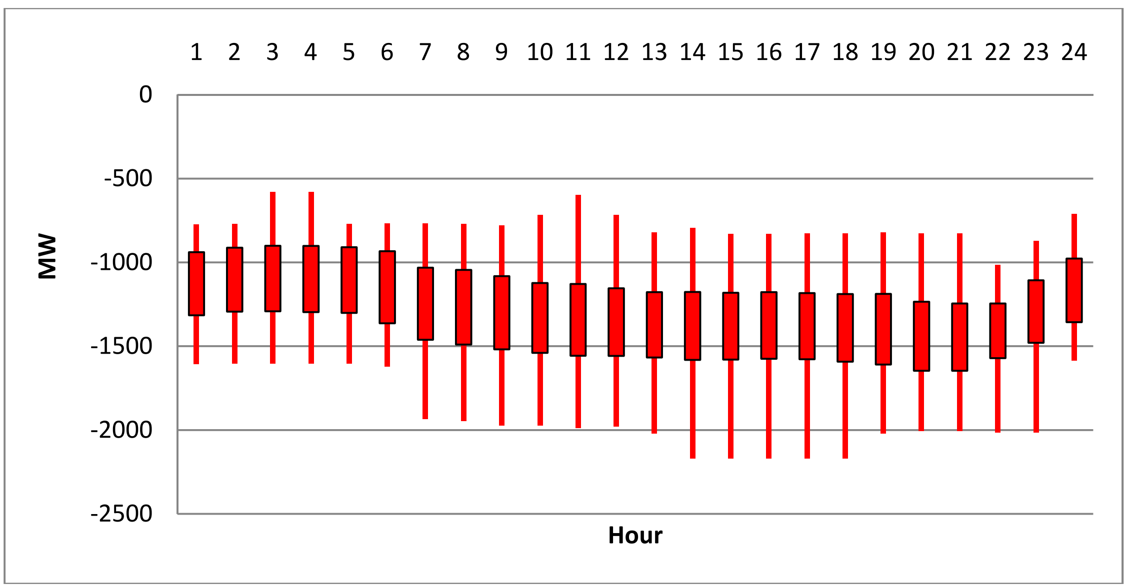


Figure B-16: Spring Regulation Down, 5-Min. Ramp Capability of Bid MW: Mar-May, 2009-2010

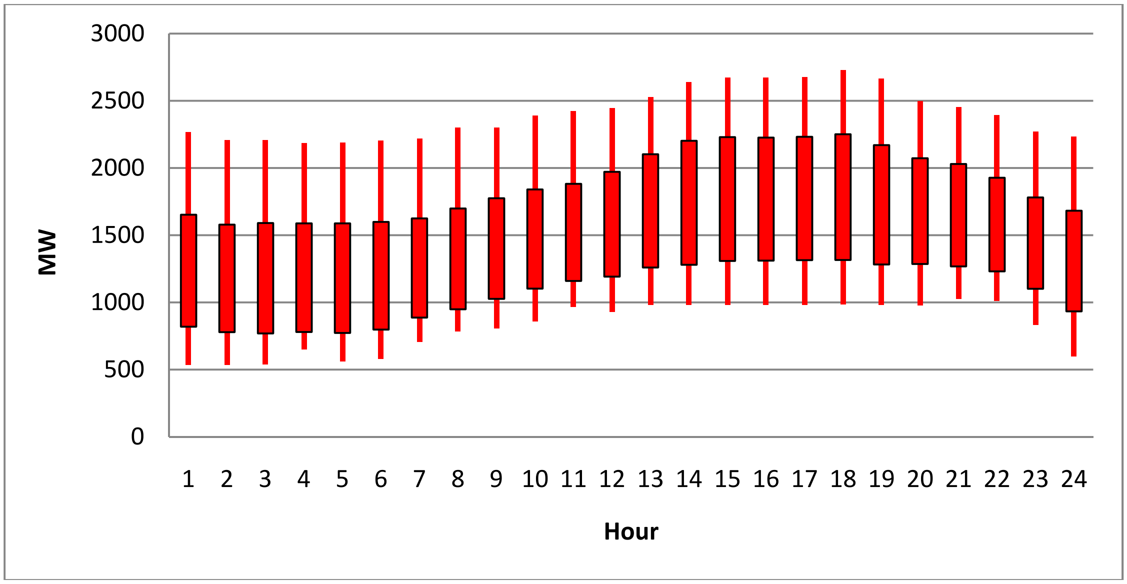


Figure B-17: Summer Regulation Up, 5-Min. Ramp Capability of Bid MW: Jun2009-Aug2009, Jun2010

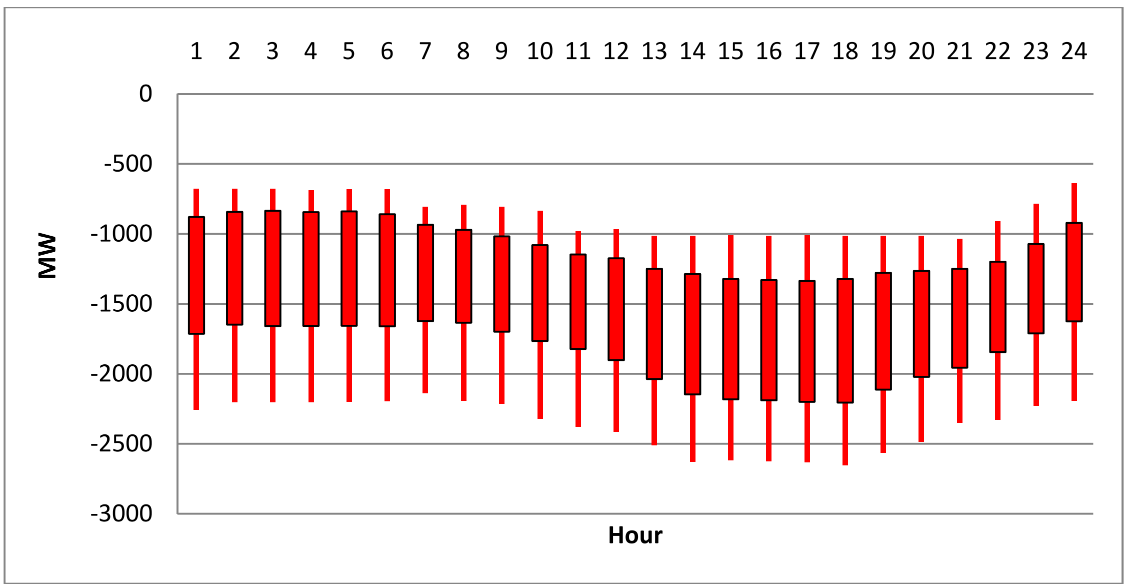


Figure B-18: Summer Regulation Down, 5-Min. Ramp Capability of Bid MW: Jun2009-Aug2009, Jun2010

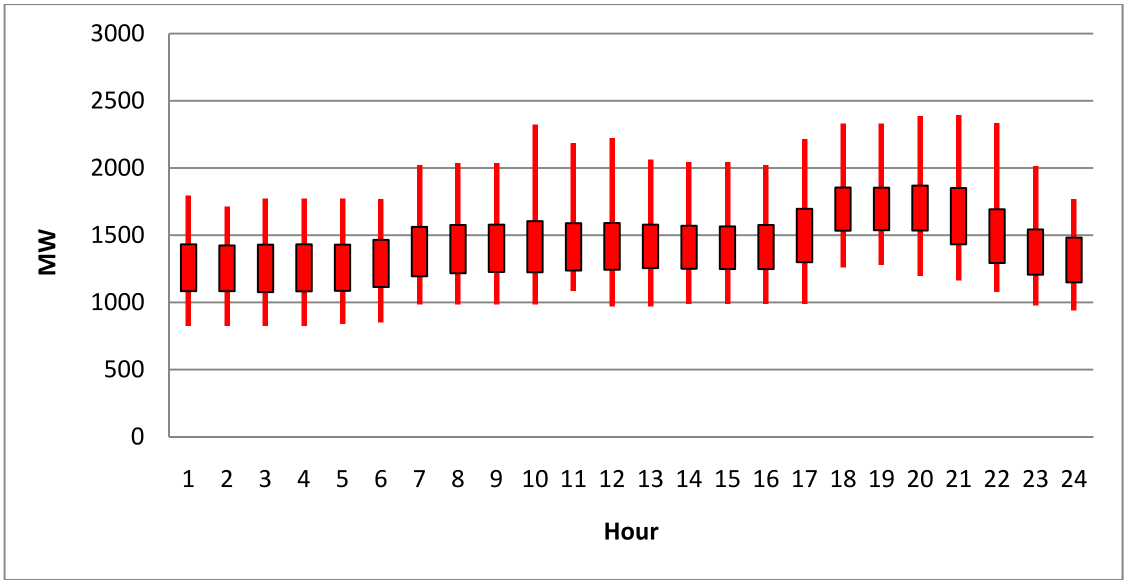


Figure B-19: Winter Regulation Up, 5-Min. Ramp Capability of Bid MW: Dec2009-Feb2010

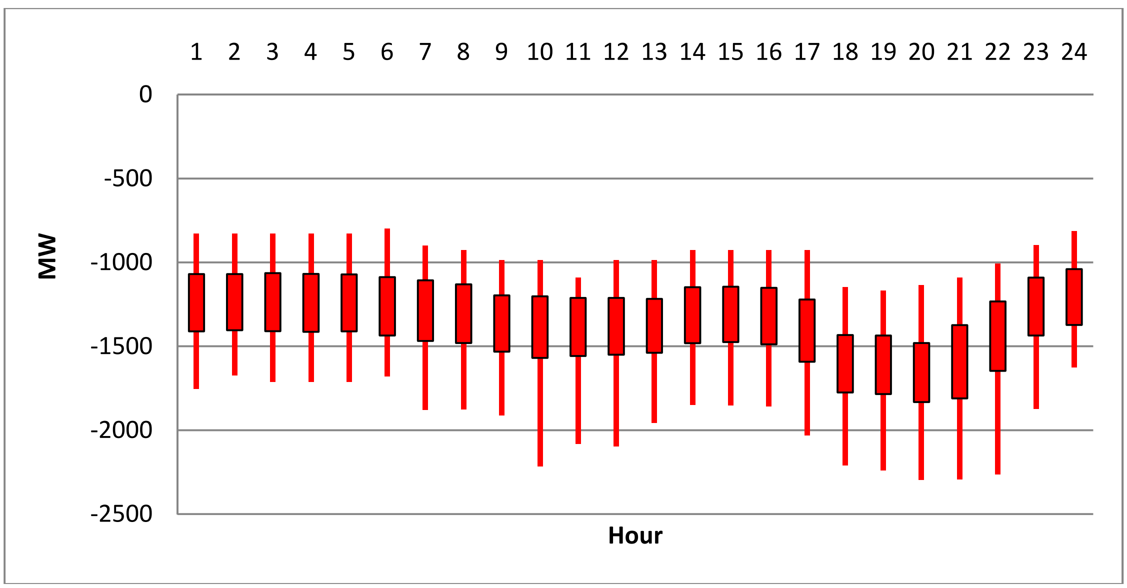


Figure B-20: Winter Regulation Down, 5-Min. Ramp Capability of Bid MW: Dec2009-Feb2010

APPENDIX C Additional Production simulation Results

C.1 Stochastic Sequential Simulation Results

C.1.1 Overview

For selected days, the ISO adopted a sequential approach to the simulations: first, conducting the day-ahead and hour-ahead simulations, then "freezing" the resulting unit commitment for simulation of the "real-time" dispatch on a five-minute time-step. This methodology is already described in the Technical Appendix. It is not practical to run the sequential, stochastic simulation, and in particular, the 5-minute real-time simulations for the whole year due to the computational burden that is involved. Therefore, it is necessary to focus these simulations only for some periods of interest. This section of the appendix describes the overall process that was used in the sequential, stochastic simulation of interesting days.

A number of stochastic simulations are required for determining the real-time operational capability of the system. These simulations are listed below.

- Annual Day Ahead (DA), stochastic
- Monthly Hour Ahead (HA), stochastic
- Monthly Real Time Hourly (RT-H), stochastic
- Daily Real Time 5 minute (RT-5), stochastic

Each simulation provides insights into the system operation and helps guide the selection of time periods for the following steps. At each step of the process the system was examined for the following operational issues:

- Overgeneration, or dump energy
- Regulation down violations (regdn)
- Regulation up violations (regup)
- Spinning Reserve violations
- Non-spinning Reserve violations

In the results presented in Section 5 of the report, overgeneration and regulation down violations are combined together (and called overgeneration) since they both represent conditions where instantaneous generation is more than load.

C.2 Stochastic Simulation

The day-ahead (DA) hourly, stochastic simulation was performed first. This simulation showed that most of the over generation occurred in May and the surrounding months Figure C-1 shows the monthly over generation from the initial deterministic case (imports 100% firm) and the Day Ahead stochastic simulation. There were no significant other violations (regulation up and spin) in these simulations. Therefore, subsequent simulations focused on four months - April, May, June and July.

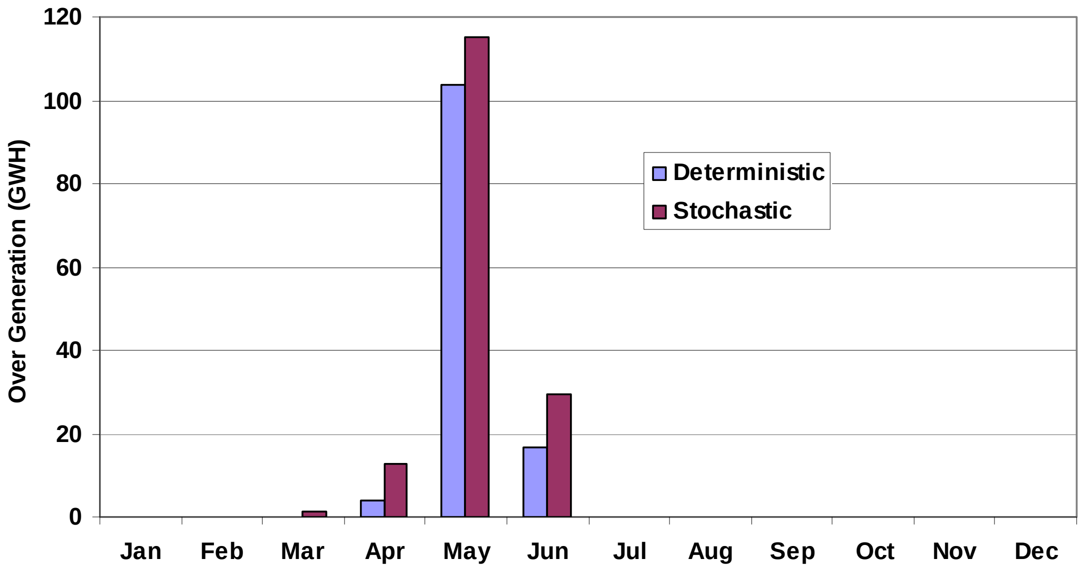


Figure C-1: Monthly over generation

With the unit commitment of long-start units from the DA simulation frozen, the hour-ahead, stochastic (hourly) simulations were performed for the four months. Both the day-ahead and hour-ahead simulations commit and dispatch to the forecasted load for 100 draws of the load forecast. Also, the wind generation in the commitment and dispatch are the same in each one the 100 iterations. Therefore, there is no uncertainty in load and wind generation in the day-ahead and hour-ahead stochastic simulations. The end-result of the day-ahead and hour-ahead stochastic simulation is a set of unit commitment for long and medium-start generators for the 100 iterations.

In order to evaluate the impact of uncertainty in load and wind generation forecasts, the unit commitment obtained from the HA market simulation (for each one of the 100 forecasts) was used to dispatch the system with actual hourly loads and hourly actual wind generation. In this real-time, hourly simulation (RT-H) simulation, only quick starts were allowed to be committed in addition to the long and medium-start units. Figure C-2 shows the monthly over generation results for the selected months, including the RT-H simulations. The month of May accounts for 80% of the annual over generation in the RT-H simulation. Figure C-3 shows the operating issues from each day from the DA, HA and RT-H simulations for the month of May. The over generation plus regulation down shortages for the RT-H simulations are shown in the last column. It should be reiterated that the over generation and regulation down violations in this simulation are due to the uncertainty in load and wind generation forecasts as modeled in the stochastic process. The RT-H simulation does not capture the impact of variability in load and wind generation since these simulations are done at an hourly time scale. The real-time, 5-minute simulations are used to capture the operational impacts of variability. This is discussed next.

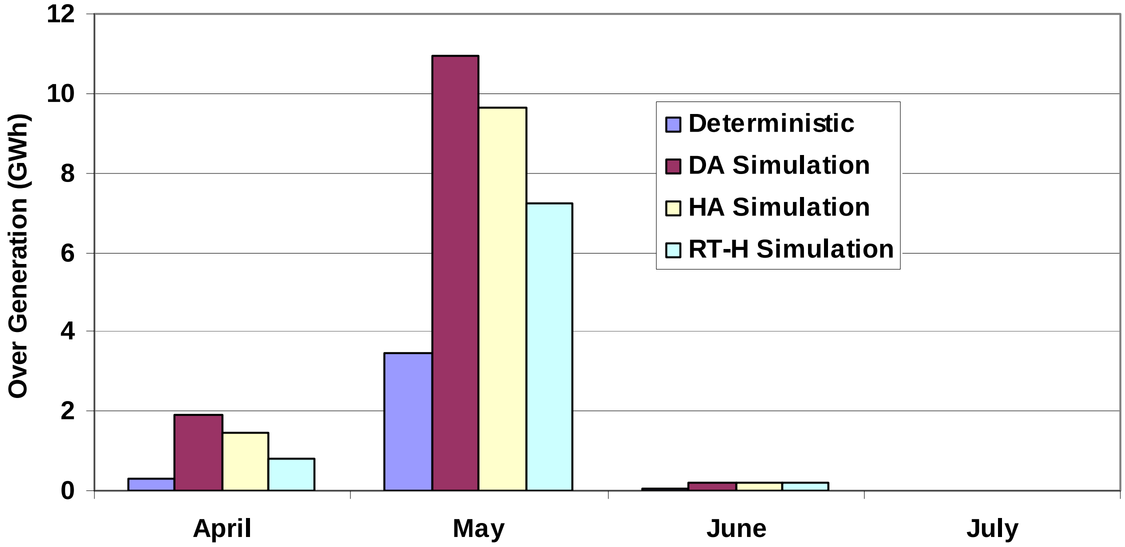


Figure C-2: Monthly over generation, imports 50% firm

From the RT-H simulations, it was decided to examine May 28th for the impact of variability in load and wind generation. Table C-1 shows the over generation results of the 5-minute (RT-5) simulation as well as the RT-H simulation. The overgeneration is higher in the RT-5 simulation since it includes the impact of uncertainty, as well as variability. The ratio of over generation in the RT-5 and RT-H simulation for May 28th is 2.2. While the RT-H identified days when uncertainty in load and wind generation is likely to result in operational problems, other methods were used to identify interesting days when the intra-hour ramps might exacerbate these problems. The next section discusses this methodology.

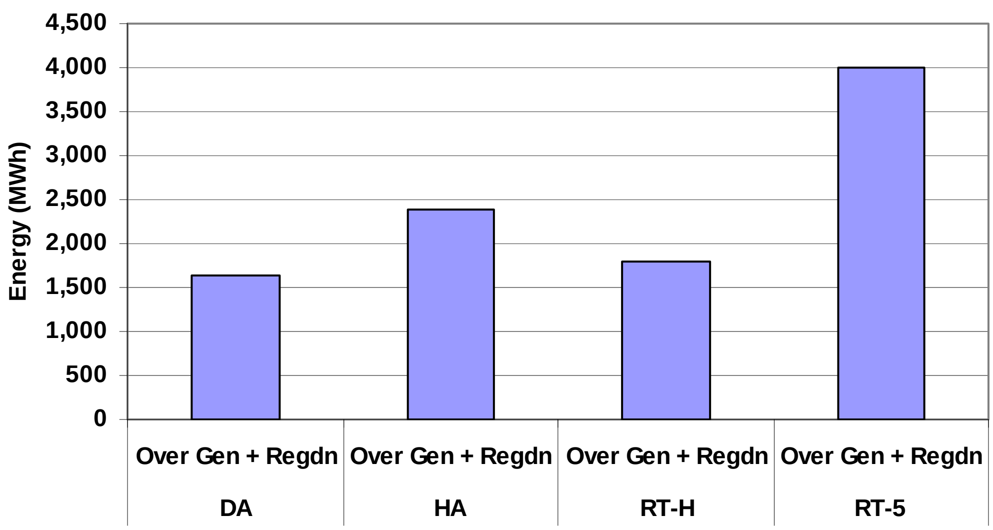


Figure C-3: Over generation for May 28th in RT-H and RT-5 Simulations.

Table C-1: Daily operating issues for May.

	DA	HA	RT-H	DA	HA	RT-H	DA	HA	RT-H
Date	Over Gen	Over Gen	Over Gen	Regdn	Regdn	Regdn	Over Gen + Regdn	Over Gen + Regdn	Over Gen + Regdn
5/1/2012	0.0	0.0	0.0	0.5	0.0	0.0	0.5	0.0	0.0
5/2/2012	1.0	0.0	0.0	1.7	1.9	0.0	2.7	1.9	0.0
5/3/2012	0.0	5.0	0.0	1.8	6.2	0.0	1.8	11.2	0.0
5/4/2012	67.8	86.5	15.2	73.2	110.7	48.4	141.0	197.2	63.7
5/5/2012	85.8	62.3	10.1	58.2	71.4	45.7	144.0	133.6	55.8
5/6/2012	5.9	2.5	1.0	18.7	11.2	8.7	24.6	13.7	9.7
5/7/2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5/8/2012	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.3	0.0
5/9/2012	167.4	292.3	247.8	92.2	110.0	132.6	259.6	402.4	380.4
5/10/2012	41.6	106.9	54.0	12.6	23.3	15.2	54.2	130.2	69.2
5/11/2012	1.2	78.6	11.4	3.8	24.1	8.0	5.0	102.8	19.4
5/12/2012	6.1	4.4	0.0	5.3	3.2	0.0	11.5	7.7	0.0
5/13/2012	18.0	10.8	0.8	6.5	5.3	0.1	24.5	16.1	0.9
5/14/2012	4.3	13.3	4.4	2.2	3.6	1.5	6.5	16.9	5.9
5/15/2012	43.8	101.4	9.8	0.0	0.0	0.0	43.8	101.4	9.8
5/16/2012	2.6	12.8	0.0	0.0	0.0	0.0	2.6	12.8	0.0
5/17/2012	7.8	3.6	0.0	0.0	0.0	0.0	7.8	3.6	0.0
5/18/2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5/19/2012	26.6	25.7	3.0	6.7	0.0	0.0	33.3	25.7	3.0
5/20/2012	241.6	356.5	93.5	152.9	201.7	164.4	394.4	558.2	257.9
5/21/2012	349.6	269.5	121.5	1.2	1.1	0.0	350.9	270.7	121.5
5/22/2012	348.2	364.4	257.8	0.0	0.0	0.0	348.2	364.4	257.8
5/23/2012	19.5	136.1	42.7	0.0	0.0	0.0	19.5	136.1	42.7
5/24/2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5/25/2012	0.0	6.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0
5/26/2012	19.2	27.7	1.9	36.7	53.1	31.6	56.0	80.9	33.6
5/27/2012	1,058.1	802.9	331.5	347.7	375.3	330.5	1,405.9	1,178.2	662.0
5/28/2012	1,140.7	1,622.0	780.3	489.8	756.9	1,021.6	1,630.5	2,378.9	1,801.9
5/29/2012	166.4	203.8	133.1	0.0	0.0	0.0	166.4	203.8	133.1
5/30/2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5/31/2012	0.4	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0
Total	3,823.8	4,595.2	2,119.8	1,311.9	1,759.4	1,808.4	5,135.7	6,354.6	3,928.1

C.3 Further Analysis for Interesting Days

A combination of statistical data analysis, generation schedules, and results from Plexos deterministic and stochastic simulations was used to find “interesting” periods during the year for more extensive analysis. These periods included

- Days when real-time net load ramp up and down events far exceeded the average hourly scheduled (forecasted) ramp
- Days when real-time net load ramp up and down events are a high percentage of the hourly flexible generation
- Days with low amounts of dispatchable generation
- Days with Dump Energy in the stochastic hourly simulations
- Days with regulation and spin shortfalls in the hourly stochastic simulation

A number of days meeting each criterion above were selected on their merits, then they were collectively ranked and prioritized to determine a subset of days for in-depth analysis.

C.4 Five-Minute Ramp Ratios

The five-minute load, wind, solar and net load ramps were analyzed to find periods during the year when maximum five-minute net load ramp in an hour was much greater than the average scheduled ramp during the hour. The general procedure was

1. create 5-minute deltas (difference between successive 5-minute periods)
2. calculate maximum positive delta and maximum negative delta in each hour
3. calculate the average delta in each hour
4. compute ratio maximum delta/average delta for each hour

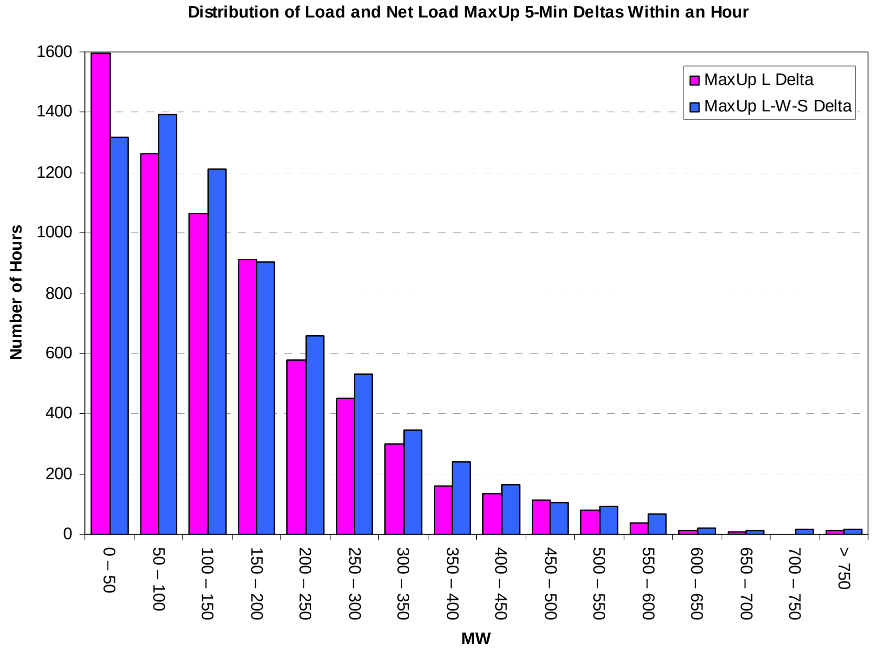
The concern is that the commitment is based on the hourly loads and therefore only consider the hourly load deltas and by extension, only the average 5-minute deltas within the hour. If a particular 5-minute delta is 10 or 20 times the average for the hour then there might not be enough ramping capability available and ramp violations could occur.

C.4.1 Load and Net Load Deltas

Figure C-4 shows the distribution of load and net load maximum 5-minute deltas in each hour of the 2006 shape year. The magenta bars show the number of positive and negative load deltas in each bin, and the blue bars show the number of positive and negative net load deltas in each bin. Net Load is defined as Load – Wind – Solar generation. As expected, each half of the distribution of deltas is skewed, but more so for load than net load.

For the positive deltas (or up-ramps), 80% of the load deltas are in the first 4 bins (200 MW or less) whereas only 68% of the net load deltas are 200 MW or less. On the tails of the distribution, there are 35 hours with a five-minute load delta of 600 MW or more, and 68 hours with a net load delta of 600 MW. However, the largest load up-ramp, 5,637 MW, is about the same as the largest net load up-ramp 5,634 MW.

The difference between load and net load is less distinct for the down-ramps. Approximately 77% of load deltas are 200 MW or less, and about 74% of net load deltas are in the same range. On the tail end, 11 load down-ramps are greater than or equal to 600 MW, compared to 19 net load down-ramps. Again, the largest load down-ramp, 5,808 MW, is about the same as the largest net load down-ramp.



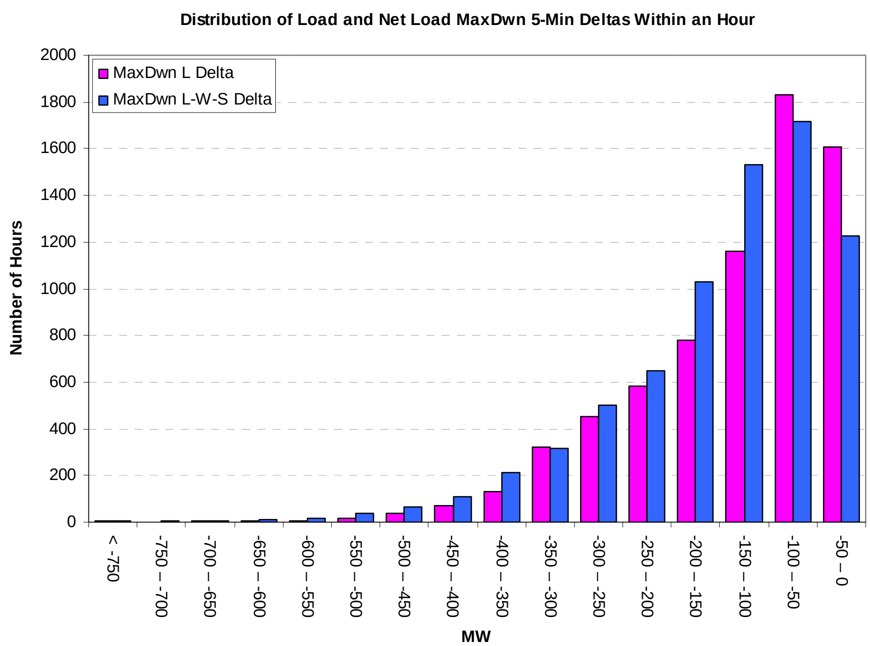


Figure C-4: Distribution of maximum 5-minute load and net load deltas in each hour

These 5-minute deltas are compared to the average 5-minute deltas within the hour to identify periods where the real-time ramping requirement outpaces the scheduled hourly ramp. Figure C-5 shows the distribution of average 5-minute ramps for load and net load in the 2006 shape year. The top plot shows the distribution of positive load and net load average 5-minute deltas, and the bottom plot shows the distribution of negative load and net load average 5-minute deltas. On both plots there are more hours with large average

5-minute deltas (on the tails of the distributions) with wind and solar than with load alone, although the difference may not be as great as expected.

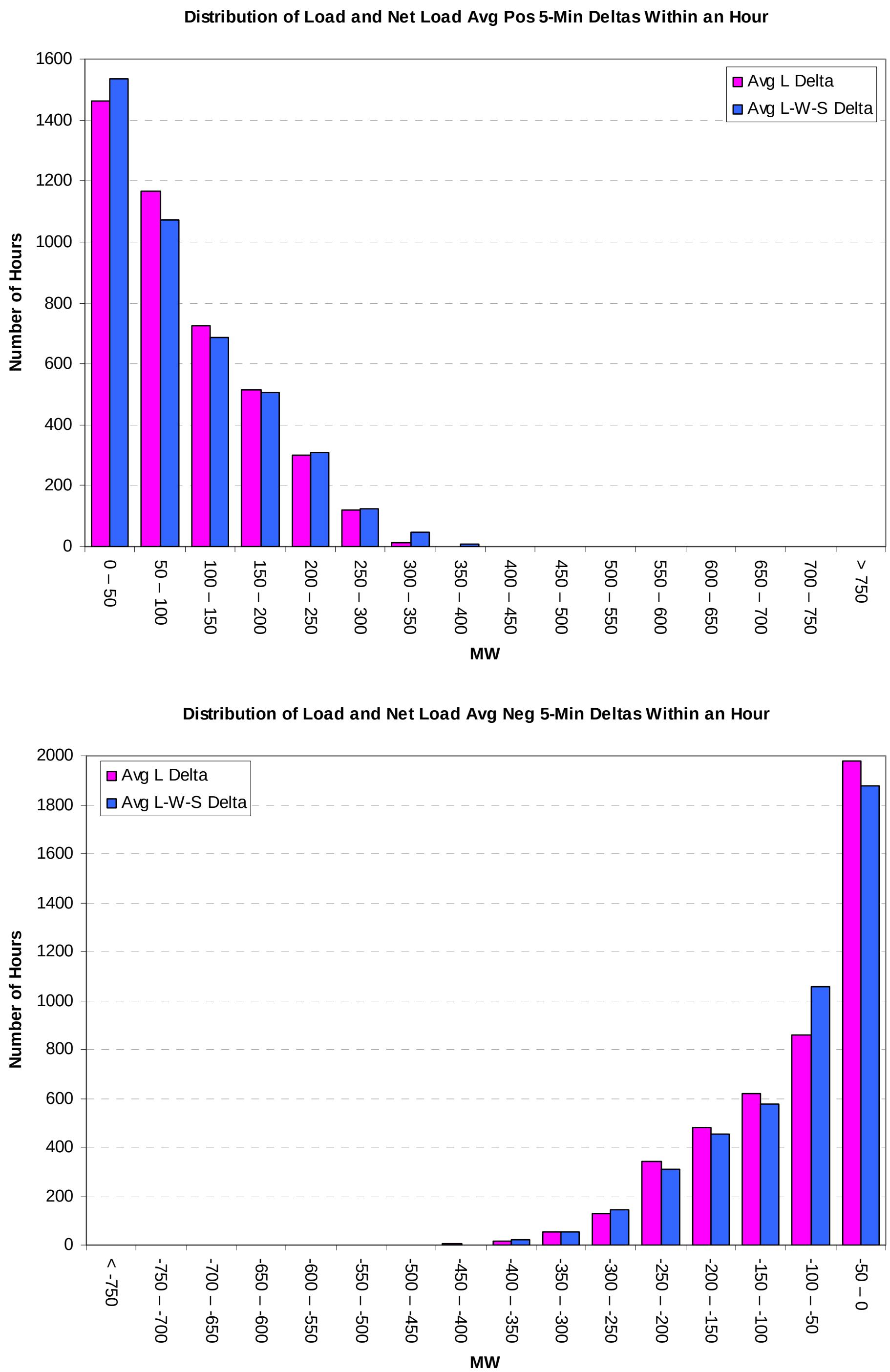


Figure C-5: Distribution of average hourly load and net load deltas

C.4.2 Max/Average Ratios

The maximum five-minute deltas and average five-minute deltas discussed above were used to compute the ratios. The simple relation is:

$$\text{Ratio} = \frac{\text{Maximum Five-Minute Ramp}}{\text{Average Five-Minute Ramp}}$$

Large ratios that are due to a small average hourly ramp (in the numerator) are not particularly interesting. Therefore a threshold was used to screen out these hours. Figure C-6 below (a scatter plot of maximum positive deltas versus average hourly deltas) shows how this threshold was determined. In the figure, magenta triangles represent a load hours and blue diamonds represent net load hours.

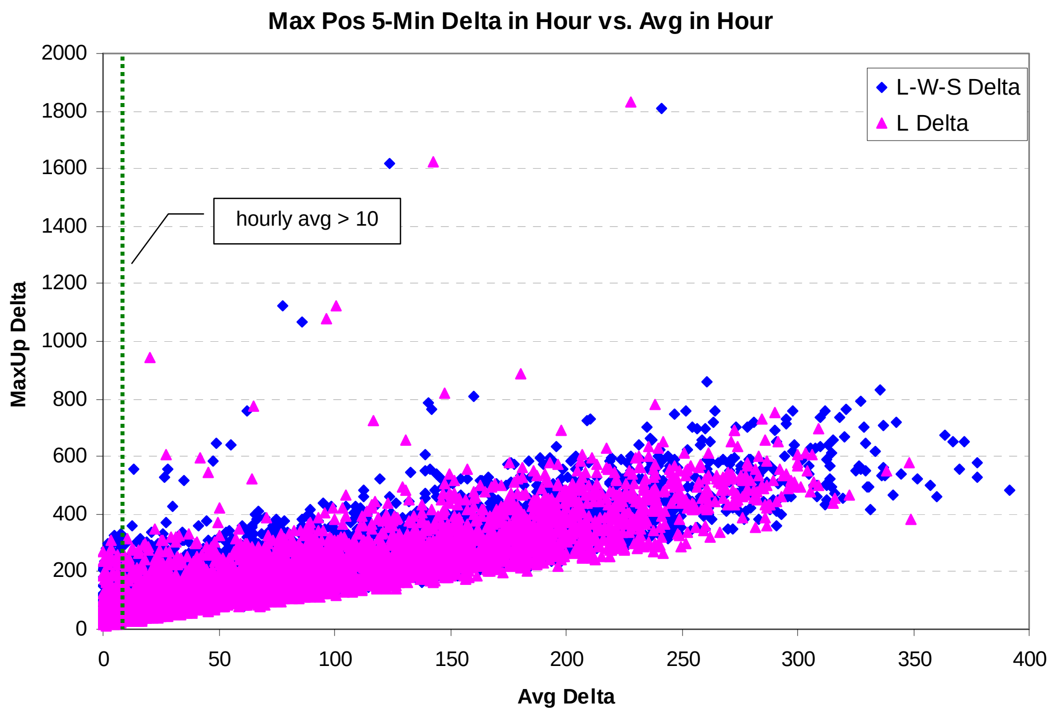


Figure C-6: Scatter plot of maximum positive deltas versus average delta in each hour

All the hours with a large maximum five-minute delta fall to the right of the vertical line at Avg Delta = 10. Therefore an initial threshold of Avg Delta > 10 was used to screen out large ratios caused by small averages. A similar threshold was used to initially screen the down-ramp ratios. Subsequently, an exercise was carried to determine if the initial threshold should be increased from 10, i.e. whether a threshold of 20 or 30 would be more selective.

Figure 7 shows the MaxUp/Avg ratios for Avg Delta >10, Avg Delta >20, and Avg Delta >30 over the year. Blue diamonds represent ratios where Avg Delta >10, magenta squares represent ratios where Avg Delta >20, and green triangles represent ratios where Avg Delta > 30. The superposition of ratios selected using these three screening values confirm that there is no advantage in filtering with a threshold greater than 10.

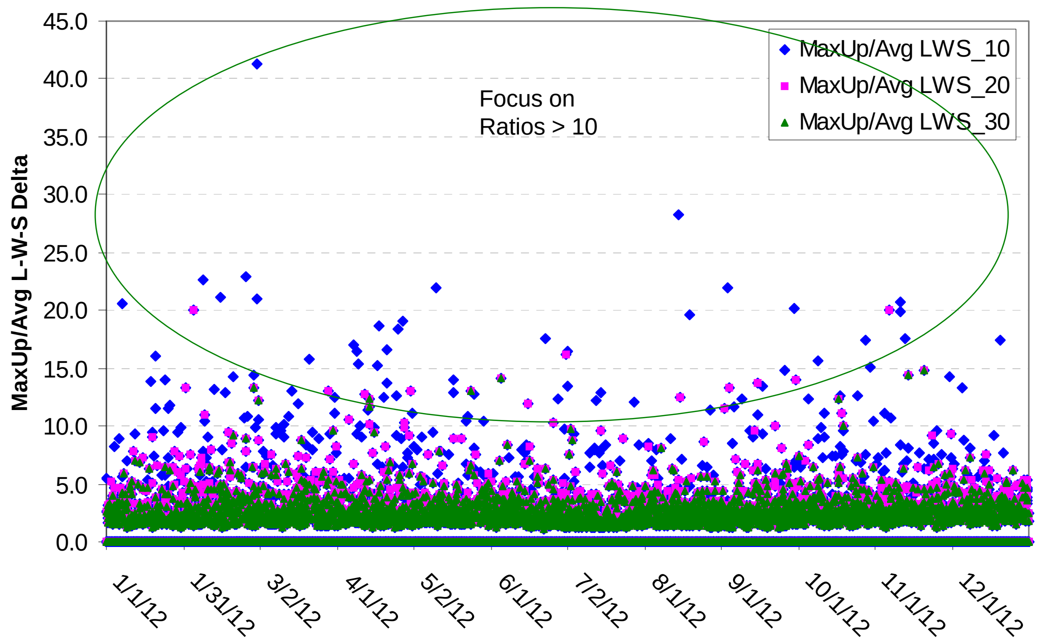


Figure C-7: MaxUp/Avg ratios for Avg Delta >10, Avg Delta >20, and Avg Delta >30

Figure C-8 shows a scatter plot of the up-ramp ratios versus the average hourly delta. As before, magenta triangles represent a load hours and blue diamonds represent net load hours. As expected, there are many large ratios clustered vertically on the left side where the average hourly delta is low.

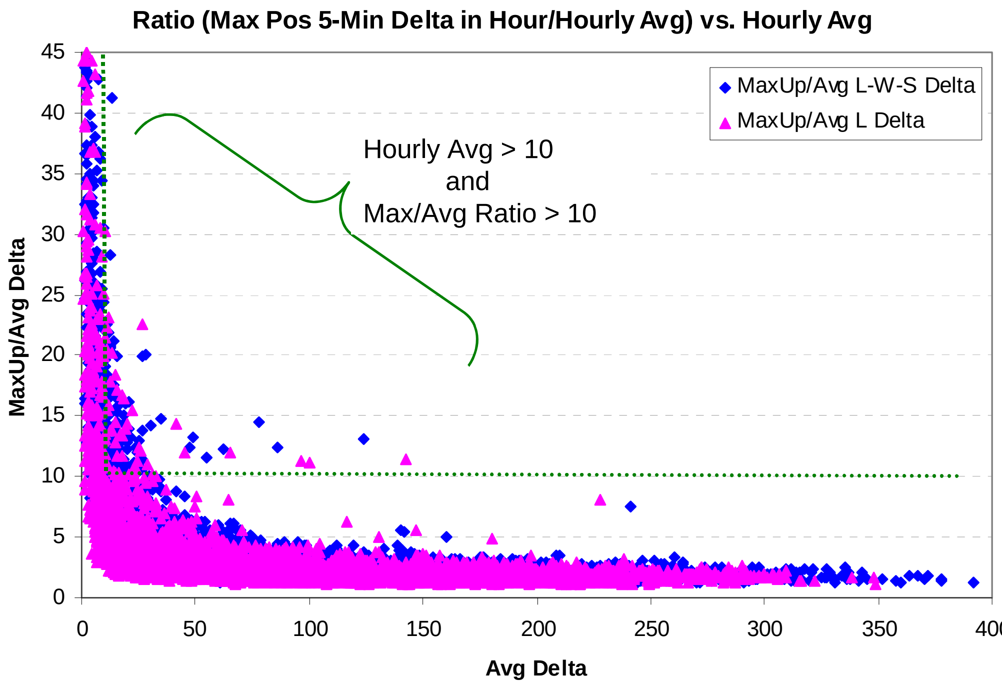


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Figure C-8: Scatter plot of MaxUp/Avg ratio versus average delta in each hour

However, the largest ratio with Avg Delta > 10 is at 41.2. In general, the set of hours with Max/Avg ratio > 10 and Avg Delta >10, (i.e. to the left of the vertical green line and above the horizontal green line) are the hours of interest from this exercise. These hours are listed in Table C-2. The hours of interest for down-ramps were determined in a similar manner and are listed in Table C-3.

Table C-2: Periods of Interest Based on MaxUp/Average Ratios

Date	Ratio	Date	Ratio	Date	Ratio	Date	Ratio	Date	Ratio	Date	Ratio
2/29/12 15:00	41.2	10/28/12 2:00	17.4	5/17/12 14:00	14.0	4/12/12 7:00	12.8	9/5/12 18:00	11.6	5/29/12 18:00	10.5
8/14/12 19:00	28.3	12/20/12 8:00	17.4	1/24/12 8:00	14.0	5/26/12 4:00	12.8	1/20/12 10:00	11.5	2/8/12 18:00	10.5
2/25/12 8:00	22.9	4/8/12 7:00	17.0	9/30/12 18:00	13.9	10/18/12 7:00	12.6	9/2/12 5:00	11.5	10/31/12 13:00	10.4
2/8/12 2:00	22.6	4/21/12 2:00	16.5	1/18/12 8:00	13.9	10/25/12 2:00	12.6	1/25/12 8:00	11.5	5/22/12 17:00	10.4
5/10/12 19:00	21.9	4/9/12 7:00	16.5	9/15/12 3:00	13.8	4/25/12 9:00	12.6	4/13/12 16:00	11.4	6/26/12 2:00	10.4
9/3/12 5:00	21.9	7/2/12 2:00	16.5	4/21/12 1:00	13.7	3/31/12 7:00	12.5	8/27/12 18:00	11.4	4/28/12 7:00	10.3
2/15/12 2:00	21.1	7/1/12 3:00	16.2	9/17/12 13:00	13.5	4/20/12 3:00	12.5	10/19/12 1:00	11.2	4/14/12 5:00	10.2
3/1/12 1:00	21.0	1/20/12 8:00	16.1	7/1/12 19:00	13.4	8/15/12 19:00	12.4	11/4/12 14:00	11.1	3/11/12 3:00	10.1
11/11/12 4:00	20.7	3/21/12 7:00	15.7	12/5/12 8:00	13.4	4/14/12 8:00	12.4	10/11/12 16:00	11.1	10/19/12 6:00	10.1
1/7/12 3:00	20.6	10/9/12 12:00	15.6	2/1/12 13:00	13.4	10/5/12 16:00	12.4	5/1/12 11:00	11.1	9/22/12 7:00	10.0
9/29/12 18:00	20.2	4/9/12 16:00	15.3	9/4/12 2:00	13.3	10/17/12 10:00	12.4	3/31/12 10:00	11.1	4/10/12 9:00	10.0
2/4/12 18:00	20.1	4/17/12 7:00	15.2	2/28/12 8:00	13.2	9/9/12 7:00	12.3	9/15/12 11:00	11.0		
11/6/12 12:00	20.0	10/30/12 2:00	15.1	2/12/12 13:00	13.2	6/28/12 2:00	12.3	2/9/12 2:00	10.9		
11/11/12 3:00	19.9	9/26/12 7:00	14.9	5/24/12 11:00	13.1	3/1/12 8:00	12.2	5/23/12 14:00	10.9		
8/19/12 5:00	19.6	11/20/12 10:00	14.8	4/30/12 19:00	13.1	7/13/12 2:00	12.2	3/13/12 8:00	10.8		
4/27/12 19:00	19.1	2/28/12 7:00	14.5	3/14/12 16:00	13.0	7/28/12 4:00	12.0	2/26/12 6:00	10.8		
4/18/12 10:00	18.7	11/14/12 7:00	14.4	3/29/12 2:00	13.0	3/17/12 7:00	12.0	2/24/12 16:00	10.7		
4/25/12 16:00	18.4	11/30/12 15:00	14.3	5/17/12 18:00	12.9	6/16/12 3:00	12.0	11/7/12 12:00	10.7		
11/13/12 3:00	17.6	2/20/12 8:00	14.3	2/17/12 2:00	12.9	1/26/12 10:00	11.7	3/1/12 9:00	10.6		
6/23/12 4:00	17.5	6/5/12 12:00	14.2	7/15/12 3:00	12.9	4/14/12 9:00	11.6	4/6/12 7:00	10.6		

Table C-3: Periods of Interest Based on MaxDown/Average Ratios

Date	Ratio	Date	Ratio	Date	Ratio	Date	Ratio
10/27/12 0:00	69.5	8/6/12 18:00	15.1	10/30/12 15:00	11.9	4/4/12 15:00	10.4
5/3/12 17:00	30.6	5/24/12 10:00	14.8	7/30/12 18:00	11.9	12/9/12 3:00	10.4
5/7/12 10:00	24.4	10/11/12 10:00	14.7	2/7/12 14:00	11.7	2/7/12 12:00	10.3
5/2/12 11:00	19.3	1/23/12 14:00	14.7	5/26/12 0:00	11.7	10/13/12 10:00	10.3
1/12/12 12:00	19.2	1/4/12 11:00	14.4	1/3/12 12:00	11.7	11/9/12 3:00	10.3
12/2/12 6:00	18.2	2/3/12 10:00	14.1	5/9/12 14:00	11.6	6/2/12 18:00	10.3
7/25/12 19:00	18.1	5/2/12 10:00	14.0	7/2/12 14:00	11.3	2/26/12 19:00	10.3
3/16/12 3:00	17.9	3/25/12 14:00	13.8	3/1/12 15:00	11.0	11/15/12 15:00	10.3
3/24/12 15:00	17.3	1/22/12 6:00	13.8	8/31/12 14:00	11.0	3/7/12 9:00	10.2
10/22/12 2:00	17.0	1/4/12 18:00	13.6	4/6/12 1:00	10.8	12/17/12 15:00	10.2
4/15/12 5:00	16.9	2/26/12 8:00	13.2	6/30/12 4:00	10.8	7/14/12 15:00	10.2
3/11/12 4:00	16.8	6/18/12 14:00	13.2	9/13/12 11:00	10.7	4/26/12 19:00	10.2
7/17/12 2:00	16.7	3/11/12 6:00	13.2	10/25/12 11:00	10.7	5/19/12 14:00	10.1
10/28/12 6:00	16.6	11/14/12 12:00	13.1	8/10/12 19:00	10.6	4/8/12 0:00	10.1
7/25/12 14:00	16.4	12/11/12 14:00	12.4	1/20/12 15:00	10.6	2/24/12 8:00	10.1
5/13/12 16:00	16.0	11/20/12 18:00	12.3	5/20/12 4:00	10.6	9/21/12 16:00	10.0
4/25/12 19:00	15.5	5/1/12 14:00	12.2	11/9/12 12:00	10.6		
5/2/12 16:00	15.4	8/26/12 4:00	12.1	4/2/12 16:00	10.6		
4/24/12 16:00	15.3	12/11/12 15:00	12.0	10/3/12 18:00	10.5		
4/24/12 19:00	15.3	7/6/12 2:00	11.9	10/7/12 15:00	10.4		

C.5 Flexible generation Ratios

The other aspect that was considered was the amount of dispatchable generation available within the hour. An hour with a relatively small ramp but with little dispatchable generation may cause more difficulty that an hour with large ramps and lots of dispatchable generation. The analysis started with the 2012 deterministic dispatch for the year based on the 2006 load profile. 50% of the imports were assumed to be fixed and the remainder dispatchable at $80/MWh. All of the Geothermal, Biomass, Nuclear, Qualifying Facilities (QF), Wind and Solar generation were assumed to be firm. Only the in-state gas fired generation was left dispatchable. Figure C-9 shows the results for the first week in May. Although the loads ranged from roughly 20,000 MW to 35,000 MW the amount of dispatchable generation, which is the difference between the load and total non-dispatchable generation, was very low at times.

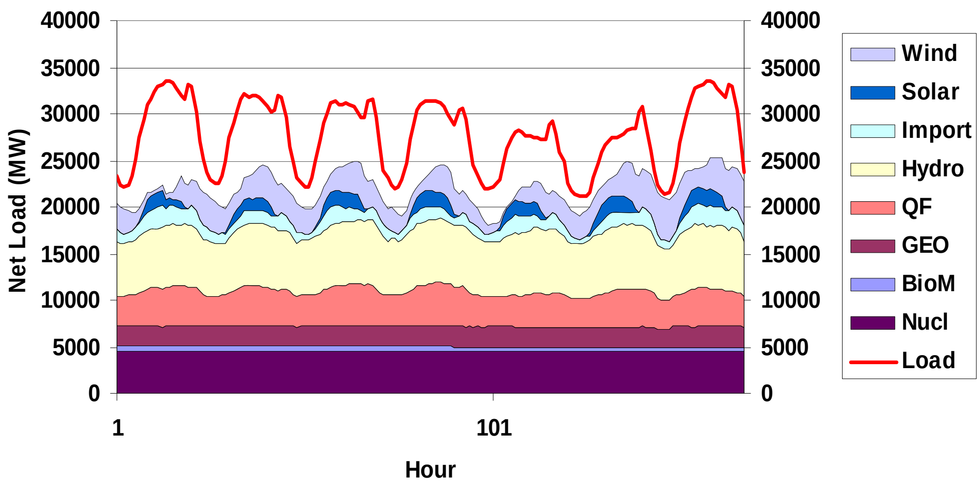


Figure C-9: Dispatch for the first week of May.

The analysis then examined each hour for "interesting" events. In addition to the hours identified previously when the maximum up and down ramps were greater than ten times the average ramp the amount of dispatchable generation was also considered. First, hours with less than 1500 MW of dispatchable generation were flagged. Then the maximum ramps were compared to the amount of dispatchable generation. Those hours when the maximum up or down 5-minute ramp exceed 15% of the dispatchable generation were identified. Table C-4 lists all of the events for the month of May. All of the evaluation criteria is shown with the items flagged highlighted in yellow. In some hours and days multiple events occurred.

Table C-4: Interesting events for May

Month	Day	Hour	MaxUp L-W-S Delta	MaxDwn L-W-S Delta	Dispatchable	Max Up / Disp	Max Dn / Disp	MaxUp/Avg LWS_10	MaxDwn/Avg LWS_10	Events
5	1	12	157.3	-89.1	10,610.9	1%	-1%	11.1		1
5	1	15	60.2	-138.4	11,494.0	1%	-1%		12.2	1
5	2	11	69.2	-213.9	9,958.6	1%	-2%		14.0	1
5	2	12	46.0	-201.9	10,135.3	0%	-2%		19.3	1
5	2	17	74.5	-204.1	8,970.0	1%	-2%		15.4	1
5	3	18	174.1	-390.3	6,207.1	3%	-6%		30.6	1
5	4	5	328.1	-17.6	2,072.8	16%	-1%	2.2		1
5	7	11	81.1	-251.2	9,680.0	1%	-3%		24.4	1
5	9	3	84.1	-72.7	1,087.3	8%	-7%			1
5	9	4	206.5	-29.3	920.0	22%	-3%	2.1		2
5	9	5	247.8	-4.3	1,441.3	17%	0%	2.0		2
5	9	6	397.6	116.5	2,572.0	15%	0%	1.9		1
5	9	15	113.8	-128.2	9,869.1	1%	-1%		11.6	1
5	10	20	253.6	-193.1	8,544.9	3%	-2%	21.9		1
5	13	17	61.6	-230.7	9,432.7	1%	-2%		16.0	1
5	17	15	141.5	-207.2	11,964.8	1%	-2%	14.0		1
5	17	19	206.4	-145.6	11,001.9	2%	-1%	12.9		1
5	19	15	60.2	-132.4	5,849.4	1%	-2%		10.1	1
5	20	4	33.4	-75.1	1,389.5	2%	-5%		3.4	1
5	20	5	95.3	-142.4	1,268.0	8%	-11%		10.6	2
5	20	7	160.7	-33.3	903.0	18%	-4%	2.7		2
5	20	8	222.6	105.1	1,021.0	22%	0%	1.5		2
5	21	2	23.9	-66.1	1,241.0	2%	-5%		3.2	1
5	21	3	21.0	-27.6	1,084.0	2%	-3%			1
5	21	4	123.5	47.1	998.7	12%	0%	1.4		1
5	21	5	225.0	-121.1	1,328.2	17%	-9%	1.9		2
5	22	2	-11.6	-104.4	883.7	0%	-12%		2.6	1
5	22	3	56.7	-61.1	691.0	8%	-9%			1
5	22	4	127.7	45.9	928.1	14%	0%	1.5		1
5	22	5	273.1	3.1	1,165.0	23%	0%	2.1		2
5	22	6	340.7	115.3	2,293.8	15%	0%	1.7		1
5	22	18	164.3	-238.1	6,125.0	3%	-4%	10.4		1
5	23	15	133.4	-78.8	9,952.5	1%	-1%	10.9		1
5	24	11	58.4	-1,231.4	9,590.6	1%	-13%		14.8	1
5	24	12	1,618.8	-449.5	9,919.5	16%	-5%	13.1		2
5	26	1	198.1	-171.1	3,111.4	6%	-6%		11.7	1
5	26	5	168.8	-125.6	2,492.5	7%	-5%	12.8		1
5	27	2	3.6	-77.8	1,277.9	0%	-6%		2.1	1
5	27	3	36.3	-45.3	1,143.1	3%	-4%			1
5	27	4	107.4	-11.2	948.2	11%	-1%	5.1		1
5	27	5	105.6	-127.3	1,050.6	10%	-12%			1
5	27	6	168.7	2.2	1,399.1	12%	0%	3.6		1
5	27	7	202.4	-159.6	895.5	23%	-18%	3.6		3
5	27	8	293.8	-181.4	969.1	30%	-19%	3.3		3
5	27	9	310.3	39.2	1,263.9	25%	0%	2.4		2
5	28	2	-12.9	-76.6	1,397.0	0%	-5%		1.8	1
5	28	3	17.6	-34.3	1,123.5	2%	-3%			1
5	28	4	65.7	1.6	1,165.2	6%	0%	2.6		1
5	28	5	135.6	-126.7	1,324.0	10%	-10%			1
5	28	6	128.9	-1.7	1,450.5	9%	0%	3.3		1
5	28	7	129.3	-9.7	914.7	14%	-1%	1.8		1
5	28	8	214.0	-199.4	692.1	31%	-29%	4.0		3
5	28	9	221.0	71.2	774.2	29%	0%	1.6		2
5	28	10	123.3	4.3	1,061.6	12%	0%	1.7		1
5	28	15	47.7	-126.2	1,414.4	3%	-9%			1
5	28	16	69.7	-28.3	1,205.6	6%	-2%	3.1		1
5	29	1	61.0	-93.8	1,340.3	5%	-7%		2.5	1
5	29	2	73.0	-104.4	1,269.5	6%	-8%		6.9	1
5	29	19	184.8	-58.9	8,122.9	2%	-1%	10.5		1

Figure C-10 shows the total number of interesting events by month. This analysis, along with the previous hourly stochastic dispatch analysis for the year, confirmed that the month of May would be the most difficult from an operational standpoint. Another summary of the statistics is shown in Table C-5.

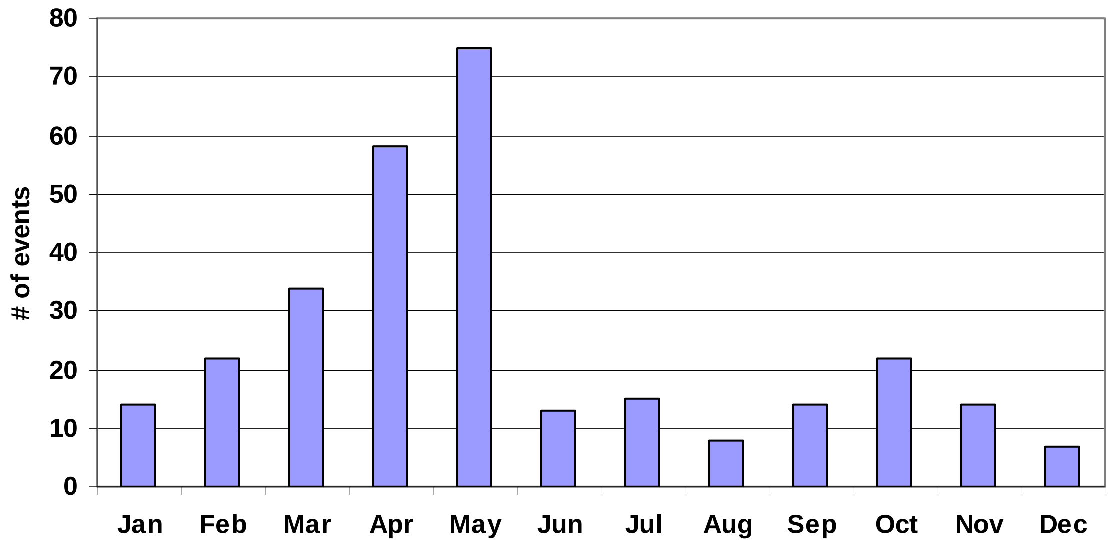


Figure C-10: Number of "interesting" event by month

Table C-5: Statistics of interesting events, 2006

Event	Count
1) Dispatchable Generation < 1500 MW	61
2) Max Up / Dispatchable > 15%	37
3) Max Down / Dispatchable > 15%	11
4) Max Up Ramp / Avg Ramp > 10	111
5) Max Down Ramp / Avg Ramp > 10	76
total events	296
Unique hours	263
Unique days	152
Days > 2 events	28

Table C-6 shows the days with more than two events happening at some time within the day. From this analysis, and based on statistics from the hourly stochastic dispatches, the days of May 16, 17, 24, 27 and 28 were selected for further sub-hourly analysis.

Table C-6: Summary of days with more than two events.

Month	Day	Events
1	20	3
2	26	3
3	1	4
3	11	3
3	25	12
3	26	4
4	6	4
4	8	3
4	9	3
4	14	7
4	15	10
4	17	4
4	19	3
4	21	5
4	25	3
4	27	3
5	2	3
5	9	7
5	20	7
5	21	5
5	22	7
5	24	3
5	27	13
5	28	14
5	29	3
6	11	3
7	2	4
10	27	3

C.6 2007 Analysis

The bulk of the analysis was performed on the 2006 load and generation shape data which had a high amount of hydro generation. The year 2007, which had significantly less hydro generation, was also analyzed. Figure C-11 shows a comparison of the generation by type for the two shape years considered. The hydro generation in 2007 is only slightly more than half of the 2006 level. The bulk of the difference is made up by increased imports and in-state gas fired generation.

Figure C-11: Comparison of generation by type for 2006 and 2007

Table C-7 Compares the amount of firm generation available each hour for the 2006 and 2007 based simulations. Because of the reduced hydro generation there is more flexible generation available to operate each hour.

Table C-7: Comparison of generation by type for 2006 and 2007

Gentyp	2006, Imports 50% Firm	2007, Imports 50% Firm
BioM	4,692	4,692
Gas	77,486	83,677
GEO	19,019	19,017
Hydro	37,240	20,662
Import	20,858	26,638
Nucl	39,967	39,967
Oil	1,010	1,010
Other	226	227
Solar	4,907	4,907
Wind	17,886	17,886
QF	39,206	42,129
Shydro	1,047	1,047
Total	263,543	261,858
Renewable	47,550	47,547
Renewable	18%	18%

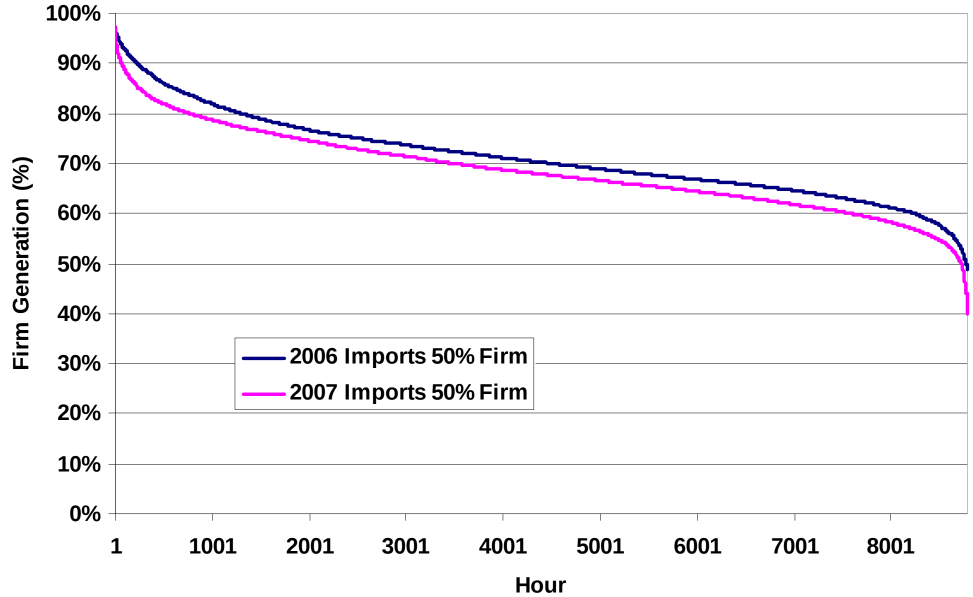


Figure C-12: Comparison of firm generation for 2006 and 2007

The operating issues (high ramping, low flexibility, etc) were also evaluated for the 2007 shapes. Figure C-13 shows the number of issues occurring each month. Similar to what was seen in the 2006 analysis, May seemed to be the worst month. Figure C-13 shows the number and type of issues for each day in May. Based on these results May 22nd and 23rd were studied at the 5-minute level.

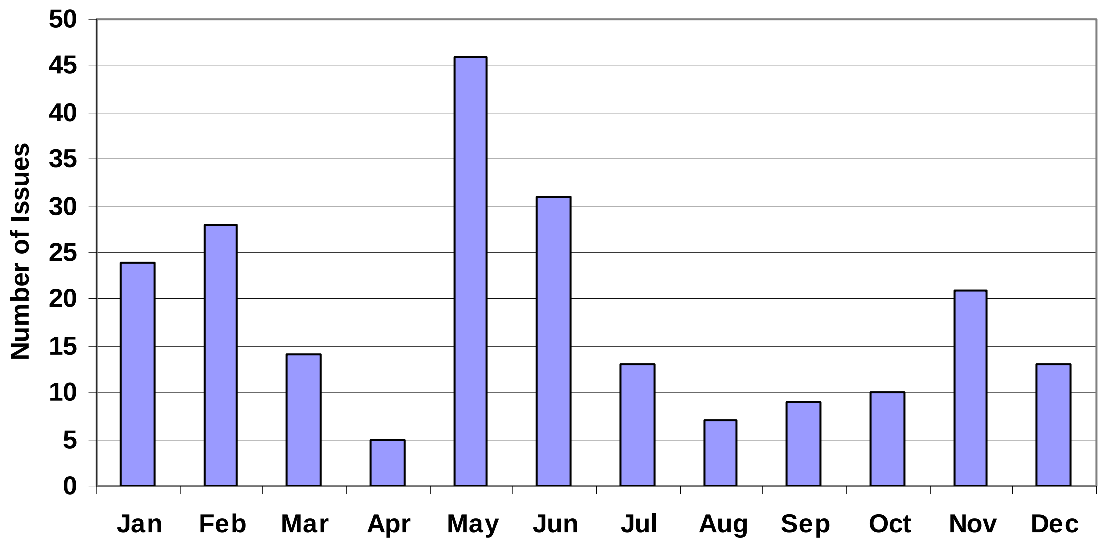


Figure C-13: Number of Operating issues in 2007

Table C-8: Daily Operating Issues in May 2007

Month	Day	Sum of Events	Max of MaxUp/Avg LW_10	Min of MaxDwn/ Avg LW_10	Max of Max Up L-W / Flexible Gen	Min of Max Dn L-W / Flexible Gen	Min of % Dispatchable Gen
5	1	1		10.9	1%	-4%	28%
5	3	2		10.6	3%	-3%	22%
5	4	1		17.1	2%	-3%	23%
5	8	3	5.9	1.6	2%	-5%	8%
5	9	1		23.4	3%	1%	28%
5	12	1		10.8	7%	-3%	25%
5	15	5	21.2	1.5	14%	-7%	9%
5	16	1	16.4		0%	-1%	28%
5	18	1		10.3	7%	1%	21%
5	19	1		11.8	7%	0%	21%
5	21	1		11.2	1%	-2%	19%
5	22	17	4.5	1.9	23%	-11%	6%
5	23	7	4.0	2.4	16%	-14%	7%
5	25	1		10.3	4%	-2%	20%
5	27	2		19.1	5%	0%	28%
5	31	1	10.0		1%	-1%	29%

C.7 Analysis of Operational capability under 20% RPS – Additional results

Sub-hourly analysis was conducted for five separate days within the month of May. Those days were the 16th, 17th, 24th, 27th and 28th. In addition to the 5-minute analysis a 10-minute analysis was done for the 24th and 28th for comparison purposes. Table C-9 shows the results from the DA, HA and RT-H analysis for comparison. The overall conclusion appears to be that if the hourly level simulations say that there is no operational issues, or only relatively small issues, then the sub-hourly analysis shows that the issues tend to go away. However, if the hourly level indicates that there may be a more significant issue then the sub-hourly simulation shows an even larger impact. Figures C-14 through Figure C-18 show the results graphically for the individual days where sub-hourly analysis was performed. Figure C-19 and Figure C-20 show similar results for May 22nd and 23rd from the 2007 analysis.

Table C-9: Comparative operational results for May

	DA	HA	RT-H	RT-5	DA	HA	RT-H	RT-5	DA	HA	RT-H	RT-5	DA	HA	RT-H	RT-5	DA	HA	RT-H	RT-5
Date	Dump	Dump	Dump	Dump	Regdn	Regdn	Regdn	Regdn	Regup	Regup	Regup	Regup	Spin	Spin	Spin	Spin	Dump+ Regdn	Dump+ Regdn	Dump+ Regdn	Dump+ Regdn
5/1/2012	0.0	0.0	0.0		0.5	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.5	0.0	0.0	0.0
5/2/2012	1.0	0.0	0.0		1.7	1.9	0.0		0.0	0.0	0.0		0.0	0.0	0.0		2.7	1.9	0.0	0.0
5/3/2012	0.0	5.0	0.0		1.8	6.2	0.0		0.0	0.0	0.0		0.7	0.0	0.0		1.8	11.2	0.0	0.0
5/4/2012	67.8	86.5	15.2		73.2	110.7	48.4		0.4	0.0	0.0		0.9	0.0	0.0		141.0	197.2	63.7	0.0
5/5/2012	85.8	62.3	10.1		58.2	71.4	45.7		0.0	0.0	0.0		1.1	0.0	0.0		144.0	133.6	55.8	0.0
5/6/2012	5.9	2.5	1.0		18.7	11.2	8.7		0.0	0.0	0.0		0.0	0.0	0.0		24.6	13.7	9.7	0.0
5/7/2012	0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0	0.0
5/8/2012	0.0	0.0	0.0		0.0	0.3	0.0		2.8	0.0	0.0		1.6	0.0	0.0		0.0	0.3	0.0	0.0
5/9/2012	167.4	292.3	247.8		92.2	110.0	132.6		0.0	0.0	0.0		9.9	0.2	0.0		259.6	402.4	380.4	0.0
5/10/2012	41.6	106.9	54.0		12.6	23.3	15.2		0.0	0.0	0.0		7.8	0.1	0.0		54.2	130.2	69.2	0.0
5/11/2012	1.2	78.6	11.4		3.8	24.1	8.0		0.0	0.0	0.0		2.1	0.0	0.0		5.0	102.8	19.4	0.0
5/12/2012	6.1	4.4	0.0		5.3	3.2	0.0		0.0	0.0	0.0		0.0	0.0	0.0		11.5	7.7	0.0	0.0
5/13/2012	18.0	10.8	0.8		6.5	5.3	0.1		0.0	0.0	0.0		0.7	0.1	0.0		24.5	16.1	0.9	0.0
5/14/2012	4.3	13.3	4.4		2.2	3.6	1.5		0.0	0.0	0.0		2.9	0.0	0.0		6.5	16.9	5.9	0.0
5/15/2012	43.8	101.4	9.8		0.0	0.0	0.0		0.0	0.0	0.0		5.5	0.6	0.0		43.8	101.4	9.8	0.0
5/16/2012	2.6	12.8	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	2.6	12.8	0.0	0.3
5/17/2012	7.8	3.6	0.0	0.2	0.0	0.0	0.0	0.1	0.0	0.0	0.0	1.2	0.1	0.0	0.0	0.0	7.8	3.6	0.0	0.3
5/18/2012	0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		1.3	0.0	0.0		0.0	0.0	0.0	0.0
5/19/2012	26.6	25.7	3.0		6.7	0.0	0.0		0.0	0.0	0.0		9.2	0.2	0.0		33.3	25.7	3.0	0.0
5/20/2012	241.6	356.5	93.5		152.9	201.7	164.4		0.0	0.0	0.0		7.2	2.3	0.0		394.4	558.2	257.9	0.0
5/21/2012	349.6	269.5	121.5		1.2	1.1	0.0		0.0	0.0	0.0		4.4	0.6	0.0		350.9	270.7	121.5	0.0
5/22/2012	348.2	364.4	257.8		0.0	0.0	0.0		0.0	0.0	0.0		7.1	4.3	0.0		348.2	364.4	257.8	0.0
5/23/2012	19.5	136.1	42.7		0.0	0.0	0.0		0.2	0.0	0.0		6.3	0.2	0.0		19.5	136.1	42.7	0.0
5/24/2012	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.4	1.8	0.0	0.0	0.0	0.0	0.0	0.0	0.3
5/25/2012	0.0	6.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		4.0	0.0	0.0		0.0	6.0	0.0	0.0
5/26/2012	19.2	27.7	1.9		36.7	53.1	31.6		0.0	0.0	0.0		1.3	0.0	0.0		56.0	80.9	33.6	0.0
5/27/2012	1,058.1	802.9	331.5	1,485.7	347.7	375.3	330.5	955.7	2.3	0.0	0.0	1,150.4	8.1	5.2	0.0	168.7	1405.9	1178.2	662.0	2441.4
5/28/2012	1,140.7	1,622.0	780.3	2,561.3	489.8	756.9	1,021.6	1,435.4	1.2	0.0	0.0	1,099.0	22.4	10.1	0.3	311.3	1630.5	2378.9	1801.9	3996.7
5/29/2012	166.4	203.8	133.1		0.0	0.0	0.0		0.0	0.0	0.0		1.6	1.3	0.0		166.4	203.8	133.1	0.0
5/30/2012	0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0	0.0
5/31/2012	0.4	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.4	0.0	0.0	0.0
Total	3,823.8	4,595.2	2,119.8		1,311.9	1,759.4	1,808.4		7.0	0.0	0.0		110.3	25.3	0.3		5135.7	6354.6	3928.1	0.0

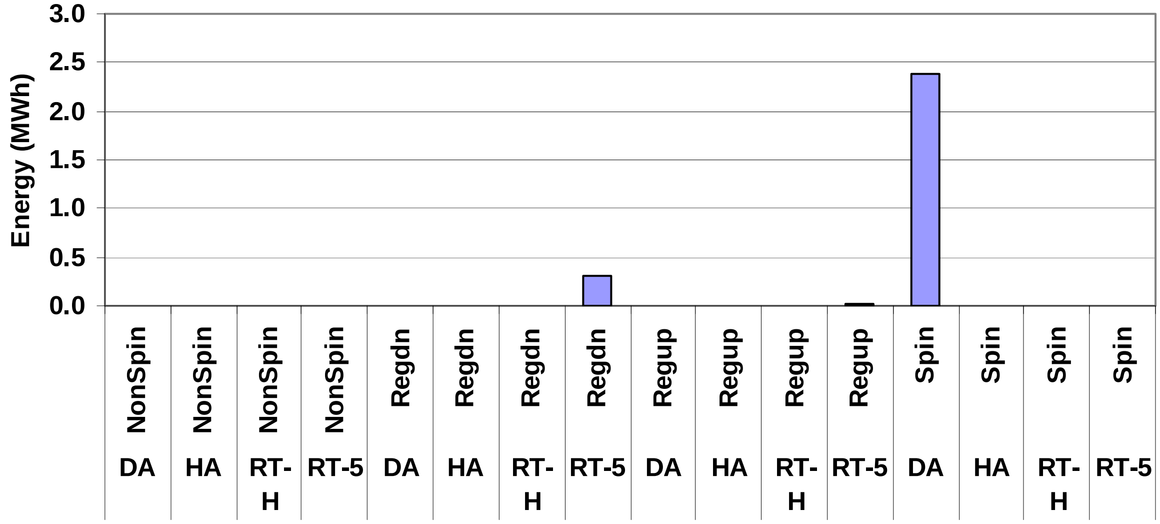


Figure C-14: May 16th Operational Issues based on 2006 Load Shapes

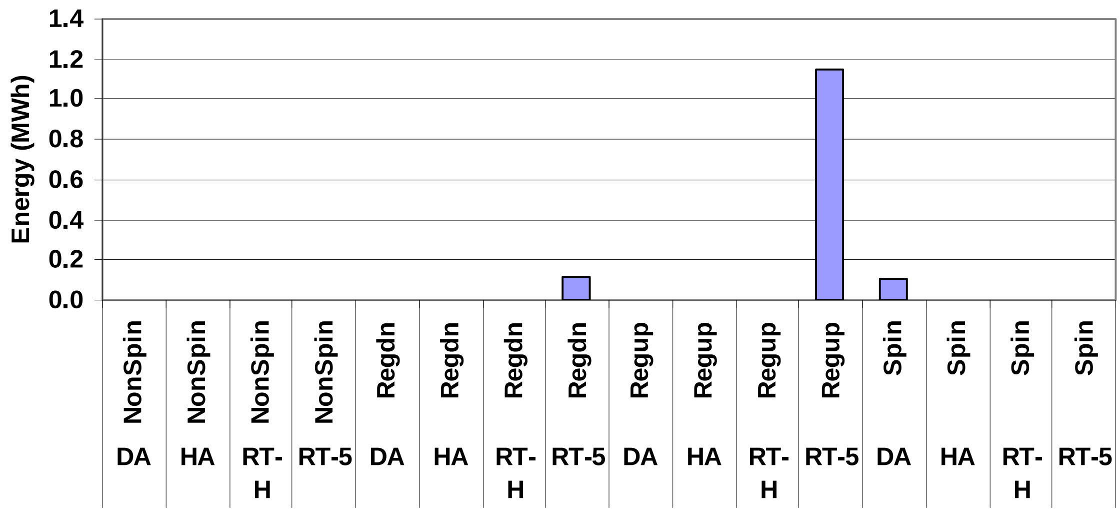


Figure C-15: May 17th Operational Issues based on 2006 Load Shapes

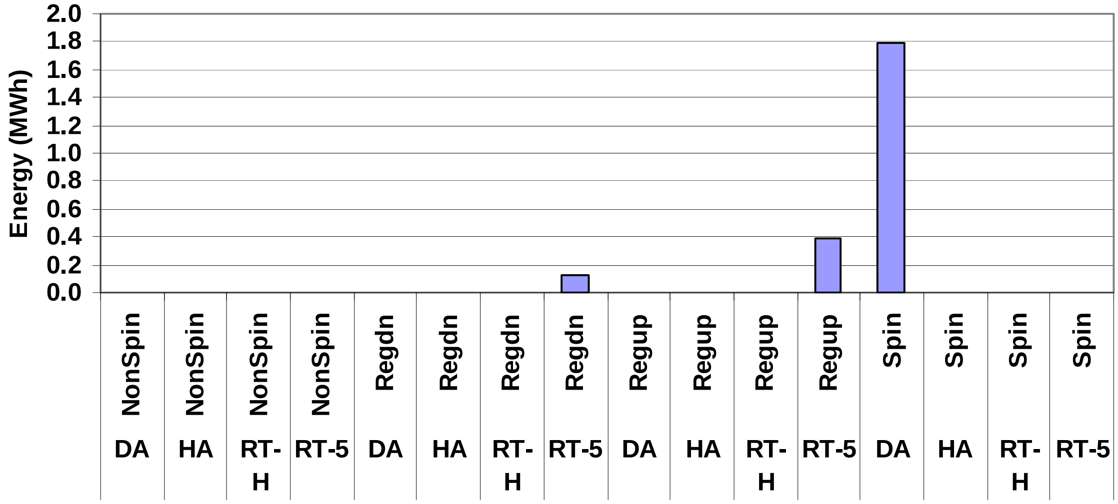


Figure C-16: May 24th Operational Issues based on 2006 Load Shapes

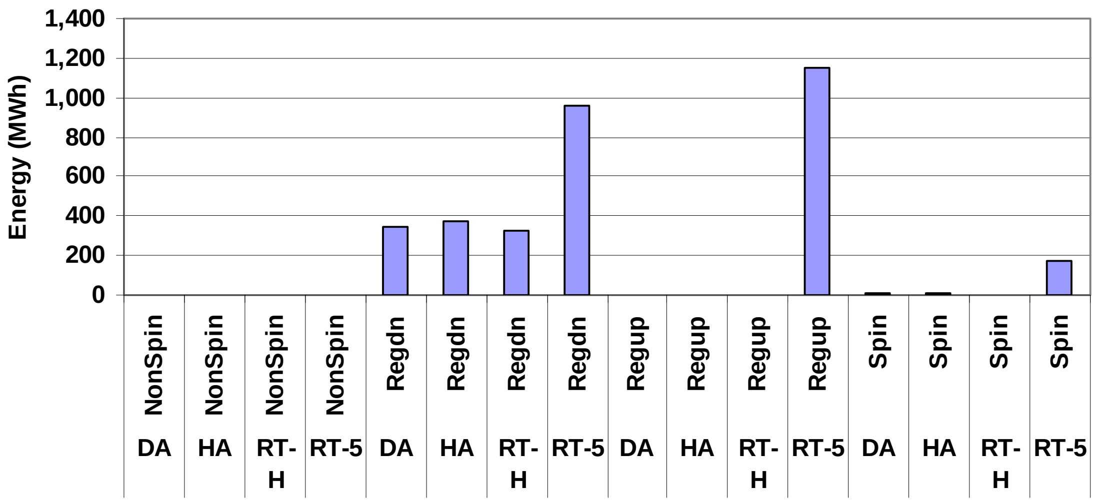


Figure C-17: May 27th Operational Issues based on 2006 Load Shapes

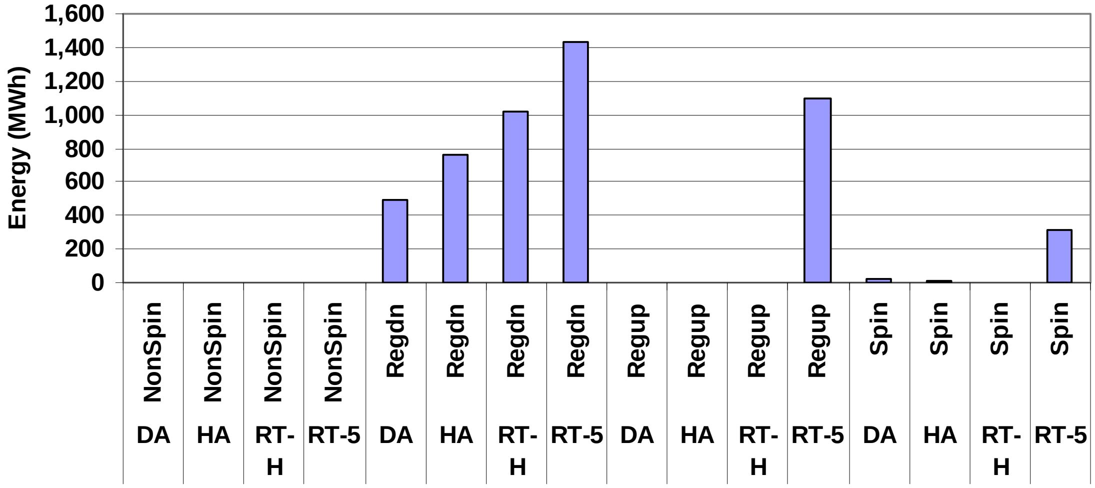


Figure C-18: May 28th Operational Issues based on 2006 Load Shapes

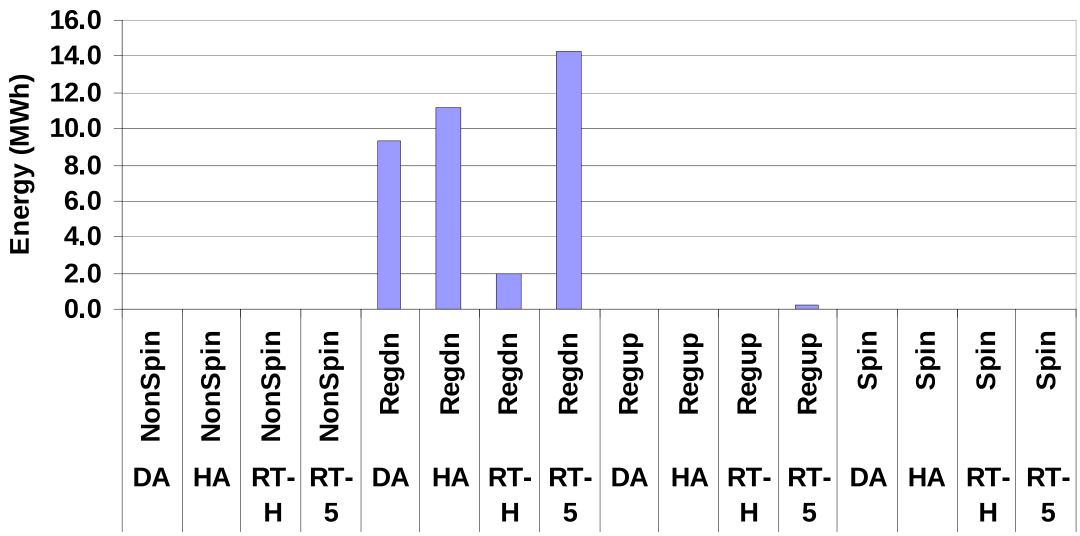


Figure C-19: May 22nd Operational Issues based on 2007 Load Shapes

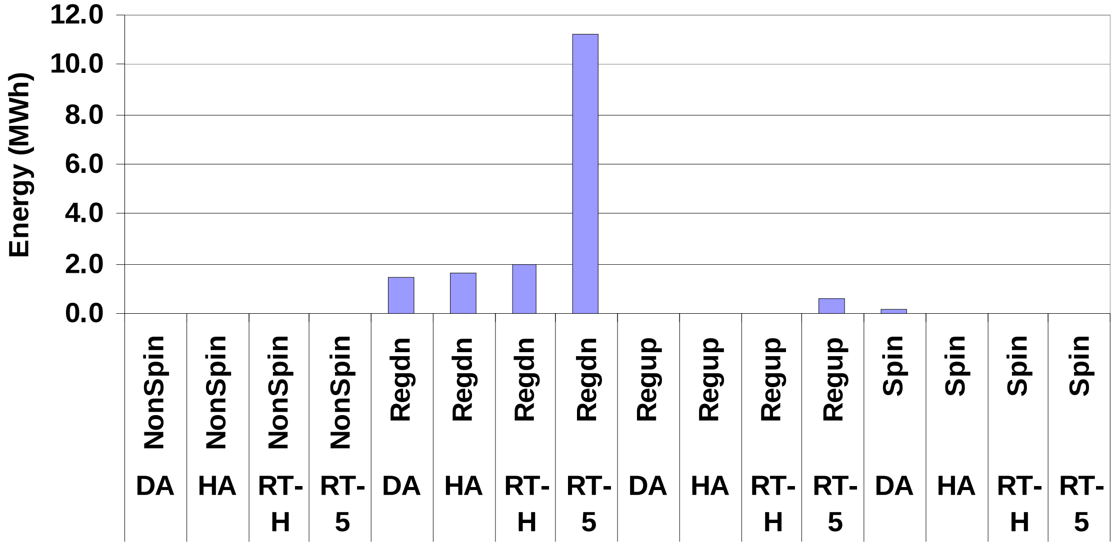


Figure C-20: May 23rd Operational Issues based on 2007 Load Shapes

Attachment D – Frequency of Real-Time Prices By Range Graph

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with

Additional Performance Based Refinements

California Independent System Operator Corporation

September 25, 2013

ATTACHMENT D

Frequency Of Real-Time Prices By Range – January 2010 to June 2011

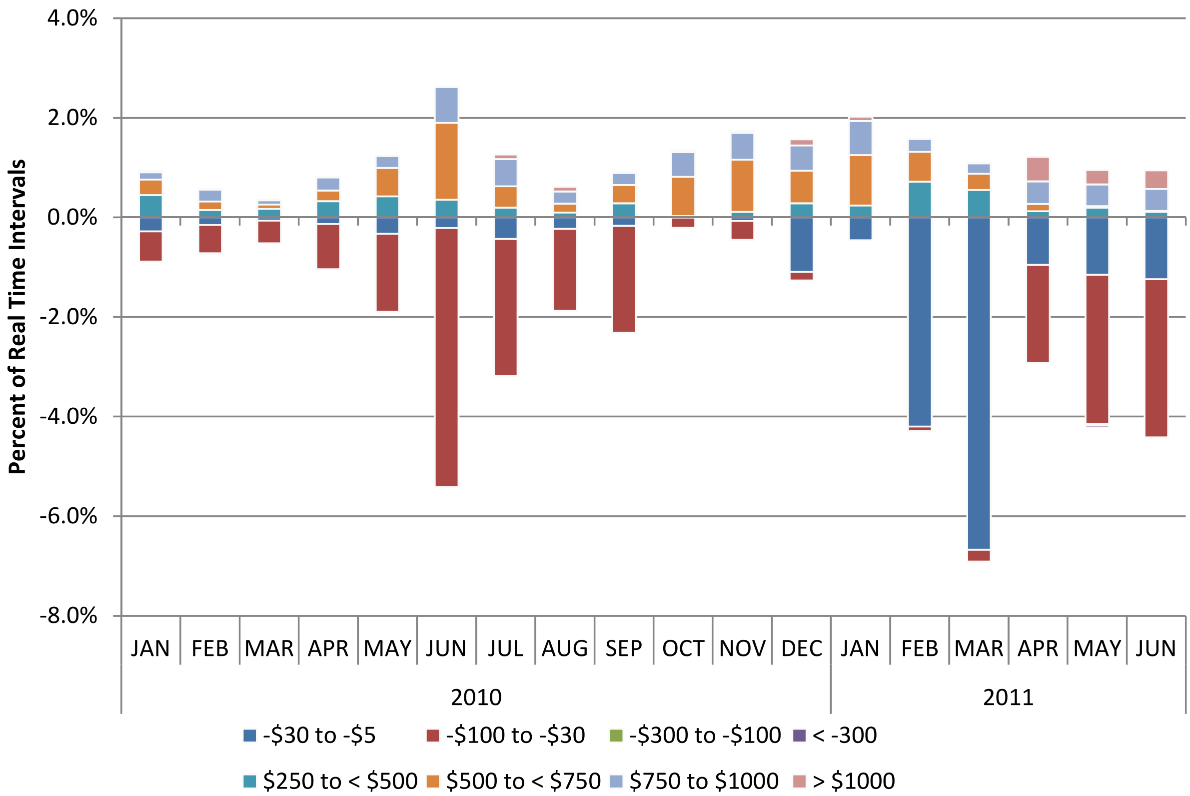


Figure 3.5 Factors causing negative real-time prices

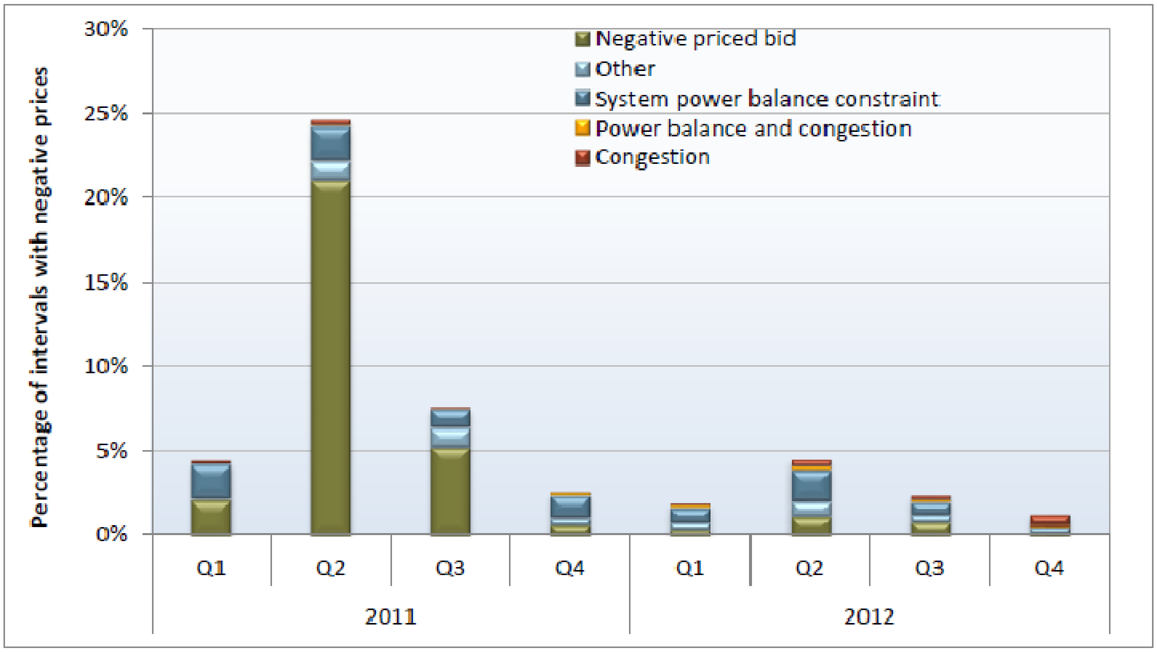
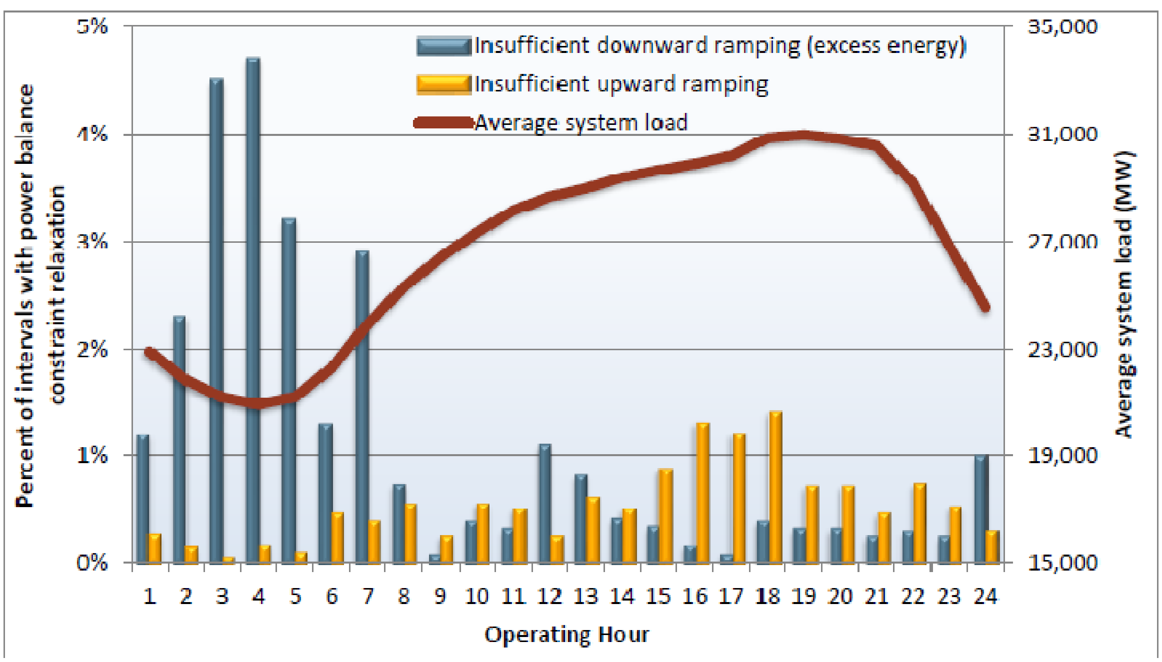


Figure 3.3 Relaxation of power balance constraint by hour (2012)



Attachment E – Final Opinion on Integration: Market and Product Review, Phase 1

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with Additional Performance Based Refinements

California Independent System Operator Corporation

September 25, 2013

FINAL
Opinion on Integration: Market and Product Review, Phase 1

by

James Bushnell, Member
Scott M. Harvey, Member
Benjamin F. Hobbs, Chairman

Members of the Market Surveillance Committee of the California ISO

December 8, 2011

1. Introduction

The Market Surveillance Committee (MSC) of the California Independent System Operator has been asked to provide an opinion on the three components of the Nov. 4, 2011 Draft Final Proposal for the Renewable Integration: Market and Product Review, Phase 1.[1] The purpose of that proposal is to identify modifications to the market rules that could be quickly implemented in order to facilitate integration of variable renewable power sources into the ISO markets. The fundamental concern being addressed is the potentially inadequate amounts in real-time of economic bids during periods of very low (i.e., negative) prices. Such inadequacies are experienced occasionally at present, and are anticipated to increase significantly in frequency as more renewable resources come on line. The economic consequences of inadequate economic bids when prices are negative is that additional within-CAISO thermal resources are required to be committed rather than less expensive imports so that decreases in loads in real-time can be accommodated by dispatching those resources downward. With a deeper pool of economic bids, including bids from renewable generators, it will become less expensive for the ISO to procure decreases in generation when needed under negative prices.

The Proposal involves three parts intended to encourage more economic bids in real-time. The first is revisions to the Participating Intermittent Resource Program (PIRP) designed to have contracting parties realize more directly the value of their real-time production so as to motivate them to bid more flexibly, in particular to offer to reduce output when the value of their output is very low and in fact negative. The second is a lowering of the bid-floor so that negative bids below the present -$30/MWh floor can be made. Presently, that floor is smaller (in absolute value terms) than the value of supplemental sources of revenue such as production tax credits and renewable energy credits received by renewable generators. When these sources of revenue are included, renewable generation can produce positive net revenues even when the energy price is below the present bid floor of -$30/MWh. The third part would alter Bid Cost Recovery (BCR) procedures to allow for separate calculation of BCR in the day-ahead and real-time markets (the latter defined for the purpose of BCR as including as bid costs in both the real-time dispatch and the Residual Unit Commitment market). The intent is to prevent generators from

[1] http://www.caiso.com/Documents/DraftFinalProposal-RenewableIntegrationMarket-ProductReviewPhase1.pdf

being motivated to refrain from offering their resource into the real-time dispatch in order to avoid either being dispatched in a manner that reduces profits earned in the day-ahead market or offsets real-time profits against day-ahead BCR payments.

Earlier versions of the PIRP, bid floor, and BCR portions of the proposal have been discussed during MSC meetings, most recently during the March 18 and September 30 2011 meetings. In addition, MSC members have participated in stakeholder calls and have reviewed stakeholder comments submitted to the ISO.

In general, the MSC strongly supports the goal of encouraging economic bids that would allow for downward generation adjustments in response to negative real-time prices. The importance and value to the system and, ultimately, consumers of such increased flexibility will grow significantly as the penetration of variable renewable rises. We support the general direction of the ISO's proposals as likely being effective in advancing that goal in the short-run, which is the focus of Phase 1 of the Market and Product Review process. However, we recommend some modifications to specific aspects of the proposals.

More specifically, we support the proposed PIRP revisions as a step in the right direction of making contracting parties bear the costs of the variability of their resources. We note that complete abolition of PIRP might result in significantly more economic bidding than the present proposal, which would maintain PIRP. However, without knowing the specific terms of existing contracts between PIRP resources and load-serving entities (LSE), nor knowing the extent to which such contracts would be modified to permit more flexible bidding, we cannot conclude that complete abolition would definitely result in appreciably more economic bids when prices are negative.

We also support the decrease in the bid floor to -$150/MWh. However, we recommend that the proposed further decrease to -$300/MWh not be automatically implemented, but rather be recommended only if it is concluded that insufficient economic bids were elicited by the -$150/MWh floor; that appreciably more economic bids would result from dropping the floor further; and that negative side effects of having dropped the bid floor to -$150/MWh are absent or acceptably small.

Finally, we support the separate calculation of BCR for the day-ahead and real-time markets, and anticipate that it will remove important disincentives to bidding in real-time. However, we are unable at this time to conclude with confidence that the Performance Measure and Persistent Uninstructed Energy Check features of the proposal will function as intended. Although we understand and appreciate the intent of those features, there is neither sufficient detail regarding the parameter values that would be used in applying these features, nor sufficient testing data to allow us to reach a conclusion about their functioning. It is important to ascertain that those features are (1) effective in discouraging strategic behavior aimed at increasing BCR payments, (2) while not inadvertently yielding large decreases in BCR payments for normal deviations from dispatch instructions. Such decreases would undermine the goal of encouraging more resources to participate in the real-time dispatch. It is possible that significant changes to the basic features as proposed would be necessary to accomplish these goals. Therefore, the procedures should be subjected to extensive testing and possible refinement. We understand that the

ISO will be conducting such tests, and we look forward to participating in the review of those results and their implications for the design of these features.

Since the issuance of the draft opinion, the ISO's proposal for the December Board meeting has been revised. The revised proposal is consistent with our recommendations on the bid floor and BCR, while revisions to PIRP have been deferred.

2. Participating Intermittent Resource Program (PIRP)

The fundamental features of PIRP are the use of ISO forecasts to determine the real-time output schedules of PIRP resources, paying PIRP resources for their real-time output based on these schedules rather than their actual real time output, and the socialization of the cost of the differences between those schedules and the actual real-time output of PIRP resources. Real-time markets in ISO systems act as balancing markets, where the ISO dispatches flexible resources based on their bids and offers to ensure that supply and demand remain constantly balanced. Individual generators or loads have committed to production schedules in advance, and if they deviate by either producing more or less than those schedules, the ISO balances the system by adjusting the output of other suppliers. A central principle of the balancing market process is that the costs (or benefits) of such deviations from schedules are paid (or earned) by the parties responsible for the deviations. These costs reflected in the real-time price: the marginal cost of adjusting the system dispatch at the moment of the deviation.

Conventional resources have both more predictability and, at in many cases, more flexibility than do most renewable sources of supply. In part because of this, the CAISO has treated some renewable resources differently than other resources in the balancing market process. Instead of being paid the value of their real-time output on an interval-by-interval basis, PIRP resources are paid the real-time price for their hourly schedule, with an adjustment for the net difference between their actual and scheduled output over the month. Thus, a wind supplier that ended up producing 1 more MWh during a month than projected in aggregate for the month would be paid for that incremental megawatt based on the average of the real-time prices over that month. This is the case even if that producer was short of production by 99 MWh in one hour in which prices were very high and had excess production of 100 MWh in another hour during which prices were very low.

If prices in all periods were the same, or close to the same, this averaging would not be a significant issue. The problem is, not all intervals are alike. In some intervals the system may badly need more power and in others may have too much. These values are captured in the interval prices. In this context the PIRP program creates several incentive problems. First, if a renewable source subject to PIRP is allowed to schedule its power, it would have an incentive to schedule more during high price periods and less during low-price periods. It would earn the higher prices on its schedules but only pay the average of all prices for the deviations from its schedules.[2] For this and other reasons, the CAISO produces the schedule for PIRP resources, rather

[2] For example, consider a PIRP generator that actually produced zero output in real time. If this generator scheduled 1 MW of output in what it expected to be the highest price interval of the month, it would then earn the scheduled price for that 1 MW. Since it does not generate at all, its monthly imbalance is -1 MW, which would be charged at the average of all monthly prices. From this, the generator nets the difference between the highest and

than leave this to the resources themselves. Second, there is a distortion in incentives to take actions to depart from the forecast-based schedule. An interval price of $500/MWh is signaling that the system highly values increased output, yet a PIRP generator would not be paid this price for its incremental output. On the other hand, a large negative price would signal the opposite, but the PIRP generator would not have an incentive to decrease its output.

It is worth tabulating the net value of these deviations for purposes of comparison. Say that the average monthly real-time price is $70/MWh. If a unit produces 1 MWh excess during an interval with a negative price (e.g., -$30/MWh), and is 2 MWh short in an hour with a high price (e.g., $100/MWh), the costs to the system of the difference between actual and scheduled output are reflected in the sum of the deviations times the respective price difference of the prices, +1 MWh * -$30/MWh − 2MWh*$100/MWh = -$230. However the generator would pay for its net monthly imbalance of 1 MWh net at the average monthly price of $70/MWh. The portion of the $230 cost to the system that is not paid by the generator ($160 =$230-$70) represents a subsidy to PIRP generators. Note that it could work the other way, as for example if a unit could be 2 MWh short when the price is -$30/MWh while overproducing by 1 MWh when the price is $100/MWh. The generator would have, again, a net negative deviation of 1 MWh for the month, and so it would pay the ISO $70/MWh*1 MWh = $70. Meanwhile, the cost to the system would actually decline by -2 MWh*-$30/MWh + 1 MWh*$100/MWh, or $160. That is, the generator pays the ISO $70, even though system costs are actually $160 lower because of the deviations. However, deviations from schedule tend to be negatively correlated with real-time prices in the case of PIRP resources because the deviations of different renewable facilities will likely be positively correlated. As a result, when renewable production is lower than projected, real-time prices are more likely to be higher, and conversely extremely low prices are more likely when renewable production is unexpectedly high.

We recognize that the PIRP program provides some value to generators. For wind producers whose output is completely random, with no control over the output, the volatility of real-time prices represents a tangible source of risk. When averaged over, say, a month, we believe that this uncertainty is likely to be considerably less than risks associated with the overall variability of wind output and real-time prices.[3] Nonetheless, for uncontrollable wind sources, PIRP can be viewed as a form of insurance against the cost of uninstructed deviations. However, in the terminology of the insurance analogy, the premiums are not actuarially fair. This is much closer to crop-insurance (a Federally subsidized instrument) than it is to auto insurance. Additionally, a common issue with insurance is that it can create incentive problems known as “moral hazard.” If a firm is insulated from the financial risks and consequences of its decisions, they will

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average real-time price. Symmetrically, if a generator would produce 1 MW in a low price interval, it would prefer to schedule zero MW, allowing it to get paid the average monthly price for the resulting 1 MW upward deviation.

[3] We anticipate that the month-to-month total imbalance costs do not greatly fluctuate, since the hour-to-hour imbalances will cancel out to a large extent. As a result, the ISO’s PIRP proposal represents a reallocation not so much of risks, but of the average of the hourly imbalances over a month, which is a much more stable quantity. We have not seen evidence that fluctuations in these costs are anywhere near as important for a typical wind generator as, for instance, fluctuations in revenues due to variations in monthly average wind production or in the ISO’s market prices.

be less inclined to take steps to avoid or mitigate those consequences. In this context, the moral hazard is the lack of incentive to adjust output in response to changes in real-time prices when a failure to adjust output would be most costly to the system. There may be ways to subsidize the cost of the insurance while still preserving the marginal incentive to respond to current interval prices.

The most important feature of the PIRP portion of the Nov. 4 Draft Final Proposal proposes the following change to the current PIRP program: that for individual PIRP resources (under both existing and future contracts), uplift costs associated with PIRP will be allocated to a scheduling coordinator (SC) of a LSE designated by the resource rather than shared by all load.[4] This proposal has evolved considerably over the last year. The ISO originally proposed to eliminate the PIRP program for new generation but faced strong opposition. The ISO then proposed to allow LSEs and generators to keep signing new contracts under the old PIRP rules until FERC approved the change. Finally, what the ISO proposes to do now is to effectively eliminate the subsidy elements of PIRP by allocating all of the deviation costs to the SC/LSE that contracts with the PIRP resource (unlike today where they all load shares the cost equally).

We believe that this assignment of costs internalizes the imbalance costs arising from variability/forecast errors to the wind generator and the SC/LSE it has designated, and is much more desirable than the current systemwide sharing of the costs. In theory, this internalization then provides incentives to parties who can do something about the imbalance costs. The parties can renegotiate contracts (if necessary) to provide incentives to bid more flexibly in the face of negative prices, and perhaps, in the long run, to build new facilities whose power outputs can be better forecast. In the case of new PIRP contracts, the SC/LSE and resources will be incented to negotiate terms that will result in more efficient operation.

However, some stakeholders and DMM are concerned that this reallocation of imbalance costs will not incent more efficient operation in the case of existing PIRP contracts. In that case, the contracting parties (the resource and its SC/LSE) would be leaving money on the table by failing to facilitate bidding in a way that allows the resource to be turned off when the negative real-time power price falls below the negative of the production tax credit and value of renewable energy credits. Possible reasons for this include the inflexibility of existing contracts and the difficulties involved in renegotiating them, as well as the absence of appropriate communications and control equipment in older wind turbines.

On the other hand, in the case of new PIRP contracts, we do not see why allocating the costs to the SC/LSE would not create the right contracting incentives going forward. If the renewables market is operating reasonably competitively, the buyers of PIRP generated power benefit from the "insurance premium" subsidy as much as the sellers of PIRP power. There is good reason to expect that if PIRP were ended completely, the resulting increase in costs would be reflected in

[4] This might normally be the LSE that has a purchased power agreement (PPA) with the resource, but this is not necessarily the case under the proposed PIRP revisions. Presumably, if another LSE takes on the cost allocation of the uplifts, it would have to be compensated by the PIRP resource for providing this financial service.

higher contract prices.[5] Either way, the SC/LSE would be the likely party to bear the brunt of the costs (explicit or implicit) of PIRP.

The ISO cannot prevent the SC/LSE from simply choosing to absorb these costs, but under the CAISO's present proposal they would no longer be able to assign them in part to other SC/LSEs. We anticipate that this will incent SC/LSEs to negotiate purchased power agreements with individual resources that provide for submission of economic bids when prices are sufficiently negative. With the costs of imbalances internalized in contracts, the contractual terms should reflect the division of those imbalances. For instance, this could result in higher PPA payments from the SC/LSE if SC/LSEs transfer imbalance costs back to the generators who might be in a better position to manage them (for instance by reducing output when prices are very negative). But if the generator would rather not manage those costs, it can arrange to pay for the equivalent of insurance from third parties or, more likely, accept lower PPA prices in exchange for the counterparty SC/LSE choosing to pay those costs instead. This can be negotiated by the parties, and the results of those negotiations will not be distorted by the present policy of sharing the imbalance costs across all load.

Note that there are two somewhat separate issues here. The first is the distribution of the costs of the imbalance insurance provided by PIRP. The second is the degree to which that insurance leads to moral hazard problems by muting incentives to respond to changing system needs. Even if it is decided that renewable firms require subsidies for insuring against the risks of imbalances (which we doubt, as these risks are likely to be less than other market risks), this can be done in a manner that still preserves incentives to respond to system prices, which will improve market efficiency.

We conclude that the ISO proposal to reallocate PIRP costs to the SC/LSE has promising potential to mitigate the distortions in bidding decisions and perhaps even investment decisions that arise from the current practice of sharing the costs of uplift charges across all load. A strong, but perhaps insufficient incentive will be provided to SC/LSEs and resources involved in present PIRP contracts to adjust bidding procedures and perhaps the contracts themselves to permit more flexibility in responding to negative real-time prices. Unfortunately, we lack sufficiently detailed information regarding the structure of typical existing contracts, either in terms of payments or control of operating decisions, to make an informed judgment as to whether complete elimination of PIRP would lead to a better outcome than the ISO's current proposal to shift the cost allocation. But that we believe that either the ISO's proposal to change the cost allocation or complete elimination of PIRP would provide needed improvements relative to the status quo. We note that more megawatts of new wind resources are expected to come on line under new PIRP contracts than already operate under existing PIRP contracts, so it is most important to get incentives right for the new resources.

[5] In general, the incidence of a new cost or tax is borne by the less price responsive (or elastic) part of the market. In this case, the "demand" for renewable power can be considered quite inelastic due to the requirements of California's renewable portfolio standard (RPS). As long as the RPS is enforced, it is likely that the costs of this PIRP adjustment will be ultimately be passed on to SC/LSEs whether they are first assigned to resources or assigned to SC/LSEs directly. The important difference to the current method is that SC/LSEs will no longer be able to spread the charges of their own PIRP related costs to other SC/LSEs.

3. Bid Floor

Recall that all the measures contained in the ISO's proposal are motivated by a goal of creating better incentives for firms to be more flexible and responsive in both their bids and their operations. The adjustment of the bid floor is another measure aimed at furthering this goal. There is a periodic and growing problem with "overgen" conditions where the system has too much energy offered at zero or even slightly negative prices. In other words, too many units are unwilling to reduce their output even though they are paying, through a negative price, for the privilege of continuing to produce power.

This rigidity comes from several sources, including a desire to maintain fixed schedules for institutional or contractual reasons. However, various policies directed at promoting renewable energy are playing an increasingly prominent role. An unfortunate side-effect of these policies is that they reward production of renewable MWh no matter whether they help or harm system performance. These policies include production tax credits (PTC) and renewable energy credits (RECs) that make production of renewable energy profitable even when the energy price is negative. Firms can pay to inject energy into the transmission grid when energy prices are negative but earn even more back in the form of PTC and REC revenues. During times of large negative prices, obliging the power system to accept renewable energy will increase system operating costs and can increase emissions relative to a better designed renewable subsidy program.[6] If the objectives of renewable energy policy is to lower costs and emissions, and to decrease renewable energy costs through learning curve effects, incentives for production that are blind to its effects on the system work against the first two objectives, and do nothing for the third. We would support revisions to renewable support schemes that would avoid the perverse operational impacts of those policies.[7] These schemes could be designed to maintain the financial levels of support for renewables while reducing or eliminating these counter-productive side-effects.

Given the renewable policies that are in place, we accept the need to lower the bid floor to encourage flexible response by generation during overgen situations. Given the present magnitude of tax credits and the cap on the price of renewable credits in California, -$150/MWh should be low enough to elicit economic bids from renewable generators. There should be very few circumstances where outside payments and other costs are large enough for a unit to operate profitably at -$150.

However markets, particularly balancing markets, do not always operate as seamlessly and smoothly as one would hope. The CAISO balancing market has often suffered from a lack of flexible bids from conventional units and renewable units, not to mention load. There appear to be contractual or perhaps institutional preferences that result in resistance to adjusting units

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[6] B.F. Hobbs, Transmission Planning and Pricing: Lessons from Elsewhere, Transmission Policies to Unlock America's Renewable Energy Resources, PESD, Stanford University, Sept. 15 2011; G. Oggioni, F.H. Murphy, Y. Smeers, "A Stochastic Version of Market Coupling with Wind Penetration," International Conference on Operations Research, August 30-September 2, 2011, Zurich, Switzerland.

[7] An example of such a reform would be to modify California law so that the renewable generation would not count towards the 33% requirement during dispatch intervals when the local price is negative. If the output in these intervals did not count towards a renewable portfolio standard (RPS) requirement, LSEs would not be interested in buying the renewable energy credits associated with this output. The incentive to generate when the price is negative would be significantly reduced, although federal production tax credits would remain.

from their schedules. Further, with some contracts, the firm in control of operating the facility may not be the one exposed to the negative energy prices. All these factors could work to limit the level of response bids that the lower cap may produce. At the same time, the lower floor will expose market participants to more price volatility.

Because we anticipate that circumstances will be rare when a unit can operate profitably at -$150/MWh,, we also recommend that further reductions in the bid floor below -$150/MWh *not* be automatic, as it is in the CAISO proposal, which would reduce the floor to -$300/MWh after one year. We believe that additional reductions should occur only after study of the impacts of the initial drop to -$150/MWh (the "opt in" approach) to determine if it was effective in eliciting more flexibility, and if there were no significant unanticipated negative effects. This includes addressing questions such as the following:

- What increase in the quantity of dec bids occurred, especially at times when they were most needed? That is, will the ISO have received enough decremental offers at prices above -$150 so that it is able to balance the system without curtailments or undue use of regulation?
- Which resources did those additional economic bids come from, and were they are reasonably cost-reflective? This information might shed light on contractual and other barriers to submission of economic bids.
- Was there unanticipated inefficient behavior that occurred when prices fall towards -$150?

This recommendation of ours has also been made by the Department of Market Monitoring (DMM), as well as several stakeholders in their comments, and we agree that some caution is justified.

One gaming concern that has been raised by DMM is that generators in generation pockets could use lower bid floors to extract larger profits if real-time transmission deratings require that the generators be dispatched down below their day-ahead schedules in real-time. Although transmission outages that reduce the transfer capability out of generation pockets between the day-ahead and real-time markets are unlikely to occur often, the ISO's local market power mitigation (LMPM) procedures would not protect the market from generators with large amounts of local market power from exploiting this situation. There is no market efficiency reason to allow such generators to extract large rents in these circumstances. If indeed such behavior is judged by DMM to be a serious risk, we would support the intent of a proposal for a targeted mitigation rule to be applied specifically in the context of such real-time transmission deratings that reduce transfer capability out of specified concentrated generation pockets below the level of day-ahead schedules. But such a rule should not use this possibility to constrain the dec offers of the all intermittent resources around the state.

4. Bid-Cost Recovery (BCR)

4.1. General Comments

In general, the economic rationale for bid-cost recovery is that in the presence of non-convex costs,[8] marginal costs based on the last accepted supply or demand bid in the system (or possibly a penalty for a violated constraint) may not "support" the cost-minimizing solution. If prices support a solution, this means that individual market participants cannot profitably deviate from the solution's schedule. However, the presence of non-convexities such as start-up and minimum load costs or prohibited operating zones mean that a generator who is scheduled in the least cost solution might lose money under the solution's prices. If prices do not support the least-cost solution, then market parties would be incented to deviate from ISO schedules or to self-schedule in order to yield higher profits for themselves. The result, however, of such deviations would be higher overall costs for the market.

Several theoretical schemes have been proposed to define supporting prices when non-convex cost functions are present in power markets. These schemes can result in something very similar to the BCR rule of paying a lump sum to a generator if its gross margin is negative to erase the incentive to shut down rather than to produce.[9] A further implication of theory is that separable decisions should, in theory, earn separate BCR-type payments. As one example, once day-ahead commitments are in place, a generator considering whether to offer in the real-time market should not face the possibility of the cost-minimizing real-time schedule resulting in a loss. Therefore, BCR payments for real-time should not depend, in theory, upon BCR payments made for day-ahead schedules. As another example, a short-start unit might be scheduled to start and shut-down for both the morning and afternoon ramps. Since these are separate decisions, an incentive is, in theory, needed to ensure that the generator is willing to start-up in both times, implying separate BCR payments for each on-off cycle.

The ISO's proposed changes to the BCR procedures would provide for separate calculation of BCR day-ahead and in real-time, as opposed to the present system of paying based on overall gross margin summed over all the markets. This is consistent with the above principle of separate BCR calculation for separable decisions. However, the proposal would retain the daily netting of costs and revenues across the 24 hours of the market. The direct purpose of the proposed change is to eliminate the elements of the current CAISO design that cause generators to self-schedule their day-ahead market schedules in real-time so that they cannot be dispatched down. One incentive for this behavior is that at present, bid cost recovery is calculated over day-ahead and real-time, so that if a generator has a profitable day-ahead schedule and then is

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[8] A convex total cost function is either linear or upward bending function of output (.e., nonnegative second derivative). Nonconvex cost functions either bend the other way in some regions, or have discrete jumps (as in start-up costs) or prohibited regions.

[9] For instance, R.P. O'Neill, P.M. Sotkiewicz, B.F. Hobbs, M.H. Rothkopf, and W.R. Stewart, Jr. "Efficient Market-Clearing Prices in Markets with Nonconvexities," Euro. J. Operational Research, 164(1), July 1, 2005, 269-285; W.W. Hogan and B.R. Ring, "On Minimum-Uplift Pricing for Electricity Markets," March 19, 2003; P.R. Gribik, W.W. Hogan, S.L. Pope, Market-Clearing Electricity Prices and Energy Uplift, HEPG,December 31, 2007

dispatched uneconomically in real-time, it makes less money than if it were not on dispatch. No other ISO/RTO has such a rule because they wanted to avoid precisely this kind of outcome.

In particular, a generator that earns a positive gross margin (revenues minus variable costs) in the day-ahead market might be reluctant to provide adjustment bids in the real-time market because such bids might be accepted but result in losses in the latter market. For instance, this could happen if a short-start unit was scheduled for the morning ramp in the day-ahead market, and then in the real-time market would be scheduled (perhaps at a loss) during the afternoon ramp. The loss in the afternoon period would not yield a BCR payment if the day-ahead morning schedule was sufficiently profitable. In the reverse situation, in which there is a loss in the day-ahead market (revenues less than costs in the absence of bid-cost recovery), the incentive to bid in real-time is blunted by the effect that at least some of the positive gross margin that could be earned in real-time would be taken away by decreasing the BCR that compensates for the day-ahead loss. This would occur because BCR is presently based on the sum of the negative day-ahead margin and the positive margin in real-time.

Therefore, the proposed separate calculation of day-ahead and real-time payments is likely to incent more adjustment bids in the real-time market. This would improve market efficiency, in terms of reducing the as-bid cost of meeting load. This does not necessarily mean reductions in consumer costs because BCR payments might rise. Simulations reported Section 4.6 in the ISO's proposal of the effect of the BCR rule change indicate that an increase in BCR payments on the order of 20% could occur; however, that analysis necessarily assumed no change in bidding behavior. In assessing the consumer impact of these improvements in market efficiency, it is important to recognize that if the Phase 1 changes are successful in eliciting more economic bids for reducing output when prices are negative, then BCR payments could actually decrease, or at least not increase as much as those simulations would indicate. This is because those additional decremental bids would reduce the magnitude of downward price spikes and hence reduce BCR payments relative to what they would have been otherwise.

Besides the market efficiency benefits of removing disincentives for suppliers to submit offer offers to be dispatched down in real-time, there are at least two other possible advantages of the proposed change. One is that the various schemes that were being used to extract uplift costs from the CAISO and were addressed by the March and June 2011 filings perhaps took advantage of the present system which bases BCR on the combined day-ahead/real-time gross margin. This opportunity would be lessened by the proposal. Another possible advantage is that the current pattern of rising minimum load offer costs may represent an effort by generators to reduce the amount of day-ahead rents that can be expropriated by the current BCR rule by raising their as-bid costs to be closer to the market price. Although this may or may not actually be the case, if it is true, then this is another inefficiency induced by the current rule that would be reduced or eliminated by the proposed change.

4.2. Performance Metric and Persistent Uninstructed Energy Check

The BCR portion of the Phase 1 proposal would apply a performance metric that would scale certain components of the bid cost recovery calculation based on deviations from ISO dispatch instructions. This prorating process is intended to remove the incentive, for instance, for a generating unit to receive a day-ahead BCR payment based on a day-ahead commitment, and then to declare an outage so that the unit would not actually run but would still received the payment. However, the performance metric only considers uninstructed deviations within a single real-time interval. Therefore, the ISO proposes to augment the performance metric with a real-time calculation of a persistent uninstructed energy index that would disqualify real-time energy from the real-time BCR calculations in the case where generators choose to deviate consistently over several periods, yielding a greater deviation between actual operation and system cost-minimizing dispatch than can result from just one interval's deviation. The check would construct a 'counterfactual' or hypothetical series of operating levels that would have occurred if the generator had adhered to the operators' instructions.

We generally support the need for the proposed performance metric and persistent deviations check, and the general philosophy behind their calculation and application. They are likely to be more effective than the present BCR procedures in avoiding potential BCR payment inflation from intentional deviations.

However, these changes represent significant departures from the previous BCR procedures at the ISO, and indeed at any other RTO or ISO. For this reason, it is important that the procedures, as well as the particular parameter values to be used to implement them, be subject to careful testing to ensure that they will work as intended. In particular, will they effectively guard against intentional inflation of BCR payments arising from unscheduled deviations? And, at the same time, will they avoid penalizing innocent behavior by prorating BCR payments in response to normal scheduling inaccuracies or errors in a way that would undermine the goal of encouraging more resources to participate in the real-time dispatch? In the absence of reporting of thorough testing of the procedures, we do not have enough information at this time to state with confidence that the procedures will solve the problems they are intended to solve without negative effects on other aspects of the market.

We recognize that there are benefits to implementing all these Phase 1 changes at once, since separation of day-ahead and real-time BCR together with decreases in the bid floor might increase gaming opportunities. However, it is not yet clear that the performance metric and Persistent Uninstructed Energy Check will be effective in addressing the potential problems relating to BCR for uninstructed output, while avoiding undesirable side effects. There needs to be evidence that these proposed procedures will in fact address the potential problems before the California ISO commits to adopting them. Therefore, we recommend that a final commitment to this portion of the BCR proposal not be made until after careful testing has been undertaken to refine the general concepts and to identify appropriate ranges of parameters, and these results have been reviewed by stakeholders. It is our understanding that the ISO will be undertaking such tests, and we look forward to participating in the review of those results and their implications for the design of these procedures.

Attachment F – Comments on Renewable Integration Product and Market Review

Fourth Revised Draft Straw Proposal

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with

Additional Performance Based Refinements

California Independent System Operator Corporation

September 25, 2013

Comments on Renewable Integration Product and Market Review:
Fourth Revised Draft Straw Proposal

Department of Market Monitoring
November 17, 2011

The Department of Market Monitoring (DMM) provides these comments on the ISO's Draft Final Proposal on its Renewable Integration Market and Product Review posted on November 4, 2011. DMM's comments on the three key aspects of this proposal are summarized below:

- **Lower Bid Price Floor.** DMM supports a lower bid price floor to incent additional downward response to alleviate over-supply conditions. As indicated in our last comments, we recommend that the ISO conduct analysis after one year of implementing the -$150/MWh bid floor and only lower the bid floor to -$300/MWh if the results indicate a lower bid floor is warranted and likely to elicit more real time flexibility. The rationale to lower the bid floor to -$300 in the Draft Final Proposal is that significant amounts of solar generation are scheduled to come online in the near future and -$150 does not cover their opportunity cost. However, most over-supply conditions (and resulting negative imbalance prices) occur in off-peak hours when solar is not producing and therefore cannot decrease production. This eliminates the need to further lower the bid price floor to accommodate the opportunity cost for solar resources. DMM has also noted that as the bid floor is lowered below the current level, this may create an incentive for suppliers within "generation pockets" to exercise market power through negatively priced bids that may be needed to mitigate congestion in the real-time market. Thus, DMM reiterates the concern that reduction of the bid price floor beyond -$150/MWh be done only in response to a study to evaluate the observed impact of the -$150/MWh bid price floor on relieving over-supply conditions and cost to generators and any further need for downward dispatchability.

- **PIRP.** The current proposal allocates the cost of the PIRP program to contracting load serving entities, but does not otherwise change any scheduling, bidding, or pricing element of PIRP. PIRP would continue to function as is today and allows any future variable energy resource and dynamic transfers to participate in the markets as a PIRP resource. The cost allocation method does provide some price transparency to the LSE contracting with these resources. However, DMM believes that the effectiveness of this additional price transparency in terms of increasing dispatch flexibility may be hindered due to contractual terms. At best, the ISO's cost allocation proposal introduces what may be a significant degree of additional administrative costs and complexity. Consequently, DMM recommends that the ISO revert back to the proposed changes in the Second Revised Straw Proposal which eliminated PIPR at the end of 2014 with limited grandfathering.

- **Bid Cost Recovery.** The current proposal separates IFM bid cost recovery calculation from RUC and RTD to create an increased incentive to submit real-time bids along with a lower energy bid floor. There are three changes since the last proposal: the performance metric, accounting for real time minimum load costs for MSG units, and eliminating incentives to deviate in real time to increase BCR. The performance metric provides some additional incentive to follow dispatch instructions compared with the current BCR method. The change in minimum load accounting ensures scheduling coordinators do not under-recover or over-recover incurred minimum load costs as a result of separating the netting. The provision to reduce the incentive to deviate in real time to increase BCR appears to have the potential to mitigate incentives for this strategy. However significant additional study is needed to refine and calibrate the measure, and determine appropriate thresholds. DMM notes that while this last BCR measure may be effective in mitigating the ability to inflate BCR payments for uneconomic energy bids through uninstructed deviations , such deviations can also be employed to receive additional minimum load compensation when a resource would otherwise be shut down. DMM believes this issue is also extremely important to address, but notes that developing an effective way of mitigating this scenario may be somewhat more complex. Thus, DMM supports the application of the type of mitigation measures for ways in which uninstructed deviations can be used to inflate real-time BCR payments, but reiterates that further study is required.

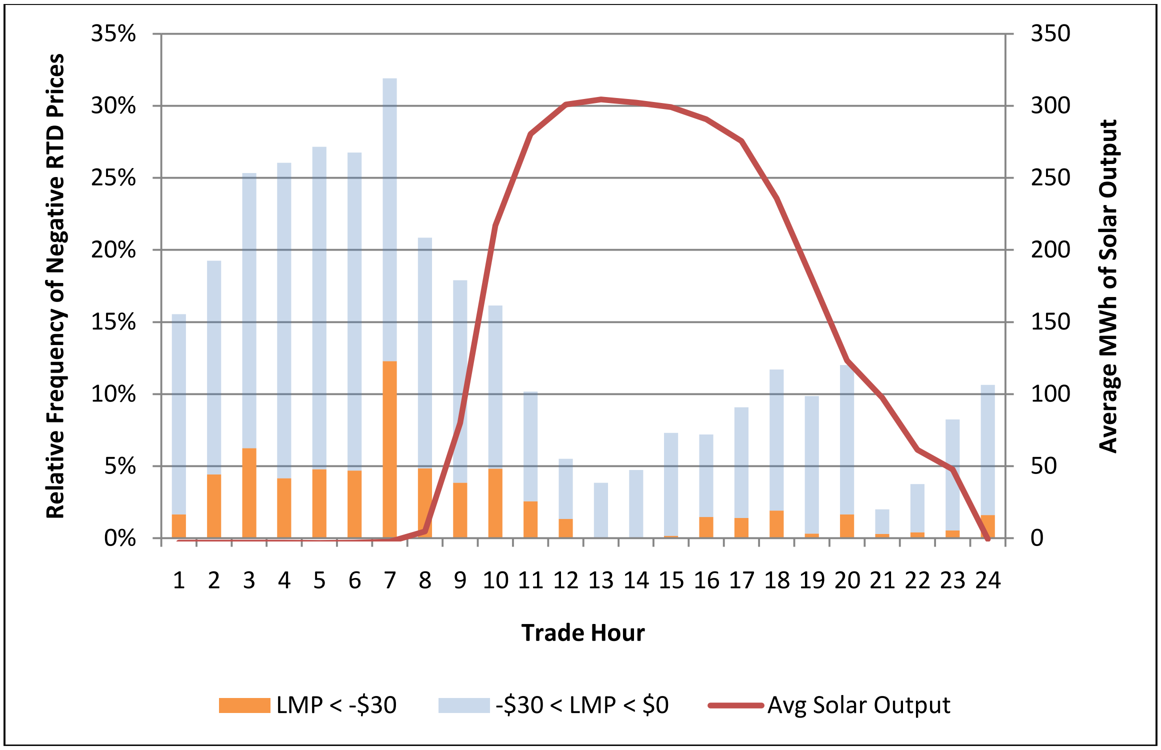
Lower Energy Bid Floor

The latest revised proposal made no changes to the lower energy bid floor. The ISO is proposing to lower the energy bid floor to -$150/MWh in the first year of implementation followed by -$300/MWh in the second year. As noted in prior comments, DMM supports a lower bid floor to elicit more downward economic bids especially in light of the mandated increase of renewable resources. The magnitude and frequency of over-supply conditions is expected to increase as more renewable variable energy resources integrate onto the grid.

DMM and several stakeholders suggested in comments and on the last stakeholder call an "opt-in" approach to lowering the bid floor to -$300/MWh after the first year as opposed to the ISO's current "opt-out" approach. The ISO responded to these suggestions stating that they will conduct analysis after one year, and if an issue arises, they will re-evaluate lowering the bid floor to -$300/MWh. If no issue is identified with a -$150/MWh, the bid floor will be lowered to -$300/MWh in the second year.

The rationale to lower the bid floor to -$300 in the Draft Final Proposal is that significant amounts of solar generation are scheduled to come online in the near future and -$150 does not cover their opportunity cost. This justification is inconsistent with the observation that over-supply conditions, and the need for additional downward dispatch flexibility, largely occur during off-peak hours when the sun is not shining and solar resources are not producing, as seen in Figure 1. The majority of decremental bids are needed in hours 3 through 7 when there is no solar output.

Figure 1: Correlation Between Negative Prices in RTD and Solar Output for January through October 2011



Instead of prescribing a schedule for further lowering the bid price floor, DMM recommends that the ISO lower the bid floor to -$150/MWh and perform an assessment of the impact of the -$150 bid floor on over-supply conditions and BCR as well as anticipated over-supply conditions and the need for additional downward dispatch capability once sufficient market data are available. This study could be used to determine if further lowering the bid price floor is warranted.

For example, there may not be any change in bidding behavior, thus the market results in -$150/MWh real time energy prices. Given the research on wind unit costs and out of market incentives, if -$150/MWh did not have an impact on bidding behavior, it may not be reasonable to assume -$300/MWh will change bidding behavior. Another outcome may be -$150/MWh is low enough to elicit the needed real time flexibility to resolve over-supply conditions through economic dispatch.

Finally, DMM has previously expressed concerns regarding the potential for more negative prices and bid floors to provide incentive to engage in uncompetitive strategies. One such strategy would be for units within uncompetitive “generation pockets" to exploit modeling inaccuracies or inconsistencies between the day-ahead and real-time markets by scheduling energy in the day-ahead market, and then submitting extremely low negatively priced bids for this energy in the real-time market. Under this scenario, the supplier is able to sell energy in the day-ahead market, and then also get paid to not provide this energy in real-time.

While such strategies have not been observed to date, we do note that the more negative the bid price floor and resulting market prices can go, the more incentive there will be to pursue such practices. In the event such behavior is observed as the bid floor is lowered, the ISO may need to develop rules to mitigate market bids or prices under this scenario. This provides additional justification for maintaining the -$150 bid price floor until an assessment of observed response, consequences, and potential need for additional downward offers can be made based on market observation.

Bid Cost Recovery

No Day-ahead MEAF

DMM generally supports the ISOs proposal to eliminate the day-ahead metered energy adjustment factor (MEAF). Eliminating the day-ahead MEAF should encourage more decremental real-time bids from traditional generators because it would no longer reduce day-ahead BCR in the event a generator is dispatched downward from its day-ahead schedule in real-time. Traditional generators may be more willing to bid economically rather than self schedule in real time, providing more economic bids for the market to utilize in over-supply conditions.

Performance Metric

DMM generally supports the proposed Performance Metric as an alternative to the day-ahead MEAF. Applied to day-ahead BCR, the performance metric provides an incentive to deliver day-ahead scheduled energy, but measured against the day-ahead schedule as it is subsequently adjusted in the real-time market. Consequently, unlike the current DA MEAF, the performance metric will not reduce day-ahead BCR payments because a unit was decremented in the real-time market. This will remove this disincentive to submit real-time decremental bids currently created by the DA MEAF.

In real-time, since this performance metric penalizes BCR for over-generation as well as under-generation, the performance metric would have desirable effect of incenting generators to follow downward dispatch instructions (i.e. deliver decremental energy) and incenting generators to not deviate uninstructed above day-ahead schedules.

However, DMM believes that the proposed performance metric may provide a relatively weak incentive to follow real-time dispatch instructions under some circumstances. Since the performance metric is based on a unit's total expected energy (i.e. the sum day-ahead and real-time schedules) divided by its total real-time output, the performance metric becomes less sensitive to deviations from real-time dispatches as the proportion of a unit's total expected energy due to a day-ahead schedule increases.

Because of concerns about market participants strategically deviating in real-time to artificially inflate bid cost recovery payments, DMM recommends that the performance metric be further evaluated in conjunction with the two additional metrics proposed by the ISO to detect persistent uninstructed energy that inflated bid cost recovery payments, as discussed below.

Real time BCR and strategic deviation

As described in the ISO's draft-final proposal, a resource can deviate from its real-time dispatch instructions as part of a strategy to inflate its BCR payments for the real-time market. This strategy can consist of a unit not following its real-time dispatch instructions either downward or upward to an output at which it is economic or at its day-ahead schedule. In addition, a unit could be positioned through uninstructed deviations where it will not receive a shutdown instruction when it is otherwise uneconomic and will continue to receive BCR to cover its minimum load costs.

The potential for both of these practices to be profitable will increase once real-time market revenue shortfalls calculated for BCR payments are no longer netted against revenue surpluses in the day-ahead market. Therefore, DMM has strongly recommended that measures to mitigate these practices be developed as an integral part of modifications being made to BCR and be implemented as soon as practicable.

Ideally, these practices would be mitigated by calculating the amount of BCR a unit would get if did not deviate from ISO dispatch instructions and limiting BCR to these amounts. However, the ISO has indicated that precisely calculating these "counterfactual" BCR payments would be extremely difficult and require a lengthy implementation period. Therefore, the ISO has instead proposed two simplified metrics to detect such uninstructed deviations that result in inflated BCR payments. These metrics that would be applied to real-time market revenues and deviations are:

- Measure A: Energy revenue shortfall due to uninstructed deviation / total energy revenue shortfall

- Measure B: Energy revenue shortfall due to uninstructed deviation / cumulative magnitude of uninstructed deviation

"Measure A" is intended to measure the persistence of uninstructed deviations that result in inflated BCR payments and "Measure B" is intended to measure the $/MWh rate at which a unit's uninstructed deviations inflate its BCR. The two metrics would be evaluated together to avoid penalizing a unit when the effect of its uninstructed deviations is small. A unit would be disqualified from BCR if the two measures combined exceeded a certain threshold.

DMM believes this is a promising approach for addressing the strategy of using uninstructed deviations to inflate BCR due to energy revenue shortfalls. However, the relationship of these metrics to amounts of uninstructed deviations and BCR payments is complex and needs to be more thoroughly evaluated to assure metrics are appropriate and to set the appropriate thresholds. Moreover, it will be important to evaluate these metrics in conjunction with the proposed Performance Metric to completely understand how all three metrics work together.

Finally, DMM notes that these metrics do not address the strategy of positioning a unit uninstructed deviations so it will not receive a shutdown instruction. A resource can deviate in a fashion that precludes the market from issuing a shut down instruction due to ramping limits, minimum down time, and the multi-period optimization that may see dispatching the resource in later hours. In these cases, the resource will have its minimum load bid (up to 200 percent of proxy cost) included in the BCR calculation. As previously noted, DMM believes this issue is equally important to address as the practice that is addressed by the proposed metrics.

Start-up costs for short-start resources

The ISO is proposing that in most cases, the current start-up cost allocation rules will still apply except under one scenario. For short-start resources that have overlapping commitment periods in the day-ahead and real-time market, the day-ahead start-up costs will be qualified based on the real-time meter for the real-time commitment period. DMM agrees with this position.

As noted in our previous comments, there are some cases during which a short-start resource could potentially receive two start-up costs, one in the day-ahead and one in real-time, without physically starting up more than once. DMM again recommends the ISO alter the proposal such that only one start-up cost is accounted for in the day-ahead market during any of those instances.

Minimum load costs

The current proposal retains the current minimum load cost calculations for non-MSG resources and for MSG resources with day-ahead and real-time dispatches in the same configuration. For MSG resources with day-ahead and real-time dispatches in different configurations, the ISO has proposed various accountings of minimum load costs for the day-ahead and real-time bid cost recovery calculations. As noted in our last comments, and by a stakeholder, the formulas initially proposed may result in a resource under or over recovering minimum load costs actually incurred in real time. This proposal revised the formula such that the resource will be guaranteed to recover only the minimum load costs actually incurred in real time. DMM agrees with the formula proposed in the latest revised straw proposal.

PIRP[1]

As noted in prior comments, DMM does not support the current proposal of continuing PIRP and allowing incoming renewable resources to participate in PIRP with a change in cost allocation. The original intent of addressing PIRP in the RIMPR Phase I initiative was to achieve additional dispatch flexibility in real time from variable energy resources. The current proposal increases the amount of (PIRP) energy self scheduled in real time

[1] DMM has released a brief white paper quantifying the potential impacts of a lower bid price floor on PIRP revenue as wells as discussion of the impact of renewable contracts on incentives for increased downward dispatch. The report can be found in the special reports section on the following page: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx.

which will *decrease* flexibility and exacerbate over-supply conditions compared to today. Furthermore, allowing intermittent resources, which are currently dynamic transfers and dispatchable in the 5 minute market, to participate in PIRP will further decrease flexibility that the market current has.

PIRP resources are still exposed to the negative real-time price for the amount of self scheduled forecasted generation. In conjunction with the lower energy floor, they will be exposed to a higher frequency of more extreme negative prices and will provide no real time economic bid on which the market can dispatch them down.

The only proposed change from the existing PIRP is the cost allocation aspect. The ISO proposes to allocate costs back to the SC of the LSE which contracts with the PIRP resource. The SC of the PIRP resource will have to provide a signed form identifying the SC of the LSE to whom the output is contracted. The intent is to provide more cost transparency of each resource and potentially provide an incentive to the SC of the LSE to reduce the cost of meeting the RPS goals. This change provides only a weak incentive, if any, for additional downward dispatch flexibility from PIRP resources to be offered. Contractual limitations on dispatch flexibility mute any revenue incentive in the short run, and renegotiating contracts to include dispatch flexibility is a long-term prospect.

There are additional benefits from being in PIRP that are not addressed by this proposal. Other cost savings include exemption from RUC capacity charges, potential increase in ancillary service costs, and flexi-ramp costs. Therefore while the PIRP uplift costs may be allocated back to the LSE, there is still a benefit to participate in PIRP.

Assuming the costs are being allocated back to the party that has an incentive to reduce those costs, they may not have the ability to do so given contract terms. It is DMM's understanding that some PPA's have a buyer curtailment clause allowing the LSE to submit bids which would curtail the output of the contracted resource for a given number of hours per year. DMM also understands that the majority of PPAs do not have such a clause, in which case the contracting LSE is not able to submit decremental bids for the resource despite the market signals and cost/revenue incentives. In the case of a contract without the ability to curtail the output, allocating costs back to the SC of the LSE in conjunction with the lower energy bid floor does provide the LSE some incentive to renegotiate flexibility into current and forthcoming contracts. However, there may be a significant lag between when the ISO implements the proposed changes and when the market sees a change in flexibility due to the time it takes to renegotiate contract terms.

Because most existing contracts do not allow for economic dispatch of the resource, there is not likely to be a significant short-term impact on downward dispatch offers from (current PIRP) renewable resources resulting from a lower bid price floor. There appears to be some direct benefit to LSEs to get additional dispatch flexibility that would help relieve over-supply conditions, reduce the frequency and magnitude of negative imbalance prices, and ultimately increase PIRP revenue the LSE receives (as the SC for the resource) that would offset contract payments from the LSE to PIRP resources. The impact of this PIRP revenue effect on the incentive to renegotiate for dispatch flexibility will depend on the extent to which the LSE is simultaneously paying for the imbalance energy provided by those PIRP resources.

The greater incentive for LSEs may lie in the potential impact of lower negative prices on the imbalance position of their load. If the LSE is over-scheduled (day-ahead scheduled load is greater than realized actual load) then the LSE will be charged the imbalance price if that price is negative. Under normal (non-over-supply) circumstances the LSE would be paid the positive price for the over-scheduled quantity. In over-supply conditions when the price is negative, the lower load contributes to the over-supply condition and the amount of load that did not materialize in the imbalance market will be charged the negative price. A lower bid price floor represents a greater exposure to this cost risk and may provide incentive for LSEs to renegotiate contracts with PIRP resources to provide additional downward dispatch flexibility to help relieve over-supply conditions.

An additional issue, not directly related to the proposed PIRP change, is the method which CPUC will use to determine if LSEs meet the RPS goals. The accounting of energy credited to meet RPS goals does not have an allowance for decreases in renewable energy to mitigate over-supply conditions. This further hinders the incentive for LSEs to submit decremental bids for PIRP resources.

Comments from the Department of Market Monitoring on
Renewable Integration: Product and Market Fourth Revised Draft Straw Proposal

September 13, 2011

The Department of Market Monitoring would like to take this opportunity to provide the ISO and stakeholders an additional perspective on the Renewable Integration: Market and Product Review Fourth Revised Draft Straw Proposal posted on August 22, 2011. These comments address the proposal to reform PIRP, lower the energy bid price floor, and changes to bid cost recovery.

- **Lower Bid Price Floor.** DMM supports a lower bid price floor to incent additional downward response to alleviate over-supply conditions. We appreciate the ISO's response to past comments by altering the proposal to include a -$150/MWh energy bid floor for the first year. However, we believe the proposal to automatically further lower the bid floor to -$300/MWh in the second year is unwarranted and could potentially impose cost onto some generators and load serving entities without significantly increasing market efficiency. DMM suggests that the proposal be modified to include the initial -$150/MWh bid floor with subsequent study of the impact of -$150/MWh that would advise future changes.

- **Bid Cost Recovery.** The current proposal separates IFM bid cost recovery calculation from RUC and RTD as a mitigation method with a lower energy bid floor. Within the proposal, the ISO eliminates day-ahead MEAF and makes adjustments to how commitment costs are accounted for in each BCR calculation in various scenarios. DMM generally supports the proposed changes as they accommodate more dispatch flexibility in real time with reduced risk of foregone revenue. We have provided some suggested modifications.

- **PIRP.** The current proposal does not change any scheduling or bidding element of PIRP. PIRP would continue to function as is today and allows any future variable energy resource to participate in the markets as a PIRP resource. DMM does not support the ISO proposal for PIRP on the grounds that it is inconsistent with integrating renewable energy resources into the market, is not technology neutral, and does not promote dispatch flexibility. The intent of this initiative was to implement changes that would elicit more flexibility from variable energy resources near-term until longer-term market enhancements are implemented through RIMPR Phase II. The ISO is deferring any changes to PIRP bidding and settlements to RIMPR Phase II and allowing additional resources to enter into the PIRP program in the interim. DMM recommends the ISO revert back to the proposed changes in the Second Revised Straw Proposal which eliminated PIPR at the end of 2014 with limited grandfathering.

Lower Energy Bid Floor

The latest revised proposal lowers the energy bid floor in a stepped approach, -$150/MWh in the first year of implementation followed by -$300/MWh in the second year. DMM supports a lower bid floor to elicit more downward economic bids especially in light of the mandated increase of renewable resources. The magnitude and frequency of over-supply conditions is expected to increase as more renewable variable energy resources integrate onto the grid. Having a more flexible real time market with increased volume of economic bids is a more efficient way to address over-supply conditions compared to the current method of uneconomically curtailing resources. As stated by DMM and other stakeholders in comments on the Second and Third Revised Straw Proposals, the bid floor should elicit additional flexibility sufficient to address most over-supply conditions while minimizing potential risk to conventional resources exposed to the negative real time price.

DMM appreciates the ISO's response of altering the last proposal from -$300/MWh bid floor to the current stepped approach starting at -$150/MWh. However DMM does not agree with the ISO proposal to automatically further lower the bid floor to -$300/MWh in the second year of implementation without supporting analysis. One reason provided by the ISO to support the -$300/MWh bid floor was the further incentive required to get solar resources to reduce output. We note that the majority of over-supply conditions where additional downward dispatch flexibility is needed occur in the off-peak hours – most of which have no sunlight to power solar resources[1].

Instead of prescribing a schedule for further lowering the bid price floor, DMM recommends that the ISO lower the bid floor to -$150/MWh and perform an assessment of the effectiveness of the new bid floor once sufficient market data are available. This study could be used to determine if a different bid floor is warranted.

Bid Cost Recovery

No day-ahead MEAF

DMM generally supports the ISOs proposal to eliminate the day-ahead metered energy adjustment factor (MEAF). The two recent filings related to bid cost recovery were made to address bidding strategies that exploited how the day-ahead MEAF adjusted day-ahead costs and revenues. As a result of the two filings, the day-ahead MEAF is not applied to (1) day-ahead costs when day-ahead energy bids are negative, and (2) day-ahead revenues when the ISO dispatches a resource down from the day-ahead ISO commitment. In both cases, the day-ahead MEAF is eliminated from the calculation. Eliminating day-ahead MEAF entirely from all day-ahead bid cost recovery calculations will not counter-act the prior two filings. Furthermore, it will accommodate more dispatch flexibility from

[1] Frequency of over-supply conditions by operating hour are provided on page 5 of DMM's *Over-supply and shortage of downward ramping supply in off peak hours* http://www.caiso.com/Documents/DraftWhitePaperonOver-supplyandShortage-DownwardRampingSupplyin-fPeakHours.pdf

traditional generators in real time by reducing negative impacts of potential net revenue losses from real time dispatch on day-ahead market revenue. Traditional generators may be more willing to bid economically rather than self schedule in real time, providing more economic bids for the market to utilize in over-supply conditions.

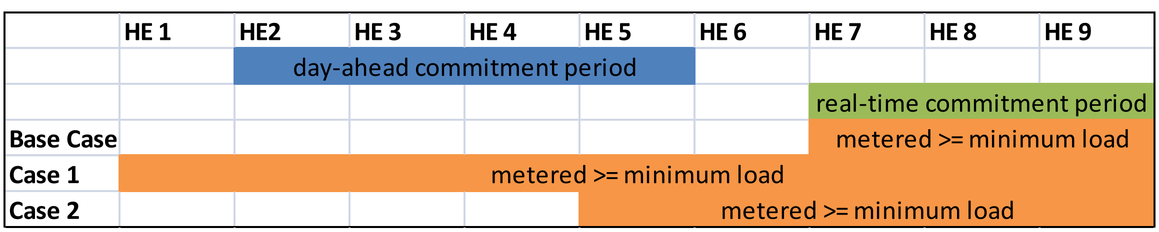
Separate day-ahead BCR from RUC/RTD BCR

DMM generally supports the ISO’s recent proposal of separating day-ahead bid cost recovery payments from reliability unit commitment (RUC) and real time dispatch (RTD) bid cost recovery payments. As previously stated, isolating day-ahead from RUC/RTD will preserve any revenues earned in day-ahead independent of real time market outcomes. Generators would more likely bid economically in real-time rather than self schedule because lower real time operating levels will not decrease net revenues earned in the day-ahead market. DMM agrees with the ISO’s proposal of maintaining netting across 24 hours within a day.

Start-up costs for short-start resources

The ISO is proposing that in most cases, the current start-up cost allocation rules will still apply except under one scenario. For short-start resources that have overlapping commitment periods in the day-ahead and real-time market, the day-ahead start-up costs will be qualified based on the real-time meter for the real-time commitment period. DMM agrees with this position.

There are two cases during which a short-start resource could potentially receive two start-up costs, one in the day-ahead and one in real-time, without physically starting up more than once. The two cases are depicted in the figure below where a resource has different day-ahead and real-time commitment periods that do not over-lap.



The base case shows a resource follows the real-time instruction and start-ups for the real-time commitment period. Currently, and in the proposal, the day-ahead start-up costs will be disqualified but the resource will receive real-time start-up costs. In case 1, the resource starts-up before the day-ahead commitment period without a real time start-up instruction, and remains on through the real time commitment period. Under the new proposal, the resource in both cases 1 and 2 will have start-up costs included in bid cost recovery calculations in the day-ahead and real-time market despite only physically starting up once. DMM recommends the ISO alter the proposal such that only one start-up cost is accounted for in the day-ahead market.

Minimum load costs

The current proposal retains the current minimum load cost calculations for non-MSG resources and for MSG resources with day-ahead and real-time dispatches in the same configuration. For MSG resources with day-ahead and real-time dispatches in different configurations, the ISO has proposed various accountings of minimum load costs for the day-ahead and real-time bid cost recovery calculations. DMM generally agrees with the ISO's proposal that the resource should not receive the total minimum load cost associated with the real-time configuration when it already received minimum load cost associated with the day-ahead configuration. Therefore, only a proportion of the minimum load cost associated with the real-time configuration should be used in real-time bid cost recovery.

Upon review of the proposed formulas used to calculate real-time minimum load costs, DMM identified a bidding strategy that could be employed to increase bid cost recovery payments in the case of over-lapping configurations where the real-time dispatch is in a higher configuration than day-ahead (Case 2 in the revised straw proposal). There is an incentive for a resource that has similar minimum load costs for both configurations to bid in such a way that the day-ahead schedule is close to minimum load of the lower configuration. The proposal allocates a portion of the minimum load cost of the higher configuration in real time based on the difference of the pmin of the higher configuration and the day-ahead schedule. Therefore, the larger the difference, the more minimum load cost accounted for in real time. This incentive becomes stronger when resources have minimum load costs registered at 200% of proxy cost. In total, the resource may receive day-ahead minimum load cost and real-time minimum load cost greater than the minimum load cost of the configuration it actually operates in during real time.

In addition to DMM's concern, a stakeholder at the latest RIMPR Phase I stakeholder meeting raised the opposite case where a resource may not be fully recovering minimum load costs for the configuration it is actually operating in during real time. Using the formulas provided in Case 2 of the revised straw proposal, the summation of day-ahead minimum load cost, day-ahead energy bid cost, and real-time minimum load cost may be less than the minimum load cost of the configuration in which the resource is operating in real-time. DMM agrees that this is also a valid issue with the current proposed method of accounting minimum load costs in real time. The resource should be entitled to recover the minimum load cost for which it physically operates in real-time.

DMM suggests that for MSG resources with day-ahead and real-time dispatches in different configurations, that the real-time minimum load cost be determined by the following formula:

RT MLC = MLC of real-time configuration – DA MLC – DA energy bid cost.

Capping the total minimum load cost accounted for in the day-ahead and real-time calculations by the minimum load cost of the real-time configuration alleviates DMM's concern with the bidding strategy *and* addresses the stakeholder's concern that the resource will not recover total minimum load cost for the real time configuration. DMM invites the ISO and other stakeholders to further review the suggested formula to ensure it addresses concerns raised in the previous stakeholder meeting and call.

PIRP

Eligibility requirement

DMM does not support the current proposal of only requiring an additional form to be submitted for eligibility such that any current and future variable resource can participate in PIRP. The purpose of the additional requirement is to be able to allocate costs back to the SC of the LSE rather than provide a disincentive to participate in PIRP. This is a step backward from the last proposal. [2]

The original intent of addressing PIRP in the RIMPR Phase I initiative was to achieve additional dispatch flexibility in real time from variable energy resources. The current proposal allows potentially thousands of megawatts not currently in PIRP to enter PIRP with no termination date. This increases the amount of (PIRP) energy self scheduled in real time which will *decrease* flexibility and exacerbate over-supply conditions compared to today. PIRP is not the only risk management tool available to variable energy resources. DMM supports reverting back to the second revised straw proposal which would eliminate PIRP by 2014 with minimal grandfathering based on technology.

Increased enrollment in PIRP is likely to increase instances of over-supply conditions. In conjunction with the lower energy bid floor, which is intended to incent (all) resources to submit economic bids, the real time market will potentially be less flexible. This may result in more extreme negative prices being set by market parameters instead of less extreme negative prices set by economic bids. A lower energy bid floor means the current -$30/MWh parameter price will become -$150/MWh, negatively impacting both conventional and PIRP resources.

PIRP resources are still exposed to the negative real-time price for the amount of self scheduled forecasted generation. Therefore they will be exposed to a higher frequency of more extreme negative prices and will provide no real time economic bid on which the market can dispatch them down. Stakeholders have proposed that hours with negative prices not be included in the monthly netting settlement of PIRP resources as a way to expose them to market signals. While this would expose PIRP resources to the negative energy price in settlements, it does not provide the market with an economic bid from which to efficiently dispatch the resources down during over-supply conditions. PIRP resources currently have the option of submitting an economic bid rather than self scheduling the forecast on an hourly basis. In hours they submit an economic bid, the hour is removed from the monthly netting settlement and instead settled on a 10-minute basis. While this would provide the market with more flexibility in those hours, to date this option has gone widely unused and as such is not a reasonable expectation for additional dispatch flexibility from PIRP resources.

[2] DMM did not support this last proposal because it allows even more participation into PIRP without a termination date.

Allocation of costs

The current proposal allocates PIRP uplift costs back to the Scheduling Coordinators of the Load Serving Entities that have contracts with PIRP resources. The allocation will be based on the percentage of PIRP megawatts contracted to each LSE. The uplift costs are the difference between what would have been settled without PIRP and what was settled with PIRP. The ISO proposal asserts that the transparency of cost to the contracting LSE may incentivize changes to PIRP participation voluntarily. This is in indirect approach to motivating change for the PIRP resources. DMM prefers a more direct approach – limiting participation and phasing the PIRP program out over a short period of time.

Attachment G – Decision on Renewable Integration- Market and Product Review Phase 1

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with Additional Performance Based Refinements

California Independent System Operator Corporation

September 25, 2013

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market & Infrastructure Development

Date: December 8, 2011

Re: **Decision on Renewable Integration – Market & Product Review Phase 1**

This memorandum requires Board action.

EXECUTIVE SUMMARY

This memo describes proposed changes to elements of the California Independent System Operator Corporation' s current market design to facilitate the integration of renewal resources onto the grid. The proposed changes include:

- Reducing the energy bid floor from -$30/MWh to -$150/MWh; and
- Changing the bid cost recovery netting methodology.

As part of the proposal for changing the bid cost recovery netting methodology, Management has been developing bid cost recovery measures with stakeholders to align incentives to follow ISO-issued dispatch instructions. Given the complexity of these new measures, additional development time is necessary to ensure that the new measures work as intended and to provide stakeholders with sufficient time to consider the impacts of these new measures. Thus, even though the complete suite of changes is not yet developed, , Management believes it is beneficial to seek Board approval of the main elements of the proposal now to provide certainty on the policy for changing the bid cost recovery netting methodology and the reduction in the energy bid floor. This will allow the stakeholder process to focus on the additional bid cost recovery measures that are appropriate as a result of this new policy. Therefore, this proposal includes a commitment to the Board that, prior to filing the elements of this proposal with the Federal Energy Regulatory Commission, Management will first obtain Board approval for theses additional bid cost recovery mitigation measures.

Management requests the ISO Board of Governor's approval to file tariff language to implement these changes and proposes the following motion:

Moved, that the ISO Board of Governors approves the proposed tariff change regarding the Renewable Integration – Market and Product Review Phase 1 as described in the memorandum dated December 8, 2011; 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, following Board approval of the remaining bid cost recovery elements of the proposal.

DISCUSSION AND ANALYSIS

In July 2010 Management began the Renewable Integration Market and Product Review with the goal to "identify and develop potential changes to wholesale market design, including market products and procedures, needed to accommodate the expected substantial increase in production by variable energy resources over the next decade."[1] This review evolved into two separate design efforts. Phase 1, which is the subject of this Board memo, identifies short term solutions for renewable integration, while the outcome of Phase 2 is the Renewable Integration – Market Vision and Roadmap, which was presented to the Board in October 2011 and provides a plan to address longer term solutions.

The scope of the Phase 1 market design effort was comprised of three elements:

(1) re-evaluate the Participating Intermittent Resource Program (PIRP) for intermittent resources;
(2) lower the energy bid floor to provide additional incentives for market participants, including intermittent to submit decremental bids; and
(3) balance the effects of changing PIRP and the bid floor on generation suppliers by reconsidering the methodology that nets bid cost recovery over all settlement periods in a trade day.

The ISO conducted an extensive stakeholder process to develop each of these components and finalize Management's proposal. Stakeholders provided invaluable feedback allowing Management to understand how these changes impact each segment of the ISO market and to craft a proposal that moves the ball forward in facilitating renewable integration.

Update the Participating Intermittent Resource Program

PIRP was designed and implemented well before there was a clear expectation of the enormous growth of variable renewable resources that is occurring under the state's

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[1] *Discussion Paper, Renewable Integration: Market and Product Review*, July 8, 2010, http://www.caiso.com/Documents/DiscussionPaperonRenewableIntegrationMarketandProductReview08-Jul-2010.pdf

Renewable Portfolio Standard requirements. The ISO's renewable integration studies have shown that the large influx of variable energy renewable resources will have significant market and operational impacts. This has resulted in the need to reassess the design of the PIRP in light of changes in state policy and advances in technology that provide new wind and solar resources with the ability to vary their output to help manage grid conditions.

In January 2002, the ISO filed the PIRP proposal with the Federal Energy Regulatory Commission to introduce provisions to facilitate the participation of eligible intermittent resources in the ISO market. At that time, before there was an RPS requirement, PIRP was designed to encourage investment in new wind and solar intermittent energy resources by mitigating the variability of the financial impact of imbalance energy costs that result when such resources inevitably go "off-schedule" (e.g., when wind patterns change). The RPS requirements are now the primary driver for renewable resource investment in California.

In addition, the original need for PIRP was based in part on technology that has now evolved to a point that draws into question the extent to which the original issues are still relevant. For example, when PIRP was implemented, the wind turbine technology generally used fixed blades that produced energy strictly based upon wind speed. The only ability to curtail wind generation in this scenario was to trip the unit thus reducing its output to zero. Today, wind turbine technology has evolved including blades that can be "feathered". In other words, their angle to the wind can be changed thus allowing the generator to continue to operate but at an output level below what could be produced with the blades in their optimal position. This now allows wind generators to respond to grid conditions through curtailing their output. This ability, in turn, helps to reduce the exposure to uplift faced by wind resources.

The same can be said for solar resources. Improvements in inverter technology allow these resources additional output flexibility not available in the past. Indeed, the ISO has been informed that many of the new purchase power agreements provide the purchaser with a limited number of hours in which the output of the resource can be curtailed. The combination of the technology, revised contractual arrangements, and the proposal contained herein, can provide for improvements in operational flexibility needed to reliably integrate large quantities of renewable resources.

To be eligible for PIRP settlement treatment, each hour a participating resource must schedule its output according to a forecast provided by the ISO. The resource's deviations from that forecast are netted across a calendar month and settled at a weighted average price, resulting in a payment, or charge, to the resource. A resource is not required to use the ISO forecast, however if it does not, it will not be considered for PIRP settlement treatment for that hour. The difference between this settlement and the settlement that would have occurred had their deviations been charged the 10 minute settlement price results in an uplift cost.[2] Currently, PIRP uplift costs are allocated broadly to all market participants based on their deviations from scheduled levels. Under this approach, the majority of the PIRP uplift costs are spread to load. Historically, these costs have been relatively small. Between June 2010 and June 2011, PIRP uplift costs totaled approximately $5.1 million.

Under Management's initial evaluation of how PIRP should be re-designed to accommodate the increasing need for dispatchability of these resources, several options for revising PIRP, including the eventual elimination of PIRP, were considered. Some stakeholders continue to have significant concerns over proposed modifications to PIRP. Management is therefore removing the proposed changes to PIRP from the renewable integration market and product review phase 1 proposal. In the second quarter of 2012, management will begin a new stakeholder process to consider revisions to PIRP. In particular, as outlined in the ISO's renewable integration market vision and roadmap, such revisions will be targeted at increasing the dispatchability of participating intermittent resources by enabling them to participate in PIRP and simultaneously submit decremental bids to indicate their willingness to curtail their output.

Lower the Energy Bid Floor

A supply resource uses its energy bids for two main purposes: first, to specify the minimum price at which it is willing to provide energy to the market; and second, to specify the maximum price it is willing to pay to "buy back" in real time energy it sold in the day-ahead market. Energy bids for the latter purpose are commonly called decremental bids because they are bids by a supplier to reduce or decrement its real-time output relative to its accepted energy schedule. The integration of large quantities of intermittent resources into the supply fleet creates an increased need for a liquid supply of such bids to manage real-time congestion and over-generation conditions.

There is currently a limited supply of decremental energy bids to enable the ISO market systems to economically reduce energy supply to balance demand when needed. This is especially critical during off-peak hours that are susceptible to much higher levels of over-generation as additional renewable energy production comes on-line. The shortage of decremental bids is due in part to an insufficiently low bid floor and also in part to contractual constraints on bidding for some plants. At the current -$30/MWh level, the bid floor provides little incentive for renewable energy resources to provide decremental energy bids. These resources receive production tax credits and contractual energy payments significantly greater than $30/MWh. Lowering the bid floor below the opportunity costs for providing energy will induce renewable and additional conventional resources to submit decremental energy bids that can be dispatched during low or negatively priced hours.

[2] The net impact can also be positive resulting in a net revenue.

In determining the level of the bid floor, Management reviewed the elements that comprised the potential revenues a wind resource could be getting outside of the ISO market. These include production tax credits that are valued at about $37/MWh, the economic value of renewable energy credits which have a limit of $50/MWh, and the Public Utilities Commission's market price referent which is used to value the costs of RPS contracts and averages around $100/MWh. Based on these values, Management believes that setting the bid floor at -$150/MWh provides leeway for at least a portion of the wind community to participate in the market at any given time. Management believes that further lowering the bid floor to -$300/MWh will likely provide additional benefits by incenting decremental bids from additional resources, including solar resource participation which has higher opportunity costs for providing energy and provide clear signals to incent investment in storage and demand response technologies that can respond quickly to over-generation conditions. Many stakeholders were uncomfortable automatically moving to levels lower than -$150/MWh until the impact of the lower bid floor can be evaluated using actual market outcomes. Therefore, Management proposes to set the bid floor level at -$150/MWh for one year and then evaluate the impact of this change. If there are no significant unanticipated negative effects, then Management will propose to lower the bid floor to -$300/MWh.

As shown in Table 1, most other ISOs and RTOs in the United States have even lower bid floors than the level Management proposes for the ISO market. These low levels have not proven to be problematic in other markets.

Table 1 – Comparison of ISO/RTO energy bid floors

ISO/RTO	Energy Bid Floor
PJM	No Bid Floor
NYISO	-$999.99/MWh
MISO	-$500/MWh
ERCOT	-$250/MWh
CAISO	-$30/MWh
ISO-NE	$0/MWh

Changes to bid cost recovery

Bid cost recovery is the process by which the ISO ensures that scheduling coordinators are able to recover start up, minimum load and energy bid costs for supply resources. The bid cost recovery calculations compare bid costs and market revenues for each resource to ascertain whether or not there is a net revenue shortfall over the course of a day. If so, the resource receives an uplift payment for that shortfall. Currently, the ISO performs the calculation for bid cost recovery over the entire trade day and nets a resource's costs and revenues across the day-ahead, real-time, and residual unit commitment markets for that trade day.

Offsetting market outcomes can lower a resource's bid cost recovery, which may discourage economic bids in the real time market. Management's proposal to lower the bid floor has increased this concern for generation resources that may not be able to ramp down their output fast enough to avoid negative real-time prices. In this situation, such resources' day-ahead market revenues could be reduced. To mitigate this risk, Management proposes revising the rules for netting costs and revenues for performing its bid cost recovery calculation so that day-ahead costs and revenues are no longer netted against residual unit commitment and real-time costs and revenues. The recommended changes are designed to promote bidding, including decremental bids, in the real-time market. Specifically, separating the netting of the bid cost recovery calculations will make market participants' decisions about offering economic bids into the real-time market independent of the outcome of the day-ahead market. Without having to consider what real-time market conditions may do to offset day-ahead market outcomes, disincentives resources may have to submit economic bids into the real-time market are alleviated. In other words, by separating the bid cost recovery netting between day-ahead and real-time, a resource's day-ahead economic decisions do not hamper its real-time decision possibilities. Having a deep pool of economic bids in the real-time market will assist the ISO in managing the grid with increasing numbers of variable energy resources.

The separation of the netting of bid cost recovery calculations is consistent with practices at PJM Interconnection, the New York ISO, ISO-New England, the Midwest ISO, and the Electric Reliability Council of Texas.

Separating the calculation of bid cost recovery between the day-ahead and real-time markets will protect supply resources day-ahead market revenues from unexpectedly low real-time market prices. With these changes to the bid cost recovery rules, historical analyses show that total bid cost recovery uplift payments are expected to increase. Management believes that this increase is appropriate because it will provide cost recovery for shortfalls based on the independent optimization choices made by those markets. Providing that cost recovery is the mechanism by which proper incentives for resources to submit real-time economic bids will be created. A deeper pool of real-time energy bids provides the market optimization with the ability to reach a more efficient least-cost dispatch. Thus, any increase to overall bid cost recovery is likely to be offset by the countervailing decrease in the cost of dispatch.

To ensure that the separation of the bid cost recovery netting does not create logical inconsistencies or adverse incentives, Management proposes three changes to bid cost recovery rules:

(1) Management recommends modifications to account for bid cost recovery by short start units dispatched in the real time market. For a short-start unit, the day-ahead optimization considers the resource's commitment costs when committed, and that commitment is financially (but not operationally) binding in the day-ahead market. The real-time market can again commit the short-start resource. These modifications will permit the ISO to separate the day-ahead and real time bid cost recovery calculations for short-start units that are committed in both the day ahead and real time markets when that commitment overlaps operating hours;

(2) For multi stage generating resources with different day-ahead and real-time configurations, Management recommends that real-time minimum load costs be calculated as the incremental change in minimum load costs between day-ahead and real-time; and

(3) Management recommends that negative minimum load costs be accounted for when a unit is completely de-committed to off-line in real time from its day-ahead schedule.

Even under the current design in which bid cost recovery calculations are netted across all markets, resources can garner greater bid cost recovery uplift payments by deviating from real-time ISO dispatch. Under the proposal to separate the netting of the day-ahead and real-time bid cost recovery calculations, this opportunity can be exacerbated. To mitigate this effect, Management recommends that the day-ahead metered energy adjustment factor be eliminated and replaced by bid cost recovery mitigation measures. Management has been developing bid cost recovery measures with stakeholders to align incentives to follow ISO-issued dispatch instructions. Given the complexity of these new measures, additional development time is necessary to ensure that the new measures work as intended and to provide stakeholders with additional time to consider the impacts of these new measures. Prior to filing the elements of this proposal with the Federal Energy Regulatory Commission, the ISO will bring the bid cost recovery mitigation measures to the Board for approval. We will then file both with FERC as a package.

POSITIONS OF THE PARTIES

<u>Update the Participating Intermittent Resource Program</u>

The load serving entities, the department of market monitoring and the Market Surveillance Committee believe that it is appropriate to suspend the program (with limited grandfathering provisions) after a reasonable amount of time.

Intermittent resource providers are generally supportive of the concept of maintaining the current program from a scheduling, bidding and pricing perspective, but disagree with changing from a pooled allocation to a resource specific allocation methodology.

Lowering the energy bid floor

Most stakeholders, including the department of market monitoring and the Market Surveillance Committee support lowering the bid floor from -$30/MWh to -$150/MWh and subsequently to -$300/MWh if the analysis confirms this direction. A few stakeholders had other recommendations:

- Calpine recommended moving to -$75/MWh initially, moving in a downward direction at a slower pace.
- Powerex advocated for a symmetrical bid cap and floor, setting the bid cap at -$1000/MWh to avoid potential unintended consequences.
- SMUD does not believe the ISO should lower the bid floor until participating intermittent resources can submit economic curtailment bid curves.

Changes to bid cost recovery

Stakeholders expressed support for the separation of the netting of bid cost recovery calculations. For the most part, the changes recommended in support of the separation of netting were also supported.

Pacific Gas & Electric recommends an alternative minimum load cost accounting rule change for multi-stage generating resources with different ISO-committed configurations in the day-ahead and real-time markets. That proposal would result in all minimum load costs being reflected in the day-ahead bid cost recovery calculation which can create adverse market incentives, whereas Management's recommendation, while inclusive of a potential inefficiency, maintains the correct market incentives by preserving the alignment between the market of the minimum load energy and that of the minimum load costs.

Several stakeholders, including the department of market monitoring and the Market Surveillance Committee, recommended that the ISO and stakeholders further develop and the bid cost recovery measures designed to align incentives to follow ISO-issued dispatch instructions. In response to their concern that they have sufficient time and detail to understand and evaluate the impacts of these new measures, Management recommends that the measures be further vetted and refined through a stakeholder targeted for completion in March 2012.

The attached matrix of stakeholder comments provides further information.

MANAGEMENT RECOMMENDATION

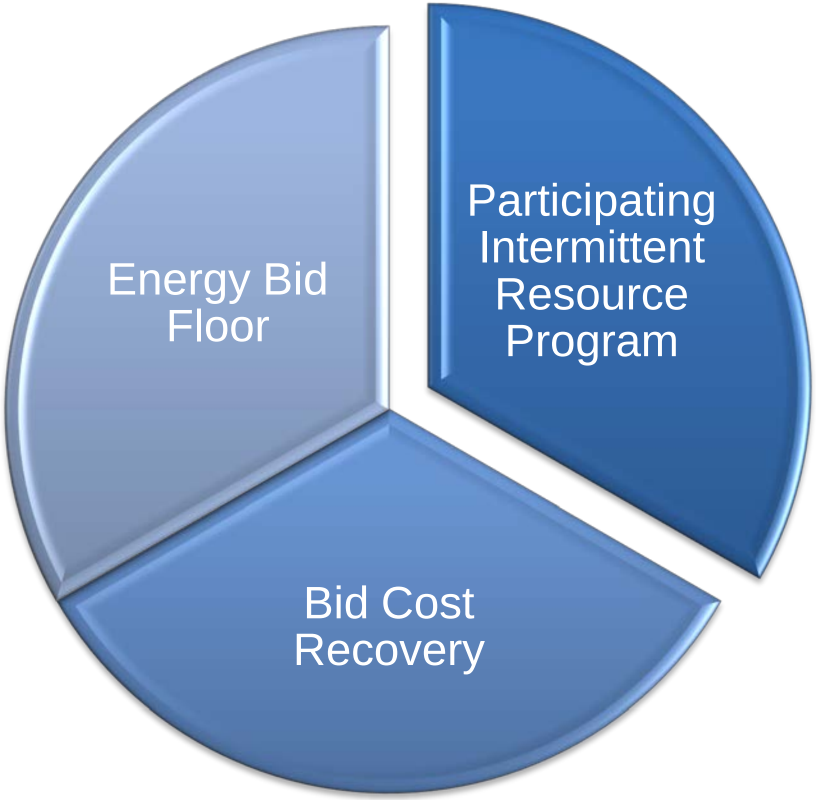
Management recommends that the Board approve the policy to implement the elements of Renewable Integration Market and Product Review Phase 1 and modify tariff provisions as outlined in this memorandum and conditionally authorize Management to make all necessary and appropriate filings with FERC to implement the proposed tariff change.

Decision on Renewable Integration – Market and Product Review Phase 1

Greg Cook
Director, Market & Infrastructure Policy

Board of Governors Meeting
General Session
December 15-16, 2011

The scope of the Renewable Integration Market and Product Review Phase 1 originally encompassed three elements.



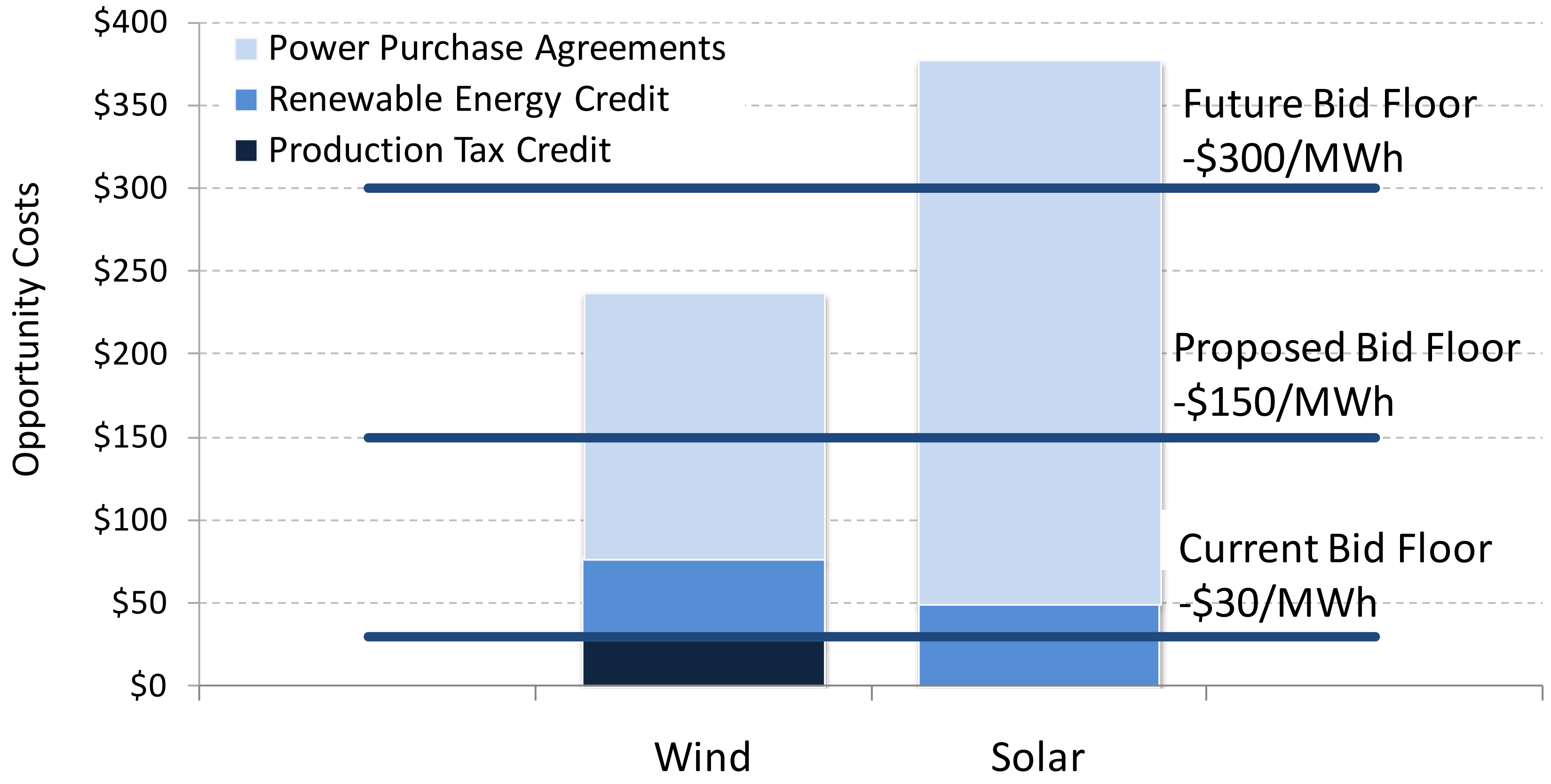
Potential changes to participating intermittent resource program deferred due to unresolved concerns.

- PIRP implemented in 2002 to mitigate risks of real-time deviations of intermittent resources
  - Pay resources based on ISO forecast derived real time schedules
  - Deviations from schedule are charged or paid monthly average price
  - Socialization of costs caused by PIRP settlement

- PIRP insulates resources from changes in real-time prices
  - No incentive to adjust output in response to changes in real-time operational conditions
  - Without PIRP, current market structure does not provide opportunity to schedule resources after day ahead market

- PIRP changes will be further considered in 2012
  - Allow decremental bidding for PIRP resources

The energy bid floor must be low enough to incent resources to be available for curtailment of output.



Bid cost recovery provides for a make-whole payment when a resource's revenues do not cover its costs.

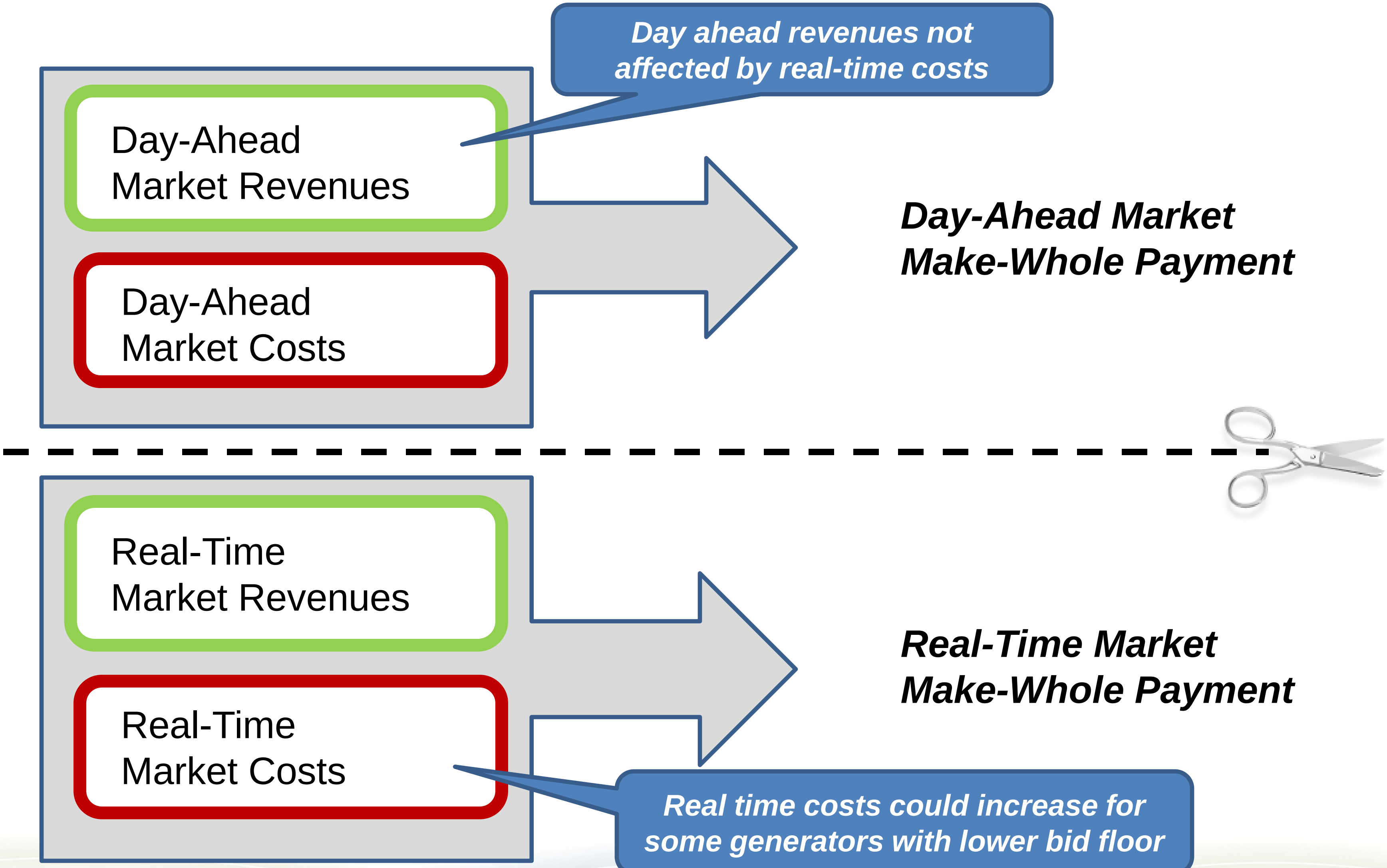
All Market revenues
- Energy revenues
- RUC capacity payment

All Market costs
- Start-up costs
- Minimum load costs
- Energy bid costs

Market revenues and market costs are netted over the day

A resource with a net shortfall over the day receives a "make-whole" uplift payment

Management recommends the separation of bid cost recovery netting.



In response to stakeholder feedback, additional bid cost recovery measures will be further vetted.

- A follow-on stakeholder process will further consider mitigation measures to align incentives to follow ISO dispatch instructions

- Management will seek Board approval for the recommended changes resulting from further refinement and stakeholder feedback in March 2012

- All changes to bid cost recovery will be filed with FERC and implemented together as a package

Stakeholders' comments on Management's proposal

Energy Bid Floor	• General support for lowering the bid floor
Bid Cost Recovery	• General support for separating the netting
Participating Intermittent Resource Program	• Significant concerns remain

Management recommends the Board approve the policy to implement Renewable Integration Market and Product Review Phase 1.

- Lowering the energy bid floor will incent additional decremental bidding.
  - Impact analysis after the first year

- Changing bid cost recovery netting in alignment with lowering the bid floor will incent more real-time bids.
  - Additional market design time for mitigation measures

- Proposal will not be filed with FERC until Board approval is obtained for bid cost recovery mitigation measures.

Attachment A

Stakeholder Process: Renewable Integration – Market & Product Review Phase 1

Summary of Submitted Comments

Stakeholders submitted nine rounds of written comments to the ISO on the following dates:

- Round One, 07/30/10 (Comments on discussion paper)
- Round Two, 10/19/10 (Comments on issue paper)
- Round Three, 01/21/11
- Round Four, 03/11/11
- Round Five, 05/11/11
- Round Six, 07/28/11
- Round Seven, 09/07/11
- Round Eight, 10/14/11
- Round Nine, 11/18/11

Stakeholder comments are posted at:
http://www.caiso.com/Documents/Renewable%20integration%20market%20and%20product%20review%20phase%201%20-%20stakeholder%20comments

Other stakeholder efforts include:

- Stakeholder meeting – 07/16/10
- Stakeholder meeting – 10/05/10
- Market Surveillance Committee meeting – 11/19/10
- Stakeholder meeting – 01/06/10
- Stakeholder meeting - 02/24/11
- Stakeholder conference call – 03/21/2011
- Stakeholder conference call – 05/03/11
- Stakeholder meeting – 07/19/11

- Stakeholder meeting – 08/29/11
- Stakeholder conference call – 09/01/11
- Market Surveillance Committee meeting – 09/30/11
- Stakeholder conference call - 10/05/11
- Stakeholder conference call – 11/08/11
- Stakeholder conference call – 11/16/11
- Market Surveillance Committee meeting - 12/08/11

California ISO
Shaping a Renewed Future

Management Proposal	PIRP Revisions	Energy Bid Floor	Bid Cost Recovery	Management Response
Brookfield	Oppose Does not support cost allocation revisions.	Supports	No Comment	<u>PIRP Revisions</u>: Management is not seeking approval of proposed PIRP revisions in the draft final proposal, but rather will continue to seek to address outstanding stakeholder concerns. <u>Energy Bid Floor</u>: Rather than automatically lowering the energy bid floor from -\$150/MWh to -\$300/MWh after one year, Management recommends evaluation of market data after one year with the bid floor at -\$150/MWh. <u>Bid Cost Recovery</u>: Management recommends seeking approval of the BCR mitigation measures after a follow-on stakeholder process through which those complex topics can be further vetted and refined.
Calpine	No Comment	Conditional Supports lowering the bid floor but prefers a more conservative value. Recommends review of market data prior to subsequent step-down of the bid floor.	Conditional Supports separation of netting but has significant concerns about the BCR mitigation measures.	
CDWR-SWP	Supports	Supports Recommends review of market data prior to subsequent step-down of the bid floor.	Supports Recommends extensive testing and calibration. Had clarifying questions about the BCR mitigation measures.	
CalWEA	Opposes Does not support cost allocation revisions.	Supports	Supports	
Duke Energy	Conditional Supports most elements, but expresses concerns about cost allocation.	No Comment	No Comment	
Iberdrola	Opposes Does not support	No Comment	No Comment	

Management Proposal	PIRP Revisions	Energy Bid Floor	Bid Cost Recovery	Management Response
	cost allocation revisions.			
NRG	Opposes Does not support cost allocation revisions.	No Comment Comments on previous iterations of the proposal were not supportive.	Conditional Does not support the proposed BCR mitigation measures.	
PG&E	Opposes Recommends elimination of the PIRP program.	Conditional Recommends review of market data prior to subsequent step-down of the bid floor.	Conditional Supports separation of netting but has significant concerns about the BCR mitigation measures.	
Powerex	Supports	Conditional States that the proposal is a good first step, strongly supports symmetrical energy bid cap and floor.	No Comment	
SDG&E	Opposes Prefer the elimination of the PIRP program, but states that cost allocation revisions are a good first step.	Conditional States that the proposal is a good first step in lowering the energy bid floor.	Supports	
Six Cities	Conditional Supports cost allocation revisions but does not support retaining the PIRP program indefinitely.	Conditional Supports lowering the bid floor but prefers a more conservative value. Recommends review of market data prior to subsequent step-	Supports Recommends refinements to the BCR mitigation measures.	

Management Proposal	PIRP Revisions	Energy Bid Floor	Bid Cost Recovery	Management Response
		down of the bid floor.		
SMUD	Opposes Does not support cost allocation revisions.	Opposes States need for additional flexibility for PIRP bidding and scheduling.	No Comment	
SCE	Conditional Prefers the elimination of the PIRP program, but states that cost allocation revisions are a good first step.	Conditional Recommends review of market data prior to subsequent step-down of the bid floor.	Conditional Supports separation of netting but has significant concerns about the BCR mitigation measures. Recommends additional time for stakeholder process. Recommends refinements to the BCR mitigation measures.	
WPTF	No Comment Recommends additional time for stakeholder process.	No Comment	No Comment Recommends additional time for stakeholder process.	

Attachment H – Bid Cost Recovery Mitigation Measures and Commitment Costs Refinement

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with Additional Performance Based Refinements

California Independent System Operator Corporation

September 25, 2013

Opinion on
Bid Cost Recovery Mitigation Measures and Commitment Costs Refinement

by

James Bushnell, Member
Scott M. Harvey, Member
Benjamin F. Hobbs, Chair
Shmuel S. Oren, Member

Members of the Market Surveillance Committee of the California ISO

May 7, 2012

1. Introduction and Summary

The Market Surveillance Committee (MSC) of the California Independent System Operator has been asked to provide an opinion on the ISO's proposals on bid cost recovery (BCR) mitigation[1] and commitment costs.[2] Earlier versions of the BCR and commitment cost proposals have been discussed during MSC meetings in 2011 and, most recently, at the March 30, 2012 MSC meeting. In addition, MSC members have participated in stakeholder calls and have reviewed stakeholder comments submitted to the ISO.

These proposals are part of the ISO's initiative to provide incentives for increased flexibility in real-time markets to facilitate integration of variable renewable power sources into the ISO markets. As part of that initiative, the ISO Board approved two elements of Phase I of the Renewable Integration: Market and Product Review[3] at the December 2011 board meeting. These elements included lowering of the bid floor in two stages and revision of the bid cost recovery mechanism (BCR) to allow for separate calculation of BCR in the day-ahead and real-time markets. Among other features, the proposal included a feature to detect and disqualify persistent uninstructed energy deviations from BCR. This is because the current ISO BCR design can offer incentives for generators to offer very high bids for part of their capacity output range and then to deviate from real-time instructions in a way that would result in high energy as-bid costs and BCR.

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[1] *Bid Cost Recovery Mitigation Measures, Draft Final Proposal*, CAISO, April 6, 2012, www.caiso.com/Documents/DraftFinalProposal-BidCostRecoveryMitigationMeasures.pdf; *Addendum to Bid Cost Recovery Mitigation Measures Draft Final Proposal*, CAISO, April 27, 2012, www.caiso.com/Documents/Addendum_BidCostRecoveryMitigationMeasuresDraftFinalProposal.pdf

[2] *Commitment Costs Refinements 2012, Draft Final Proposal*, California ISO, April 11, 2012, www.caiso.com/Documents/DraftFinalProposal-CommitmentCostRefinements.pdf; *Addendum to Commitment Costs Refinements Draft Final Proposal*, CAISO, April 27, 2012, www.caiso.com/Documents/Addendum-CommitmentCostsRefinementsDraftFinalProposal.pdf

[3] www.caiso.com/Documents/DraftFinalProposal-RenewableIntegrationMarket-ProductReviewPhase1.pdf

The MSC submitted an opinion to the Board in December offering general support for those proposals. [4] In the opinion, the MSC cautioned that the performance of the revised BCR mechanism would depend on specific parameter choices, and that the system should be subjected to extensive testing before parameter values are selected and the system is implemented. In particular, we were unable at that time to conclude with confidence that the Performance Measure and Persistent Uninstructed Energy Check features of the proposal would function as intended. We stated that additional detail regarding the parameter values that would be used in applying these features along with additional testing data would be needed to allow us to reach a conclusion about their functioning. We also said that it would be important to ascertain that those features are (1) effective in discouraging strategic behavior aimed at increasing BCR payments, (2) while not inadvertently yielding large decreases in BCR payments for normal deviations from dispatch instructions. Such decreases would undermine the goal of encouraging more resources to participate in the real-time dispatch. We noted that testing might indicate that significant changes to the basic features as proposed would be necessary to accomplish these goals.

In the April 6 draft final BCR mitigation proposal, the ISO presents details of the mechanism, including parameters to be used in its implementation. In the present opinion, we comment on that implementation. In particular, we express our support for its major features, including the modified day-ahead metered energy adjustment factor; the real-time performance metric; and the persistent uninstructed energy (PUIE) check.

However, we believe that further examination is needed to determine the particular threshold values to be used to determine whether persistent uninstructed energy would be disqualified. In particular, although the analysis of historical data in the draft BCR proposal is very helpful in understanding the potential frequency of mitigation, it is not presently clear whether the instances in which generators would have had bid costs disqualified actually represent abuse or not. Nor is it clear whether or not significant cases of abuse might pass the proposed threshold and avoid mitigation. The MSC also recommends that the criteria used to determine whether mitigation will take place also include consideration of a total dollar or dollar/MW of capacity threshold.

Turning to the commitment cost proposal, as a general principle, we support the recovery of legitimate and verifiable start-up (SU) and minimum-load (ML) costs when they are incurred as part of the least-cost operation of the ISO market. We have addressed in past opinions the design of the limitations imposed by the ISO on how such fixed costs can be bid.[5] Our recommendations attempted to balance the need for responsiveness to changing fuel and other costs, while

[4] Market Surveillance Committee of the CAISO, *Final Opinion on Renewable Integration: Market Product Review, Phase 1*, www.caiso.com/Documents/MSC_Final_Opinion_RenewableIntegrationMarketProductReviewPhase1.pdf

[5] Market Surveillance Committee of the California ISO, *Comments on Changes to Bidding Start-Up and Minimum Load*, July 16, 2009, www.caiso.com/Documents/FinalOpiniononStart-UpandMinimumLoadBiddingRules.pdf; Market Surveillance Committee of the California ISO, *Opinion on Changes to Bidding and Mitigation of Commitment Costs*, June 4, 2010, www.caiso.com/Documents/FinalOpiniononChanges-BiddingandMitigation-CommitmentCosts.pdf

limiting opportunities to take advantage of local market power to recover inflated as-bid levels of these costs. We expressed explicit support for accounting not only for fuel cost portion of SU and ML costs, but also the increased wear-and-tear costs to the generation unit due to the increased number of starts and the opportunity cost of a start due to maintenance contract and environmental restrictions on the total annual number of starts or run-hours. The ISO's present commitment cost proposal is certainly a step in the right direction on this issue. We noted previously that developing a reasonably accurate methodology for determining what these costs are for each generation unit is difficult to achieve, and that it is desirable to have a local market power mitigation methodology that focuses the application of mitigation on generators at locations where generators may have the ability to submit inflated SU and ML bids that will clear in the market.

The present proposal offers an improved methodology for estimating certain components of SU and ML costs that are not presently included in proxy bid and registered cost calculations, which we strongly support. In particular, the proposal would allow for inclusion of grid management charges, CO_2 costs, and maintenance costs in SU and ML proxy bids, which we support, as well as ex post recovery of operational flow order costs. This permits the lowering of the cap upon registered SU and ML costs to 150% of the proxy value, which we believe could be lowered further within a year to 125% if experience indicates that actual costs are generally below that value. Presently, we lack the information necessary to determine whether one or the other, or some different value, would be best.

We identify two further enhancements to the commitment costs proposal that we believe could improve the efficiency of system operations by allowing bids to more fully reflect costs. The complexity of these enhancements means that it is not practical to implement these enhancements in the commitment costs proposal at this time. Therefore we recommend that the ISO initiate, at an appropriate time, a stakeholder process that would move towards developing and implementing a follow-up proposal.

The first enhancement whose consideration we recommend concerns SU and ML opportunity costs due to limitations upon starts and run-hours. These can be significant for some units, but are not provided for in this proposal. At previous MSC meetings addressing the topic in 2009 and 2010, such costs were mentioned as important, and we have previously recommended consideration of their inclusion.[6] We repeat that recommendation here.

Second, we recommend that consideration be given in a future stakeholder process to including costs associated with operational flow orders (OFOs) in SU and ML bids used in the real-time market software if those costs can be reasonably anticipated with enough lead-time so that reasonably verifiable values can be included. If possible, this is much preferable to recovery based upon after-the-fact calculations because it is important for market efficiency that unit commitment decisions be based on all known costs. Otherwise, units might be committed which would not otherwise have been if their SU and ML costs had included OFO costs, thereby unnecessarily increasing costs. We recommend that a study be undertaken of the potential magnitude of OFO costs under alternative market conditions with the objective of determining whether they could

[6] Ibid.

be large enough to be relevant to commitment decisions, and if significant efficiency improvements could then result from including them in SU and ML bids.

Finally, we also make a long-term recommendation that the ISO consider possibilities for more tailored mitigation of market power in commitment costs. This would involve relaxing constraints on allowable bids where markets are likely to be highly contested (for example, by allowing them to change bids more often than monthly) and having tighter constraints where exceptional dispatch, load pocket conditions, or other constraints limit contestability. However, we were not able at this time to identify a transparent, readily implemented, and defensible basis for such a refined system, and so recommend that such tailored mitigation not be included in this proposal, but that it be studied for possible implementation in future BCR revisions.

2. BCR Mitigation

2.1 General Comments

As we explained in our December 2011 opinion on Phase 1, the BCR mitigation procedure would apply a performance metric that would scale certain components of the bid cost recovery calculation based upon deviations from ISO dispatch instructions. This prorating process is intended to remove the incentive, for instance, for a generating unit to receive a day-ahead BCR payment based on a day-ahead commitment, and then to declare an outage so that the unit would not actually run but would still received the payment, or for a unit to receive BCR for generation in excess of ISO dispatch instructions.

However, the performance metric only considers uninstructed deviations within a single real-time interval. Because of the way the ISO calculates dispatch instructions relative to a resource's actual metered output at the time the real-time dispatch software begins its calculations, uninstructed deviations that continue over time can impact ISO real-time dispatch instructions in future intervals. This means that uninstructed deviations calculated solely relative to the dispatch instructions for the current interval will not accurately reflect the *cumulative* deviations by the resource. In other words, a unit may only narrowly deviate from a dispatch order in a current interval, but that order might only be necessary because of additional non-compliance in previous intervals. In some cases a unit can force the dispatch, through previous non-compliance, to provide instructions it can profit from through bid-cost recovery and other mechanisms.

Therefore, the ISO proposed to augment the performance metric with a real-time calculation of a persistent uninstructed energy index (PUIE) that would disqualify real-time energy from the real-time BCR calculations in the case where generators choose to deviate consistently over several periods, yielding a greater deviation between actual operation and system cost-minimizing dispatch than can result from just one interval's deviation. The check would construct a "counterfactual" or hypothetical series of operating levels that would have occurred if the generator had adhered to the operators' instructions.

In our previous opinion, we expressed our support for the need for the proposed performance metric and persistent deviations check, and the general philosophy behind their calculation and application. They are likely to be more effective than the previous BCR procedures in avoiding potential BCR payment inflation from intentional deviations. We reiterate that general support here.

We support the proposed metered energy adjustment factor and performance metric. Although it has been suggested that more generally applicable uninstructed deviation penalties should be used instead, we prefer the more tightly focused proposal made by the ISO. We believe that in the vast majority cases, the appropriate "penalty" is just the real-time cost of energy, which represents the market's cost of making up for a market party's imbalance. We support this proposal's narrow applicability of adjustments to situations involving BCR payments. In the below comments, we focus on the persistent uninstructed energy check and its use for disqualifying certain as-bid energy cost shortfalls from eligibility for BCR, since this is the item that has attracted the most stakeholder attention.

2.2 Persistent Deviation Criteria for Disqualifying Energy Bid Cost Recovery

In our December 2011 opinion, we also noted that the revised BCR mechanism represents a significant departure from the previous BCR procedures at the ISO, and indeed at any other RTO or ISO. For this reason, we argued that it is important that the procedures, as well as the particular parameter values to be used to implement them, be subject to careful testing to ensure that they will work as intended. In particular, will they effectively guard against intentional inflation of BCR payments arising from unscheduled output, i.e., deviations from the ISO's dispatch instructions? And, at the same time, will they avoid penalizing innocent behavior by prorating BCR payments in response to normal scheduling inaccuracies or errors in a way that would undermine the goal of encouraging more resources to participate in the real-time dispatch? At the time that opinion was written, the specific triggers for mitigating persistent uninstructed deviations had not been defined.

In the ISO draft final proposal, specific triggers are provided, along with statistics based on historical data on how often they would have been violated in the past. There are two indices that are proposed for use in determining whether mitigation of persistent uninstructed deviations would occur (measures A and B, defined on p. 16 of the proposal). The final draft proposal has proposed that the following combinations of A and B would not trigger mitigation:

1. A less than 3%;
2. B less than 3 $/MWh; or
3. Combinations of A and B that satisfy both A less than 10% and B less than 10 $/MWh.

The first two criteria represent revisions to the previous proposal, and provide an additional safe harbor for generators whose deviations are small and quite possibly due to normal operational variations. In particular, if A is positive but B is small (or B is positive and A is zero), we do not believe it is necessary to adjust BCR, since BCR is close to zero anyway. Such points lie on or very near the A and B axes in Figures 3.3.4-1 (p. 17) and 3.3.2-5 (p. 23) of the proposal. The set of combinations in the third criterion was proposed in earlier versions of the BCR proposal.

On the other hand, there might be cases where A and B are both barely satisfy criterion 3 (e.g., A = 9% and B = $9/MWh), but the total dollar amount is large. Therefore, we recommend that the ISO examine these cases from the historical record to determine the magnitude of BCR associated with persistent uninstructed deviations. If the amounts are significant in some cases, we recommend that the above criteria be modified so that if the total dollar amount is above some total $/interval threshold that mitigation be triggered even if any of the above criteria are satisfied. Alternatively, to account for the fact that generators can be very different in size, this threshold could instead be phrased in terms of $/interval per MW of installed capacity, with some de minimus total $/interval amount below which mitigation would not be triggered.

In particular, we are concerned that the reasons for observed persistent deviations in the past are not understood, and as a result the thresholds might be set at levels that result in disqualification of BCR in cases where deviations are the result of normal operating variations. Several stakeholders share this concern. If the loss of BCR would then be significant and frequent, that could act to discourage real-time bidding by needed resources. We recommend that the data analysis conducted in Section 3.3.5 of the proposal be extended in order to inform possible adjustments to the proposed parameters. In particular, the possibilities of false positives and negatives should be examined by, first, determining, if possible, the reasons for a sample of historical instances that violate the proposed deviation criteria; second, doing the same for instances that come close, but do not violate the criteria; and, third, assessing the resulting impact on BCR for those units. We believe that such an analysis will provide useful information for fine-tuning the parameters to ensure that an appropriate balance is struck between reducing incentives for the inefficient bidding and generation output strategies that are the concern of the PUIE check, and the risk of discouraging participation in the real-time market by resources that would likely require BCR. We note that as output by variable renewable energy sources increases, instances of very low or negative real-time prices will happen more often, which could increase the frequency of BCR for thermal resources.

2.3 What Energy Bid Costs Should be Disqualified if Persistent Deviations Occur?

During the March 30, 2012 MSC meeting, we expressed support for revising the draft proposal so that the only energy bid costs that would be excluded from the BCR calculations would be those that were identified as persistent uninstructed deviations during intervals that the performance measures were violated. The draft proposal at that time would have resulted in disqualification of all energy bid costs from those intervals, which we believed would have been overly severe and perhaps would discourage resources from participating in the real-time dispatch. We support the change represented by the revised proposal of April 6, in which only the deviations identified as persistent uninstructed deviations would be excluded. This makes the penalty more proportionate to the impact of the potentially intentional over-generation, and will avoid the possible problem that might arise from incenting generators to skew somewhat towards undergenerating in order to avoid the risk of losing all energy bid BCR.

3. Commitment Costs

3.1 General Comments

Presently, market participants can choose between two methods for bidding their start-up and minimum load costs. Under the Proxy Cost option the market participant submits its start-up and minimum load costs on a daily basis, with the bids capped by the ISO's proxy cost calculation. Under the registered cost option, the start-up and minimum load cost bids submitted by the market participant must remain constant for 30 days and are required to be no more than twice a cost-based measure calculated by the ISO. This 100% head-room allows for volatility of spot fuel costs and for SU and ML costs that are excluded from the proxy. Regarding volatility, the ISO's analysis shows that spot fuel costs rarely exceed 110% of the monthly gas price used to calculate gas costs under the registered cost option. Although spot prices for individual days might be significantly higher than the monthly gas price, the single highest day is not the relevant measure under the registered price option for high capacity factor units that would operate many or most days (and be required to submit the same bids on all of those days under the registered cost option). For such units the amount of headroom needed for that reason is well below 100%. However, for low capacity factor units, their fuel costs can be significantly above average monthly levels, especially if periods of high electricity demand coincide with higher daily gas prices, so somewhat more head room can be justified in those cases. Intraday gas costs can also be higher than daily price indices. Finally, volatility may be higher in future months and years than it has been over the past few years during the recession. Thus, headroom of more than 10% could perhaps be justified on volatility grounds alone, especially for lower capacity factor units.

It would normally be more efficient for a gas-fueled generator in particular to vary its start-up and minimum load offer costs on a daily basis to reflect variations in gas prices as permitted under the ISO's Proxy Cost methodology. However, the ISO's Proxy cost measure has historically not included all costs. Hence, generators for whom those costs are substantial might prefer to submit bids based on the registered cost option, despite the inefficiency of being constrained to submit the same offers for 30 days. Hence, the present 100% headroom also allows for miscellaneous SU and ML costs that are not captured in the proxy; presently, these include maintenance costs, opportunity costs of start-ups, emissions costs, grid management charges, and possibly others. To the extent that those costs can be explicitly included in the proxy cost, the need for market participants to bid using the registered cost method is reduced. Further, to the extent that those costs can be explicitly included in the registered cost, the allowed percentage headroom over the ISO calculated costs can be decreased. Therefore, given the ISO's proposal to include many more categories of costs in the base registered costs, we agree with the ISO that the allowed head room above these estimated costs under the registered cost option can be decreased. If it was possible to allow inclusion of opportunity costs and operational flow order costs in bids (as we suggest below should be considered in future revisions of the commitment cost rules), then we would be comfortable with the percentage of headroom being lowered from 100% to 25%. However, the present proposal excludes opportunity costs from calculations of proxy costs, and provides no means for their recovery. For this reason, somewhat more headroom could be justified in the registered cost option.

However, we do not make a recommendation for a particular value for amount of head-room, since we do not have estimates of the likely magnitudes of opportunity costs. We do note that if maintenance costs typically amount to approximately one-third of the presently allowed proxy cost, then the ISO's proposal to allow 50% head-room would result in the same total allowable bid under the registered cost option as the previous 100% head-room. If maintenance costs are typically less than 33%, then a 50% head-room would generally result in lower total allowable bids than under the present head-room. However, we do not have information on typical maintenance costs and so cannot assess whether the ISO's proposed change would result in a significant decrease, on average, in the overall allowable SU and ML bids under the registered cost option.

As information is lacking that would definitively support one or another cap, we therefore suggest proceeding cautiously by lowering the cap, as proposed by the ISO, to 150% immediately. We recommend that then within a year it be lowered further to 125% if the ISO makes a finding that fuel cost variations, opportunity-costs, and other omitted costs are highly unlikely to exceed 25% of proxy costs for the great majority of generating units.

If all significant categories of costs are included in SU and ML proxy bids, then we would find merit in the suggestion that the head-room percentage be applied just to the fuel cost portion of the proxy. On the other hand, if potentially important categories are omitted, such as opportunity costs, then the purpose of the headroom is not just to insure against gas price volatility risks, but also to accommodate other categories of SU and ML costs that are not captured in the proxy. This is the case with the ISO's proposal. Therefore, we believe that the proposal's application of the percentage to the entire SU and ML cost, and not just the fuel cost portion, is appropriate.

3.2 Focusing Mitigation on Units with Local Market Power

The philosophy of mitigation in the energy market is to focus mitigation on units possessing local market power. In contrast, the mitigation system for SU and ML bids is system-wide. However, we expect that generating units that are not in locations that would confer local market power would have a strong market incentive to submit bids reflecting their actual SU and ML costs to the extent permitted by ISO rules. On the other hand, units located in load pockets or other areas in which they possess local market power might be able to inflate their SU and ML offers to levels well above their costs yet still clear in the market. We believe that it is desirable to focus mitigation on those resources having locational market power, including that due to the various minimum on-line rules. In the long run, therefore we recommend that mitigation efforts be focused upon areas with persistent local market power, while giving more flexibility to generators outside such areas. The MSC has previously recommended a dynamic local market power mitigation (LMPM) procedure similar to that used for energy bids.[7]

For instance, this proxy cost approach would be made more focused, and could eventually be turned into a cap on start-up and minimum load bids with the market participant allowed to vary its bids every day as long as they were under the cap. Also, areas with persistent market power

[7] Footnote 5, supra.

could have tighter head-room percentages for the registered cost option, and other areas could have looser percentages.

However, implementation of such a system would mean that the occurrence of persistent market power would have to be defined. The procedure would have to dynamic (responsive to changing market conditions), transparent, and a valid reflection of local market power. Unfortunately, the new local market power mitigation procedure (LMPM), based upon the contribution to locational marginal prices (LMPs) of shadow prices of uncompetitive transmission constraints, is not applicable to lumpy decisions to commit generating units. This is because commitment of units needed to resolve uncompetitive constraints will often result in those constraints becoming nonbinding and having a zero shadow price. Because of such conceptual challenges, as well as practical considerations, development of such a LMPM-like system for SU and ML bids is not possible within the context of this proposal, but should be considered in the future.

3.3 Negotiated Maintenance Costs

In general, procedures involving negotiation to determine which costs can be recovered have poor incentive properties. If (1) a generator faces relatively little competition in a locally constrained area, so that higher SU costs would not lower the frequency of commitment, and (2) the generator usually obtains BCR for its SU costs, then incentives to minimize costs are dampened. The expense and relative lack of transparency of negotiated costs are further disadvantages.

To the extent that (1) most start-ups are not subjected to BCR, and (2) maintenance costs are non-discretionary, involving standard contracts with vendors, then we are less concerned with the incentive effects of negotiations. It would be useful to have data on the percentage of incurred SU costs for various classes of units that are recovered through BCR. If the percentages are small, then our concern over the negotiated cost option is less. However, this percentage may increase in the future as more renewable capacity comes on line, and episodes of very low or negative prices become more frequent.

Nonetheless, we recognize the need for negotiation given the great variations in types of generators and maintenance contracts. Therefore, we urge the ISO to put into place procedures for identifying benchmarks for classes of units; for identifying cases in which maintenance costs are considerably above benchmark levels; and for providing incentives for lowering those costs, such as allowing recovery of only a portion of costs that are above identified benchmarks.

3.4 Opportunity Costs of Start Ups

Opportunity costs for start-ups arise as follows. A generating unit that has a limited number of starts per year due to maintenance contract requirements incurs an opportunity cost for starting up if there is a positive probability that the generator will run out of starts before the end of the summer high load season; that is, a start now results in foregoing net revenue later in the year. The amount of this opportunity cost depends on the probability of using up all the allowable starts, and the gross margin (price minus variable cost, including SU and ML costs) that would have been earned in the later start.

Opportunity costs can also arise for operating hours if a unit has a limited number of run-hours because of environmental or other limitations. In that case, a similar opportunity cost arises that should legitimately be reflected in ML bids.

Although such opportunity costs are difficult to estimate, they can be large for some units in some years. If disregarding those costs results in units burning through all their allowable starts or run-hours early in the summer, this can significantly hurt market efficiency by decreasing the availability of needed resources later in the summer. A possible approach to correcting this problem would be to allow generators to negotiate an opportunity cost component in their SU or ML costs, and if such a component is included, have it be updated throughout the high demand season to reflect changing expectations concerning probability of running out, fuel costs, and prices.

Clearly, this calculation would be complex, costly, and relatively difficult to monitor and verify. To calculate opportunity costs, a generator would have to make a showing of a binding constraint that can reasonably be expected to bind. Then it would be necessary to approximate the probability of lost opportunities and the gross margin (prices minus variable costs) associated with them based upon reasonable expectations of future energy prices. This calculation would consider the number of starts or run-hours available versus the rate at which the unit has been committed. The relevant gross margin would be for the 'marginal' start - the future start that would be precluded because a start was instead scheduled today.[8]

The ISO is not recommending such a procedure for estimating and including opportunity costs in SU and ML proxy bids at this time because of the practical challenges involved in its design and implementation in the timeframe available. Therefore, we recommend that consideration be given to inclusion of opportunity costs in proxy costs in a new stakeholder process in the near future.

If no provision is eventually made for including opportunity costs in SU and ML bids, this could result in significant inefficiencies. An obvious inefficiency would be if a unit runs out of available starts or run-hours early in the season. A less obvious, but also potentially important inefficiency, can arise if a generator tries to prevent that outcome by choosing designation as a "use limited resource" in order to be exempt from the all-hours must-offer requirement. This would prevent commitment during certain hours. However, as wind penetration increases, the times

[8] Such a calculation of opportunity costs could in theory take place through a negotiation process, based on some standardized procedure. This is not an easy calculation, but some standard and conservative values might be agreed upon that would be better than zero (the present value). Once quantified, then one approach to including opportunity costs in SU or ML bids could be to have a separate daily or weekly changing registered cost component to SU or ML costs.

Another alternative for calculating opportunity costs could rely more on historical data. The purpose would be to estimate the gross margin for the marginal start in the relevant time windows in past years. A rough approximation might be the margin that is exceeded some X% of the time in the, for instance, the last month of the time window. The procedure could then adjust this margin for differences in fuel costs between the historical period and the present season, and also account for how binding the constraint is (the number of starts or run-hours used relative to those available) if that affects the likelihood of running out of starts or run-hours.

when that generator would optimally be dispatched might occur more frequently during off-peak hours which cannot be anticipated by inflexible monthly use plans. Large inefficiencies are likely to arise if a significant amount of capacity withdraws itself from the market during many hours in this manner. It would be more efficient to instead allow high SU and ML bids that reflect opportunity costs of operation, which then gives flexibility to the market software to determine whether or not it is worthwhile to run the units. We recommend that a study be conducted to determine if inefficiencies of this type are resulting from monthly use plans, and if so, what their significance is. Development of a procedure to include opportunity costs in SU and ML proxies would help avoid this potential inefficiency.

3.5 Operational Flow Order Costs

We agree with the premise of the commitment cost proposal that it is important to enable generators to recover significant operational flow order (OFO) costs, since they have the potential to materially affect SU and ML costs. Although OFO costs have recently been very minor, there were much higher levels on occasion in previous years according to PG&E data.[9] Also, changes in pipeline pressure rules and the possibility of tight electricity supplies in the coming months might cause such charges to become larger and more frequent than in the recent past.

As a general principle, it is desirable that any costs that can materially contribute to SU and ML costs be reflected in SU and ML bids so that the costs can actually influence unit commitment decisions, and so improve market efficiency. After-the-fact recovery of such costs can help to make generators whole, and by lowering the risk of non-recovery of costs, can encourage participation in the real-time market, which is desirable. However, after-the-fact recovery could distort unit commitment choices. As a result, costs may be incurred that the market software would have chosen to avoid, if those costs had been fully reflected in SU and ML bids.

In the particular case of OFO costs, their inclusion in SU and ML bids are also desirable from a gas and electric system reliability standpoint. This is because OFO's can be pipeline specific and if it would be much better to meet load with a gas-fired generator served by a pipeline that has not imposed an OFO than one that has.

Application of this general principle in the case of OFO costs would require an ability to adjust reference bids for real-time SU and ML bids daily in response to OFO costs, or the creation of a registered cost component to those SU and ML bids. A requirement would be that it would be practical to anticipate OFO costs in time for such a procedure; because OFO costs are usually known at the time the bid is submitted, in which case this inclusion seems reasonable. It would also be necessary to reasonably expect that OFO costs are fully marginal for the unit (i.e., are part of the incremental cost of starting up and running a unit). Although there are ambiguities in allocating OFO costs among multiple units coming under a single gas contract, it appears likely that OFO costs are fully felt for marginal decisions.

[9] www.pge.com/pipeline/operations/ofo/ofoarch.shtml. For instance, as recently as July 10, 2010, there were days with charges amounting to $5/mmBTU, and during the crisis, charges as high as $25/mmBTU occurred.

If these conditions are met, and if the costs of implementation are reasonable relative to anticipated market efficiency benefits, we would recommend that consideration be given to instituting a procedure to include reasonably anticipatable OFO costs in the proxy, rather than after the fact. On the other hand, reasons for not including OFO costs in SU and ML can include the complexity of implementing such a procedure; uncertain or minor efficiency improvements in commitment; and ambiguities in assigning costs to particular units and possible opportunities for strategic behavior that these ambiguities might present.[10]

We do not have data that would allow us to compare the efficiency benefits of including OFO costs in SU and ML bids to the expense of implementing such a procedure. Because of the uncertain possibilities for strategic bidding that inclusion of OFO costs in bids might open up, we support for now the ISO's proposal for after-the-fact recovery.

However, if there is a potential for OFO costs to become more important in the future, so that disregarding them in real-time unit commitment decisions would result in significant inefficiencies, then this issue should be addressed in a stakeholder process and further consideration given to including OFO costs in allowable real-time SU and ML bids.

4. Conclusion

In summary, we support the goals and most of the specific elements of the commitment cost and BCR mitigation proposals. In the case of the commitment cost proposal, it is an important step towards inclusion of all relevant costs in start-up and minimum-load bids, which is desirable for both cost-recovery and market efficiency reasons. For this reason, we support the proposed lowering of the cap upon registered SU and ML costs to 150% of proxy costs, and further recommend that it be lowered to 125% a year later if the ISO finds that total SU and ML costs are very likely to fall under that tighter cap. We recommend that consideration be given in a future stakeholder process to address inclusion of an additional category in proxy costs (opportunity costs of start-ups and run-hours). We also recommend that consideration be given in the future to including operational flow order costs in real-time SU and ML bids, rather than recovering such costs after the fact if such costs have the potential to be large enough to significantly affect commitment decisions and market efficiency.

For the BCR mitigation proposal, there remains uncertainty over whether the criteria for identifying persistent uninstructed deviations will indeed catch most circumstances in which such deviations are deliberate actions intended to inflate BCR payments, will avoiding penalizing inadvertent and unintentional deviations. Further analysis is desirable of historical patterns of deviation.

[10] We note that opportunities for strategic behavior can also arise if OFO costs are recovered after-the-fact as proposed. If OFO costs cannot be included in the SU and ML bids and have to be recovered in an ad hoc reimbursement later, then allocation among units can become an issue. This is because there are revenues and costs for a group of units, and some will have had profits and others will not in a particular day before the OFO costs are accounted for. As a result, how OFO costs are allocated could impact the total BCR. Allocation rules could also affect efficiency; for instance, if the ISO allocates all the OFO costs to the profitable units, this will lead to undesirable incentive problems. Therefore, strategic behavior considerations do not necessarily favor after-the-fact recovery of OFO costs.

In the long run, we would prefer a BCR mitigation system that, like the local market power mitigation procedure for energy, focuses on locations where competition cannot be relied upon to incent efficient bidding for start-up and minimum load costs.

Attachment I – Opinion on Mitigation Measures for Bid Cost Recovery

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with Additional Performance Based Refinements

California Independent System Operator Corporation

September 25, 2013

Opinion on
Mitigation Measures for Bid Cost Recovery

by

James Bushnell, Member
Scott M. Harvey, Member
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Shmuel S. Oren, Member

Members of the Market Surveillance Committee of the California ISO

Final of December 5, 2012

1. Introduction

The Market Surveillance Committee (MSC) of the California Independent System Operator has been asked to provide an opinion on the ISO's proposals for mitigation measures to be applied to bid cost recovery (BCR).[1] Mitigation of BCR has been the subject of several MSC meetings over the past few years, and a previous version of the most recent proposal was discussed at the Oct. 19, 2012 MSC meeting in Folsom. In addition, MSC members have participated in stakeholder calls and have reviewed stakeholder comments submitted to the ISO. The MSC has considered BCR mitigation in two recent opinions. These included the Dec. 9, 2011 opinion on Phase 1 of the Market Product Review,[2] and the later May 7, 2012 opinion focusing on BCR mitigation[3], which addressed the ISO's earlier draft proposal of April 6, 2012.

Our major recommendation is that we support the simple and transparent approach to monitoring persistent real-time deviation from dispatch instruction. Previous proposals for mitigating the adverse effect of persistent uninstructed deviations on real-time BCR payments attempted to scale the payment by using scaling factors that try to track uninstructed energy and scale the BCR payments accordingly. The intent of such scaling was to produce a strategy-proof payment scheme that will incentivize participation in the real-time market while neutralizing opportunities to inflate BCR payments through adverse behavior. Unfortunately, that approach was too complicated and non-transparent. Furthermore, from a theoretical perspective, a strategy-proof payment scheme may be impossible when the bidders' strategy space allows them to adjust both bid

[1] California ISO, *Third Revised Draft Final Proposal on Bid Cost Recovery Mitigation Measures*, Draft of Nov. 26, 2012, www.caiso.com/Documents/ThirdRevisedDraftFinalProposal_BidCostRecovery MitigationMeasuresNov26_2012.pdf

[2] Market Surveillance Committee of the CAISO, *Final Opinion on Renewable Integration: Market Product Review, Phase 1*, Dec. 9, 2011, www.caiso.com/Documents/ MSC_Final_Opinion_RenewableIntegrationMarket-ProductReviewPhase1.pdf

[3] J. Bushnell, S. Harvey, B.F. Hobbs, and S. Oren, *Opinion on Bid Cost Recovery Mitigation Measures and Commitment Costs Refinement*, Market Surveillance Committee of the CAISO , May 7, 2012, www.caiso.com/Documents/MSCFinalOpinion-BidCostRecoveryMitigationMeasures_ CommitmentCostsRefinement.pdf

price and delivered quantity. Auction theory is based on the premise that awarded quantities in an auction are binding, and market clearing rules and payments designed so as to incentivize truthful bidding and efficient outcomes. We are not aware of any theory which addresses the possibility of winning bids not supplying the quantities awarded to them in the auction. Two-settlement systems (day-ahead and real-time) and various ad hoc heuristics implemented by various ISOs were designed to minimize strategic manipulation through bid price and uninstructed deviations but there is no theoretical gold standard to guide such rules. Consequently, a simple enforcement mechanism that penalizes noncompliance with respect to quantity delivery seems a reasonable solution. However monitoring and appropriate parameter tuning in response to that monitoring are essential, based on observed behavior. If persistent uninstructed deviations occur that inflate BCR and yet escape mitigation, then structural change to the mitigation system may be required.

The opinion is organized as follows. The next section presents some background on the development of this BCR proposal, and summarizes the previous MSC opinions addressing BCR and mitigation. In Section 3, the salient features of the most recent CAISO proposal are reviewed, and we offer some observations on those features. Our recommendations are presented in Section 4.

2. Background

The BCR proposal is part of the ISO's initiative to provide incentives for increased flexibility in real-time markets to help integrate sources of variable renewable power into the ISO markets. As part of that initiative, the ISO Board approved two elements of Phase I of the Renewable Integration: Market and Product Review[4] at the December 2011 board meeting. These elements included lowering of the bid floor along with revision of the BCR mechanism to permit a separate calculation of BCR in the day-ahead and real-time markets. Among other elements, the proposal included a feature to detect and disqualify persistent uninstructed energy deviations from BCR. This is because the current ISO BCR design can provide incentives for generators to offer very high energy bids for part of their capacity output range and then deviate from real-time instructions in a way that would result in high energy-as-bid costs and, ultimately, inflated BCR.

The MSC submitted an opinion to the Board in December 2011 that offered general support for those proposals.[5] In the opinion, the MSC cautioned that the performance of the revised BCR mechanism would depend on specific parameter choices, and that the system should be subjected to extensive testing before parameter values are selected and the system is implemented. In particular, we were unable at that time to conclude with confidence that the Performance Measure and Persistent Uninstructed Energy Check features in the proposal would function as intended. We stated that additional detail regarding the parameter values that would be used in applying these features along with additional testing data would be needed to allow us to reach a conclusion about their effectiveness. We also said that it would be important to ascertain that those fea-

[4] www.caiso.com/Documents/DraftFinalProposal-RenewableIntegrationMarket-ProductReviewPhase1.pdf

[5] *Op. cit.*, Note 2, *supra*.

tures are (1) effective in discouraging strategic behavior aimed at increasing BCR payments, while (2) not inadvertently yielding large decreases in BCR payments for normally expected deviations from dispatch instructions. Such decreases would undermine the goal of encouraging more resources to participate in the real-time dispatch by submitting economic offers. We noted that testing might indicate that significant changes to the basic features as proposed would be necessary to accomplish these goals.

In our May 7, 2012 opinion focusing on BCR,[6] we commented on the April 6 draft final BCR mitigation proposal, in which the ISO presented details of a proposed mechanism, including parameters to be used in its implementation. In particular, we expressed general support for its major features, including the modified day-ahead metered energy adjustment factor; the real-time performance metric; and the persistent uninstructed energy (PUIE) check. We also stated our opinion that careful study is needed to justify particular parameters used in these procedures to avoid false negatives (not mitigating when instead mitigation should take place) and false positives (mitigating when unnecessary). That proposal was not submitted to the Board, and further analysis and discussions with stakeholders have resulted in the Nov. 26, 2012 draft final proposal that we are discussing in this opinion.

3. The Revised CAISO Proposal for BCR Mitigation

In its third revised draft final proposal of November 26, 2012, the CAISO proposes several modifications of its previously proposed mitigation measures, targeted at behaviors that could inflate BCR payments in the day-ahead and real-time markets as well as payments for residual energy. The CAISO proposes that the new mitigation measures applicable to BCR be put in place at the same time that the BCR calculations for day-ahead and real-time are separated, since the separation could exacerbate the potential for inefficient bidding strategies.

The proposed mitigation measures attempt to strike a fine balance between three basic objectives:

1. Enabling eligible resources to appropriately recover as-bid costs when following CAISO dispatch instructions;
2. Reducing or eliminating incentives for inefficient market behavior and bidding strategies that are designed to increase uplift payments; and
3. Preserving incentives for suppliers to provide economic bids into the real-time market, which has been the motive for the separation of BCR calculation for the day-ahead and real-time markets.

Specifically, the proposed mitigation measures address three types of payments: (1) BCR for day-ahead market schedules, (2) BCR for real-time dispatch, and (3) payments for residual energy produced when resources are ramped from their initial state to the instructed level (during intervals when the price paid for such energy is less than the resource's offer price for that output level during the reference hour). The new CAISO proposal bases energy BCR on the resource's

[6] *Op. cit.*, Note 3, *supra*.

economic bid, as long as the resource follows its dispatch instruction within a prescribed tolerance level that is set forth in the proposal. The CAISO is also proposing to pay for residual energy as-bid, with exceptions for persistent deviations and ramping from exceptional dispatches and minimum load rerates.

In general, we support the CAISO proposal of using economic bids as a benchmark for BCR (when a resource follows dispatch instructions), since the resources' economic bids (which have presumably passed the market power mitigation screen) are accounted for in the optimization algorithm that determined their dispatch instructions for the interval under consideration. Further mitigation of these economic bids (e.g., replacement with default energy bids (DEB)), as suggested in earlier proposals, is not warranted *if* the resource is in compliance with its dispatch instructions.

But at the same time, it should be recognized that the starting point for the dispatch optimization in an interval could be the result of a series of prior deviations so that even if a unit follows dispatch instructions within an interval, it could be compensated for energy resulting from its initial state arrived at by upward deviations from instructions in prior intervals. The DMM has expressed concern regarding potential multi-interval deviation strategies that can inflate BCR and we concur with that concern and recommend close monitoring of whether such adverse behavior is occurring. For the situation just mentioned, as will be discussed in more detail below, a strategy of deliberate upward deviations could be motivated by the possibility of earning large make-whole payments in subsequent intervals if the energy bid in those intervals is well above the LMP. This was the concern that motivated the previous PUIE proposal. However, given the complexity of that PUIE proposal, we understand (and some of the MSC members support) the ISO's dropping of the proposed PUIE mechanism in favor of a simpler and more transparent approach to meeting the stated goals of this proposal.

The CAISO proposes that mitigation would be applied to the offers used to calculate BCR payments for the real-time market only when a resource is not in compliance with real-time dispatch instructions in a manner that would inflate BCR payments. This occurs when a resource over-generates when being dispatched above its day-ahead schedule or under-generates when being dispatched below its day-ahead schedule without being instructed to do so by the ISO. In the day-ahead market, the main concern expressed in the CAISO proposal is that a resource that is scheduled based on its day-ahead bids will collect BCR for its day-ahead schedule even if it does not deliver all of the scheduled energy in real-time. To address this concern, the existing CAISO BCR rules prorate costs and revenue components in the day-ahead BCR calculation by applying in each interval a metered energy adjustment factor (MEAF) that derates the scheduled energy by the amount of energy above the minimum load block that is delivered in real-time. However, the updated MEAF calculation in the new proposal will not penalize a resource for following dispatch instructions (within a tolerance band) in intervals in which the CAISO dispatches the resource downwards from its day-ahead schedule. This modification of the current day-ahead MEAF is an improvement and will reduce the likelihood of unintended adverse effects from the application of the MEAF, such as discouraging real-time decremental bids.

It is not obvious to us, however, that uninstructed reductions in output below the day-ahead schedule provide an economic justification for prorating day-ahead BCR payments calculated based on the day-ahead schedule. The day-ahead schedule is financially binding and a unit would have to replace any energy shortfall from day-ahead schedule with purchases in the real-time market (paying the real-time LMP) whether they receive BCR or not. Prorating BCR payments to resources committed uneconomically in the day-ahead market based on deviations from day-ahead schedule implies that units receiving BCR are not just financially liable for their day-ahead schedules but also have a physical obligation to adhere to that schedule. The DMM suggests that such an obligation may be justified on reliability grounds. However, even if reliability is indeed the motive for such proration of BCR payments, we see no economic reason to treat units receiving BCR any different than other units with regard to deviations from day-ahead schedules. Nonetheless, in any case, the proposed application of the MEAF is an improvement over the current rules.

The new proposed mitigation of the real-time BCR payments is based on compliance criteria that attempt to categorize the persistency of deviation from dispatch instructions. The mitigation is applied by replacing economic bids in the BCR calculation with the lowest of:

- the LMP,
- the economic bid submitted by the unit, and
- the default energy bid (DEB).

The deviation metric for each interval is based on changes in metered energy in successive intervals relative to the instructed change. When the metered change deviates from the instructed change by a prescribed tolerance (10%) in a direction that could inflate BCR payments, the interval is flagged. The persistency metric is based on the number of flagged intervals within a two hour moving time window and is categorized into two zones;

1. Below a low threshold of flagged intervals (3 intervals), then deviations are forgiven;
2. Above a certain upper threshold (4 intervals), deviations are instead deemed persistent and the mitigation is applied to all offers within the entire two hour window.

Under the new CAISO proposal, the above mitigation rules for energy bid cost recovery will also be applied to residual energy produced by a resource while ramping from its state at the beginning of an interval to its instructed state.

The CAISO proposal also addresses real-time behavior that is designed to prevent shutting down of a unit; this strategy involves deviating from dispatch instructions so as to stay above the minimum load level, which would trigger a mandatory shut-down. Likewise, the proposal addresses uninstructed start up of units. Absent the proposed rules, both types of deviations from CAISO dispatch instructions could result in inflated BCR payments. The CAISO proposes to treat such units in effect as self-dispatched, which would disqualify them from collecting BCR on their minimum load costs.

The DMM had raised two main objections to the mitigation procedure as proposed in earlier versions of the proposal. The first objection was the use of LMP in the cost base for BCR calculation, on the grounds that such use may encourage adverse bidding behavior attempting to manipulate the LMP. If, on the other hand, real-time BCR was determined interval-by-interval and not netted across multiple intervals (with appropriate allocation of start-up costs among intervals), this would not be a problem.[7] We strongly support such separation which is essential to incent economic real-time bids in every interval. Netting across intervals so that profits in one interval are deducted from the real-time BCR in another interval will undermine the original purpose of separating the day-ahead BCR from real-time BCR payment in order to encourage resources to participate in the real-time dispatch throughout the day. This would be a particular problem for resources that might be started up and shut down more than once in a day.

We understand that the DMM concern over this issue has at least been partially dealt with in the latest draft proposal,[8] where the thresholds for the number of intervals in the persistency metric have been modified. However, our concern over the incentive effects of calculating real-time BCR over the entire day remain, and we would prefer a finer-grained resolution for calculation of BCR in order to encourage energy offers into the real-time market.

The second DMM concern is that the proposed approach does not address multi-period strategies aimed at inflating real-time BCR payments, as we described above. We agree with that concern, in particular one may envision a strategy such as that depicted in Figure 1 below in which a high bid unit ramps up for two intervals although it was instructed to ramp down, but after those two intervals follows instructions to ramp down. According to the proposed rules such behavior will not incur any penalty (since two intervals deviation is below the mitigation threshold) and yet it produces a strip of excess energy[9] that will be remunerated as-bid. Unfortunately, the original PUIE proposal, which attempted to address such behavior, turned out to be too complex and non-transparent and led to the current proposal for simpler metrics for monitoring persistent deviations. We support this simpler approach in spite of this limitation because it is not clear that in practice such a bidding and operating strategy can be profitably applied within the thresholds of the California ISO proposal. However, we recommend vigilant monitoring to detect the use of such multiperiod deviation strategies. If such strategies are indeed a problem, adjustment of parameters may be required or the entire approach may need to be revisited and modified.

[7]Alternatively, BCR could be calculated over a single start-up/shut-down cycle, so that if a unit is started up twice in a day the real-time pre-dispatch, real-time BCR would be calculated separately over each cycle (B. Hobbs, "Bid Cost Recovery", MSC Meeting, March 18, 2011, www.caiso.com/Documents/ BidCostRecovery-MSCPresentation.pdf).

[8] Note 1, *supra*.

[9]This is instructed energy from the perspective of that interval (the operator has requested this level of operation), and is so classified for the purposes of settlement. This renders that energy eligible for BCR. However, considering the previous several intervals, this energy is, economically speaking, uninstructed, because it results directly from the upward deviations from instructions in previous intervals.

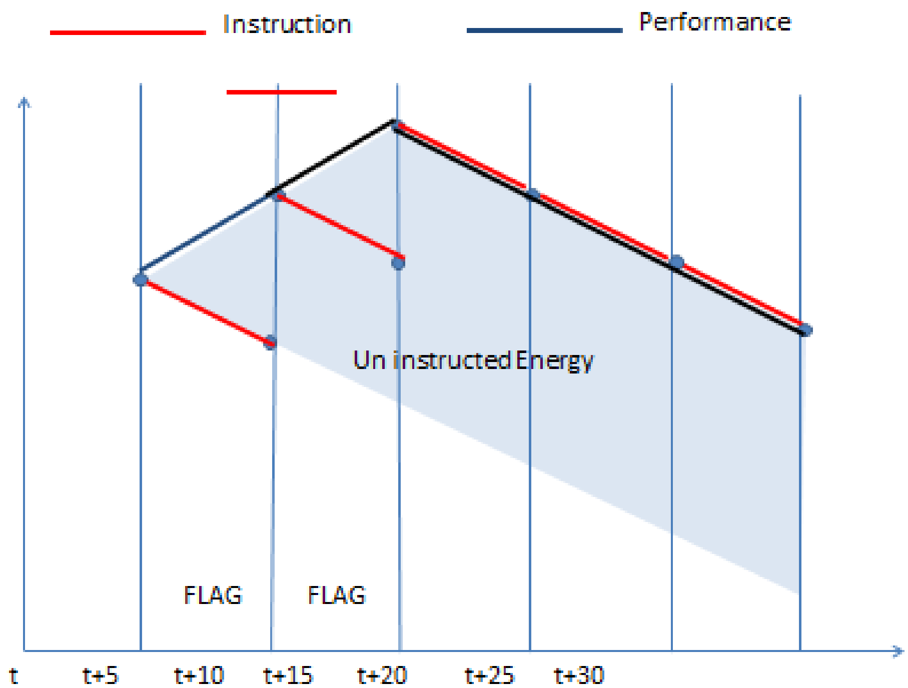

Figure 1: A multi-interval deviation strategy to create uninstructed energy

4. Recommendation on Mitigation and BCR

We support the new and transparent approach proposed by the ISO for monitoring persistent real-time deviations from dispatch instruction and subsequent mitigation of adverse impact of these deviations on real-time BCR payments. We also support the proposed treatment of behavior aimed at avoiding shut-down or initiating uninstructed start-up in order to inflate BCR payments.

It should be recognized, however, that the choice of parameters such as the 10% tolerance band and the upper and lower thresholds for the deviation persistency metric is ad hoc. The ultimate goal of these parameter choices should be to strike a balance between the economic consequences of type 1 and type 2 errors in mitigation—that is, over mitigation that may deter participation in the real-time market vs. missing adverse behavior that results in inflated BCR payments.[10] Therefore, it is important that the implementation of the proposed methodology be monitored closely over a trial period, say one year, and that the setting of the parameters be re-evaluated at the end of that period based on statistical evidence regarding real-time market participation, frequency of mitigation and real-time BCR payments.

[10] In the most recent BCR draft proposal (Note 1, *supra*.), the frequency of flagging was estimated based on Sept. 2012 data. Out of approximately 94,000 generating unit operating hours in that month, three or more intervals were flagged in 2.5% of them.

Furthermore, given some of the concerns we have mentioned about multi-period strategies to inflate BCR (see Figure 1, above), we further recommend that the CAISO monitor the implementation of the proposed rules from the beginning to assess whether there problems are occurring resulting from such strategies. If this is the case, then the CAISO should address it with rule changes as soon as practical. Such rule changes should not be limited to changing parameter choices in the currently proposed methodology and should consider other approaches to identifying multi-period strategies for inflating BCR if appropriate depending on the behavior observed.

Compared to earlier versions of the BCR mitigation proposal, the CAISO's current proposal has narrowed the scope of the remedies by focusing only on the possibility of inflating BCR payments. Consequently the persistent deviation metric only flags deviations from dispatch in directions that can result in inflated BCR. However, uninstructed deviations from dispatch in any direction could degrade the outcome of the optimization. It can be argued that the economic justification for any BCR uplift is to provide a side payment from consumers to producers when producers are being dispatched against their economic interest in order to support a socially optimal solution. However, this justification for BCR payments becomes inapplicable if a resource does not follow dispatch instructions which can undermine the social gain from dispatching that resource. Unless the deviation relaxes an overly conservative constraint assumed in the dispatch optimization, it is inherently suboptimal. While it may be difficult to determine the social cost due to uninstructed deviation by resources, the cost of corrective regulation can provide a rough estimate of the uninstructed deviation cost. In any case, it can be argued that uninstructed deviations beyond a tolerance band should disqualify a resource from receiving BCR payments, as will happen in the case of real-time BCR payments under the real-time performance metric under this proposal. On the other hand the general problem of penalizing uninstructed deviations is a very broad issue, and reaches beyond the scope of this proposal which focuses on inflated BCR payments. Therefore, we accept the CAISO approach to only flag deviations that have the potential to inflate BCR.

With regard to proration of day-ahead BCR when units underperform relative to their day-ahead schedules, it appears that the proration may impose significant costs on resources that are uneconomically scheduled for energy above minimum load (which is what is subject to the DA MEAF), beyond the cost of settling deviations between their day-ahead schedules and real-time output at the real-time price. We support the CAISO proposal as an improvement over the current design. If there is an issue in the CAISO real-time prices such that settling deviations between day-ahead schedules and real-time output at real-time prices provides insufficient incentive for resources to adhere to their day-ahead schedules, then any changes to address such a reliability concern should be applied to all resources with day-ahead schedules, not just those who receive BCR because they were committed uneconomically in the day-ahead market.

Finally, we support the proposed mitigation of BCR payment for units who try to avoid shut down by maintaining output above their Pmin level contrary to ISO instructions, or who start up uninstructed.

Attachment J – Comments on Bid Cost Recovery Mitigation Measures, Second Revised Draft Final Proposal

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with Additional Performance Based Refinements

California Independent System Operator Corporation

September 25, 2013

Comments on Bid Cost Recovery Mitigation Measures
Second Revised Draft Final Proposal

Department of Market Monitoring
November 14, 2012

Summary

The Department of Market Monitoring (DMM) appreciates the opportunity to provide comments on the Bid Cost Recovery (BCR) Mitigation Measures Second Revised Draft Final Proposal. The comments below apply only to Section 7 of the ISO's revised proposal (re: Cost and revenue basis for energy cost recovery and residual imbalance energy). Please see DMM's comments on the Revised Draft Final Proposal for our opinion on other aspects of the proposal.[1]

DMM views the current proposal as being potentially less effective than the prior proposals in terms of protecting against large costs caused by uninstructed deviations that can inflate BCR and Residual Imbalance Energy (RIE) payments. DMM has shared these concerns with ISO staff prior to issuance of the ISO's revised proposal, and is providing these comments at this time for consideration by stakeholders.

Concerns with proposal

DMM has identified situations in which the proposed persistent deviation metric may not make it uneconomic for a resource to deviate from dispatch in order to collect revenues set by the resource's bid price.

For example, consider a resource that bids energy at the $1,000/MWh price cap, unilaterally ramps up its output above its day-ahead schedule for 8 RTD intervals (40 minutes) of an hour, and ignores the ISO's downward dispatch instructions during this time. Under the current proposal, during this hour, the resource's BCR bid cost basis for the optimal energy that would result from these deviations would be mitigated to the minimum of (a) the market LMP, (b) the unit's DEB, or (c) the unit's bid price. Thus, if the unit's actual cost was higher than the LMP, the unit might incur a relatively small loss during this period. However, at worst, the unit would receive the LMP and would have this same LMP used as the bid cost for optimal energy provided during this period.

Meanwhile, during the following hour the resource would receive real-time payment based on its $1,000/MWh bid price while the resource followed its dispatch back down to its day-ahead schedule in subsequent intervals. This is because the ISO's proposal would only mitigate the BCR bid cost basis or RIE settlement price for the 8 RTD intervals in which a resource deviated in any 2-hour window. A resource could use those 8 RTD

[1] http://www.caiso.com/Documents/DMM%20Comments-BidCostRecoveryMitigationMeasuresRevisedDraftFinalProposal_01oct2012.pdf

intervals to position itself at a high output level despite submitting extremely high bids in the current and surrounding hours.

Specifically, while the resource followed its dispatch back down to its day-ahead schedule:

- Any Optimal Energy would have the current hour's high submitted bid used as the bid cost basis for BCR; and
- Any Residual Imbalance Energy would be settled directly on the high bids from a neighboring hour.[2]

Resources could utilize the above strategy to set their own revenues at levels that would significantly exceed what they could expect to receive from bidding their costs and following dispatch instructions. Moreover, less obvious and more difficult to detect variations of the above strategy could be used to inflate BCR and RIE. The following section provides a simple but realistic example of this concern.

Illustrative example

For this example, assume the following unit characteristics and market conditions:

- Unit is scheduled in day-ahead market at minimum load (25 MW).
- Unit ramp rate = 2.5 MW/minute
- Unit maximum operating level ≥ 125 MW
- Unit marginal operating cost = $30/MWh
- Market clearing price = $20/MWh
- Unit bid price = $1,000/MWh

Further assume the following unit operating and dispatch pattern (as depicted in Table 1):

- Starting in hour 1 interval 5, the unit begins to deviate upward.
- By the end of hour 1, the unit reaches an operating level of 125 MW.
- Starting in hour 2, the unit begins to follow its downward dispatch.
- By hour 2, interval 7, the unit is back down to its dispatch level of 25 MW minimum load.

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[2] The extent to which the resource's high payments while following its dispatch down from the deviations were divided between BCR and RIE would depend on the timing of the deviations relative to the beginning of an hour.

Table 1. Illustrative example of potential gaming scenario under persistent deviation metric

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			Real-time energy				Real-time energy revenue					
Hour	RTD Interval	Operating level (MW)	Uninstructed Energy	Optimal Energy	Residual Energy	Marginal Operating Cost	Uninstructed Energy	Optimal Energy	Residual Energy	Interval Compliance Check	Optimal Energy Bid cost ($/MWh)	Total Optimal Energy Bid Cost ($)
1	1	25	0.00	0.00	0.00	$0	$0	$0	$0	Pass	n/a	$0
	2	25	0.00	0.00	0.00	$0	$0	$0	$0	Pass	n/a	$0
	3	25	0.00	0.00	0.00	$0	$0	$0	$0	Pass	n/a	$0
	4	25	0.00	0.00	0.00	$0	$0	$0	$0	Pass	n/a	$0
	5	37.5	1.04	0.00	0.00	$31	$21	$0	$0	Fail	n/a	$0
	6	50	2.08	0.00	0.00	$63	$42	$0	$0	Fail	n/a	$0
	7	62.5	2.08	2.95	0.00	$94	$42	$59	$0	Fail	$20	$59
	8	75	2.08	3.99	0.00	$125	$42	$80	$0	Fail	$20	$80
	9	87.5	2.08	5.03	0.00	$156	$42	$101	$0	Fail	$20	$101
	10	100	2.08	6.08	0.00	$188	$42	$122	$0	Fail	$20	$122
	11	112.5	2.08	7.12	0.00	$219	$42	$142	$0	Fail	$20	$142
	12	125	2.08	8.16	0.00	$250	$42	$163	$0	Fail	$20	$163
2	1	112.5	0.00	0.00	7.29	$219	$0	$0	$7,292	Pass	n/a	$0
	2	100	0.00	0.00	6.25	$188	$0	$0	$6,250	Pass	n/a	$0
	3	87.5	0.00	0.00	5.21	$156	$0	$0	$5,208	Pass	n/a	$0
	4	75	0.00	0.00	4.17	$125	$0	$0	$4,167	Pass	n/a	$0
	5	62.5	0.00	0.00	3.13	$94	$0	$0	$3,125	Pass	n/a	$0
	6	50	0.00	0.00	2.08	$63	$0	$0	$2,083	Pass	n/a	$0
	7	37.5	0.00	0.00	1.04	$31	$0	$0	$1,042	Pass	n/a	$0
	8	25	0.00	0.00	0.00	$0	$0	$0	$0	Pass	n/a	$0
	9	25	0.00	0.00	0.00	$0	$0	$0	$0	Pass	n/a	$0
	10	25	0.00	0.00	0.00	$0	$0	$0	$0	Pass	n/a	$0
	11	25	0.00	0.00	0.00	$0	$0	$0	$0	Pass	n/a	$0
	12	25	0	0	0	$0	$0	$0	$0	Pass	n/a	$0
						$2,000	$313	$667	$29,167			$667

Optimal energy bid cost	$667
Optimal energy revenue	$667
BCR-->	$0

Uninstructed energy revenue	$313
Optimal energy revenue	$667
Residual energy revenue	$29,167
BCR	$0
Operating cost	($2,000)
Net profit	$28,146

Under this scenario, the settlement would work as follows:

- **Uninstructed energy.** The unit would have 1.04 MWh of uninstructed energy in hour 1, interval 5 and 2.08 MWh of uninstructed energy during intervals 6 through 12 (Col. B) This uninstructed energy is paid the market clearing price (Col. F), but is not factored into BCR calculations.
- **Optimal energy.** Starting in hour 1, interval 7 a portion of the unit's uninstructed generation would actually begin to get classified as optimal energy (Col. C). This optimal energy is paid the market clearing price (Col. G). Under this scenario, the bid cost for this optimal energy used in BCR calculations would be the market clearing price (Col. J). This is because the unit fails to comply with dispatch instructions 8 out of the 24 RTD intervals in hours 1 and 2. Under the ISO's proposal, in this case the bid cost used in BCR would be the minimum of (a) the LMP, (b) the unit's DEB, or (c) its market bid).
- **Residual imbalance energy.** Starting in hour 2, interval 1 the unit's uninstructed generation would actually begin to get classified as residual imbalance energy (Col. D). This RIE is paid the bid price from the prior hour ($1,000/MWh), as shown in Col. H). This is because starting in hour 2 the unit complies with dispatch instructions as the unit is ramped down to its minimum operating level.
- **Bid cost recovery.** Under this scenario, the only revenues and costs included in the BCR calculation are those for optimal energy. Under this scenario, this optimal energy is paid the LMP (Col. G) and its bid cost is equal to the LMP (Cols. J and K). Therefore, these market revenues equal bid costs and the BCR equals zero.
- **Net profits.** The unit's operating cost ($30/MWh) is above the market clearing price ($20/MWh) throughout this two hour period. However, since the unit receives it's bid price of $1,000/MWh for 29.17 MWh of RIE, it makes an overall profit of $28,146 from real-time energy during this two hour period.

Conclusions

The inclusion of a modest persistent deviation metric in this proposal makes its treatment of BCR an improvement over current BCR settlement. However, this is not the case for RIE settlement. Compared to the proposal, the RIE settlement method used today provides better protection against the most egregious forms of persistent deviation to set their own settlement price. The ISO's current proposal is potentially less effective than the prior proposals in terms of protecting against large costs caused by uninstructed deviations that can inflate Residual Imbalance Energy (RIE) payments. In particular, the proposed persistent deviation metric may not identify and mitigate persistent deviation used to inflate BCR and RIE as effectively as does the PUIE check. The additional sophistication of the PUIE check is required to identify and mitigate the use of uninstructed deviations in prior intervals to inflate BCR and RIE in subsequent intervals. DMM believes the added simplicity of the proposed persistent deviation metric may not justify the decrease in its effectiveness relative to the PUIE check.

Attachment K – Comments on Bid Cost Recovery Mitigation Measures, Third Revised Draft Final Proposal

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with Additional Performance Based Refinements

California Independent System Operator Corporation

September 25, 2013

Comments on Bid Cost Recovery Mitigation Measures
Third Revised Draft Final Proposal

Department of Market Monitoring
December 4, 2012

Summary

The Department of Market Monitoring (DMM) appreciates the opportunity to provide comments on the Bid Cost Recovery (BCR) Mitigation Measures Third Revised Draft Final Proposal.

In DMM's comments on Management's prior proposal, we provided a numerical example of a scenario under which it would still be relatively profitable for a generating unit to routinely deviate from ISO dispatch instructions.[1] Management's third proposal has been revised in a manner that significantly reduces the potential profits from this scenario, as illustrated in the following section of these comments. These modifications include the following:

- Reducing, from 4 to 3, the number of settlement intervals a resource can deviate during a two hour period before triggering BCR and RIE mitigation for the entire period.

- Eliminating an intermediate deviation zone rule that would only mitigate BCR and RIE for intervals in which significant deviation occurred, rather than the entire two hour period.

These modifications make Management's third proposal simpler and more effective. With these changes, DMM believes the third revised proposal effectively mitigates potential abuses of settlement rules for real-time bid cost recovery and residual energy, without being overly complex or diminishing incentives to actively participate in the real-time market. DMM believes the final proposal effectively balances these various objectives. However, DMM recommends that the ISO monitor the effectiveness of this approach on an ongoing basis. DMM believes that the more complex Persistent Uninstructed Energy (PUIE) metric developed in the first stage of this stakeholder process represents an effective metric that can be automated and incorporated in the ISO's ongoing market quality review process.

Analysis of Third Revised Proposal

This section utilizes the same example included in DMM's comments on the ISO's second revised proposal to assess the potential profitability for a generating unit to

[1] *Comments on Bid Cost Recovery Mitigation Measures: Second Revised Draft Final Proposal,* Department of Market Monitoring, November 14, 2012. http://www.caiso.com/Documents/DMM-Comments-BidCostRecoveryMitigationMeasuresSecondRevisedDraftFinalProposal.pdf

routinely deviate from ISO dispatch instructions under the proposed settlement rules. The example also incorporates a more detailed accounting of optimal and uninstructed energy each interval.

Consider a resource that bids energy at the $1,000/MWh price cap, unilaterally ramps up its output above its day-ahead schedule for the last 5 RTD intervals (25 minutes) of an hour, and ignores the ISO's downward dispatch instructions during this time. Under the third revised proposal, during this hour, the resource's BCR bid cost basis for the optimal energy that would result from these deviations would not be mitigated and would therefore be the unit's $1,000/MWh bid price. Uninstructed energy would be paid the LMP.

Meanwhile, during the following hour the resource would receive real-time payment based on its $1,000/MWh bid price for residual energy while the resource followed its dispatch back down to its day-ahead schedule in subsequent intervals.

Illustrative example

For this example, assume the following unit characteristics and market conditions:

- Unit is scheduled in day-ahead market at minimum load (25 MW).
- Unit ramp rate = 2.5 MW/minute
- Unit maximum operating level ≥ 87.5 MW
- Unit marginal operating cost = $30/MWh
- Market clearing price = $20/MWh
- Unit bid price = $1,000/MWh

Further assume the following unit operating and dispatch pattern (as depicted in Table 1):

- Starting in hour 1 interval 7, the unit begins to deviate upward.
- By the 11^{th} interval of hour 1, the unit reaches an operating level of 87.5 MW.
- In order to follow its dispatch instructions for all of hour 2, the unit begins ramping down during the last interval of hour 1.
- By hour 2, interval 4, the unit is back down to its day-ahead schedule of 25 MW.

Table 1. Illustrative example of gaming opportunity under persistent deviation metric

Hour	RTD Interva	(A) Operating level	(B) Real-time energy: Uninstructed Energy	(C) Real-time energy: Optimal Energy	(D) Real-time energy: Residual Energy	(E) Marginal Operating Cost	(F) Real-time energy revenue: Uninstructed Energy	(G) Real-time energy revenue: Optimal Energy	(H) Real-time energy revenue: Residual Energy	(I) Interval Compliance Check	(J) Optimal Energy Bid cost ($/MWh)	(K) Total Optimal Energy Bid Cost ($)
1	1	25	0.00	0.00	0.00	$0	$0	$0	$0	Pass	n/a	$0
	2	25	0.00	0.00	0.00	$0	$0	$0	$0	Pass	n/a	$0
	3	25	0.00	0.00	0.00	$0	$0	$0	$0	Pass	n/a	$0
	4	25	0.00	0.00	0.00	$0	$0	$0	$0	Pass	n/a	$0
	5	25	0.00	0.00	0.00	$0	$0	$0	$0	Pass	n/a	$0
	6	25	0.00	0.00	0.00	$0	$0	$0	$0	Pass	n/a	$0
	7	37.5	0.52	0.00	0.00	$15.63	$10	$0	$0	Fail	n/a	$0
	8	50	1.56	0.00	0.00	$46.88	$31	$0	$0	Fail	n/a	$0
	9	62.5	2.60	0.00	0.00	$78.13	$52	$0	$0	Fail	$1,000	$0
	10	75	3.13	0.52	0.00	$109.38	$63	$10	$0	Fail	$1,000	$521
	11	87.5	3.13	1.56	0.00	$140.63	$63	$31	$0	Fail	$1,000	$1,563
	12	75	2.08	2.60	0.00	$140.63	$42	$52	$0	Fail	$1,000	$2,604
2	1	62.5	0.00	0.00	3.65	$109.38	$0	$0	$3,646	Pass	n/a	$0
	2	50	0.00	0.00	2.60	$78.13	$0	$0	$2,604	Pass	n/a	$0
	3	37.5	0.00	0.00	1.56	$46.88	$0	$0	$1,563	Pass	n/a	$0
	4	25	0.00	0.00	0.52	$15.63	$0	$0	$521	Pass	n/a	$0
	5	25	0.00	0.00	0.00	$0.00	$0	$0	$0	Pass	n/a	$0
	6	25	0.00	0.00	0.00	$0.00	$0	$0	$0	Pass	n/a	$0
	7	25	0.00	0.00	0.00	$0.00	$0	$0	$0	Pass	n/a	$0
	8	25	0.00	0.00	0.00	$0.00	$0	$0	$0	Pass	n/a	$0
	9	25	0.00	0.00	0.00	$0.00	$0	$0	$0	Pass	n/a	$0
	10	25	0.00	0.00	0.00	$0.00	$0	$0	$0	Pass	n/a	$0
	11	25	0.00	0.00	0.00	$0.00	$0	$0	$0	Pass	n/a	$0
	12	25	0	0	0	$0.00	$0	$0	$0	Pass	n/a	$0
						$781	$260	$94	$8,333			$4,688
			13.02	4.69	8.33							
					26.04							
					$480.00							

Optimal energy bid cost	$4,688
Optimal energy revenue	$94
BCR-->	$4,594

Uninstructed energy revenue	$260
Optimal energy revenue	$94
Residual energy revenue	$8,333
BCR	$4,594
Operating cost	($781)
Net profit	$12,500

Under this scenario, the settlement would work as follows:

- **Uninstructed energy.** The unit's uninstructed energy would increase in hour 1 from .52 MWh in interval 7 to 3.13 MWh in intervals 10 and 11 before decreasing to 2.08 MWh as the resource begins ramping down in interval 12 (Col. B). This uninstructed energy is paid the market clearing price (Col. F), but is not factored into BCR calculations.
- **Optimal energy.** Starting in hour 1, interval 10 a portion of the unit's uninstructed generation would actually begin to get classified as optimal energy (Col. C). This optimal energy is paid the market clearing price (Col. G). Under this scenario, the bid cost for this optimal energy used in BCR calculations would be the unit's $1,000/MWh bid price. This is because the unit has avoided triggering BCR/RIE mitigation by complying with dispatch instructions in at least 18 out of the 24 RTD intervals (9 out of the 12 settlement intervals) in hours 1 and 2.
- **Residual imbalance energy.** Starting in hour 2, interval 1 the unit's uninstructed generation would actually begin to get classified as residual imbalance energy (Col. D). This RIE is paid the bid price from the prior hour ($1,000/MWh), as shown in Col. H. This is because starting in hour 2 the unit complies with dispatch instructions as the unit is ramped down to its minimum operating level.
- **Bid cost recovery.** The only revenues and costs included in the BCR calculation are those for optimal energy. Under this scenario, this optimal energy is paid the LMP (Col. G) and its bid cost is equal to the unit's $1,000/MWh bid. The BCR payment is the $4,594 by which the unit's bid costs exceed its revenues for its optimal energy.
- **Net profits.** The unit's operating cost ($30/MWh) is above the market clearing price ($20/MWh) throughout this two hour period. However, the unit receives its bid price of $1,000/MWh for 8.33 MWh of RIE, and the unit's 4.69 MWh of Optimal Energy receives BCR payments based on its $1,000/MWh bid cost basis. Therefore, the unit makes an overall profit of $12,500 from real-time energy during this two hour period.

Attachment L – Comments on Bid Cost Recovery Mitigation Measures, Revised Draft Final Proposal

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with Additional Performance Based Refinements

California Independent System Operator Corporation

September 25, 2013

Comments on Bid Cost Recovery Mitigation Measures
Revised Draft Final Proposal

Department of Market Monitoring
October 1, 2012

Summary

The Department of Market Monitoring (DMM) appreciates the opportunity to provide comments on the Bid Cost Recovery (BCR) Mitigation Measures Revised Draft Final Proposal. The current proposal is a substantial improvement over current BCR rules. The proposal's implementation would significantly reduce the opportunities for exploiting residual imbalance energy and bid cost recovery uplift payments. However, DMM believes further work is needed to effectively mitigate issues this proposal is designed to address. Within the framework of the ISO's current proposal, we believe at least two adjustments should be made to the proposal for the cost basis for energy cost recovery (ECR) and residual imbalance energy (RIE):

- Incorporating LMP into the cost basis for energy cost recovery creates adverse incentives for strategic bidding and deviating from dispatch. The cost basis for energy cost recovery should be the minimum of Default Energy Bid (DEB) and bid price for incremental energy and the maximum of DEB and bid price for decremental energy.

- While we strongly support the RIE settlement approach proposed in the August 28, 2012 filing as a short-term measure, RIE settlement can be further improved through this stakeholder process. In particular, RIE should be settled in exactly the same way as Optimal Energy, but the reference hour bid price should replace the current hour bid price in the cost basis calculation for energy cost recovery.

Other comments and concerns are summarized below:

- The ISO proposal, even if it incorporates the above recommendation to remove LMP from the cost basis for ECR, may not effectively remove incentives for manipulative bidding and deviations by units for which it is profitable to operate when guaranteed to be paid at their DEBs. These remaining incentives to deviate up in order to obtain DEBs could create market inefficiencies, gaming concerns, and reliability problems. As a result, we are concerned that the ISO's proposal may not effectively address an original objective of the initiative: to mitigate the potential for over-generation as increased reliance is placed on intermittent renewable energy.

Below we provide more detail on specific aspects of the proposal.

Positive aspects of proposal

Replacing bid recovery with energy cost recovery

An energy uplift mechanism should help a resource following its dispatch instructions to recover its operating costs over a period of time if the resource's market revenues are insufficient to cover those costs. To the extent that the design of the uplift mechanism creates revenue opportunities in excess of the resource's costs, the uplift mechanism can cause inefficient energy market outcomes. Instead of participating in energy markets in ways that maximize in-market energy payments, resources may attempt to maximize out-of-market uplift payments. Strategies to maximize uplift payments include:

- Decoupling energy bids from actual operating costs; and
- Deviating from operating instructions.

These strategies cause energy market outcomes to systematically differ from the commitment and dispatch of the most efficient resources.

Guaranteeing resources the recovery of their bid prices creates adverse incentives for resources to deploy strategies intended to maximize out-of-market uplift payments. The ISO's proposal to instead guarantee resources the recovery of their energy costs greatly reduces these adverse incentives. Moreover, the ISO's proposal still allows resources to recover their operating costs in the event their energy market revenues fall short of their associated operating costs.

Opponents of the ISO's proposal may argue that Default Energy Bids do not reflect a resource's actual costs. If DEBs are less than actual costs, resources that bid actual cost may not receive at least their operating costs over the course of a day. If DEBs are greater than actual costs, in specific circumstances resources that bid actual cost may lose a small amount of money when buying back IFM schedules. However, any resource that believes its DEBs do not reflect its costs can work with the ISO's vendor to customize its DEBs and make its DEBs reflect its actual costs. Therefore we believe the argument that DEBs may not reflect actual costs is not a valid argument against the ISO's proposal.

Real-time Performance Metric

DMM supports the application of the Performance Metric in real-time to scale incremental and decremental RT schedules (including RUC or RT minimum load costs) according to the portion of those schedules actually delivered. Given that RT BCR is only for the RT schedules that are incremental (or decremental) to the DA schedule, a unit should receive the RT BCR in proportion to its performance in meeting only those incremental (or decremental) schedules.

The PM tolerance band is a reasonable approach for mitigating the adverse impact that ramping and other measurement errors would have on applying the Performance Metric to small real-time incremental dispatches.

Modified DA MEAF

The Modified DA MEAF may provide some value relative to no DA MEAF by creating incentives for units that receive DA ECR to follow their RT dispatch instructions when, in some circumstances, they may otherwise have incentives to deviate down from that dispatch. The ISO feels that reliability concerns create sufficient justification for implementing the Modified DA MEAF.

DMM supports the matrices (Table 3.1-1 and Figure 3.2.2-2 in the Revised Draft Final Proposal) defining when the MEAF and PM will be applied to costs and revenues. These tables specify that the DA MEAF and PM will only be applied to, and will therefore only scale down, energy bid costs and revenues that contribute to increasing ECR in specific circumstances where triggered.

Disqualifying minimum load cost recovery when unit deviates to avoid shut-down

Resources may have adverse incentives to strategically attempt to maximize uplift payments for registered minimum load costs. The ISO proposes to disqualify minimum load cost from the energy cost recovery calculations for periods when the resource would have been shutdown if not for uninstructed deviations. The ISO's proposal appears to effectively target only the resources whose deviations from dispatch cause the resource to collect minimum load costs. DMM supports this portion of the proposal.

Concerns with proposal

Incorporating LMP into the cost basis for energy cost recovery

Incorporating LMP into the cost basis for energy cost recovery creates adverse incentives for strategic bidding and deviating from dispatch. While the proposal is an improvement over the current BCR bid cost basis rules, the proposal may still create the incentive for resources to bid at the price cap, operate at maximum capacity, and ignore operating instructions to decrease output. Some simple adjustments to the proposal would mitigate these adverse incentives while still helping to ensure resources recover their operating costs over a day.

DMM believes *locational marginal price* should not be included in the two equations specifying the cost basis that will be used in energy cost recovery on page 18 of the Revised Draft Final Proposal.

Instead, we recommend that the cost basis for energy cost recovery calculations for incremental energy should be:

$$\min(default\ energy\ bid, bid\ price)$$

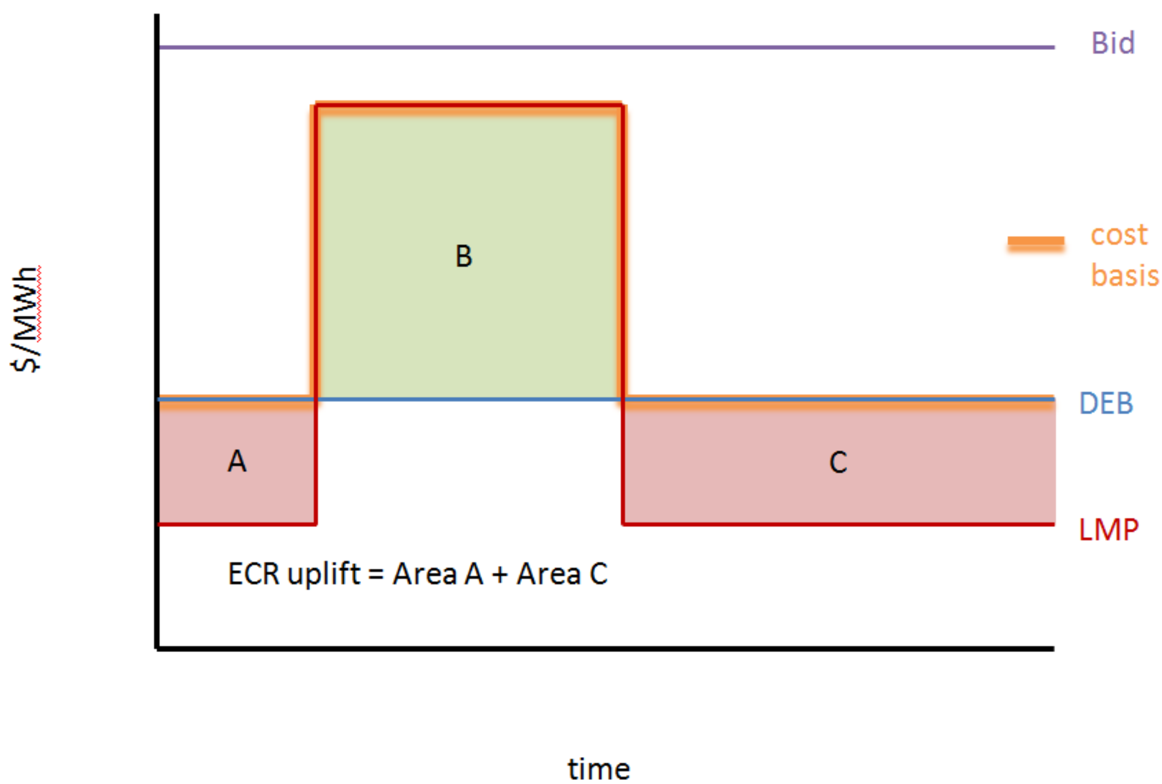
For decremental real-time energy, this should be:

$$\max(default\ energy\ bid, bid\ price)$$

Under both approaches, a resource receives the LMP for its output over a day. The recommended removal of LMP from the cost basis will result in a resource only receiving uplift if its energy costs exceed those LMP revenues over the *day*. With the current proposal, however, a resource can secure itself an uplift payment every *interval* that its energy costs exceed LMP revenues, regardless of how much the resource's revenues may have exceeded costs over the day. This weakens the fundamental market incentive for a resource to reduce its output when the resource's costs are expected to exceed its revenues.

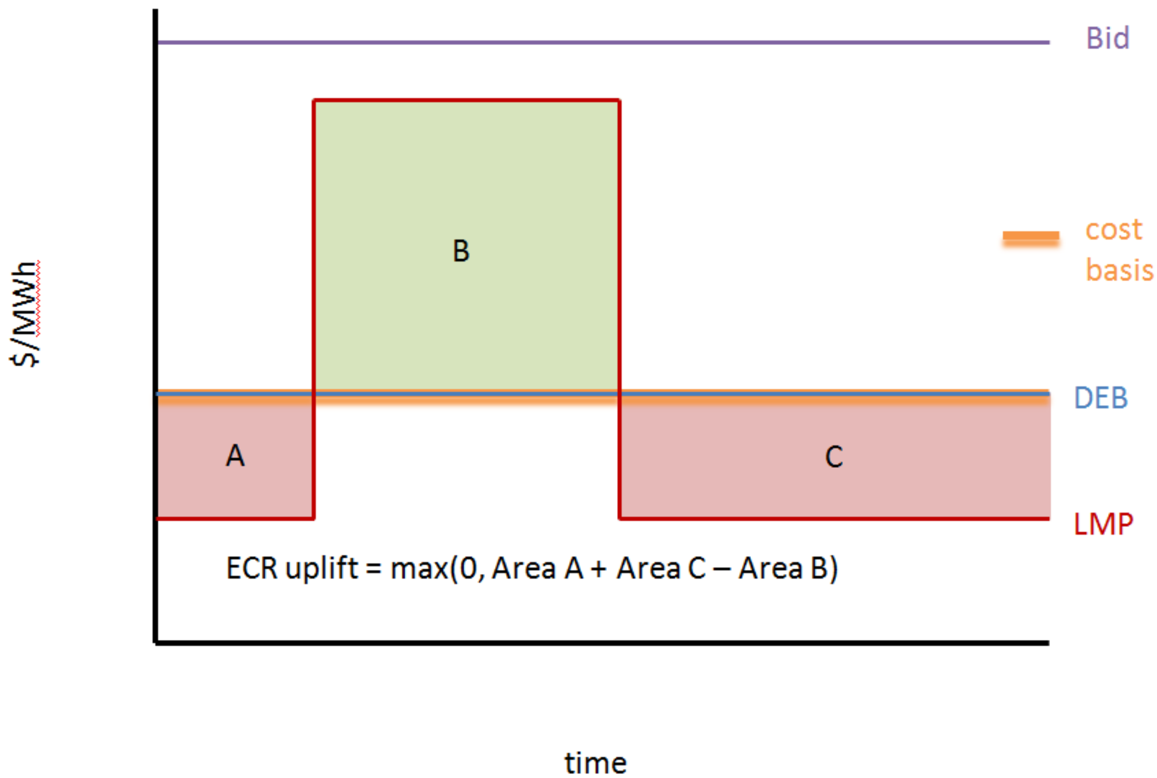
Figures 1 and 2 illustrate the ECR cost basis and uplift for a resource bidding at the price cap and operating at Pmax under both proposed cost basis formulations. The red line is the resource's per MWh revenue; the blue line is the resource's per MWh cost and DEB; the orange highlight is the resource's per MWh ECR cost basis.

Figure 1: ECR cost basis under ISO proposal for resource operating at Pmax



The LMP for a resource bidding at the price cap would rarely exceed the resource's bid. [1] Therefore, under the current proposal, when LMP exceeds the resource's costs, the ECR cost basis would be the same as the resource's Instructed Energy revenues. The resource's actual surplus revenues (Area B) for these intervals would not be included in ECR calculations. However, during intervals when the resource's costs exceed the LMP, the ECR cost basis would exceed the ECR revenues. The revenue shortfalls (Area A and Area C) would be included in ECR calculations. Because there would not be revenue surpluses to offset these shortfalls, a resource bidding at the cap and operating at Pmax could secure ECR uplift payment making it whole for every interval its energy costs exceed its energy revenues.

Figure 2: Recommended approach for ECR cost basis



Removing the LMP from the cost basis, such a resource would only receive uplift if its energy costs exceed its energy revenues over a *day*. When LMP exceeds the resource's costs, DMM proposes that the ECR cost basis be the resource's DEB, rather than LMP. In this way, the resource's revenue surpluses (Area B) are included in the ECR uplift calculations. The resource would only receive uplift if its shortfalls (Area A + Area C) exceeded its surpluses (Area B) over the day.

Relative to DMM's proposed change, the current proposal removes the market incentive for many resources to reduce their output when the resource's operating costs are

[1] LMP could exceed the resource's bid on the rare occasions when LMP exceeds the price cap

expected to exceed its energy revenues. With the LMP removed from the cost basis, a resource seeking net revenues in excess of its costs over a day should reduce its output when it expects its energy costs to exceed its energy revenues. This is because the unit would be operating at a loss during such time periods, and ECR would only compensate the unit for those losses if the shortfalls (A+C) exceeded the unit's total revenue surpluses (B) over the day. Therefore, any power the resource is producing when LMP is below the operating costs directly reduces the net profits the resource may earn over the day.

Under the current proposal, however, resources that bid the price cap do not have the same incentive to reduce output when the LMP is expected to be below the resource's operating costs. During intervals when the resource earns a profit (LMP exceeds cost), the ISO proposal would not count that profit as a 'surplus' in the ECR calculation. Therefore, when the resource expects to be operating at a loss (LMP below cost), that operating loss for all instructed energy will be made up through ECR uplift. The resource's overall revenues (LMP + ECR Uplift) will equal the resource's costs for the interval regardless of whether or not the resource reduces its output or operates at Pmax. However, if the resource reduced its output during intervals it expected LMP to be below its cost, the resource would not be at maximum output whenever LMP exceeded costs. Therefore, resources would maximize their profits for Instructed Energy by operating at Pmax, even during intervals they expect non-uplift revenues to be below their operating costs.[2]

Not fully incorporating RIE into energy cost recovery

DMM strongly supports the August 28, 2012 FERC emergency filing, which settles incremental RIE as max(LMP, min(reference hour bid, default energy bid)). This settlement method is an improvement over the previous RIE settlement method. However, similar incentives to those discussed above still exist under the August 28 FERC filing RIE settlement method. Here we propose improvements to the RIE settlement method proposed in the August 28 FERC filing. These suggested improvements could not be implemented quickly enough to include in the August 28 filing; however, this stakeholder process creates the opportunity to further improve the settlement design.

We propose RIE be settled like Optimal Energy, and included in ECR along with Optimal Energy. The difference between RIE and OE settlement should only be their cost basis for ECR. Therefore, RIE would be paid the current interval's LMP. RIE would be directly included in ECR along with Optimal Energy, but the cost basis for RIE for incremental (positive) energy would be:

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[2] Note, however, that the incentive to deviate up from dispatch is somewhat mitigated by the fact that ECR uplift is only paid for instructed energy. Even if a unit decides to operate at Pmax while bidding the price cap, its dispatch will be Pmax minus however far the unit can ramp down in a RT interval. Therefore, when cost exceeds LMP, the resource will not receive uplift to cover its operating losses for the uninstructed energy in the MW range between its dispatch and Pmax. These operating losses from uninstructed energy could provide incentives to follow dispatch for faster-ramping, smaller resources.

$$\min(\mathit{default\ energy\ bid}, \mathit{reference\ hour\ bid\ price})$$

For decremental energy, this would be:

$$\max(\mathit{default\ energy\ bid}, \mathit{reference\ hour\ bid\ price})$$

Therefore, all RIE and OE would be paid LMP and the resource would receive uplift to make it whole for its costs over the day if the energy revenues for RIE and OE fell short of the resource's operating costs.

Note that it is important to use the reference hour bid in the ECR cost basis for RIE because RIE is ramping energy at the beginning or end of an hour. RIE is caused by the resource's bids from a prior or subsequent hour. Therefore, bids from a prior hour that are well below a resource's costs could cause RIE as the resource ramps down during the current hour. The appropriate cost basis for the RIE is the low bid cost in the prior hour that caused the unit to be at a high operating point at the beginning of the current hour.

Incentives to over-deliver real-time energy

In its RI-MPR Phase 1 Draft Final Proposal, the ISO discussed the importance of creating incentives for resources to not exceed their dispatch instructions. However, even if the ISO incorporates the above recommendation to remove LMP from the cost basis for ECR, the ISO proposal may not effectively remove strategic bidding and deviation incentives for units that are content with receiving no more than their DEBs as revenues. These remaining incentives to deviate up in order to obtain DEBs could create market inefficiencies, gaming concerns, and reliability problems. As a result, we are concerned that the ISO's proposal may not effectively address an original objective of the initiative: to mitigate the potential for over-generation as increased reliance is placed on intermittent renewable energy.

In particular, we are concerned that under the ISO's proposal resources that chose to deviate up from dispatch would be guaranteed to receive their DEBs as daily revenues for their Instructed Energy. DEBs are allowed to be somewhat higher than operating costs. Therefore, higher cost units may find it profitable to operate uninstructed and receive DEBs. This will be a growing concern as the price floor is lowered and intermittent renewable resources increasingly depress prices during off-peak hours.

One approach to addressing this problem might be for the ISO to commit to monitoring for the potential gaming and reliability problems the ISO previously identified as being associated with the over-delivery of RT incremental (or decremental) schedules. However, DMM cautions that this approach could require a significant on-going commitment by the ISO (and is beyond the monitoring capabilities of DMM). In addition, it may be very difficult to identify potential "gaming" and rely on behavioral market rules to deter or mitigate such behavior. As a result we believe the ISO should be prepared to implement an automated disincentive to over-delivery, such as an Uninstructed Deviation Penalty, should over-delivery prove to be problematic.

Including minimum load costs in DA ECR for resources shutdown in RT

DMM has some concern about including minimum load costs in DA ECR for resources following their shutdown instructions in RT. The ISO proposes the following:

1) If the resource is committed in the DA and it does not receive a shutdown instruction in RT, then the inclusion of its minimum load cost in DA ECR will depend on whether or not the resource operates at least at its minimum load (less the tolerance band).
2) If the resource is committed in the DA and it receives a shutdown instruction in RT, then the Performance Metric will be applied to the resource's minimum load ECR calculation in the DA.

Therefore, if the resource is committed in the DA and then follows a RT shutdown instruction, the resource's minimum load cost (and revenue) will be included in the DA ECR calculation. Eliminating ECR for DA minimum load when the resource is shut down by the ISO in RT may disincent downward dispatch flexibility and result in higher levels of self-scheduling.

On the other hand, including MLC in the DA ECR calculation when the resource is committed in the DA and follows a RT shutdown instruction may provide incentive for strategic bidding targeted at maximizing ECR payments instead of providing energy in the spot market. In particular, this feature of the proposal can be exploited if a DA bidding strategy exists through which a resource can reliably obtain DA BCR. Therefore, the ISO should monitor for such strategies and be prepared to adjust this feature of the proposal.

Attachment M – Decision on Enhancements to Improve Price Consistency

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with

Additional Performance Based Refinements

California Independent System Operator Corporation

September 25, 2013

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President – Market & Infrastructure Development

Date: October 25, 2012

Re: **Decision on Enhancements to Improve Price Consistency**

This memorandum requires Board action.

EXECUTIVE SUMMARY

Management is seeking Board approval of a proposal to implement three market functionality enhancements that will improve price and dispatch consistency in the ISO market. Pending approval from the Board of Governors and the Federal Energy Regulatory Commission, Management is targeting spring 2013 for implementing these changes.

> ***Moved, that the ISO Board of Governors approves the proposal to implement the price consistency enhancements as described in the memorandum dated October 25, 2012; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all the necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.***

DISCUSSION AND ANALYSIS

The ISO market software optimizes supply and demand bids offered by scheduling coordinators to determine awards and prices for energy and ancillary services markets while respecting operational and market constraints. In a market solution, awards and prices are expected to be consistent with one another. In the simplest scenario, a supply bid is expected to be awarded only if the clearing price is equal to or greater than the bid-in price. Similarly, a demand bid should only be awarded if the clearing price is equal to or lower than the bid-in price. However, given the interplay of market design features, this expected outcome may not always be achieved. In some market solutions, the clearing price at an intertie location may not support the import or export award. In other market situations, physical or convergence bid awards at trading hubs or default load aggregation points may not be consistent with bid-in prices.

While such price and dispatch inconsistencies are infrequent, the ISO has observed that most of them occur due to three specific situations. As a result, Management proposes to implement three enhancements that will address price inconsistencies arising from these three scenarios. These enhancements address several stakeholder concerns and increase the efficiency of the ISO market.

After careful consideration of input from stakeholders and ISO software developers, Management recommends that the price consistency enhancements listed below be incorporated into the tariff and ISO systems. The recommended solutions balance stakeholder feedback and system software capabilities to accommodate the enhancements.

Management recommends the following three enhancements to the market functionality:

1. *Use both awards and prices from the pricing run.*

   Due to the way constraints are enforced in the market optimization, the ISO energy market requires two market runs, a scheduling run and a pricing run. Each run produces awards (dispatches) and prices. Currently, the binding awards are taken from the scheduling run while the binding prices are taken from the pricing run. Management proposes to use both awards and prices from the pricing run.

   Under normal conditions when the solution can be achieved using submitted bids that are in the normal bid range of -$30 and bid cap of $1000, the outcomes between the scheduling and pricing runs are expected to be reasonably consistent to one another. However, in cases where a solution cannot be achieved using economic bids, the scheduling run uses administrative price parameters for relaxing market constraints (e.g., self-schedules) that are outside of the economical bid range but are necessary to adjust in order to achieve a market solution. These administrative price parameters are set to different levels for different market constraints to ensure such uneconomical adjustments are consistent with established priorities. When the market solution uses uneconomic parameters to achieve a solution, the resulting prices in the scheduling run would no longer strictly reflect economic bids but rather would reflect the higher administrative price parameters.

   To achieve a solution that is reflective of economic bids, a pricing run is introduced. In the pricing run, the administrative parameters used in the scheduling run are replaced by parameter values that reflect the bid floor or cap depending on the nature of the scheduling run solution. The prices and schedules in the pricing run should be consistent with one another. As a result, Management proposes to use both the pricing and awards from the pricing run.

2. *Use a hard bid floor.*

   Another reason for the inconsistency between the scheduling run and pricing run is due to the use of a soft bid floor. Under the current market rules, the bid floor is a soft floor such that bids below the bid floor may be submitted and are still included in the determination of the market solution. However, such bids below the bid floor are not allowed to set the price. Based on historical data, bids below the bid floor have been consistently submitted to the ISO market. A soft bid floor creates the opportunity for inconsistent price and bid awards at least for the resource that submitted the bid below the bid floor. Such bids may also create price inconsistencies for other resources elsewhere in the system.

   To eliminate inconsistencies due to the soft bid floor, Management proposes to replace the soft floor with a hard bid floor. Management recommends making this change effective concurrent with the change of the bid floor from -$30 to -$150, as defined in the scope of the initiative for Renewable Integration: Market and Product Review, Phase I. Having a hard bid floor will eliminate the corresponding inconsistencies between the scheduling and pricing.

3. *Use a different price to settle default aggregate points and trading hubs.*

   The third mechanism for price and award inconsistencies relates to how aggregate prices for default aggregate load points and trading hubs are formed. Currently, the price for such aggregations is determined based on the weighted average price of all constituent pricing nodes weighted by the quantity of load or supply at each node. As a result, an aggregate price may be affected by any redispatch adjustments the market software makes to resources at individual nodes that are effective in relieving congestion. Due to the way these aggregated scheduling points are used to manage congestion, the weighted average price of the constituent nodes may be inconsistent with the bid price of an awarded bid at an aggregated scheduling point.

   To address this issue, Management proposes to use an aggregated price that is derived directly from the market optimization based on the effectiveness of the total aggregation on relieving congestion, rather than the weighted average price of the total awarded quantities at the constituent nodes, which is based on the effectiveness of individual nodes at relieving congestion. This change would minimize price inconsistencies arising from the use of weighted average prices. This enhancement will be applied to both the day-ahead market and real-time market.

POSITION OF PARTIES

The price consistency enhancements recommended herein received wide support from stakeholders. There was some concern raised over whether the proposed pricing changes for settling default load aggregation points and trading hubs might create opportunities for exploitive market behavior. The ISO carefully considered this concern and concluded it would not pose a credible opportunity for such behavior due to the difficulty in effectively predicting when such a strategy would be profitable to engage in. To further address this concern, the ISO will apply the same aggregate pricing methodology to both the day-ahead market and the real time market. Nonetheless, it is something that Management will closely monitor. A stakeholder matrix is attached for your reference.

MANAGEMENT RECOMMENDATION

The enhancements proposed here will effectively address the three most common causes for pricing inconsistencies in the ISO market. These enhancements are designed to improve market efficiency and received wide support from stakeholders. For these reasons, Management recommends that the Board approve the proposed pricing enhancements described above.

Attachment N – Table: Description of Proposed Tariff Changes

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with Additional Performance Based Refinements

California Independent System Operator Corporation

September 25, 2013

Table: Description of Proposed Tariff Changes

Tariff Sections	Description
11.5.5	Change to reinstate rule that residual imbalance energy be paid "as-bid" subject to the deviation threshold, consistent with settlement of residual imbalance energy prior to August 28, 2012, emergency filing, with certain exceptions as provided in proposed Section 11.17. Add rules for settlement of residual imbalance energy when the resource is dispatched down from a minimum load re-rate in real-time.
11.8	Remove language that indicates netting of costs and revenues across day-ahead and real-time markets and instead point to sections below for details regarding the calculations. Additional clarifying changes.
11.8.1.3	Add rule that specifies payment of integrated forward market minimum load plus the incremental (negative or positive) real-time minimum load costs when the configurations committed in the day-ahead and real-time differ to capture proposed change for multi-stage generating resources settlement of minimum load costs in cases where there are different configurations committed in the day-ahead and real-time market.
11.8.2	Add reference that bid costs are subject to Day-Ahead Metered Adjustment Factor and the Real-Time Performance Metric.
11.8.2.1.1	Delete (d) as no longer relevant in light of new start-up rules. Clarify how actual start-ups will be detected in (e). Add new part (h) to specify payment of start-up costs for short-starts started by the ISO in the real-time during a day-ahead commitment period.

Table: Description of Proposed Tariff Changes

Tariff Sections	Description
11.8.2.1.2	In part (c) add requirement that integrated forward market minimum load is subject to real-time performance metric under certain conditions. In part (d) add similar language that applies specifically to multi-stage generating resources. In part (e) specify normal rule that applies if conditions in (c) and (d) do not apply. In part (f) clarify how multi-stage generating resources will be determined to be on for purposes of qualifying their minimum load. In part (g) add requirement that IFM and RUC Minimum Load Costs payments, respectively, are disqualified based on application of Shut-down State Variable.
11.8.2.1.5	Add reference to application of Day-Ahead Metered Energy Adjustment factor to IFM Energy Bid Cost and the application of real-time performance metric. Reference 11.17.2.3 to indicate bid basis for energy bid costs when a resource has been shut-down. Add reference to application of real-time performance metric to multi-stage generating resources specifically. Deleting last sentence as reference is incorrect.
11.8.1.1.7.1	Add clarification on how a multi-stage resource is determined to actually be on.
11.8.2.2	Restore to IFM Market Revenue calculation to provisions prior to March 25, 2011 filing and introduce application of Day-Ahead Metered Energy Adjustment Factor.
11.8.2.2.1	Restore to IFM Market Revenue calculation to provisions prior to March 25, 2011 filing and introduce application of Day-Ahead Metered Energy Adjustment Factor.
11.8.2.2.1.2	Delete consistent with need to restore to IFM Market Revenue calculation to provisions prior to March 25, 2011 filing and introduce application of Day-Ahead Metered Energy Adjustment Factor.
11.8.2.2.2	Delete consistent with need to restore to IFM Market Revenue calculation to provisions prior to March 25, 2011 filing and introduce application of Day-Ahead Metered Energy Adjustment Factor.

Table: Description of Proposed Tariff Changes

Tariff Sections	Description
11.8.2.2.2.1	Delete consistent with need to restore to IFM Market Revenue calculation to provisions prior to March 25, 2011 filing and introduce application of Day-Ahead Metered Energy Adjustment Factor.
11.8.2.2.2	Restore to IFM Market Revenue calculation to provisions prior to March 25, 2011 filing and introduce application of Day-Ahead Metered Energy Adjustment Factor.
11.8.2.5	Add new section to explain how the day-ahead metered energy adjustment factor is applied.
11.8.3	Clarify existing language.
11.8.3.1.1	In part (g) add clarification for how the ISO will determine an actual start-up.
11.8.3.1.2	Add reference to application of Real-Time Performance Metric to Real-Time Minimum Load Cost. Add requirement that IFM and RUC Minimum Load Costs payments, respectively, are disqualified based on application of Shut-down State Variable. Remove description of minimum load calculation in light of proposed changes to 11.8.1.3 to capture new settlement of multi-stage generating resource minimum load costs.
11.8.3.14.1	Clarify existing language on how a multi-stage generating resource is determined to actually be on.
11.8.3.3.2	Add clarifications to Metered Subsystem settlement in light of separating of day-ahead and real-time bid cost recovery.
11.8.4	Add reference to Persistent Deviation metric.
11.8.4.1.1	Clarify how actual start-ups will be detected in (f). Add new part (h) to specify payment of start-up costs for short-starts started by the ISO in the real-time during a day-ahead commitment period specified above in section 11.8.2.1.1.

Table: Description of Proposed Tariff Changes

Tariff Sections	**Description**
11.8.4.1.2	Add reference to Real-time Performance Metric and delete reference to old qualification for minimum load cost. Add rule that real-time minimum load will include negative minimum load revenue.
11.8.4.1.5	Add references to real-time performance metric and persistent deviation metric. Add reference to settlement of energy bid costs for optimal energy associated with ramping from de-rated energy.
11.8.4.1.7	Clarifying change.
11.8.4.1.7.1	Add language that was inadvertently left out in prior filings related to determination of real-time market transition similar to existing language in the integrated forward market and residual unit commitment sections.
11.8.4.2	Add reference to application of the real-time performance metric and persistent deviation metric.
11.8.4.2.1	In (a) clarify that instructed imbalance energy included energy from minimum load from a unit committed in residual unit commitment process. Eliminate references to application of real-time metered energy adjustment factor in (a). Delete old (b) because it no longer applies with the adoption of the real-time performance metric.
11.8.4.2.2	Add reference to application of the real-time performance metric
11.8.4.3.1	Clarify existing language.
118.4.3.2	Modifications to align metered subsystem settlement with separation of day-ahead and real-time bid cost recovery.
11.8.4.4	New section describing application of real-time performance metric.

Table: Description of Proposed Tariff Changes

Tariff Sections	Description
11.8.5	Add new sections to indicate how the unrecovered bid cost uplift may be affected by the application of the day-ahead metered adjustment factor.
11.8.5	Separate 11.8.5 into two parts 11.8.5.1 so that IFM uplift is calculated separately from RUC and RTM which are netted with each other.
11.8.6	Change to incorporate separation of the day-ahead and real-time bid cost recovery when calculating uplift amounts for purposes of allocation.
11.8.6.2	Change to incorporate separation of the day-ahead and real-time bid cost recovery when calculating uplift amounts for purposes of allocation.
11.8.6.3	Change to incorporate separation of the day-ahead and real-time bid cost recovery when calculating uplift amounts for purposes of allocation.
11.8.6.3.2	Change to incorporate separation of the day-ahead and real-time bid cost recovery when calculating uplift amounts for purposes of allocation.
11.8.6.4	Change to incorporate separation of the day-ahead and real-time bid cost recovery when calculating uplift amounts for purposes of allocation.
11.8.6.4.1	Change to incorporate separation of the day-ahead and real-time bid cost recovery when calculating uplift amounts for purposes of allocation.
11.8.6.4.2	Change to incorporate separation of the day-ahead and real-time bid cost recovery when calculating uplift amounts for purposes of allocation.
11.8.6.6	Change to incorporate separation of the day-ahead and real-time bid cost recovery when calculating uplift amounts for purposes of allocation.

Table: Description of Proposed Tariff Changes

Tariff Sections	**Description**
11.17	New Section describing application of persistent deviation metric and thresholds, add shut-down state variable, and description of bid-basis after a shut-down.
39.6.1.4	Modify language to lower and harden bid floor.
Appendix A	Definition of Day-Ahead Metered Adjustment Factor modified to describe new metered energy adjustment factor.
Appendix A	Dispatch Interval Clarify length of Dispatch Interval for real-time contingency dispatch.
Appendix A	Dispatch Operating Target Add new definition.
Appendix A	Expected Energy Modify to fix typographical error.
Appendix A	IFM Bid Cost Uplift Modify to eliminate need for netting IFM, RUC and RTM.
Appendix A	Performance Metric Tolerance Band Add new definition.
Appendix A	Persistent Deviation Metric Add new definition.

Table: Description of Proposed Tariff Changes

Tariff Sections	Description
Appendix A	Persistent Deviation Metric Threshold Add new definition.
Appendix A	Real-Time Metered Energy Adjustment Factor Delete definition as this is replaced with real-time performance metric.
Appendix A	Real-Time Performance Metric Add new definition.
Appendix A	Residual Imbalance Energy Modify to change the calculation of residual imbalance energy based on reference settlement interval.
Appendix A	Shut-Down State Variable Add new definition.

Attachment O – Direct Testimony of Bradford Cooper

Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with Additional Performance Based Refinements

California Independent System Operator Corporation

September 25, 2013

Exhibit No. ISO-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER13-____-000**

DIRECT TESTIMONY OF
BRADFORD COOPER
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

Q. Please state your name, title, and business address.

A. My name is Bradford Cooper. I am the Manager, Market Design and Regulatory Policy of 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 master of business administration with concentrations in both finance and technology management from the University of California, Davis. I also have a bachelor of science in geology. Prior to joining the ISO, I was an analyst and project manager for 15 years responsible for environmental assessment and remediation. I joined the ISO in 2002 as senior data quality auditor. From 2003 – 2005, I was compliance program development manager. From 2005 until January 2012, I was lead market monitoring analyst in the ISO’s Department of Market Monitoring. In this capacity, I monitored, analyzed, and reported on market activity and performance, recommended market design changes, and reviewed market design changes proposed by the ISO. Since January 2012, I have been the ISO's manager of market design and regulatory policy.

Q. What are your duties and responsibilities at the ISO?

A. I manage a team of five people responsible for developing ISO market design policy. We lead the ISO stakeholder processes that develop changes to the ISO market design and develop new market design features, including the changes proposed in this filing. We are responsible for obtaining approval from the ISO Board of Governors on any new policy developed by ISO management. We provide technical and policy expertise in support of regulatory filings, including the development of tariff language and supporting documentation. We also support the implementation of new policy changes and serve as subject matter experts on implemented features. We work closely and in collaboration with the Market Surveillance Committee (MSC) and the Department of Market Monitoring (DMM) in developing our proposals.

Q. Have you provided testimony previously?

A. Yes, I have provided testimony as part of ISO's August 28, 2012, filing in FERC Docket ER12-2539, in which the ISO proposed, in part, to modify its residual imbalance energy settlements to address the potential exercise of market power.

Q. What is the purpose of your testimony?

A. My testimony describes the ISO's proposed changes to its market rules in this tariff amendment as they relate to how the ISO calculates bid cost recovery payments for generation resources participating in the ISO markets. The primary change is to calculate and pay bid cost recovery to resources separately for the day-ahead and real-time markets, without netting all of a resource's bid costs and revenues for the two markets together. This is an important change needed to provide increased incentives for resources to submit economic energy bids to the real-time market. I also describe changes for calculating bid cost recovery for short-start resources and multi-stage generators that are appropriate under separate bid cost recovery calculations for the day-ahead and real-time markets.

In addition, I describe several measures to prevent resources from engaging in adverse strategic behavior to inflate bid cost recovery payments. These measures will be important with the implementation of the ISO's proposal to calculate and pay bid cost recovery separately for the day-ahead and real-time markets, which will result in the ISO no longer netting revenues and surpluses between those two markets. One of the measures I describe is designed to address the potential for resources to inflate bid cost recovery and residual imbalance energy payments by persistently deviating from the real-time market's dispatch instructions.

I also describe changes to bid cost recovery and residual imbalance energy settlement that are appropriate in the circumstance of a temporary increase to a resource's minimum load and in the circumstance when the ISO exceptionally dispatches a resource. Finally, I describe a change to residual imbalance energy settlement that will apply in the event a resource is ramping over multiple hours.

I. Background and Overview of the ISO Markets

Q. Please provide an overview of the ISO's day-ahead energy market.

A. The ISO operates a day-ahead and real-time market based on locational marginal pricing for energy and ancillary services. In the day-ahead market, the ISO conducts an integrated forward market based on bid-in demand and supply for energy, which results in feasible day-ahead schedules for generation resources. Day-ahead supply schedules are hourly schedules for energy at specific pricing nodes in the ISO system. Generating resources within the ISO can submit three-part bids to the ISO market that consist of a start-up cost, a cost for operating at the resource's minimum operating level cost (normally referred to as minimum load cost), and an energy bid cost for energy above a resource's minimum operating level. This market design provides strong incentive for suppliers to submit bids that reflect the true marginal cost of energy from each resource. Start-up and minimum load costs are based on either a cost-based rate (known as proxy costs) or a monthly bid that that may be up to 150 percent of a resource's start-up and minimum load costs (known as a registered cost), as recently proposed by the ISO in FERC Docket No. ER13-2296. Energy bids can vary from hour-to-hour and are only limited by the maximum bid price of $1,000/MWh. Energy scheduled in the day-ahead market for each trading hour is settled based on the hourly day-ahead locational marginal price. Each resource's day-ahead market schedule is financially binding, meaning that resources will be paid the day-ahead locational marginal price for that hour regardless of actual performance in real-time. However, if resources generate below their day-ahead schedule in the real-time market they must pay back the undelivered day-ahead energy at the real-time locational marginal price. The second portion of the day-ahead market following the integrated forward market is the residual unit commitment process in which the ISO commits additional capacity it may need for reliability.

Q. Please describe the real-time energy market.

A. In real-time, the ISO conducts a five-minute market in which it dispatches units up or down based on submitted supply bids and the forecast for real-time demand. Consequently, resources may continue to generate at their day-ahead schedules, sell additional energy beyond their day-ahead schedule, or not produce as much as scheduled in the day-ahead market. Any additional energy produced in the real-time market is classified as incremental imbalance energy. Any energy scheduled in the day-ahead market not produced in real-time is classified as decremental imbalance energy. Imbalance energy is settled based on the real-time locational marginal prices. Incremental imbalance energy results in a payment to the resource while decremental imbalance energy results in a charge to the resource (assuming the locational marginal price is positive).

In the real-time market, participants can submit different bid prices for each hour. These supply bids must be in the form of a monotonically increasing energy bid curve. The real-time dispatch process produces feasible dispatch instructions for resources. Whereas the ISO settles the day-ahead market hourly, it settles real-time energy in ten-minute intervals based on the locational marginal prices for the two five-minute dispatch intervals that make up each ten-minute settlement interval. The ISO conducts a separate real-time process in the hour-ahead scheduling process for clearing intertie imports and exports, and those schedules are settled based on the hourly hour-ahead locational marginal price. In addition, the real-time market includes a process that looks out in 15-minute intervals one to four hours in the future that issues startup and shutdown instructions to resources and procures any additional ancillary services needed for the upcoming hour.

Resources can resubmit bids in the real-time market for their day-ahead market scheduled energy. If they do not rebid this energy, the real-time market treats the day-ahead scheduled energy as a “self-schedule.”

The real-time market respects these self-schedules and only alters them in the event of constraints in the market that become binding.

Q. Is all real-time energy settled in the same way?

A. No. For every ten-minute settlement interval, the ISO determines the amount of incremental or decremental energy that is instructed in the real-time market, which is referred to as instructed imbalance energy. The ISO also calculates the extent to which units deviated above or below this dispatch instruction by comparing the metered output of each resource to this dispatch instruction. These amounts are referred to as positive or negative uninstructed imbalance energy. Currently, the ISO settles instructed and uninstructed imbalance energy similarly because the ISO does not have any uninstructed deviations penalties. The ISO settles instructed imbalance energy at the average of the two real-time locational marginal prices for the two five-minute dispatch intervals in a 10-minute settlement interval, weighted by the amount of energy dispatched in each interval. The only difference for the uninstructed imbalance energy is that the price used for settlement is the *simple* average of the locational marginal prices in the two dispatch intervals. Negative uninstructed imbalance energy is charged the locational marginal price, while positive uninstructed energy is paid the locational marginal price.

Q. Please describe what you mean by feasible schedules and dispatches.

A. When clearing the ISO markets, the ISO market optimization considers and honors key physical characteristics of each generation resource. For example, both the day-ahead and real-time markets honor the minimum amount of time a resource must remain in operational mode and the minimum amount of time a resource must remain in shutdown mode. Therefore, in considering whether to schedule a resource, the ISO market optimization considers these characteristics and the economics associated with scheduling or dispatch these resources based on these characteristics. Similarly, the ISO market will consider and honor a resource's ramp rates, or the speed at which it can ramp its output up or down. Consequently, in scheduling the fleet of resources within the ISO, the market is able to consider the ramp rates of each different resource at different operating levels and issue dispatches that are feasible given these ramping limitations. This ensures that the dispatches are operationally feasible and enables the ISO to use the market optimization solution in dispatching its system reliably to the extent possible. In order to ensure that all schedules and dispatches are feasible, the ISO market software may dispatch a unit at an output level for which the resource's energy bid price is not consistent with the locational marginal price.

Q. Please provide examples of conditions that may result in a situation in which the locational marginal price does not cover a resource's submitted energy bid or start-up and minimum load costs.

A. The ISO market may schedule or dispatch a resource at its minimum load and energy payments at the locational marginal price may not cover these costs. An example of when this can happen is when the ISO market honors a resource's minimum run time. It is possible that the optimization will find it economically optimal to schedule or dispatch a resource for energy above minimum load for a given time period, even though the resource will have to operate for a longer period once started.

In many instances, resources also must ramp up or down at a given rate, which results in the resource producing energy at an output level for which its bid price may be greater than the locational marginal price. This can occur when, for example, the real-time market is ramping a resource up for energy needed in future intervals or once a resource ramps up but the locational marginal price is lower than the real-time market predicted. Similarly, the real-time market may predict that there will be an excess of energy in future intervals and that the locational marginal prices will be lower than a resource's energy bid, and as a result dispatch the resource below its day-ahead schedule. If this forecast is incorrect, the locational marginal price may be greater than the resource's energy bid, which expressed the price below which it was willing to "buy-back" its day-ahead scheduled energy.

To the extent the locational marginal price is not sufficient to cover a resource's submitted energy bid, ISO settlement provisions, referred to as bid cost recovery, ensure the resource recovers these costs, subject to the resource having a shortfall in overall revenue from the ISO market compared to its bid cost.

In addition, in the real-time market, the ramping energy that occurs when a unit is ramping up or down from a real-time market bid dispatched in an adjacent hour is classified as residual imbalance energy and is paid based on the resource's bid or the locational marginal price as I describe further below.

Q. Please describe the bid cost recovery process.

A. The bid cost recovery mechanism is a series of market rules and calculations that together serve as the mechanism for ensuring that resources dispatched or scheduled by the ISO receive their unrecovered energy bid costs. In addition, the ISO pays for start-up and minimum load costs for resources it commits separately from the cost of energy alone. The ISO accounts and pays for these costs through the bid cost recovery mechanism. Therefore, the bid cost recovery mechanism performs the following four functions: 1) calculates the applicable bid costs to be paid if a resource is dispatched or scheduled by the ISO; 2) determines the applicable market revenues earned by that resource; 3) offsets the calculated bid costs by the market revenue to determine bid cost recovery uplift to be paid to the resource (netting); and 4) allocates to ISO load and exports the total cost of the bid cost recovery uplift paid to resources.

Q. **How does the ISO calculate the applicable bid costs paid to a resource?**

A. Bid costs include a resource's start-up and minimum load costs and its energy and/or ancillary services bid costs. The ISO pays a resource's unrecovered start-up and minimum load bid costs only for time periods in which the ISO committed the resource. Furthermore, the ISO pays a resource for its unrecovered bid costs through the bid cost recovery process only if the resource has a net revenue shortfall over the course of a calendar day. The ISO calculates whether a resource has a net revenue shortfall by summing all the revenue the resource earns based on ISO market day-ahead schedules, and then subtracting the resource's costs to meet these schedules and dispatches, based on the resource's bid costs.

Q. **Please describe the ISO's current method of calculating a resource's net market revenues.**

A. Currently, the ISO only pays unrecovered bid costs through its bid cost recovery process if a resource has a net revenue shortfall over both the day-ahead and real-time markets. A resource has a revenue shortfall when its market revenues are less than its bid costs (*i.e.*, revenues minus bid costs are negative). A resource has a revenue surplus when its market revenues are greater than its bid costs (*i.e.,* revenues minus bid costs are positive). If a resource has a revenue shortfall in one market and but a revenue surplus in another, the ISO nets these against each other in calculating whether the resource has a net revenue shortfall over the calendar day.

Figure 1 illustrates a stylized example of bid cost recovery payments in real-time and day-ahead under the ISO's current bid cost recovery rules. In this scenario a resource has a minimum load cost of $700/hour and bid cost for incremental energy above minimum load of $30/MWh. It has these same costs in both the real-time and day-ahead markets. The day-ahead market schedules the resource to provide 20 MWh in each hour, the resource's minimum load, in all hours except for hour 2 where the day-ahead market schedules it at 75 MWh. In the day-ahead market, the resource has a revenue surplus of $600.

In the real-time market, the resource also submits energy bids priced at $30/MWh. This time, in hour 4, the ISO dispatches the resource incrementally to 55 MWh, but the average locational marginal price in the real-time market turns out to be only $10/MWh, below the resource's bid cost. For its energy dispatched by the real-time market, the resource has a total bid cost of $1,650 (55 MWh times $30/MWh), but is only paid $550 (55 MWh times $10/MWh).

Under the ISO's current bid cost recovery rules, the ISO nets the resource's revenue surplus of $600 in the day-ahead market against its

$1,100 revenue shortfall in the real-time market before it pays bid-cost recovery to the resource. The resource receives a $500 bid cost recovery payment to cover the remaining net revenue shortfall.

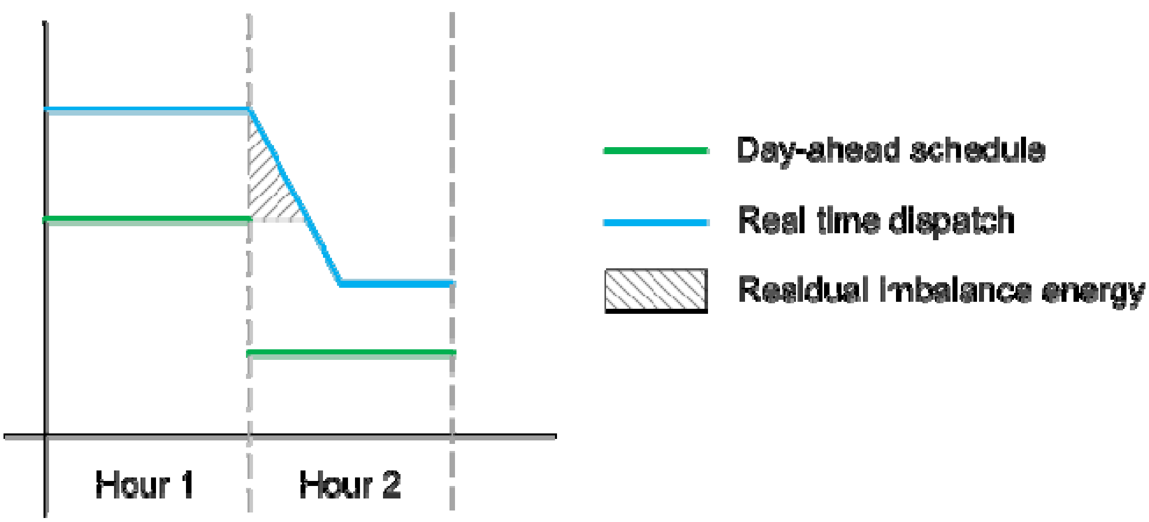
Figure 1. Example of bid cost recovery in the real-time and day-ahead markets

		Hour 1	2	3	4	5	
Day-ahead market	Market revenue						
	Schedule (MWh)	20	75	20	20	20	
	LMP ($/MWh)	$25	$50	$25	$25	$25	
	Revenue ($)	$500	$3,750	$500	$500	$500	
					Total market revenue		$5,750
	Bid costs						
	Energy ($)	$0	$1,650	$0	$0	$0	$1,650
	Min load ($)	$700	$700	$700	$700	$700	$3,500
					Total bid costs		$5,150
				Revenue surplus (shortfall)			$600
Real-time market	Market revenue						
	Dispatch (MWh)	20	75	20	75	20	
	Imbalance energy (MWh)	-	-	-	55	-	
	LMP ($/MWh)	$25	$50	$25	$10	$25	
	Revenue ($)	$0	$0	$0	$550	$0	
					Total market revenue		$550
	Bid costs						
	Energy ($)	$0	$0	$0	$1,650	$0	$1,650
					Total bid costs		$1,650
				Revenue surplus (shortfall)			-$1,100

Q. Please describe residual imbalance energy.

A. Residual imbalance energy is a category of real-time energy that is utilized for settlement purposes. The residual imbalance energy classification captures energy that occurs when a unit is ramping down from a bid dispatched in the real-time market at the end of a previous hour or ramping up to a bid dispatched at the beginning of an upcoming hour. Residual imbalance energy is additional ramping energy beyond any ramping energy attributable to a change in the resource's day-ahead schedule from one hour to the next. Figure 2 illustrates the portion of ramping energy that would be classified as residual imbalance energy for a unit that was already scheduled to ramp down due to the decrease in its hourly schedule from one hour to the next. Thus, residual imbalance energy is only the ramping energy attributable to real-time market energy dispatches and not to the hourly day-ahead schedule change. In addition, ramping energy produced because of a bid dispatched within the current hour is not classified as residual imbalance energy.

Figure 2. Residual imbalance energy



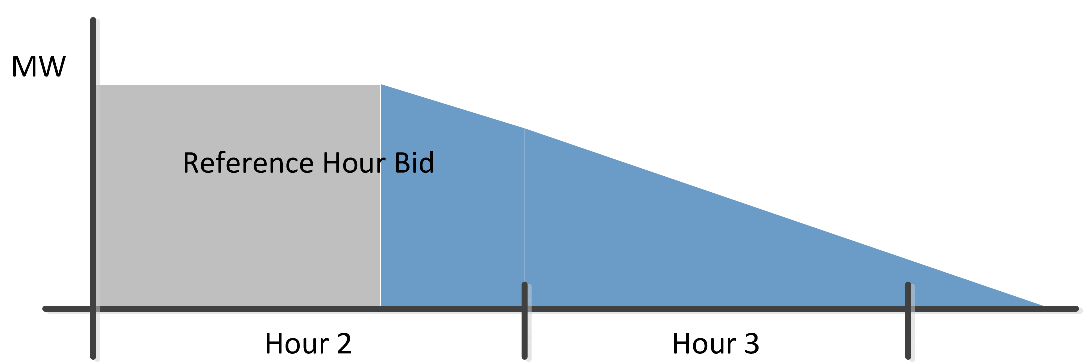
Q. How does the ISO currently settle residual imbalance energy?

A. The ISO currently settles all incremental residual imbalance energy as follows. If the locational marginal price in the five-minute dispatch interval in which the residual imbalance energy occurs is greater than the lesser of: (1) the resource's default energy bid price, or (2) its reference hour bid price, the ISO settles the residual imbalance energy in that interval at the dispatch-interval locational marginal price. If the dispatch-interval locational marginal price is lower than the lesser of (1) the resource's default energy bid price, or (2) its reference hour bid price, the ISO settles the residual imbalance energy in that interval at the lesser of (1) the resource's default energy bid price, or (2) its reference hour bid price. Similarly, for any given five-minute dispatch interval, the ISO settles a resource's decremental residual imbalance energy (*i.e.*, that is below its day-ahead scheduled energy) at the lesser of (1) the dispatch-interval locational marginal price, or (2) the greater of (a) the resource's default energy bid price or (b) its reference hour bid price. The ISO adopted this settlement following its emergency filing made on August 28, 2012, in FERC Docket ER12-2539, on an emergency basis to address the possible expansion of residual imbalance energy payments through a resource's exercise of market power when persistently deviating from ISO instructions. The ISO recognized at the time that there may be more tailored methods for preventing the inflation of residual imbalance payments, but given the speed with which it was necessary to mitigate for this outcome, the ISO proposed an easily implementable method. Since then, the ISO has identified that the persistent deviations can expand bid cost recovery payments in a similar manner and has developed a more tailored approach to address this issue for both cases, as discussed later in my testimony.

Q. What is the reference hour bid?

A. The reference hour bid is the energy bid in the hour where the incremental or decremental dispatch instruction was issued. Figure 3 illustrates the reference hour bid in the circumstance where a resource is ramping down across hours. In hour 2, the resource begins ramping downward. In hour 3, the reference hour bid price is the bid price in the prior hour, hour 2.

Figure 3. Reference hour bid illustration



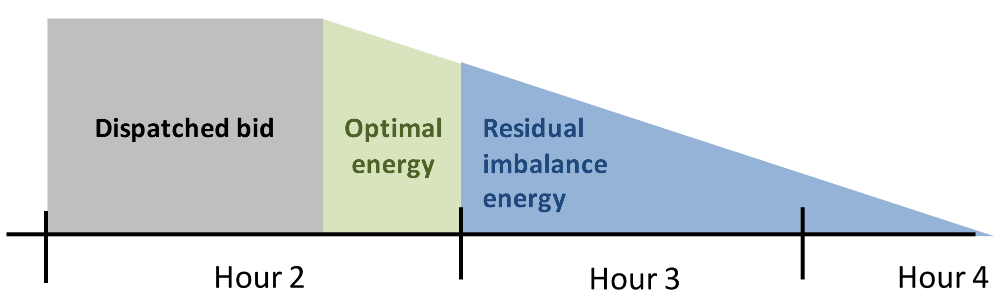
Q. Does the ISO consider residual imbalance energy in the bid cost recovery calculations?

A. No, the ISO does not include residual imbalance energy in its bid cost recovery calculations for a resource. In addition, payment for residual imbalance energy is not subject to a daily net revenue shortfall as bid cost recovery payments are.

Q. Is there any type of ramping energy that can occur pursuant to ISO real-time market dispatches that is subject to bid cost recovery payments?

A. Yes, the ISO classifies ramping energy attributable to a real-time market dispatch in the same hour as "optimal energy," which is subject to bid cost recovery. Figure 4 illustrates the difference between residual imbalance energy and optimal energy.

Figure 4. Residual imbalance energy and optimal energy



II. Need To Separately Pay Bid Cost Recovery For The Day-Ahead And Real-Time Markets To Incent Economic Bidding In The Real-Time Market.

Q. Please describe why the current bid cost recovery settlement rules may discourage generators from submitting real-time economic bids.

A. Under the current rules, if a resource has a revenue surplus in the day-ahead market but has a revenue shortfall in the real-time market, these are netted with any revenue shortfalls in the real-time. Consequently, the resource makes less profit than if the resource had not participated in the real-time market by submitting economic energy bids indicating its price at which it is willing to be dispatched by the ISO.

The example in Figure 1 is useful in also illustrating why the current bid cost recovery netting rules create a disincentive for scheduling coordinators to submit energy bids into the real-time market. Under current market rules in the example shown in Figure 1, the ISO nets the resource's day-ahead market revenue surplus of $600 against its $1,100 revenue shortfall in the real-time market when calculating the resource's bid-cost recovery payment. The resource is made-whole over both markets, but in this scenario the resource loses the revenue surplus it earned in the day-ahead market because the ISO nets the resource's day-ahead market revenue surplus against its real-time market shortfall. If the resource had not submitted energy bids to the real-time market, then the real-time market would not have dispatched the resource to provide incremental energy. The resource would not have incurred a revenue shortfall in the real-time market and would have kept the revenue surplus it earned in the day-ahead market. The netting, therefore, creates a disincentive to submit real-time economic bids and instead the resource might be inclined to only deliver its day-ahead scheduled energy to avoid being exposed to a revenue shortfall in the real-time market. This would be in contrast to what happened when the resource submitted economic bids to the real-time market, and the resource only recovered its bid costs netted over both markets and is left with no profit.

Under the rules to separate the day-ahead and real-time market bid cost recovery calculations the ISO proposes in this filing, the resource would keep its revenue surplus from the day-ahead market and would be made-whole for all of its $1,100 real-time market revenue shortfall. Its overall profits would be $600, rather than $0 under the current rules. Therefore, separating the markets would remove the potential for a resource that economically bids in to the real-time to have its day-ahead profits decreased by a real-time market dispatch.

Q. Does the current bid cost recovery mechanism also discourage resources from submitting economic bids to the real-time market when the resource has a revenue shortfall in the day-ahead market, rather than a revenue surplus?

A. If a resource has a revenue shortfall in the day-ahead market then the ISO's bid cost recovery calculations will credit any net revenues earned in the real-time market against the resource's day-ahead market revenue shortfall. This decreases the profits a resource could obtain from economically bidding into the real-time market. In this case, the ISO first nets any profits the resource earns in the real-time market against its day-ahead market revenue shortfall. Therefore, here again netting the surplus and shortfall across the day-ahead and real-time market creates a disincentive for a resource to submit economic energy bids to the real-time market.

Q. You described an example of how the ISO's current bid cost recovery rules provide a disincentive to submit economic bids for incremental energy to the real-time market. Do they provide a similar disincentive to submit economic bids to the real-time market to provide decremental energy?

A. Yes, a resource providing decremental energy in the real-time market under the current rules also faces a potential loss of the profit it made in the day-ahead market. Figure 5 illustrates this concept. In this example, the resource's bids $30/MWh for energy above minimum load and its costs for minimum load costs are $700/hour. The day-ahead market schedules the resource for 75 MWh in each hour and the day-ahead market locational marginal price is $50/MWh. Consequently, the resource has a revenue surplus of $7,000 in the day-ahead market, which is calculated by subtracting $11,750 in bid costs from $18,750 in revenues.

In the real-time market, the resource re-submits an economic bid for its energy at $30/MWh in this example. This bid means it is willing to provide incremental energy if the locational marginal price is at least $30/MWh and is willing to provide decremental energy, or in other words, to “buy-back” its day-ahead schedule, if the locational marginal price is less than $30/MWh. In the second hour, the average real-time locational marginal price decreases to $25/MWh so the real-time market dispatches the resource to its 20 MW minimum load. The locational marginal price over the fourth hour then increases to $100/MWh, but the resource cannot ramp back up quickly enough to its day-ahead schedule to avoid having to pay $100/MWh for the decremental energy below its day-ahead schedule. In this scenario, the resource then pays back 25 MWh at the real-time price of $100/MWh, in other words it is charged $2,500. As in the earlier incremental energy example, the real-time short-fall is offset by the day-ahead revenue surplus. The $7,000 in surplus in the day-ahead offsets the $1,350 in shortfall in the real-time and the resource does not recover the $1,350 revenue shortfall in the real-time market from the bid cost recovery process. This means that the resource would have had more profit had it not been economically dispatched in the real-time market.

Figure 5: Example of BCR netting the real-time and day-ahead markets with real-time decremental energy

		Hour					
		1	*2*	*3*	*4*	*5*	
Day-ahead market	**Market revenue**						
	Schedule (MWh)	75	75	75	75	75	
	LMP ($/MWh)	$50	$50	$50	$50	$50	
	Revenue ($)	$3,750	$3,750	$3,750	$3,750	$3,750	
						Total market revenue	***$18,750***
	Bid costs						
	Energy ($)	$1,650	$1,650	$1,650	$1,650	$1,650	$8,250
	Min load ($)	$700	$700	$700	$700	$700	$3,500
						Total bid costs	***$11,750***
						Revenue surplus (shortfall)	***$7,000***
Real-time market	**Market revenue**						
	Dispatch (MWh)	75	50	20	50	75	
	Imbalance energy (MWh)		(25)	(55)	(25)		
	LMP ($/MWh)	$50	$25	$25	$100	$50	
	Revenue ($)	$0	-$625	-$1,375	-$2,500	$0	
						Total market revenue	***-$4,500***
	Bid costs						
	Energy ($)		$750	$1,650	$750		-$3,150
						Total bid costs	***-$3,150***
						Revenue surplus (shortfall)	***-$1,350***
Net BCR	**Net Revenue across markets**						
	DA market ($)						$7,000
	RT market ($)						-$1,350
						Net revenue	***$5,650***

Q. Has the ISO looked at whether the separation of real-time and day-ahead bid cost recovery payments will increase overall bid cost recovery payments to generators?

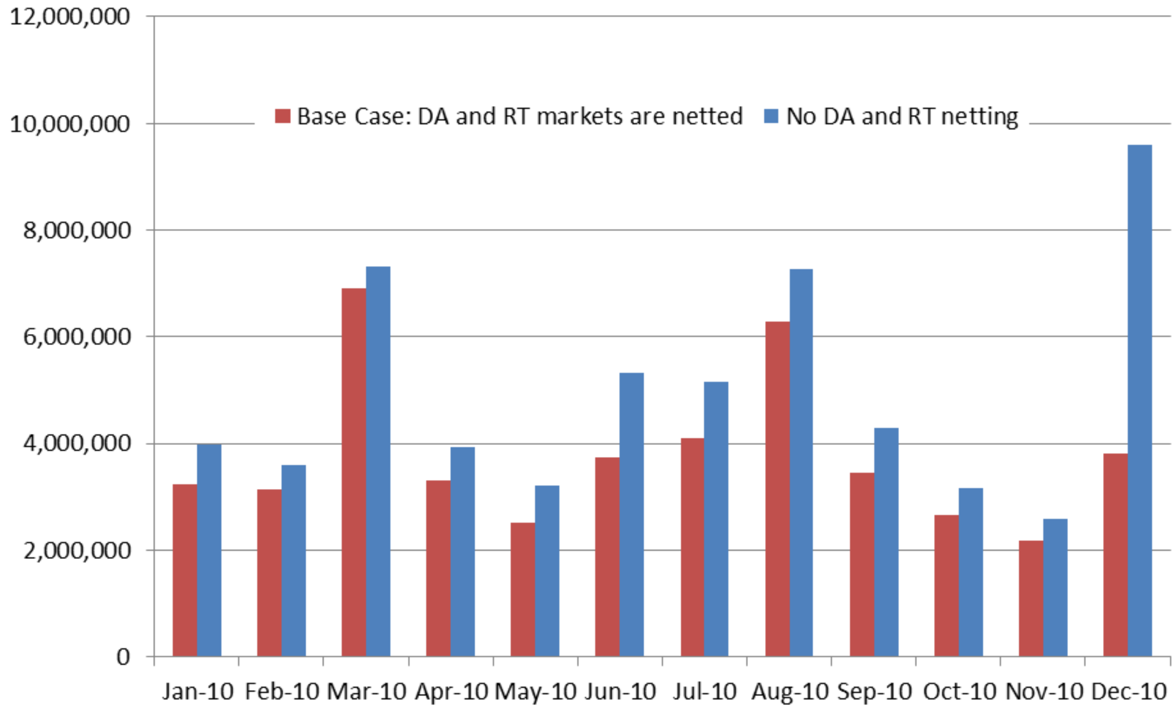
A. Yes, the ISO evaluated past settlement data to evaluate the likely impact the separation of the day-ahead and real-time bid cost recovery mechanism would have on total bid cost recovery payments. We found that separating bid cost recovery between the day-ahead and real-time markets would likely increase overall bid cost recovery payments at most by approximately 20 percent.

Q. Please summarize how the ISO conducted this study and its findings.

A. The ISO used bid-cost recovery data in 2010 to estimate the impact of netting bid cost recovery calculations separately in the day-ahead and real-time. (The ISO proposes to continue to net bid cost recovery payments across the 24 hours of each market.) The ISO calculated estimates of overall bid cost recovery payments under two scenarios. The first scenario was that the ISO netted each resource's day-ahead and real-time market revenue surplus/shortfall together. This provided a base case that was considered the "status quo." For the second scenario, the ISO calculated each resource's revenue surplus/shortfall separately for the day-ahead and real-time markets.

Figure 6 summarizes the results of this estimate. The difference between scenario 1 and scenario 2 illustrate the expected increase in total bid cost recovery payments. Note that the values for December 2010 are likely not indicative of future values because they resulted from the "shake-out" period during the introduction of new market functionality.

Figure 6. Summary results of bid cost recovery payments scenario analysis



Q. Is this 20 percent increase indicative of what is likely to happen with the proposed changes?

A. No. This result is an estimate of the upper most boundary of the amount by which bid cost recovery might increase. The analysis does not take into consideration that the totality of the ISO's proposal should trigger behavioral changes that should tend to decrease bid cost recovery costs. Removing the netting between markets will incent additional economic bids in the real-time market. When the ISO is in an over-generation situation, additional economic bids can relieve downward price spikes. Therefore, the changes in the bid cost recovery rules should decrease the magnitude of downward price spikes overall. This will cause a decrease in the amount of bid cost recovery payments to resources to compensate resources during negative price periods.

Q. Are the changes to the bid cost recovery rules, along with separating netting, needed to provide increased incentives for short-start units to submit economic bids into the real-time market?

A. Yes, short-start units require an additional rule change affecting the accounting of their start-up costs because of their unique ability to start up in the real-time. The rule change is necessary to align incentives to submit real-time economic bids when day-ahead and real-time market bid cost recovery is separated.

Q. Can you please explain in greater detail why short-start units are unique?

A. Yes. As defined in the ISO tariff, a "short-start unit" is a resource that: 1) has a cycle time less than five hours, which is comprised of the start-up time plus minimum run time; 2) has a start-up time less than two hours; and 3) can be fully optimized with respect to this cycle time. Because these resources can be started up in real-time, ISO commitment in the day-ahead market is financially, but not operationally binding. This is not the case for medium and long-start resources, for which day-ahead commitment instructions are both operationally and financially binding and receive day-ahead start-ups as part of their day-ahead schedules. Since short-start units can quickly respond to changing system conditions, they are re-optimized in the real-time market and the real-time market may change the time the resource is started.

Q. Please provide an example of how current bid cost recovery rules consider short-start units and explain how these rules must change once the ISO separates day-ahead and real-time bid cost recovery.

A. I provide two simple examples to illustrate why the bid cost recovery rules for short-start units must be further modified. For the first example, assume that the day-ahead market schedules a short-start unit to operate from hour five through hour nine. Under current rules, the ISO will consider the short-start unit's start-up costs to be a day-ahead market cost if the real-time market starts the resource in hour five as scheduled in the day-ahead market and the resource follows the real-time market dispatch. For the second example, assume the short-start unit has the same day-ahead schedule, but the real-time market delays its start until hour seven. If the short-start unit follows the real-time market dispatch instruction to start later than scheduled in the day-ahead market, the later start will cause the resource's start-up costs to be categorized as a real-time market cost, even though the resource actually started during the period scheduled in the day-ahead market. This also occurs if the real-time market starts the resource earlier than its day-ahead schedule while there is still an overlap with the day-ahead schedule.

This is not an issue under the current rules because the ISO considers day-ahead and real-time market costs together in determining a resources single bid cost recovery payment for a day. However, separating bid cost recovery between the day-ahead and real-time markets will, under the second example, lead to similar disincentives to submit economic bids to the real-time market as I described earlier. The short-start unit may attempt to protect its day-ahead market bid cost recovery by either leaving its day-ahead schedule as a self-schedule in the real-time market, or by not following the real-time market dispatch instruction if this instruction delays a start-up to a time that still overlaps with its day-ahead schedule.

Therefore, the ISO proposes a specific rule change for short-start units to categorize start-up costs as a day-ahead market cost if the real-time market dispatch overlaps with the day-ahead schedule, and even if the real-time start-up instruction delays or advances the start-up from what the day-ahead market scheduled.

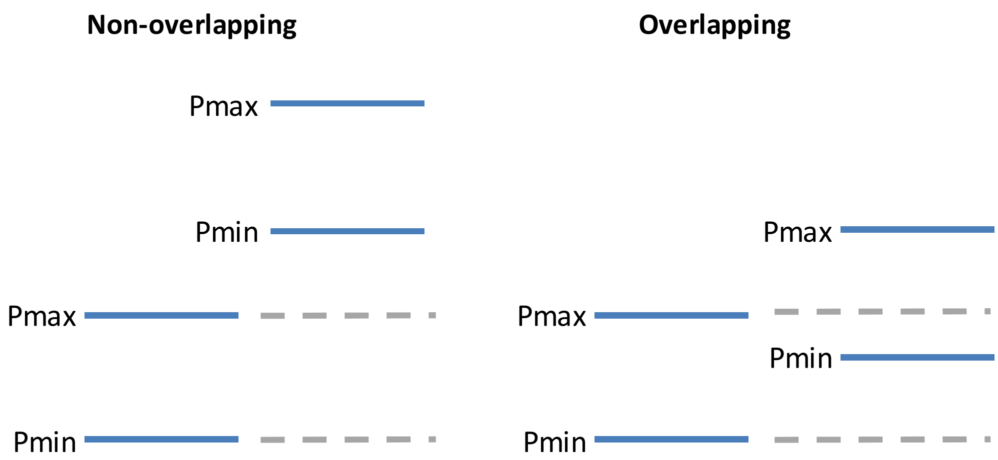
If a short-start unit receives a real-time market dispatch that does not overlap with its day-ahead schedule, under the existing bid cost recovery rules the ISO will consider the start-up costs as real-time market costs if the resource follows the real-time market's dispatch. The ISO proposes to retain this current rule because it is consistent with the intent of separate bid cost recovery payments for the day-ahead and real-time markets.

Q. Are there additional changes to the bid cost recovery rules needed for multi-stage generators consistent with the ISO's proposal to pay bid cost recovery separately for the day-ahead and real-time markets?

A. Yes. Multi-stage generators have multiple configurations and each configuration has a maximum operating level (Pmax), a minimum load (Pmin), and a minimum load cost that is unique to the configuration. The ISO needs additional rules for multi-stage generators because the real-time market may dispatch them to a different configuration then scheduled in the day-ahead market. These additional rules are needed to allocate these different minimum load costs appropriately between the day-ahead and real-time markets.

Figure 7 below shows two different multi-stage generator configuration scenarios with higher and lower configurations. A configuration is considered *higher* if that configuration's Pmin is a greater MW amount than the Pmin of the other configuration. The minimum load cost of the higher configuration must always be greater than that of the lower configuration. On the left-hand side of Figure 7, the multi-stage generator has two configurations that are not overlapping. On the right-hand side, the configurations are overlapping because the Pmax of the lower configuration is higher than the Pmin of the higher configuration (though the Pmin of the higher configuration is still higher than the Pmin of the lower configuration).

Figure 7. Non-overlapping and overlapping configurations



Q. How does the ISO account for minimum load costs for multi-stage generators scheduled in different configurations between the day-ahead and real-time markets under its current bid cost recovery rules?

A. Under today's rules, the ISO only considers the minimum load cost of the configuration dispatched by the real-time market in calculating a multi-stage generator's bid cost recovery payment when the real-time market dispatches a resource to a different configuration. For example, if a multi-stage generator has a day-ahead schedule in a lower configuration but the real-time market dispatches it to a higher configuration, then the ISO only includes the minimum load cost of the higher configuration in its calculation of the resource's bid cost recovery payment for a day.

Q. What rule change is necessary to correctly account for multi-stage generator minimum load costs when the configurations differ between the day-ahead and real-time markets when bid cost recovery is paid separately for the two markets?

A. A rule change is necessary for overlapping configurations to not double count the minimum load costs by the amount of the overlap. To do so, the ISO proposes a new rule that will allocate only a multi-stage generator's incremental minimum load cost to its real-time market bid cost recovery if it is dispatched to a different configuration by the real-time market than scheduled in the day-ahead market. The cost allocated to the real-time market will be the difference in minimum load costs of the configuration dispatched by the real-time market and the minimum load costs of the configuration scheduled in the day-ahead market. This difference may be a negative cost (*i.e.*, a savings) if the real-time configuration is lower than the day-ahead scheduled configuration. The minimum load costs of the day-ahead scheduled configuration will be included in the resource's day-ahead market bid cost recovery calculations.

Q. Can you provide an example comparing the current rule, the double counting, and this proposed rule change?

A. Yes. Let me provide two examples showing an incremental and a decremental scenario. For the incremental scenario, I assume the real-time market dispatches a multi-stage generator to a higher configuration than scheduled in the day-ahead market. The configuration scheduled by the day-ahead market has a minimum load cost of $700/hour and the configuration dispatched by the real-time market has a minimum load cost of $1,000/hour. Figure 8 below shows the difference in how these costs are accounted for under: (1) the current rules, (2) the current rules under bid cost recovery separation if there was not a rule change to adjust for double counting of the minimum load costs; and (3) the proposed rule change. The ISO's current rules account for only the real-time configuration minimum load costs as shown in row [1] for columns [B] and [C]. The total minimum load cost is $1,000/hour, which is the real-time configuration minimum load cost and shown in column [D]. If the ISO does not implement a rule change but separates bid cost recovery, then row [2] for columns [B] and [C] show that both the day-ahead and real-time minimum load costs will be included in bid cost recovery. The total minimum load cost under this methodology is $1,700/hour, which is the sum of the day-ahead and real-time minimum load costs. This higher total cost reflects an overlap comprised of the minimum load for the lower configuration. Figure 7 above provided examples of non-overlapping and overlapping configurations. Under both configurations, the Pmin of the higher configurations are incremental to the Pmin of the lower configuration. In other words, by accounting for the full minimum load costs of the day-ahead and real-time configurations, the Pmin of the lower configuration is double counted. In row [3], the proposed rule change is explained in columns [B] and [C] where the minimum load cost accounted for in the real-time market is calculated as the difference between the real-time and day-ahead minimum load costs. In this example, it is $300/hour which is the real-time cost of $1,000 *minus* the day-ahead cost of $700/hour. By only considering the incremental cost for the real-time, the total minimum load cost is $1,000/hour as shown in column [D]. This is the same total minimum load cost as the current rule shown in row [1] in column [D].

Figure 9 shows the same multi-stage generator in a decremental scenario where the real-time market dispatches it to a lower configuration than scheduled in the day-ahead market. The main difference is in row [3] column [C] where the incremental cost is *negative* $300/hour. By considering the incremental cost in the real-time market, the total minimum load cost is $700/hour as shown in column [D]. This is the same total minimum load cost as the current rule shown in row [1] in column [D].

Figure 8. Multi-stage generator minimum load cost – incremental scenario

		Minimum load cost accounted for:	Explanation	Minimum load cost ($/hour)	Total cost ($/hour)
		[A]	[B]	[C]	[D]
[1]	Current rule	Day-ahead	None	n/a	$1,000
		Real-time	Real-time configuration minimum load cost	$1,000	
[2]	Double-counting minimum load costs	Day-ahead	Day-ahead configuration minimum load cost	$700	$1,700
		Real-time	Real-time configuration minimum load cost	$1,000	
[3]	Proposed rule change for incremental real-time minimum load cost	Day-ahead	Day-ahead configuration minimum load cost	$700	$1,000
		Real-time	Real-time configuration minimum load cost minus day-ahead configuration minimum load cost	$1,000 - $700 = $300	

Figure 9. Multi-stage generator minimum load cost – decremental scenario

		Minimum load cost accounted for:	Explanation	Minimum load cost ($/hour)	Total cost ($/hour)
		[A]	[B]	[C]	[D]
[1]	Current rule	Day-ahead	None	n/a	$700
		Real-time	Real-time configuration minimum load cost	$700	
[2]	Double-counting minimum load costs	Day-ahead	Day-ahead configuration minimum load cost	$1,000	$1,700
		Real-time	Real-time configuration minimum load cost	$700	
[3]	Proposed rule change for incremental real-time minimum load cost	Day-ahead	Day-ahead configuration minimum load cost	$1,000	$700
		Real-time	Real-time configuration minimum load cost minus day-ahead configuration minimum load cost	$700 - $1,000 = ($300)	

Q. Can you summarize the impact of this rule change for multi-stage generators?

A. Yes. The allocation appropriately accounts for the total minimum load costs incurred. In the examples I described immediately above, the sum of the allocated day-ahead and real-time minimum load costs equals the actual minimum load cost of the configuration dispatched by the real-time market. This rule change will align the total minimum load cost allocation with the intent of the bid cost recovery separation.

III. <u>The Need For Modifications To The Rules That Scale Bid Cost Recovery Payments Based On Actual Energy Delivery.</u>

Q. Does the ISO propose to modify the existing bid cost recovery settlement rules that scale bid cost recovery payments based on actual energy delivery?

A. Yes. The ISO proposes to modify these rules to increase the incentive to provide real-time economic energy bids to the real-time market. It is also proposing modifications to these rules that are appropriate once the ISO pays bid cost recovery separately for the day-ahead and real-time markets.

Q. Please describe the existing bid cost recovery settlement rules to only pay bid cost recovery for delivered energy?

A. The ISO's current bid cost recovery rules contain certain scaling factors, referred to as the "day-ahead and real-time metered energy adjustment factors" that are used to reduce bid cost recovery payments to ensure a resource's payment is only based on costs for energy that it actually delivered. These scaling factors are ratios that measure a resource's metered energy relative to its scheduled or dispatched energy and range between 0 and 1 so that when applied to cost and/or revenue accounting as part of the bid cost recovery calculations they scale those amounts by the applicable ratio. The ISO applies these factors to a resource's costs and/or revenues in each settlement interval over a day.

Q. Does the ISO propose to modify the day-ahead and real-time metered energy adjustment factors?

A. Yes. The ISO proposes to modify the day-ahead metered adjustment factor so that it will not reduce a resource's day-ahead market bid cost recovery payments if the real-time market dispatches it below its day-ahead schedule and the resource follows the dispatch. This modification is necessary to increase the incentive for resources to provide economic energy bids to the real-time market. Such bids will allow the ISO to dispatch the resource below its day-ahead schedule, rather than leave these day-ahead schedules as "self-schedules" in the real-time market. This way, resources will not be at risk of the ISO reducing their day-ahead bid cost recovery payment because the real-time market dispatched it to a lower level than its day-ahead schedule. In addition, the ISO will apply the adjustment factor based on the resource's meter compared to its day-ahead schedule or the ISO dispatch.

The day-ahead metered energy adjustment factor will continue to ensure that if a resource does not deliver all of its day-ahead market scheduled energy, unless the real-time market dispatches the resource to produce less than its day-ahead schedule, the resource's bid costs (and/or revenues) will be scaled before it is included in the day-ahead market bid cost recovery calculations. This scaling will adjust the resource's bid costs and/or market revenues, depending on whether costs or revenues are positive or negative, so they reflect only the costs incurred to produce energy the resource actually delivered consist with where the ISO dispatched the resource.

The ISO also proposes to replace the existing real-time metered energy adjustment with a "real-time performance metric" that will provide appropriate incentives under separate bid cost payments for the day-ahead and real-time market. Similar to the way it applies the existing real-time metered energy adjustment factor, the ISO proposes to apply this real-time performance metric to a resource's incremental or decremental energy dispatched by the real-time market. However, different from the way the ISO applies the existing real-time metered energy adjustment factor today, the ISO proposes to apply the real-time performance metric to a resource's *day-ahead* market bid cost recovery when the day-ahead market schedules a resource or multi-stage generator configuration but the real-time market shuts it down. Like the day-ahead metered energy adjustment factor, the ISO will apply the real-time performance metric based on the resource's meter compared to the ISO dispatch.

Q. Please describe the ISO's proposed modifications to the day-ahead metered energy adjustment factor in more detail.

A. The ISO currently calculates the day-ahead metered energy adjustment factor as:

$$\frac{\text{Metered Energy} - \text{DA SS} - \text{DA MLE} - \text{Standard ramping}}{\text{DA Scheduled Energy} - \text{DA SS} - \text{DA MLE}}$$

Where:

$\text{DA SS} = \text{day-ahead self-schedule energy}$

$\text{DA MLE} = \text{day-ahead minimum load energy}$

The ISO proposes a modified day-ahead metered energy adjustment factor that it would calculate as:

$$\min\left\{1, \left|\frac{\text{Metered Energy} - \text{DA MLE} - \text{Regulation Energy}}{\min\{Total\ Expected\ Energy, DA\ Scheduled\ \text{Energy}\} - \text{DA MLE}}\right|\right\}$$

Similar to the existing day-ahead metered energy adjust factor, the modified day-ahead metered energy adjustment factor is a number that ranges between 0 and 1 depending on the metered energy a resource delivers relative to its schedule or dispatch. For each settlement interval, which in the day-ahead market is one hour, the ISO calculates the factor for a resource and then uses it as the ratio by which to reduce the resource's bid costs and/or revenues it uses as part of the resource's day-ahead market bid cost recovery calculations. When the resource's real-time market dispatch is at or above its day-ahead schedule, the modified day-ahead metered energy adjustment factor will be 1 if the resource operates at or above its day-ahead schedule. In this situation, the modified day-ahead metered energy adjustment factor will progressively reduce from 1 to 0 depending on how far the resource operates below its day-ahead schedule. When the resource's real-time schedule is less than its day-ahead schedule, the modified day-ahead metered energy adjustment factor will be 1 if the resource operates at or above its real-time schedule. In this situation, the modified day-ahead metered energy adjustment factor will progressively reduce from 1 to 0 depending on how far the resource operates below its real-time schedule.

The proposed formula also applies the adjustment factor based on the resource's meter compared to its day-ahead schedule or the total expected energy from ISO dispatch. This is accomplished by removing both the day-ahead self-schedule energy and the standard ramping energy. Instead, the formula measures the metered energy above the minimum load net of regulation as compared to the total expected energy in the case of a decremental real-time dispatch or the day-ahead scheduled energy in the case of an incremental real-time dispatch, both net of the minimum load energy.

The removal of regulation energy is necessary to make the formula consistent and to align it with the intent of the policy changes proposed in this filing. First, regulation energy is not included in the calculation of total expected energy in the denominator. To make the formula consistent, regulation energy is subtracted from the numerator. Second, this modification also aligns the formula with the policy intent because delivery of regulation energy should not be assessed since it is provided by a resource under the ISO's control via direct electronic signal. Therefore, regulation energy should not be included in the day-ahead metered energy adjustment factor.

The ISO will multiply the resource's bid costs and/or revenues by the modified day-ahead metered energy adjustment factor using rules that apply the modified day-ahead metered energy adjustment factor respectively to the resource's bid costs and/or revenues depending on whether they are positive or negative. This will result in the modified day-ahead metered energy adjustment factor always scaling down a resource's day-ahead bid cost recovery payment when the resource deviates below its real-time instruction and does not deliver its full day-ahead schedule. I describe this in more detail further down in this testimony.

Q. Can you provide an example of how the proposed day-ahead metered energy adjustment factor differs from the existing factor to illustrate how it will not reduce the day-ahead bid cost recovery payments in the event a resource delivers less than its day-ahead scheduled energy in response to the real-time market dispatching the resource below its day-ahead schedule?

A. Yes. The difference lies in a modification to the formula to consider the minimum of either: (1) the total real-time dispatched energy, or (2) the day-ahead scheduled energy, rather than just the latter. In other words, the modification to the formula will scale a resource's bid costs and/or revenues based on the resource's metered energy compared to either its: (1) real-time instructed dispatch if the resource has been dispatched down by the real-time market, or (2) day-ahead schedule if the resource has not been dispatched down by the real-time market.

I will provide an example that shows how the existing day-ahead metered energy adjustment factor would reduce day-ahead bid cost recovery, without the modification to the formula, even though the resource follows an ISO real-time dispatch to move the resource below its day-ahead schedule. Assume that a resource has day-ahead schedule of 100 MWh, a minimum load of 20 MWh, and no ramping or regulation energy at the interval of analysis as shown in Figure 10 below. The resource follows a real-time market dispatch to decrement down to 50 MWh. Under the existing day-ahead metered energy adjustment factor calculation shown below, the resource's factor is below 1, which reduces the costs the ISO includes in its bid cost recovery calculations, even though it has followed the real-time market dispatch down. The modified metered energy adjustment factor on the other hand accounts for this dispatch down by considering the real-time instructed dispatch (noted as the total expected energy) and produces a factor equal to one.

Figure 10. Comparison of existing day-ahead metered energy adjustment factor to modified day-ahead metered energy adjustment factor

MWh	Existing day-ahead metered energy adjustment factor	Modified day-ahead metered energy adjustment factor
Metered energy	50	50
Day-ahead minimum load energy	20	20
Day-ahead scheduled energy	100	100
Standard ramping	0	n/a
Regulation energy	n/a	0
Total expected energy	n/a	50
Resultant factor	0.375	1

Q. What is purpose of the real-time performance metric?

A. The real-time performance will be used as part of the ISO's real-time market bid cost recovery calculations and is similar to the existing real-time metered energy adjustment factor. Both these factors are similar to the day-ahead metered energy adjustment factor in that they scale bid cost recovery payments based on delivered energy. The real-time performance metric will ensure the ISO only pays bid cost recovery for energy dispatched by the real-time market that a resource delivers.

The real-time performance metric is different from the existing real-time metered energy adjustment factor in that it will also apply to minimum load costs due to real-time market dispatches and residual unit commitment process commits, to which the current factor does not apply. The ISO also proposes to apply the real-time performance metric to *day-ahead* market minimum load and incremental energy bid costs when the real-time market shuts down a resource originally scheduled in the day-ahead market. These differences are to provide appropriate incentives under separate bid cost recovery payments for the day-ahead and real-time markets to deliver all dispatched energy when started by the real-time market and to comply with real-time market shutdown instructions.

Q. Please describe how the ISO proposes to calculate and apply the real-time performance metric.

A. The ISO proposes to calculate the performance metric for each settlement interval as follows:

$$\min\left\{1, \left|\frac{Metered\ Energy - Day\ Ahead\ Scheduled\ Energy - Regulation\ Energy}{Total\ Expected\ Energy - Day\ Ahead\ Scheduled\ Energy}\right|\right\}$$

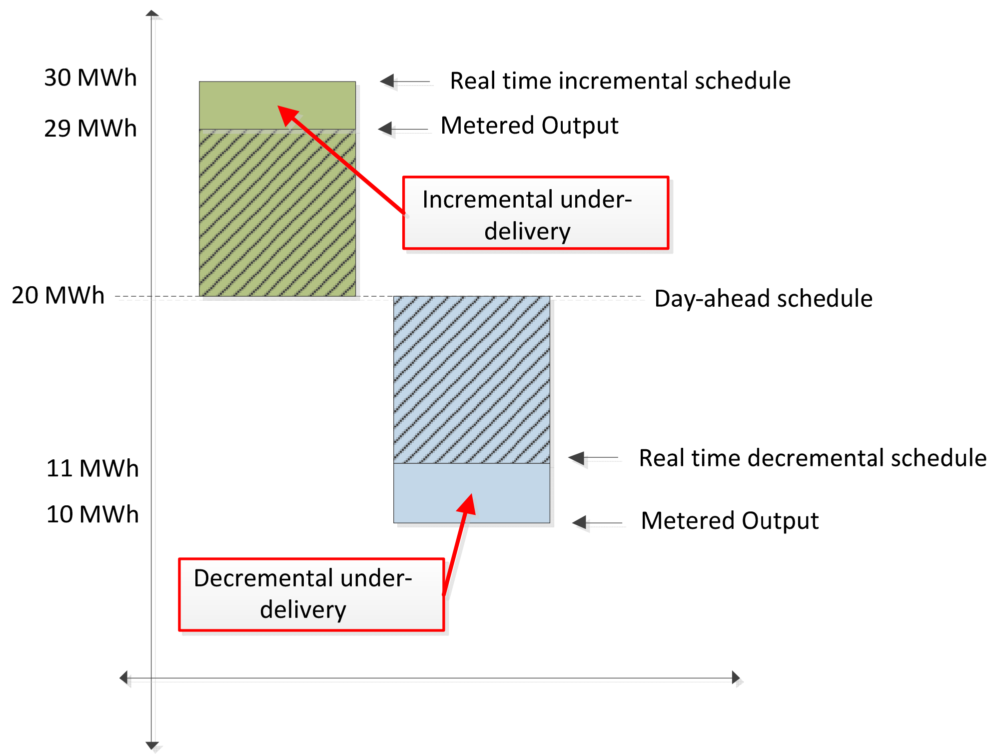
The ISO proposes to apply the real-time performance metric to a resource's bid costs (and/or market revenues depending on whether costs or revenues are positive or negative) for incremental or decremental energy dispatched by the real-time market. The real-time performance metric is based on the resource's meter compared to the total expected energy from ISO dispatch. As with the day-ahead metered energy adjustment factor, the formula does not include day-ahead self-schedule energy or the standard ramping energy. Instead, the formula measures the metered energy above the day-ahead schedule net of regulation as compared to the total expected energy above the day-ahead schedule. The ISO also proposes to apply the real-time performance metric to a resource's or multi-stage generation resource configuration's minimum load costs (and/or revenues) when the real-time market or residual unit commitment process starts-up a resource or multi-stage generation resource configuration, or shuts down a resource or multi-stage generation resource configuration. Finally, the ISO proposes to apply the real-time performance metric to costs (and/or revenues) used in the *day-ahead* market bid cost recovery calculations, in the event the real-time market shuts down a resource or multi-stage generation resource configuration originally schedule in the day-ahead market.

The ISO will apply the performance metric to costs and revenues based on whether the costs or revenues are respectively positive or negative using the same rules as I will describe later in this testimony for the day-ahead metered energy adjustment factor.

There are additional rules the ISO will use in applying the real-time performance metric. The performance metric will equal zero if the real-time market dispatches a resource above its day-ahead schedule but the resource's metered output is less than its day-ahead schedule. The performance metric will also equal zero if the real-time market dispatches a resource below its day-ahead schedule but the resource's metered output is greater than its day-ahead schedule.

The real-time performance metric adjusts a resource's bid costs (and/or revenues) in the event a resource under-delivers relative to real-time market incremental or decremental dispatch instructions. It will not affect bid cost recovery if a resource over-delivers energy relative to a real-time market dispatch instruction. Figure 11, below, illustrates the two circumstances in which the real-time performance metric will adjust a resource's bid costs (and/or revenues).

Figure 11. Real-time Performance Metric



The first circumstance is shown by the dispatch above the resource's day-ahead schedule illustrated in Figure 11, which shows an example of the performance metric's application to an incremental real-time market dispatch. The resource in this example has a day-ahead schedule to deliver 20 MWh and is dispatched by the real-time market for 10 MWh of incremental energy above its day-ahead schedule, which means the real-time market dispatches the resource to deliver a total of 30 MWh. However, in this example, the resource only delivered 29 MWh, which means it only delivered nine MWh of the 10 MWh of incremental energy the real-time market dispatched. Consequently, the ISO would calculate the resource's real-time performance metric for the settlement interval as 0.9, (29 MWh – 20 MWh) ÷ (30 MWh – 20 MWh). The real-time performance metric only scales costs (and/or revenues) in the event a resource under-delivers energy dispatched by the real-time market. Therefore, for example, if the resource delivered 31 MWh in the settlement interval, the real-time performance metric would be one.

In the incremental dispatch example shown in Figure 11, both bid costs and revenues would both be positive if the resource submitted positively-priced energy bids and the locational marginal price was positive. Consequently, consistent with the rules I describe for the day-ahead metered energy adjustment factor later in this testimony, the ISO would apply the performance metric to the resource's bid costs used in the real-time market bid cost recovery calculations, but not to the resource's real-time market revenues. So for example, if the resource's bid costs for the settlement interval were $1,000 and the performance metric was 0.9, the ISO would include bid costs of $900 ($1,000 * 0.9) in its bid cost recovery calculations for the resource.

The second circumstance in which the performance applies in Figure 11, which shows an example of how the ISO would apply the performance metric to a real-time market dispatch below the resource's day-ahead scheduled, *i.e., decremental* dispatch. In this example, the real-time market dispatches the resource for 10 MWh of decremental energy below its 20 MWh day-ahead schedule, which means the real-time market dispatches the resource to deliver a total of 10 MWh. However, in this example, the resource delivered 11 MWh, which means it under-delivered the *decremental* energy dispatched by real-time market, delivering only nine MWh of the 10 MWh of *decremental* energy the real-time market dispatched. Consequently, the ISO will calculate the resource's real-time performance metric for the settlement interval as 0.9 (11 MWh – 20 MWh) ÷ (10 MWh – 20 MWh). The real-time performance metric only scales bid costs and/or revenues in the event a resource under-delivers energy dispatched by the real-time market. Therefore, if, for example, the resource delivered nine MWh in the settlement interval, the real-time performance metric would be one.

In the decremental dispatch example shown in Figure 11, both bid costs and revenues would be negative if the resource submitted positively priced energy bids and the locational marginal price was positive. Consequently, the ISO would apply the real-time performance metric to the resource's real-time market revenues used in its real-time market bid cost recovery calculations, but not to the resource's costs. Therefore, for example, if the resource's market revenues for the settlement interval were -$1,000, representing the energy the resource "bought-back" in the real-time market and the performance metric was 0.9, the ISO would include market revenues of -$900 (-$1,000 * 0.9) in the resource's bid cost recovery calculations.

Q. Why does the performance metric only scale bid costs (and/or revenues) when a resource under-delivers energy dispatched by the real-time market and does not scale bid costs (and/or revenues) in the event a resource over-delivers energy dispatched by the real-time market?

A. The performance metric only scales bid costs (and/or revenues) when a resource under-delivers energy because its purpose is to scale the costs (and/or revenues) the ISO uses in its bid cost recovery calculations for energy eligible for bid cost recovery. Only dispatched energy is eligible for bid cost recovery. Conversely, energy produced as a result of over-delivery of a real-time market dispatch instructions is not eligible for bid cost recovery payments. Therefore, applying the real-time performance metric to this over-delivered energy would go beyond the intended purpose of scaling a specific bid cost and/or revenue for undelivered energy otherwise eligible for bid cost recovery.

Q. Why does the ISO propose to apply the real-time performance metric to a resource's or multi-stage generator's minimum load costs when the real-time market starts-up a resource, in addition to applying it to the resource's costs for energy produced above minimum load?

A. It is appropriate to adjust minimum load costs used for the bid cost recovery calculations, in addition to adjusting bid costs for energy above minimum load, when a resource under-delivers energy in response to a real-time market dispatch instruction. When the real-time market starts up a resource, it typically dispatches the resource to start-up and deliver more energy than just the resource's minimum load, making it important for the resource to deliver all the dispatched energy, not just the minimum load energy. The metric the ISO currently uses to determine if a resource's minimum load costs are included in the real-time market bid cost recovery calculations merely assesses whether the resource operated at least at its minimum load. Consequently, the ISO proposes to apply the real-time performance metric to all of a resource's costs and/or revenues used in the real-time market bid cost recovery calculations, including minimum load costs, when the real-time market starts a resource or multi-stage resource configuration. This will appropriately scale all of a resources costs (and/or revenues) in the bid cost recovery calculations based on delivered energy.

Q. Why does the ISO propose to apply the real-time performance metric to a resource's or multi-stage generator's costs (and/or revenues), including those used in the <u>day-ahead</u> bid cost recovery calculations, in the event the real-time shuts down a resource or multi-stage resource configuration?

A. In the event the real-time market shuts down a resource or multi-stage resource configuration, the real-time performance metric appropriately measures the resources compliance with the shutdown instruction. For this reason, the ISO proposes to apply it to a resource's or multi-stage resource configuration's bid costs (and/or revenues) used in the day-ahead market bid cost recovery calculations in the event the real-time market shuts a resource down. This includes minimum load costs (and/or revenues) as well as costs (and/or revenues) for energy above minimum load. The ISO proposes this change to provide resources appropriate incentives to follow real-time market shutdown instructions and do not have incentives to keep running to preserve day-ahead market bid cost recovery payments.

When the real-time market does not shut down a resource scheduled by the day-ahead market, the ISO includes the resource's minimum load costs in its day-ahead market bid cost recovery calculations if the resource operates at least at its minimum load. However, if the ISO applied this rule under bid cost recovery separation when a resource scheduled by the day-ahead market is subsequently shut down by the real-time market, the resource could receive bid cost recovery for day-ahead market costs by not shutting down. Under the ISO's proposal to apply the performance metric to costs (and/or revenues) used in the day-ahead market bid cost recovery calculations, the resource's costs will not be fully included in the day-ahead bid cost recovery calculations unless it followed the real-time shutdown instruction. For example, assume a resource is committed at its 50 MW minimum load in the day-ahead market and the real-time market subsequently dispatches the resource to

0 MW (i.e. it shuts down the resource.) If the resource ignores the real-time decommitment and keeps operating at its minimum load, the ISO would calculate the performance metric as 0 (50 MWh – 50 MWh) ÷ (0 MWh – 50 MWh). The rationale is the same for applying it to incremental energy costs (and/or revenues) used in the day-ahead market bid cost recovery calculations.

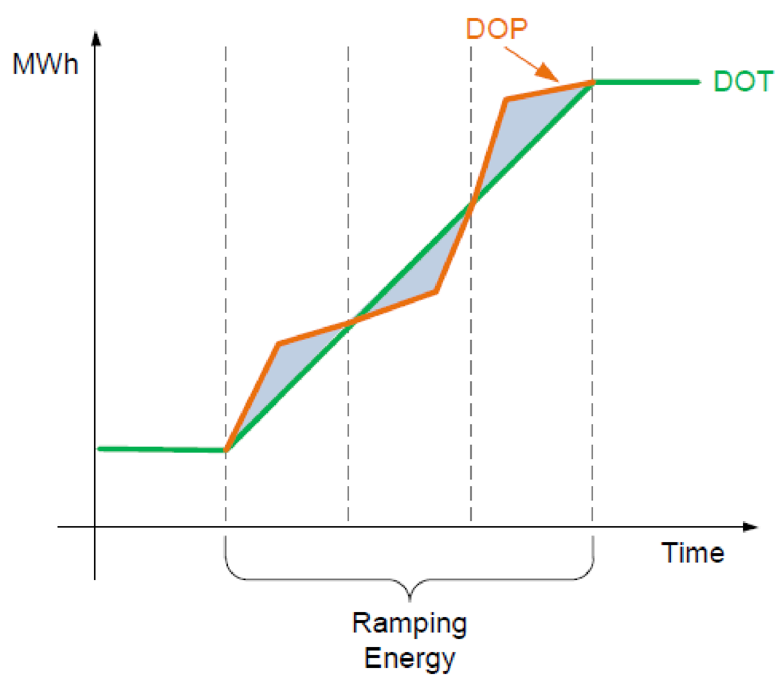
Q. Does the ISO propose accommodations to account for inadvertent or unavoidable deviations in its applying the day-ahead metered energy adjustment factor and real-time performance metric?

A. Yes, the ISO proposes a "tolerance band" before applying these factors so they do not reduce bid cost recovery payments for small deviations from dispatch that may legitimately be due to ramping or other operational constraints. This tolerance band will result in the ISO not applying the modified day-ahead metered energy adjustment factor or real-time performance metric in a settlement interval if a resource's deviation from schedule or dispatch is no more than the greater of 5 MW or 3 percent of the resource's maximum output (Pmax), plus an additional amount termed the "ramping tolerance." Also, the ISO will not apply the real-time performance metric when a resource is starting up, shutting down, during a multi-stage generator's transition period, when a resource is crossing through a forbidden region, or if there is a dispatch operating point correction due to a verbal dispatch instruction issued by the ISO.

Q. What is the ramping tolerance component of the tolerance band?

A. The ISO designed the "ramping tolerance" to accommodate instances in which a resource's ramp rate can change over the course of a settlement interval and to reflect that a resource's dispatched operating point can be different than the basis for the amount of energy calculated as dispatched by the ISO's settlement system. Figure 12 illustrates this concept. The resource's amount of energy used in settlements, which is used to calculate the performance metric is the dispatch operating point (dispatch operating point, shown by the orange line); however, the ISO's dispatch instructions use the dispatch operating target (dispatch operating target, green line).

Figure 12. Ramping Tolerance



The dispatch operating point is always at the mid-point of each dispatch interval. The dispatch operating point is determined based on the resource's ramp-rates and is the resource's meter as compared against to calculate the performance metric. The tolerance band captures the difference between the linear curve from between the dispatch operating targets and the ramping curve reflected by the dispatch operating points.

IV. <u>The Need For Tariff-Based Metrics To Eliminate Incentives To Engage In Adverse Market Behavior To Expand Unjust Bid Cost Recovery Payments.</u>

Q. Please describe how paying bid cost recovery separately for the day-ahead and real-time markets may provide an incentive for adverse market behavior.

A. As I discuss above, paying bid cost recovery separately for the day-ahead and the real-time markets is an important rule change to incentivize resources to submit more real-time economic bids. However, doing so may increase incentives for adverse strategic market behavior that could inflate bid cost recovery because the ISO would pay a resource for a revenue shortfall in either the day-ahead or real-time markets, without first netting the shortfall against any revenue surplus in the other market. Consequently, this may provide a resource greater assurance that it could profit from adverse market behavior than it does today. As I describe in more detail below, without mitigating measures, there would be a number of ways in which resources could inflate their bid cost recovery payments. More specifically, resources could strategically bid or strategically deviate from ISO market schedules or dispatches to inflate bid cost recovery, or they could start up or shut down without a dispatch instruction for inflating bid cost recovery.

Q. What measures has the ISO identified as important to have together with the separation of bid cost recovery to guard against adverse strategic behavior?

A. The ISO has identified several additional measures necessary to eliminate incentives for adverse strategic behavior that would inflate bid cost recovery payments. As I describe below, some of these measures build on existing measures the ISO has already adopted for the same purpose, and the ISO proposes to retain those. Others are new measures that are needed when the ISO performs day-ahead and real-time bid cost recovery separately. All of the measures, when triggered, will reduce a resource's cost and/or revenue inputs into its bid cost recovery calculations so that any adverse strategic behavior does not inflate its bid cost recovery payment.

The first of these measures are proposed modifications to the rules regarding the application of the day-ahead metered energy adjustment factor and the real-time performance metric to a resource's costs and revenues. These modifications will further ensure these factors never have the unintended effect of inflating bid cost recovery payments rather than scaling the payments to reflect delivered energy. The second of these measures is a proposed metric to ensure a resource cannot inflate real-time market bid cost recovery by persistently deviating from dispatch instructions. The third of these measures is a proposed metric to ensure the ISO does not pay bid cost recovery for minimum load costs to a resource that strategically deviates from real-time market dispatch instructions such that it prevents the real-time market from shutting it down. I describe each of these measures in more detail below.

In addition to these measures, the ISO proposes that a resource that starts up without a start-up instruction from the ISO is not eligible for bid cost recovery. The ISO proposes this to ensure it only pays bid cost recovery to resources that are operating pursuant to ISO market schedules or dispatches.

Q. Do the ISO settlement rules contain any measures today to dissuade strategic adverse market behavior to inflate bid cost recovery payments?

A. Yes**. T**he ISO modified the day-ahead metered energy adjustment factor in its emergency filings with the Commission on March 25, 2011, in FERC Docket No. ER11-3149, and June 22, 2011, in FERC Docket No. ER 11-

3856, to amend the ISO tariff to address specific strategic behavior then observed in the ISO markets.

In the 2011 filings, the ISO modified the application of day-ahead metered energy adjustment factor so that it would not apply it to a resource's day-ahead market revenues (*i.e.*, set the day-ahead metered energy adjustment factor to one as applied to revenues), and to not apply it to negatively priced energy bid costs. The 2011 modifications appropriately reflected that all of a resource's day-ahead market revenues should be included in its day-ahead market bid cost recovery calculations because the resource receives these revenues despite its output level in real-time. The 2011 modifications also eliminated an incentive for adverse strategic bidding consisting of a two-part strategy in which the resource 1) submits negatively priced energy bids to the day-ahead market so the day-ahead market commits a resource, and then 2) the resource bids into the real-time market forcing the ISO to dispatch the resource to minimum load. Prior to the 2011 modifications, this strategy resulted in the day-ahead metered energy adjustment factor being a number near zero, which had the effect of "cancelling-out" the effect the negatively-priced energy bids would otherwise have on the bid cost recovery calculations, which would be to decrease the bid cost recovery payment amount. Not applying the metered energy adjustment factor to negatively priced bids mitigates this bidding strategy.

Q. What additional rules are necessary to ensure there is no incentive to engage in the same activities the ISO tried to address with its emergency filings in 2011?

A. As I described earlier in this testimony, the ISO proposes to modify the day-ahead metered energy adjustment so that it will be calculated as one when the ISO dispatches a resource below its day-ahead schedule in the real-time market and the resource follows the dispatch. In addition to creating increased incentives for decremental bids in the real-time market, this also provides increased protection against the adverse strategic behavior that was addressed in the 2011 emergency filings. This adverse strategic behavior exploited that the day-ahead metered energy adjustment factor will be less than one when the real-time market dispatches a resource below its day-ahead schedule. The ISO's proposed modification ensures that the metered energy adjustment factor does not reduce costs (and/or revenues) used in the day-ahead bid cost recovery calculations when the real-time market dispatches a resource below its day-ahead schedule.

In this filing, the ISO proposes to restate the same rules previously adopted clearly in the tariff so it is clear when the ISO will apply the modified day-ahead metered energy adjustment factor to a resource's costs or revenues. In addition, the ISO is proposing to apply these same rules to the real-time performance metric so it also appropriately scales costs and revenues.

Q. Please explain what elements in the way the ISO's proposed day-ahead metered energy adjustment factor and real-time performance metric are designed to effectively scale bid cost recovery payments to reflect only delivered energy and cannot be used to inflate bid cost recovery payments.

A. There are two aspects of the proposed factor and metric that ensures this result. First, both of these factors can only be numbers between 0 and positive 1. Because it is bounded by zero it cannot change the sign (*i.e.*, positive or negative) of the value to which it is applied. Therefore, it is not possible, for example for the factors to expand bid cost recovery payments by turning market revenues to negative, thereby discounting the amount of revenue calculated to offset bid costs. Similarly, because it is also bounded by one, it cannot increase the value to which it is applied. This means it cannot increase the costs accounted for nor can it increase the positive revenues uses to offset those costs.

Second, the ISO is proposing to include a series of rules that build upon the 2011 emergency modifications to be applied to the metered energy adjustment factor and real-time performance metric. These rules will continue to appropriately scale bid cost recovery payments to reflect actual energy delivery while also ensuring resources will not be able to employ adverse strategic bidding to use these factors to inflate bid cost recovery payments. The rules are further refined and enhanced to consider more comprehensively all the various combinations of positive and negative costs and revenues. The ISO designed these rules to ensure the modified day-ahead metered energy adjustment factor and real-time performance metric always have the intended effect of scaling bid cost recovery payments to reflect only delivered energy and will never increase bid cost recovery. This ensures that bid cost recovery payments are appropriately scaled to reflect actual energy delivery while also ensuring resources will not be able to employ adverse strategic bidding to use these factors to inflate bid cost recovery payments.

Q. Please describe the specific four rules the ISO proposes to add in the application the day-ahead metered energy adjustment factor and real-time performance metric for this purpose.

A. This series of rules consists of the following four provisions. The first rule is that when a resource's day-ahead market bid costs and market revenues for a settlement interval are both positive, the ISO will apply the modified day-ahead metered energy adjustment factor or real-time performance metric to the bid costs, but will not apply it to the market revenue side. This provision similar to the tariff change made in the March 25, 2011, emergency filing in which the ISO proposed to not apply the metered energy adjustment factor to a resource's accounting of market revenue. This is to reflect that the resource's bid costs should be scaled because it only incurred costs for the energy it produced, and to reflect that all of its market revenues should be included because the resource receives these revenues despite its actual output. This rule will only reduce bid cost recovery payments and not increase them because a resource's bid cost recovery payment is based on bid costs minus revenues, and if both bid costs and revenues are positive, scaling bid costs only will reduce the bid cost recovery payment overall. As an example, assume a resource has a bid cost of $20/MWh and is scheduled for 10 MWh at a $10/MWh locational marginal price, but only delivers 7 MWh. The ISO would calculate its revenue shortfall as $40 (0.7 * $20/MWh * 10 MWh) – ($10/MWh * 10 MWh). I will use this example further below to illustrate the fourth provision of these rules.

Q. Please explain the second rule.

A. The second rule is that when a resource's day-ahead bid costs for a settlement interval is greater than or equal to zero, and the market revenues are negative, the ISO will apply the day-ahead metered energy adjustment factor or real-time performance metric to both costs and revenues. This provision ensures the bid costs are scaled based on delivered amounts consistent with the first provision of these rules. This provision scales the negative market revenues to ensure negative revenues are treated consistently with the fourth provision of these rules, which I describe below and applies when both costs and revenues are negative. The ISO proposes this additional rule so that it more comprehensively addresses all circumstances in addition to the ones addressed in 2011 emergency filings.

Q. Please explain the third rule.

A. The third rule is that when a resource's day-ahead market bid costs for a settlement interval are negative and the market revenues are greater than or equal to zero, the ISO will not apply the day-ahead metered energy adjustment factor or real-time performance metric to the bid costs or to the market revenues calculation. This provision is essentially the same rule change made in the ISO's June 22, 2011 emergency filing. When a resource's bid costs are negative, scaling these costs in its bid cost recovery calculation would increase its bid cost recovery payment and could be used as part of a strategic adverse bidding strategy involving negative bids. Consequently, this provision specifies the ISO will not apply the modified day-ahead metered energy adjustment to negative bid costs because doing so would increase the resource's day-ahead bid cost recovery payment.

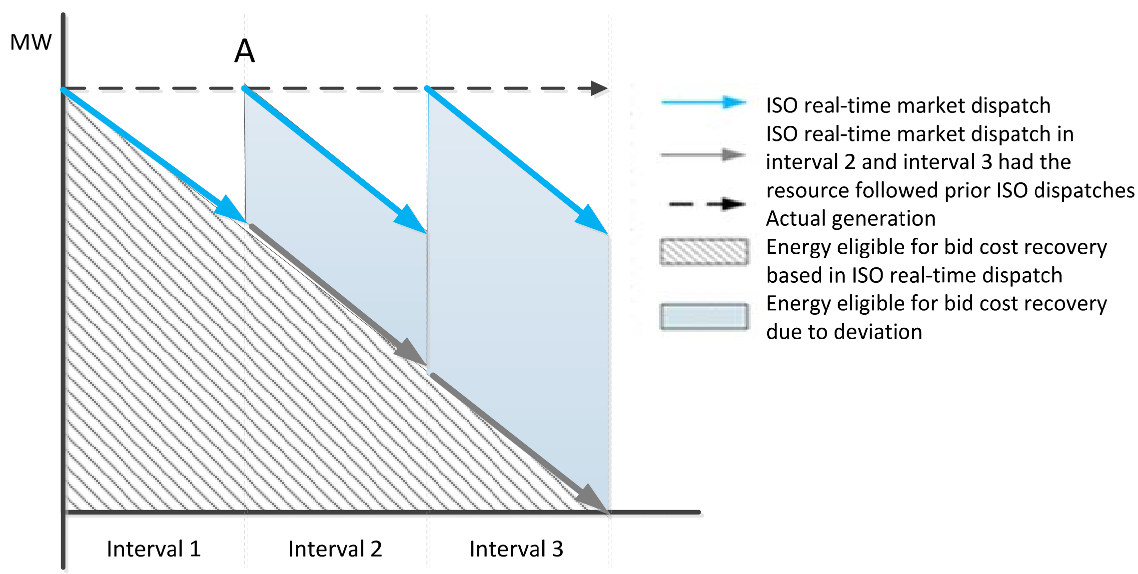
Q. Please describe the fourth rule.

A. The fourth rule is that when a resource's day-ahead bid costs and market revenues for a settlement interval are both negative, the ISO will apply the day-ahead metered energy adjustment factor or real-time performance metric to the revenues but will not apply these to the bid costs. This circumstance would exist in the day-ahead market if a resource submitted a negatively priced energy bid and the locational marginal price was negative. (In the real-time market, it would exist under these same conditions for incremental energy or, for decremental energy, this circumstance would exist with a positively priced energy bid and a positive locational marginal price.) I will provide an example to show that this provision scales bid cost recovery payments to reflect actual energy delivered like the first rule, except it scales the revenue side rather than the cost side to reflect that these are both negative values, rather than being positive values as covered by the first rule. Assume a resource as a bid cost of -$10/MWh and is scheduled for 10 MWh at a -$20/MWh locational marginal price, but only delivers 7 MWh. The ISO would calculate its revenue shortfall for as $40 (-$10/MWh * 10 MWh) – (0.7 * -$20/MWh * 10 MWh). This is the same revenue shortfall calculated for the example shown for the first provision of these rules, which had the same proportion of energy delivered.

Q. How could a resource inflate its bid cost recovery for the real-time market by deviating from dispatch instructions?

A. By persistently deviating, a resource can inflate its bid cost recovery payments for the real-time market. Persistent deviations can increase the amount of energy eligible for bid cost recovery, with the deviations cumulatively increasing the additional amount of dispatched energy eligible for bid cost recovery relative to the amount that would have existed if the resource followed the dispatch instructions. This is possible because the real-time market dispatches resources from their current output level rather than from the output the resource would have been at if it followed previous dispatch instructions. Figure 13, below, illustrates this situation.

Figure 13: Persistent deviation from real-time ISO dispatch



In this example shown in Figure 13, the resource's real-time market dispatch is depicted by the light blue line, and the resource's actual output is depicted by the dashed black arrow. The resource does not follow the real-time market's dispatch for interval 1 (light blue arrow) and so, for interval 2, the real-time market issues a new dispatch based on the resource's actual output level (point A) rather than from what the resource's output would have been had it followed the dispatch for interval 1. This example shows the resource continuing to not follow subsequent downward dispatches in intervals 2 and 3, with the dispatches shown by the solid grey arrows and the resource's output shown by the dashed black arrow. In this scenario, the real-time market would likely be dispatching the resource down because the locational marginal price is below the resource's energy bid price. By ignoring the real-time market dispatch instructions the resource could be continuously dispatched uneconomically and receive a bid cost recovery payment based on its bid cost. The resource could therefore be able to increase the amount of energy eligible for a bid cost recovery payment relative to the amount that would have existed if the resource had followed the real-time market dispatch instructions. This is represented in Figure 13 by the light blue shaded area. In contrast, the hashed area in Figure 13 shows the energy that would have been eligible for bid cost recovery had the resource followed the real-time market dispatch instructions.

Q. Is there a similar potential for resources to inflate residual imbalance energy payments by persistently deviating from real-time market dispatch instructions?

A. Yes, in the same manner I described above for energy eligible for bid cost recovery, persistent deviations can inflate the amount of energy settled as residual imbalance energy.

Q. How does the ISO propose to address the potential for resources to inflate bid cost recovery or residual imbalance energy payments by persistently deviating from dispatch instructions?

A. The ISO proposes to implement a metric to detect persistent deviations. The metric will evaluate each resource's response to real-time dispatch instructions in each 10-minute settlement interval and will flag each interval in which a resource deviated from a dispatch by more than a threshold value. The ISO would then adjust the bid costs used to calculate a resource's bid cost recovery payment, or would mitigate the residual imbalance energy settlement, if four or more settlement intervals were flagged in a two-hour "rolling window."

Q. What is the threshold value the persistent deviation metric will use to determine if a resource followed an ISO dispatch instruction?

A. The persistent deviation metric will compare the amount the real-time market dispatches a resource down or up in an interval compared to the amount the resource moves down or up. The persistent deviation metric for each settlement interval will be the ratio of (1) the resource's metered energy in the prior interval minus the metered energy in the instant interval; and 2) the metered energy in the prior interval minus the resources total expected energy in the instant interval.

The ISO will flag a settlement interval if the deviation is in a direction that would inflate bid cost recovery or residual imbalance energy and the metric exceeds a threshold, consisting of the following two conditions.

First, a resource cannot deviate from its dispatched change in output level by more than 10% of the dispatched change in output level. For example, if a resource is dispatched to decrease its output by 50 MW in a settlement interval, the settlement interval would be flagged if the resource did not reduce its output by at least 45 MW (i.e. over-generated by more than 5 MW).

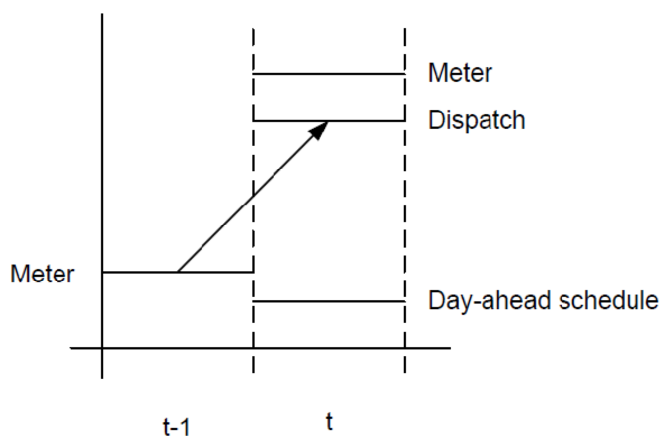
Second, the settlement interval will only be flagged under the preceding criteria if the deviation is greater than 10% of its ramp capability over the 10-minute interval. For example, a resource that has a 5 MW/min ramp rate and can ramp 50 MW over a 10-minute settlement interval will not have settlement intervals flagged for deviations 5 MW or less (50 MW * 10%). This will avoid triggering the persistent deviation metric for small deviations from small dispatched changes to output level.

Q. Can you provide an example of how the persistent deviation metric will be evaluated?

A. I provide four cases with diagrams showing intervals t-1 and t, where t is the interval being evaluated and t-1 is the previous interval. Case 1 and 2 are instances in which persistent deviations would inflate bid cost recovery for incremental energy and case 3 and 4 are instances in which persistent deviations would inflate bid cost recovery for decremental energy

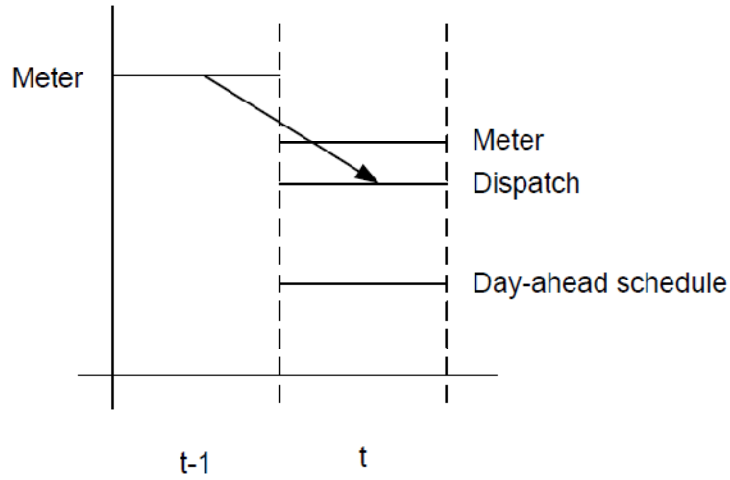
Case 1 is shown in Figure 14 below where the resource is dispatched up in real time and is operating above its day-ahead schedule. In this case, interval t is flagged if the deviation is greater than 10% of the resource's 10-minute ramp capability and the persistent deviation metric is calculated to be greater than 110%.

Figure 14: Case 1 – Increment above day-ahead schedule



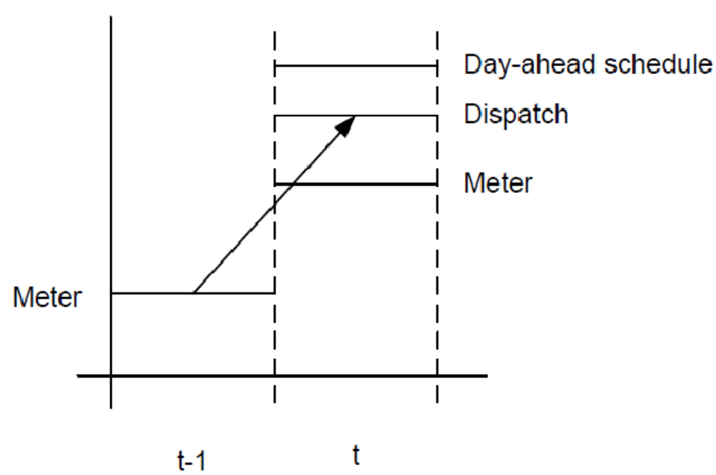
Case 2 is shown in Figure 15 below where the resource is dispatched down in real time and is operating above its day-ahead schedule. In this case, interval t is flagged if the deviation is greater than 10% of the resource's 10-minute ramp capability and the persistent deviation metric is calculated to be less than 90%.

Figure 15: Case 2 – Decrement above day-ahead schedule



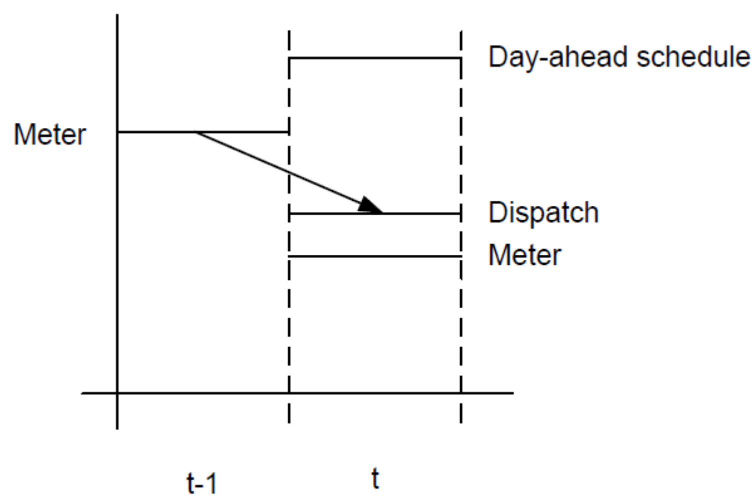
Case 3 is shown in Figure 16 below where the resource is dispatched up in real time and is operating below its day-ahead schedule. In this case, interval t is flagged if the deviation is greater than 10% of the resource's 10-minute ramp capability and the persistent deviation metric is calculated to be less than 90%.

Figure 16: Case 3 – Increment below day-ahead schedule



Case 4 is shown in Figure 17 below where the resource is dispatched down in real time and is operating below its day-ahead schedule. In this case, interval t is flagged if the deviation is greater than 10% of the resource's 10-minute ramp capability and the persistent deviation metric is calculated to be greater than 110%.

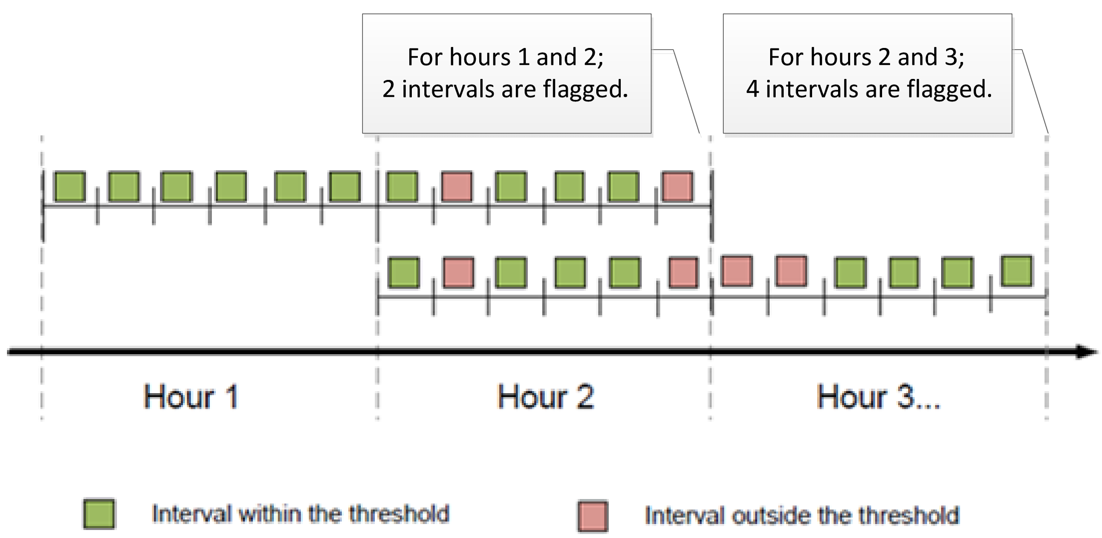
Figure 17: Case 4 – Decrement below day-ahead schedule



Q. Please describe in more detail how the ISO will count flagged intervals within the two-hour rolling window.

A. The ISO proposes to evaluate the persistent deviation metric for a resource for each hour over a two-hour rolling window that consists of the twelve ten-minute settlement intervals that comprise the current hour and the previous hour. The ISO will adjust the resource's bid cost used in its real-time market bid cost recovery calculations or mitigate residual imbalance energy settlement for the two-hour rolling window period if four or more settlement intervals are flagged. Figure 18 provides an example to illustrate this. In this example, two settlement intervals are flagged in hour 2 and no intervals are flagged in hour 1. This means the resource is below the four flagged interval criteria for the two-hour rolling window as evaluated for hour 2. Moving to hour 3, two additional intervals are flagged. This means the resource has four intervals are flagged in the two-hour rolling window as evaluated for hour 3. Therefore, the ISO will adjust the resource's bid costs used in the real-time market bid cost recovery calculations or mitigate residual imbalance energy settlement for hours 2 and 3.

Figure 18. Persistent deviation metric two-hour rolling window



Q. How will the ISO adjust a resource's bid costs used as part its real-time market bid cost recovery calculation's or mitigate residual imbalance energy settlement if four or more intervals are flagged in the two-hour rolling window?

A. For the intervals that are flagged, for purposes of calculating the bid cost for incremental energy (excluding minimum load energy) in the resource's real-time market bid cost recovery calculations, or for establishing the reference hour bid for residual imbalance energy settlement, the ISO will use the minimum of: (1) the resource's default energy bid; (2) the resource's submitted bid; and (3) the locational marginal price. Similarly, decremental energy the ISO will use the maximum of (1) the resource's default energy bid, (2) the resource's submitted bid, and (3) the locational marginal price.

Q. Why is the bid cost used in the bid cost recovery calculation or the reference hour bid used for residual imbalance energy settlement mitigated in this manner?

A. The ISO proposes to use the minimum of these three bids in order to provide the resource the least amount of incentive to deviate from ISO dispatch instructions while still ensuring the resource is at least compensated for its costs. If a resource's bid was mitigated to the higher of locational marginal price or default energy bid cost, the resource would have the incentive to over-generate and be guaranteed the higher of the locational marginal price or its default energy bid at all times. The resource would always be at least made whole by deviating and then would earn additional rents whenever the locational marginal price went above the default energy bid cost.

Q. How does the four interval threshold guard against persistent deviations while still allowing for inadvertent or unavoidable deviations?

A. The ISO proposes to mitigate persistent deviations without diminishing incentives to participate actively in the real-time market. The ISO has estimated the effect of the application of the persistent deviation metric using market data for September 2012. The analysis looked at the distribution of resource-hours according to the number of flagged intervals within an hour and includes only a very conservative (that is, low) approximation of the minimum deviation threshold based on the resource's 10-minute ramping capability. Figure 19 shows the results of this analysis. The ISO found that 97.5% of resource-hours had 3 or fewer flagged settlement intervals. Because of the complexity of modeling the rolling two-hour window, this analysis instead evaluates the distribution of resource-hours according to the number of flagged intervals within an hour. The resource-hours included are limited to hours in which a resource was dispatched up or down. This analysis includes only a very conservative (that is, low) approximation of the minimum deviation threshold based on the resource's 10-minute ramping capability. This ramping capability is considered in order to avoid catching very small deviations that would reasonably be considered inadvertent. In other words, this analysis likely captures small deviations that would not be caught under the actual application of these rules. The results of this analysis can be interpreted by looking at the proportion of resource-hours with no flagged settlement intervals. This shows that 97.5% of resource-hours had 3 or fewer flagged settlement intervals. It is important to note that, when a rolling two-hour window is considered, it may be that some of the instances in which one hour has three or fewer intervals flagged, and it is adjacent to an hour with flagged intervals that push the two-hour window over threshold.

Figure 19. Effect of persistent deviation metric

Number of flagged settlement intervals in an hour	Number of resource-hours	Percentage of resource-hours
3 or fewer	91,738	97.5%
More than 3	2,333	2.5%

Q. What additional analysis did the ISO rely on to come to this conclusion?

A. The ISO's DMM reviewed the proposal and analyzed the potential profitability for a resource to persistently deviate from ISO dispatch instructions under the proposed settlement rules.[1] They found the proposal effectively mitigates potential abuses of settlement rules for real-time bid cost recovery and residual energy, without being overly complex or diminishing incentives to actively participate in the real-time market. To demonstrate this finding they showed an illustrative example of a potential gaming opportunity under the previous market rules. Their example presumes a resource is bid into the real-time market at a high price, then unilaterally ramps up its output above its day-ahead schedule for the last 5 real-time dispatch intervals (25 minutes) of an hour, and ignores the ISO's downward dispatch instructions during this time. They demonstrate that the four-interval threshold prevents the resource from making excessive revenues even in the case a resource deviates significantly for four intervals in a single hour and then is compliant for three or fewer intervals in the next hour.

Q. Please describe how the default energy bid would be defined.

A. The default energy bid would be the same bid that the resource must establish with the ISO under section 39.7 of its tariff. The exact same default energy bid would be used for this purpose. I describe that process

[1] http://www.caiso.com/Documents/DMM-Comments-BidCostRecoveryMitigationMeasuresSecondRevisedDraftFinalProposal.pdf

here for the sake of completeness in explaining the ISO's proposal, but my explanation should not suggest any changes to the current methodology.

A resource may select one of three options for calculating its default energy bid: (1) variable cost based, (2) locational marginal price based, and (3) negotiated.

The first option is to base the default energy bid on the resource's variable costs. These are determined by considering the resource's incremental fuel costs and standard variable operations and maintenance costs that are specified in the ISO tariff for different generation technologies. Ten percent is added to these costs to determine the default energy bid. The default energy bid under this option consists of different bid prices at different ranges of MW output based on heat rate information that the resource submits. These are calculated daily for natural gas-fired resources to account for varying natural gas prices. An additional amount is added to a resource's default energy bid under this option if a resource's bids are frequently mitigated under the ISO's market power mitigation procedures.

The second option uses the locational marginal prices at the resource's location as the basis for the default energy bid. The default energy bid is established at the 25th percentile of the locational marginal prices in hours when the resource was scheduled or dispatched by the ISO market over the past 3 months.

The third option is to negotiate the default energy bid. This option is intended for resources for which a resource's actual costs cannot be accurately reflected under the variable cost option. Examples of such costs are opportunity costs or the costs for non-standard operations. The default energy bids established under this option can either be set for each month or can be formulaic in which the default energy bid can vary by day as the inputs to the formula vary.

Q. Is there currently a settlement inconsistency involving bid cost recovery for periods when a generator is ramping up to or down from a temporary increase to its minimum load that is reported through the ISO's outage reporting system?

A. Yes. Energy produced by a generator during the period of a temporary increase to its minimum load is <u>not</u> eligible for bid cost recovery. However, under the current rules the optimal energy produced while ramping up to or down from the rerated minimum load is eligible for bid cost recovery. Although the energy in both cases is related to a rerated minimum load, the current treatment in the ISO's bid cost recovery calculations is inconsistent,

Q. Please describe how the ISO proposes to address this.

A. The ISO proposes to treat the optimal energy produced while ramping up to or down from a temporary increase in a resource's minimum load in the same manner as the energy during the period of the rerated minimum load is treated. In both cases the bid cost the ISO will use in the resource's bid cost recovery calculations will be the resource's locational marginal price. This will result in this energy not being eligible for bid cost recovery.

Note that this change applies to optimal energy, which is eligible for bid cost recovery. Further down in this testimony I will describe a similar change the ISO is proposing for the settlement of residual imbalance energy produced while ramping up to or down from a minimum load rerate. As I described earlier, residual imbalance energy is not included in bid cost recovery.

Q. Are their currently settlement inconsistencies involving bid cost recovery and ramping to or from an exceptional dispatch?

A. Yes. There is an inconsistency between the way in which the ISO settles exceptional dispatches and optimal energy produced while a resource is ramping up to or down from an exceptional dispatch. Even though the exceptional dispatch settlement price may be mitigated to a price based on the resource's default energy bid rather than its submitted bid, the ISO does not currently reflect this mitigated price in the bid costs for this ramping energy that are included in the bid cost recovery calculations. Currently, the ISO uses the unmitigated bid price in the bid cost recovery calculations for this ramping energy.

Q. Please describe how the ISO proposes to address this.

A. The ISO proposes to address this by using the same bid price in the bid cost recovery calculations for the ramping energy produced while a resource is ramping up to or down from an exceptional dispatch as the bid price used to settle the exceptional dispatch energy. This will make the bid costs it uses in a resource's bid cost recovery calculations for the ramping energy be based on the same bid price used to settle the exceptional dispatch energy.

Q. Please describe the rule change the ISO proposes related to a resource's failure to shut down when the real-time market dispatches it to shut down.

A. The ISO proposes that a resource not be eligible for bid cost recovery of minimum load costs from the effective time of a binding shutdown instruction until the resource's maximum minimum down time, as registered with the ISO, has expired. Otherwise, a resource could potentially ignore a real-time market shutdown instruction and still be eligible for bid cost recovery payments for its minimum load costs. This circumstance may not be mitigated by the persistent deviation metric because the real-time market will stop attempting to dispatch the resource from its minimum load to an "off" state once the dispatch interval is later than any future market schedule the resource has minus its minimum down time.

Q. Please describe how a generator could position itself to avoid a shutdown instruction and how this could enhance bid cost recovery?

A. The real-time market's real-time unit commitment process that starts-up and shuts down resources only issues binding shutdown instructions if the resource can ramp down to its minimum load within the upcoming 15-minute pre-dispatch interval. Consequently, a resource could potentially deviate in an upward direction from its real-time market dispatch instructions enough so that it cannot ramp down to its minimum load in the upcoming 15-minute interval. In this event, the real-time unit commitment process would be unable to issue the resource a binding shutdown instruction. A resource could potentially have an incentive to do this to obtain bid cost recovery payments for its minimum load costs.

Q. Please describe how the ISO proposes to mitigate the potential for a resource to avoid a shutdown instruction to inflate its bid cost recovery.

A. The ISO proposes a metric that would detect when a resource deviates in an upward direction from its real-time market dispatch instructions enough that the real-time unit commitment process cannot issue a binding shutdown instruction.

In addition to the binding shutdown instructions the real-time unit commitment process issues for the upcoming 15-minute interval, the real-time unit commitment process issues advisory shutdown instructions for the 15-minute intervals further in the future. As long as market conditions remain the same and the resource follows its dispatch instructions, the real-time unit commitment process issues advisory shutdown instructions for future 15-minute intervals and then finally issues a binding shutdown instruction once the resource can ramp to its minimum load in the upcoming 15-minute interval. Once the real-time unit commitment issues an advisory shutdown instruction to a resource, this shutdown metric would measure a resource's cumulative upward deviation from dispatch. The shutdown metric will indicate a resource has deviated from its real-time market dispatch enough to avoid a shutdown in the event the resource's dispatched output level minus the cumulative MW of deviation from dispatch measured by the shutdown metric exceeds the resource's minimum load. In this event, the ISO proposes not to pay a resource bid cost recovery for minimum load costs until after it shuts down and it is restarted by the market.

V. <u>Issues related to the Settlement of Residual Imbalance Energy</u>

Q. Describe the changes the ISO is proposing to its settlement of residual imbalance energy.

A. The ISO proposes to return to settling residual imbalance energy at the reference hour bid price. The ISO's intended its current settlement of residual imbalance energy based on a resource's default energy, which as implemented in August 2012, to be an interim mitigation measure until it could implement the mitigation measures described in this filing. As I will describe below, these mitigation measures should mitigate the potential for a resource to inflate residual imbalance energy payments.

Q. Has the ISO identified adverse market incentives that must be addressed if residual imbalance energy is settled based on the reference hour bid?

A. Yes, as I described earlier in this testimony and in my in my testimony submitted as part of the ISO's August 28, 2012, filing in FERC Docket ER12-2539, in which the ISO proposed, in which it first identified the possibility that a resource could persistently deviate from its real-time market dispatch instruction to inflate its residual imbalance energy.

Another way a resource could potentially inflate residual imbalance energy payments is through an adverse strategic bidding strategy involving submission of differently priced energy bids to the real-time market for in adjacent hours. I will describe this strategy and how the ISO proposes to mitigate the potential for a resource to use it to inflate residual imbalance energy settlement later in this testimony.

Q. Are there other changes the ISO is proposing to the settlement of residual imbalance energy?

A. Yes, this filing also proposes changes to align the settlement of residual imbalance energy when a resource is ramping up to or down from a temporary increase to its minimum load that is reported through the ISO's outage reporting system or ramping up to or down from an exceptional dispatch. I describe these proposed changes in more detail later in this testimony.

Q. Please describe how the ISO now proposes to mitigate the potential for resources to inflate residual imbalance energy settlements by persistently deviating from dispatch.

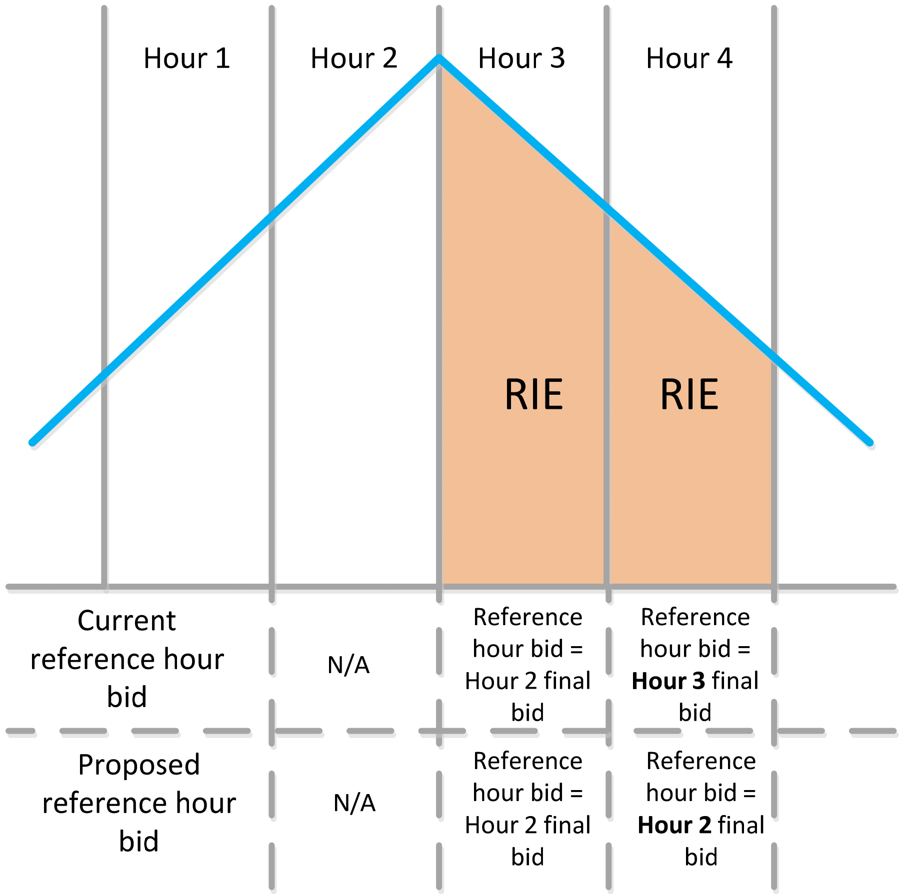
A. As described earlier in this testimony, the ISO proposes to mitigate this by applying the proposed persistent deviation metric to residual imbalance energy settlement. As I also described earlier, in the event a resource exceeds the persistent deviation metric evaluation criteria, the ISO proposes ISO to settle residual imbalance incremental energy at a mitigated price.

Q. Please describe how a resource could inflate residual imbalance energy settlement using an adverse strategic bidding strategy consisting of submitting different priced bids to the real-time market for adjacent hours.

A. The strategy consists of a resource (1) submitting low-priced energy bids so the real-time market dispatches the resource to a high output level, and (2) subsequently submitting high-priced energy bids for the following hours. This will result in some of the resource's residual imbalance energy would be settled at the high bid price. This strategy is not currently possible under the current residual imbalance energy settlement provisions, because residual imbalance energy is currently settled based on a resource's default energy bid, but could become possible under the residual imbalance energy settlement provisions proposed in this filing without the mitigation measure I describe below.

This strategy would exploit the ISO's current rule for determining the reference hour bid that is the basis for residual imbalance energy settlement. Figure 20 illustrates the situation that would enable this strategy along with the ISO's proposed mitigation measure. The ISO currently defines the reference hour bid as the resource's energy bid for the immediately prior hour when a resource is ramping down from a dispatched incremental bid (or up from a dispatched decremental bid). As shown by Figure 20, under "Current payment," the reference bid for hour 4 is currently the bid submitted for hour 3, and the reference bid for hour 3 is currently the bid submitted for hour 2.

Figure 20. Proposed Change to Reference Hour Bid



Using the example shown in Figure 20, a resource employing this strategy would submit low-priced bids for hour 1 and hour 2. As Figure 20 illustrates, this would likely cause the real-time market to ramp the resource up to a high output level. The resource would submit high-priced bids, *e.g.*, $1,000/MWh, for hours 3 and 4. The real-time market would then likely ramp the resource down because these bids would likely be uneconomic. In the event the resource has a slow enough ramp rate, it make take more than one hour for the resource to ramp down to its minimum load, as shown in the example in Figure 20. Consequently, the resource will receive residual imbalance energy payments at the high bid price after the first hour when the resource is ramping down. In the example shown in Figure 20, the resource would receive whatever high-bid price it submitted for hour 3 as its residual imbalance energy payment for hour 4.

Q. How does the ISO propose to address this issue?

A. This ISO proposes to eliminate the potential for this strategy by defining the reference hour bid as the bid that was originally dispatched that led to the ramping energy. As illustrated in Figure 20 under "Proposed payment," this would define the bid submitted for hour 2 as the reference hour bid for hour 3 and for hour 4. This eliminates the potential for this strategy because ISO will settle the residual imbalance energy in the hours the resource is ramping down, hour 3 and hour 4, at the low price of the bid for hour 2, which originally led to the real-time market dispatching the resource up to a high output level. This change is also consistent with the original intent of the design of residual imbalance energy settlement, which was to settle residual imbalance energy at the bid price of the energy that was dispatched that led to the residual imbalance energy.

Q. Does the ISO propose changes to residual imbalance energy settlement for periods when a resource is ramping up to or down

from a temporary increase to its minimum load that is reported through the ISO's outage reporting system?

A. Yes. Similar to the changes the ISO is proposing for optimal energy produced while ramping up to or down from the rerated minimum load, the ISO proposes to settle residual imbalance energy resulting from a rerated minimum load at the locational marginal price. This change will result in all ramping energy resulting from a rerated minimum load being settled on the same basis, the locational marginal price, as energy resulting from the rerated minimum load itself.

Q. Thank you. I have no further questions.

DECLARATION OF WITNESS

I, Bradford Cooper, declare under penalty of perjury that the statements contained in the foregoing Testimony of Bradford Cooper on behalf of the California Independent System Operator Corporation in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this 25th day of September, 2013.

/s/ Bradford Cooper
Bradford Cooper