California ISO
Shaping a Renewed Future

October 7, 2011

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

Re: California Independent System Operator Corporation
Docket No. ER11-____- 000

Amendments to California ISO FERC Electric Tariff to Implement the Flexible Ramping Constraint and Provide Related Compensation

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act,[1] and Part 35 of the Federal Energy Regulatory Commission's (FERC or the Commission) regulations, 18 C.F.R. Part 35, and in compliance with Order No. 714 regarding electronic filing of tariff submittals,[2] the California Independent System Operator Corporation (CAISO) hereby submits for filing the attached amendments to its Fifth Replacement FERC Electric Tariff. The CAISO is filing these amendments to enable the CAISO to implement the flexible ramping constraint in its real-time market processes and to provide just and reasonable compensation to resources that resolve the flexible ramping constraint.

The CAISO respectfully requests an effective date of December 13, 2011, for the proposed tariff sheets and a Commission order by December 8, 2011, to provide sufficient time to consider any implications of the Commission's order in time for implementation on December 13th.

I. BACKGROUND

A. The CAISO Energy and Ancillary Services Market Structure

The CAISO runs a series of energy and ancillary services markets to establish energy schedules and dispatches and ancillary services awards necessary to serve

1 16 U.S.C. § 824d.

2 *Electronic Tariff Filings*, Order No. 714, FERC Stats. & Regs. ¶ 31,276 (2008).

load efficiently and reliably. This includes a day-ahead market, consisting of the integrated forward market and the residual unit commitment process. The CAISO procures sufficient energy and ancillary services in the integrated forward market to meet bid-in demand. In the residual unit commitment process the CAISO procures additional capacity to meet forecasted CAISO demand.

In the real-time, the CAISO runs an additional scheduling and dispatch runs to make any adjustments necessary from the day-ahead market results based on forecasted demand. In the hour-ahead scheduling process, the CAISO clears and schedules energy imports and exports, and ancillary services imports, which is necessary because the Western interconnection outside of the CAISO is operated largely based on hourly transmission schedules. Subsequently, the CAISO conducts a short-term unit commitment process through which the CAISO commits resources that require two to five hours to start, and a real-time unit commitment process that runs every fifteen minutes to procure additional real-time ancillary services and commit additional units. Finally, the CAISO conducts a five-minute real-time market through which it ensures adequate resources are dispatched to meet its forecast of demand. The real-time dispatch is primarily run as the real-time economic dispatch, but can also be conducted as a real-time contingency run through which the CAISO can dispatch energy from operating reserves designated as contingency only, or as the real-time manual dispatch.

Through its markets, the CAISO procures four types of ancillary services: regulation up and down and spinning and non-spinning operating reserves. The CAISO day-ahead and real-time markets co-optimize the procurement of energy and ancillary services.

B. Causes of Insufficient Ramping Capability in the Five-Minute Real-Time Dispatch

The CAISO has observed that in certain situations operating reserves and regulation service procured in the real-time market combined with the units awarded energy in the fifteen-minute real-time unit commitment process do not provide the CAISO sufficient ramping capability and flexibility to meet conditions in the five-minute real-time dispatch interval. This lack of ramping capability is a result of how the real-time unit commitment and the real-time dispatch optimize resources. The real-time unit commitment optimizes resources to meet a single imbalance energy forecast amount for the fifteen-minute interval by committing or de-committing resources sufficient to meet that forecast. This optimization process assumes a perfect load forecast, generation resources acting in accordance with their dispatch, and constant conditions over the interval. The conditions assumed in the forecast, however, often do not materialize as forecasted. This can occur for reasons such as: resources shutting down without sufficient notice; variable energy resources delivering more or less than forecast, including sudden changes in expected deliveries; contingency events; high hydro run-off decreasing resource flexibility; interties tagging and delivering less than awarded in hour-ahead scheduling process; and interchange ramp in and out between hours.

In cases where there are changes between the forecast assumptions of real-time unit commitment and the actual conditions during real-time dispatch, the CAISO may not have sufficient ramping capability to meet its needs. This is because there are times when real-time unit commitment optimizes resources so efficiently based on the forecast that there is little or no additional on-line and available unscheduled capacity for five-minute dispatch to meet any variation from the forecast assumed in real-time unit commitment.[3] In addition, real-time unit commitment dispatches units to meet the average imbalance energy needs for each 15 minute interval but not necessarily sufficient to meet the imbalance energy needs for every 5 minute interval within the 15 minute interval. This issue is more prominent when the load is increasing in the morning and evening ramps, as these are times when there is greater intra-interval variation within a 15-minute real-time unit commitment interval.

Operating reserves procured by the CAISO are designated by suppliers as either contingent or non-contingent. Contingent reserves can only be dispatched when contingency conditions occur, such as an unplanned outage, transmission contingency event, or an imminent or actual system emergency. Non-contingent reserves can be dispatched in real-time to meet imbalance energy needs assuming we have sufficient contingency reserves. In addition, operating reserves are procured to meet minimum requirements to cover a contingency event. Only to the extent the extra reserve is necessary for a contingency can the CAISO use the reserves. This limits the available ramping capability available from the operating reserves.

C. The Consequences of Insufficient Ramping Capability

As a result of the limitations discussed above, the CAISO lacks sufficient ramping capability and operational flexibility. Combined with the uncertain magnitude of differences between expected conditions in real-time unit commitment and real-time dispatch these limitations result in both operational and market impacts. During conditions of real-time imbalance flexibility shortages, the CAISO will automatically begin leaning on regulation capacity and available operating reserves that have not been flagged for use only in case of a contingency. The CAISO's next available options are either to begin leaning on other balancing authority areas in the interconnection or be forced to dispatch and potentially deplete its operating reserves. If this leaning becomes excessive or the CAISO is not able to maintain its operating reserves, the CAISO could jeopardize its ability to meet NERC operating criteria and could incur penalties. In the most extreme circumstances, imbalance shortages can result in the

[3] In some circumstances, the real-time unit commitment optimizes such that enough units are committed at a level sufficiently below their maximum operating levels and sufficiently above their minimum operating levels that the ISO has sufficient ramping capability. In the current design of the market software, such a beneficial result is unplanned and beyond the ISO's control.

CAISO being forced to consider firm load curtailment and be subject to reliability compliance actions from WECC/NERC.

D. Steps the CAISO Has Already Taken to Reduce Variations between Real-time unit commitment and Real-Time Dispatch

The CAISO has already implemented several measures to reduce the uncertainty of imbalance conditions expected between hour-ahead scheduling process and the real-time dispatch. These measures include: 1) improving consistency between the HASP and real-time dispatch forecasts; 2) accounting for hourly intertie ramp when scheduling hourly intertie energy in HASP; 3) improving the real-time load forecasting tools; and 4) providing improved guidance to the operators regarding HASP and real-time load adjustment practices. Although these measures have yielded improvements, they have not provided the CAISO sufficient operational flexibility to meet the variability and uncertainty of real-time imbalance conditions.

II. DISCUSSION OF FILING

A. Description of the Flexible Ramping Constraint

To address the CAISO's continued periods of insufficient ramping capability and operational flexibility, the CAISO proposes to implement a new flexible ramping constraint in the market optimization in all the real-time pre-dispatch runs, which include the hour-ahead scheduling process, the real-time unit commitment process, and the short-term unit commitment process, and real-time economic dispatch run as part of the real-time dispatch process. Under the flexible ramping constraint, unit commitment and dispatch will ensure the availability of a pre-specified quantity of upward-ramping capability requirement in hour-ahead scheduling process, short-term unit commitment process, real-time unit commitment and real-time dispatch. The flexible dispatch capability constrained to be available as a result of this constraint in hour-ahead scheduling process, short-term unit commitment, and real-time unit commitment will be provided by committed flexible resources not designated to provide regulation or contingency reserves (spinning and non-spinning reserves) and whose upward capacity is not committed for load forecast needs.[4] This capacity will then be available for five-minute dispatch instructions from the real-time dispatch, and if dispatched above minimum load will be eligible to set real-time locational marginal prices subject to other eligibility provisions established in the CAISO tariff section 34.19.2.3. Enforcement of this constraint is designed to ensure that sufficient upward capability of dispatchable resources is committed to enable the real-time dispatch to follow load reliably and efficiently over an estimated range of potential variability of net load around the load forecast. By providing the CAISO greater dispatch flexibility, this constraint should significantly alleviate the above-described reliability and operational issues observed in the CAISO's operation of the grid.

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[4] This constraint will only apply to internal generation resources and proxy demand response resources and does not apply to static or dynamic import or exports in the ISO's market.

While the flexible ramping constraint can also be enforced to ensure sufficient downward ramping capability of dispatchable resources, the CAISO plans to only implement the constraint to ensure sufficient upward ramping capability at this time. Maintaining sufficient upward ramping capability more directly resolves reliability concerns. Furthermore, a downward ramping constraints, if not designed properly could actually exacerbate over-generation conditions because it may result in loading resources to higher levels only to dispatch them down later when the system needs downward ramping capability. However, this creates greater possibility for over-generation in the first instance. In addition, the CAISO has determined that other market based measures such as lowering the bid floor are more appropriate to address the over-generation concerns. The CAISO is pursuing these changes in another stakeholder process, which is about to complete and will be the subject of a subsequent filing with the Commission. For these reasons, the CAISO does not seek to enforce a downward ramping constraint at this time.

B. Determination of Flexible Ramping Constraint Quantities

The quantity of the flexible dispatch capability will be determined by operators using tools that will estimate the: 1) expected level of imbalance variability; 2) uncertainty due to forecast error; and 3) differences between the hourly, 15 minute average and actual 5 minute load levels. The expected level of historical imbalance variability will consider the statistical pattern of supply variation including expected variation due to scheduled changes in interchange ramp. Uncertainty due to forecast error will also factor in the historical differences between the hour ahead forecast level and the actual load. To ensure transparency, the CAISO will publish the quantity of upward needs used in the constraint for each relevant market process (*i.e.*, real-time unit commitment and real-time dispatch).

The CAISO may enforce the constraint in the hour-ahead scheduling process, the real-time unit commitment, the short-term unit commitment or the real-time economic dispatch. The constraint will select dispatch capacity that is deemed to be flexible as constrained capacity to be available as a result of the flexible ramping constraint in run. Any such capacity will not be selected from capacity that is designated to provide regulation or operating reserves, and will not offset the required procurement of those regulation or operating reserves in the real-time unit commitment. In the real-time dispatch the resources that resolve the flexible ramping constraint in the corresponding real-time unit commitment run will be the only resources used to resolve the flexible ramping constraint enforced in the real-time economic dispatch.

The flexible ramping constraint can only be satisfied by dispatchable generating units and proxy demand response resources that are on-line and committed with ramping capability for which a scheduling coordinator has submitted economic bids for energy for the applicable trading hour. This constraint cannot be satisfied by resources external to the CAISO system, known as system resources. The quantity of the flexible ramping capacity for each applicable CAISO market run will be determined by CAISO operators using tools that estimate the: 1) expected level of imbalance variability; 2) uncertainty due to forecast error; and 3) differences between the hourly, fifteen (15) minute average and historical five (5) minute demand levels.

Consistent with these terms, the CAISO proposes to add to its tariff a description of the proposed Flexible Ramping Constraint as a defined term in Appendix A and a new section 27.10 that describes the conditions under which the constraint will be enforced and what resources can actually satisfy the constraint.

C. Compensation for Resources Resolving the Flexible Ramping Constraint

The enforcement of the flexible ramping constraint in the real-time unit commitment can give rise to opportunity costs for resources that are committed to resolve the flexible ramping constraint. Specifically, if a resource is not awarded incremental ancillary services or energy in real-time unit commitment because its capacity is being held back to meet the flexible ramping constraint, then it foregoes the revenue from those incremental awards. The CAISO proposes to compensate all resources that are identified as having resolved the applicable flexible ramping constraint at the shadow price of the constraint for the applicable interval. The flexible ramping constraint shadow price is the marginal unit's resource specific opportunity cost. Thus, all units resolving the constraint will be paid at the opportunity cost of the marginal unit. The CAISO further proposes that the costs of the flexible ramping constraint be allocated to measured demand, which consists of metered load and exports.

The specific calculation of a resource's opportunity costs will be measured through the shadow price of the constraint. In real-time unit commitment (including the hour-ahead scheduling process), incremental ancillary services are awarded for the first 15-minute interval and the awarded ancillary services are settled at the ancillary service marginal price from the first 15-minute interval in the horizon.

All remaining intervals are advisory for ancillary services and may become binding in subsequent 15-minute real-time unit commitment runs. Real-time unit commitment also commits or de-commits resources to meet forecasted load, but this does not result in binding energy settlement. Therefore, an opportunity cost can arise in real-time unit commitment if a resource was not awarded ancillary services in the binding 15 minute interval in order to reserve capability in any interval across the real-time unit commitment horizon. The resource specific opportunity cost attributed to ancillary services can be calculated as the difference between the ancillary service marginal price and the resource's ancillary services bid price.

As an example, assume the spinning reserves 15-minute ancillary service marginal price were $5.00. If a resource had a $3.00 bid for spinning reserves, but was not awarded incremental spinning reserves in order to resolve the flexible ramping constraint over the horizon, then the resource incurred an opportunity cost of $2.00.

However, if the resource had a $7.00 bid for spinning reserves, even though the upward ramping capability of the resource resolved the flexible ramping constraint over the horizon, the resource did not incur an opportunity cost because the resource would not have been awarded incremental spinning reserves due to its bid price.[5] This example illustrates that an opportunity cost only arises when awards are financially binding. However, since the market co-optimizes energy and ancillary services across the horizon, the implementation of a pure opportunity cost compensation mechanism cannot be easily implemented.

Since the CAISO co-optimizes for ancillary services and energy in the real-time unit commitment and real-time dispatch processes, it is difficult to decompose the shadow price to only the ancillary services portion which is financially binding in real-time unit commitment. Therefore, CAISO proposes to compensate resources at the flexible ramping shadow price when the constraint is binding in the first interval. The flexible ramping shadow price is the resource specific cost of the marginal unit that resolves the constraint. Moreover, since real-time unit commitment co-optimizes ancillary services and energy across the entire horizon, the shadow price will be based on the ancillary services opportunity cost and reductions in energy committed, even though the energy price is not binding for settlement purposes. This will fully compensate generating units for any ancillary-services opportunity cost incurred due to the flexible ramping constraint.

All resources providing capacity to meet the flexible ramping constraint will be compensated based on the product of the ramping MW quantity of capacity that the resource has been awarded and the flexible ramping constraint shadow price. All resources used to meet the flexible ramping constraint will be compensated even if a specific resource does not have a resource specific opportunity cost. This is because the shadow price reflects the marginal unit's opportunity cost, similar to how the locational marginal price for energy is based upon the marginal unit and not an individual resource's energy bid.

Under the CAISO's proposal, compensation and procurement of flexible ramping capacity will only occur in the real-time unit commitment, not the real-time dispatch. The management of the flexible ramping constraint in real-time dispatch allows the CAISO to manage ramping capacity provided for in real-time unit commitment due to changes between the 15 minute real-time unit commitment run and the 5 minute real-time dispatch run. The flexible ramping capacity requirement will not increase but may decrease from the real-time unit commitment requirement depending on the interval in the real-time dispatch horizon. In addition, the resources that participate in resolving the flexible ramping constraint in the real-time dispatch will only come from the resources which resolved the constraint in real-time unit commitment. Therefore, no opportunity cost can arise for resources in real-time dispatch which were not previously compensated through the real-time unit commitment shadow price. Because real-time

[5] A key assumption in this example is that the bid price represents the price at which the resource is indifferent to being awarded a specific ancillary service (in this example, spinning reserve).

unit commitment is the clear market where opportunity cost exists due to interplay with other services, the CAISO thus proposes only to compensate for flexible ramping in real-time unit commitment and not real-time dispatch.

The CAISO recognizes that it is difficult to evaluate fully at this time the incremental costs associated with the enforcement of the flexible ramping constraint as whether the constraint ultimately binds will be determined by a number of operational, economic and environmental conditions present at the time the market is optimized. During market simulations of the constraint, the CAISO did observe the shadow prices. However, these results could not be relied on for determining the potential costs because the results depend heavily on actual conditions at the time the constraint is enforced. In its opinion, the CAISO's Market Surveillance Committee (MSC) supported the enforcement of the constraint but cautioned against the potential for the cost of enforcing the constraint exceeding the benefits.[6] The MSC recommended that the CAISO retain the ability to make adjustments of the parameters used in implementing the flexible ramping constraint in order to strike an appropriate balance between the risk of too little flexible ramping capability and the excessive payments that may occur if much more than is needed is acquired. The CAISO agrees that it is necessary to observe and evaluate the performance and costs associated with the constraint. For this reason, the CAISO is committed to providing regular reports to market participants regarding the performance and costs associated with enforcing the constraint as reflected through the shadow price based payments described above. If ordered by the Commission, the CAISO agrees to file such reports with the Commission and an explanation taken to balance the competing interests.

Consistent with these terms, the CAISO proposes to add new section 11.25 in the CAISO tariff to reflect the compensation for resources that are indentified as contributing to relieving the Flexible Ramping Constraint.

III. DESCRIPTION OF STAKEHOLDER PROCESS

The stakeholder process commenced on June 24, 2011 with publication of the CAISO's combined issue paper and straw proposal.[7] This was followed by publication of the draft final proposal on July 20, 2011 and approval of the proposal by the CAISO's Board of Governors on August 25, 2011. Throughout this process, the CAISO has observed broad agreement by stakeholders that the CAISO has an operational need for the flexible ramping constraint to ensure sufficient resources are available for dispatch to meet fluctuations in real-time conditions. While the CAISO believes that its proposal

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[6] http://www.caiso.com/Documents/FinalOpinion_Payment_Provision_FlexibleRamping.pdf

[7] More information on the ISO's stakeholder process is available at: http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingConstraint.aspx.

has overall stakeholder support, some stakeholders have objected to certain aspects of the CAISO's proposal.[8]

A. Applying the Flexible Ramping Constraint in the Residual Unit Commitment Process is Unnecessary

In the initial issue paper/straw proposal, the CAISO proposed to implement the flexible ramping constraint in the market optimization for the residual unit commitment process conducted in the day-ahead market. Some stakeholders questioned the need to include the constraint in residual unit commitment given that the primary objective of the flexible ramping constraint is to ensure sufficient flexibility between real-time unit commitment and real-time dispatch. The CAISO agreed that enforcing the flexible ramping constraint in residual unit commitment reserves ramping capacity too early in the market process and does not provide enough of the flexibility needed to resolve the problems that are the impetus for the instant filing. Accordingly, the CAISO's draft final proposal proposed to limit application of the constraint to real-time unit commitment and real-time dispatch. Aside from this change, there were no material changes made between the issue paper/straw proposal and the draft final proposal.

B. Procuring Additional Non-Contingent Spinning Reserves Does Not Adequately Address the Ramping Concerns

Several stakeholders highlighted that the upward ramping operational need could be met by non-contingent spinning reserves the CAISO already procures. These stakeholders suggest that the CAISO could procure additional spinning reserves, which would be compensated at the spinning reserve price. The CAISO understands this viewpoint but believes that pursuing this option is not likely to be as effective in the CAISO's current market system. The CAISO does not have separate requirements for non-contingent and contingency-only spinning reserves. The CAISO market instead identifies only a single operating reserve requirement for each procurement interval, which can be met by any combination of contingency-only and non-contingent reserves. Also, the designation of spinning reserves as being non-contingent and contingency-only is based on the market participant's election. Since the market optimization would have no control over how much non-contingent reserve is procured, simply increasing the operating reserve requirement would not necessarily result in procuring the necessary additional quantities of non-contingent spinning reserves (as opposed to contingency-only spinning reserves) to meet ramping needs.

The CAISO acknowledges that the CAISO could address this concern by modifying the market software to procure non-contingent spinning reserve as a separate market product. This constraint, if binding, would result in price divergence between non-contingent and contingent-only spinning reserves and would look very much like

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[8] A matrix of stakeholder comments and ISO responses is available at: http://www.caiso.com/Documents/110825DecisiononFlexibleRampingConstraintCompensation-StakeholderMatrix.pdf.

two separate products. Creating new market products is beyond the scope of current proposal and not feasible within the time frame that the CAISO needs to address the need for greater flexibility by making greater use of the flexible capacity already bid into the market. The intent of the flexible ramping constraint is to meet operational needs in the immediate term.

C. Cost Allocation to Measured Demand

Several stakeholders question the allocation of costs to measured demand, arguing that such allocation does not follow cost causation principles. The CAISO's proposal to allocate costs of flexible ramping constraint compensation to measured demand aligns with the existing allocation of ancillary services. For this reason, the CAISO believes its approach is justified based on principles in its current market design. Furthermore, allocating costs to measured demand provides a more administrable process and simplifies implementation of the flexible ramping constraint and its associated compensation mechanism.

D. The Flexible Ramping Constraint as an Interim Solution

Some stakeholders, as well as the CAISO's MSC,[9] expressed support for this proposal conditioned on it being a temporary solution. This view is driven by the notion that the use of a modeling constraint to provide ramping capability, combined with indirect compensation and the costs of that compensation borne completely by load is less desirable than creating a new market product with bid-based pricing. In response to this viewpoint, the CAISO notes that the Renewable Integration Market and Product Review Phase 2 stakeholder initiative[10] is addressing the creating of a new ramping product, along with general approaches to allocating renewable integration costs. Additionally, when the CAISO's Board of Governors approved the flexible ramping constraint proposal it specifically required "Management to report back by February of 2012 on progress towards a longer-term solution, including a proposed target implementation date."[11]

IV. EFFECTIVE DATES

The CAISO respectfully requests that the tariff amendments, contained in the instant filing, be approved as of December 13, 2011.

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9 The Market Surveillance Committee's option is available at: http://www.caiso.com/Documents/110825DecisiononFlexibleRampingConstraintCompensation-MSCOpinion.pdf.

10 Renewables Integration Market Vision & Roadmap Day-of Market, Initial Straw Proposal, at 18-20 (Jul. 6, 2011) (discussing the potential for a new ancillary service called Real Time Imbalance Service).

11 The requirement to provide a progress report by February 2012 is stated in the Board of Governors' motion approving the proposal. The motion is available at: http://www.caiso.com/Documents/110825DecisiononFlexibleRampingConstraintCompensation-Motion.pdf.

V. COMMUNICATIONS

Communications regarding this filing should be addressed to the following individuals. The individuals identified with an asterisk are the persons 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 CAISO 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 CAISO Tariff. In addition, the CAISO is posting this transmittal letter and all attachments on the CAISO website.

VII. ATTACHMENTS

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

Attachment A Revised CAISO Tariff Sheets – Clean

Attachment B Revised CAISO Tariff Sheets – Blackline

Attachment C California ISO Board of Governors Memo – "Decision on Flexible Ramping Constraint Compensation"

Attachment D Market Surveillance Committee Final Opinion

VIII. CONCLUSION

For the foregoing reasons, the CAISO 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,

By: */s/ Anna A. McKenna*

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California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

Flexible-Ramping Constraint Compensation Amendment

Attachment A – Clean Tariff

October 7, 2011

11.25 Flexible Ramping Constraint Compensation

All resources identified as resolving the Flexible Ramping Constraint in the binding RTUC interval are awarded Flexible Ramping Constraint capacity and will be compensated for such capacity based on the Flexible Ramping Constraint Shadow Price. The Shadow Price of the binding Flexible Ramping Constraint represents the reduction of the total Energy and Ancillary Services procurement cost associated with a marginal change of that constraint. The Shadow Price is zero (0) if the Flexible Ramping Constraint is not binding. The compensation will equal the product of the upward ramping MW quantity of Flexible Ramping Constraint capacity the specific resource is awarded and the Shadow Price of the binding Flexible Ramping Constraint for the applicable interval. All costs associated with payments made pursuant to this Section 11.25 are allocated to all Scheduling Coordinators pursuant to their Measured Demand.

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27.10 Flexible Ramping Constraint

The CAISO may enforce a Flexible Ramping Constraint in the HASP, RTUC, STUC, and RTED. Any flexible Dispatch capacity constrained to be available as a result of the Flexible Ramping Constraint in RTUC will come from capacity that is not designated to provide Regulation or Operating Reserves, and will not offset the required procurement of those Regulation or Operating Reserves in RTUC. To the extent a resource incurs an opportunity cost for not providing Energy or Ancillary Services in the RTUC interval as a result of a binding Flexible Ramping Constraint, all resources resolving that Flexible Ramping Constraint will be compensated pursuant to Section 11.25. In RTD the resources identified as resolving the Flexible Ramping Constraint in the corresponding RTUC run will be the only resources used to resolve the Flexible Ramping Constraint enforced in RTD. The Flexible Ramping Constraint can be satisfied only by committed online dispatchable Generating Units and Proxy Demand Response resources with ramping capability for which a Scheduling Coordinator has submitted Economic Bids for Energy for the applicable Trading Hour. This constraint cannot be satisfied by System Resources. The quantity of the flexible ramping capacity for each applicable CAISO Market run will be determined by CAISO operators using tools that estimate the: 1) expected level of imbalance variability; 2) uncertainty due to forecast error; and 3) differences between the hourly, fifteen (15) minute average and historical five (5) minute Demand levels.

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Appendix A
Master Definition Supplement

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- Flexible Ramping Constraint

A constraint that may be enforced in the optimization of a given CAISO Market run to ensure that the unit commitment or Dispatch of resources for intervals beyond the applicable commitment or Dispatch period provide for the availability of required capacity for Dispatch in subsequent Real-Time Dispatch intervals as further described in Section 27.10.

* * *

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

Flexible-Ramping Constraint Compensation Amendment

Attachment B - Marked Tariff

October 7, 2011

11.25 Flexible Ramping Constraint Compensation

All resources identified as resolving the Flexible Ramping Constraint in the binding RTUC interval are awarded Flexible Ramping Constraint capacity and will be compensated for such capacity based on the Flexible Ramping Constraint Shadow Price. The Shadow Price of the binding Flexible Ramping Constraint represents the reduction of the total Energy and Ancillary Services procurement cost associated with a marginal change of that constraint. The Shadow Price is zero (0) if the Flexible Ramping Constraint is not binding. The compensation will equal the product of the upward ramping MW quantity of Flexible Ramping Constraint capacity the specific resource is awarded and the Shadow Price of the binding Flexible Ramping Constraint for the applicable interval. All costs associated with payments made pursuant to this Section 11.25 are allocated to all Scheduling Coordinators pursuant to their Measured Demand.

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27.10 Flexible Ramping Constraint

The CAISO may enforce a Flexible Ramping Constraint in the HASP, RTUC, STUC, and RTED. Any flexible Dispatch capacity constrained to be available as a result of the Flexible Ramping Constraint in RTUC will come from capacity that is not designated to provide Regulation or Operating Reserves, and will not offset the required procurement of those Regulation or Operating Reserves in RTUC. To the extent a resource incurs an opportunity cost for not providing Energy or Ancillary Services in the RTUC interval as a result of a binding Flexible Ramping Constraint, all resources resolving that Flexible Ramping Constraint will be compensated pursuant to Section 11.25. In RTD the resources identified as resolving the Flexible Ramping Constraint in the corresponding RTUC run will be the only resources used to resolve the Flexible Ramping Constraint enforced in RTD. The Flexible Ramping Constraint can be satisfied only by committed online dispatchable Generating Units and Proxy Demand Response resources with ramping capability for which a Scheduling Coordinator has submitted Economic Bids for Energy for the applicable Trading Hour. This constraint cannot be satisfied by System Resources. The quantity of the flexible ramping capacity for each applicable CAISO Market run will be determined by CAISO operators using tools that estimate the: 1) expected level of imbalance variability; 2) uncertainty due to forecast error; and 3) differences between the hourly, fifteen (15) minute average and historical five (5) minute Demand levels.

* * *

Appendix A
Master Definition Supplement

* * *

- Flexible Ramping Constraint

A constraint that may be enforced in the optimization of a given CAISO Market run to ensure that the unit commitment or Dispatch of resources for intervals beyond the applicable commitment or Dispatch period provide for the availability of required capacity for Dispatch in subsequent Real-Time Dispatch intervals as further described in Section 27.10.

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California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

Flexible-Ramping Constraint Compensation Amendment

Attachment C – Board of Governors Memorandum

October 7, 2011

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market & Infrastructure Development

Date: August 18, 2011

Re: **Decision on Flexible Ramping Constraint Compensation**

This memorandum requires Board action.

EXECUTIVE SUMMARY

Management proposes to implement a new flexible ramping constraint in the market optimization to address identified reliability and operational issues. The ISO has observed that, in certain situations, reserves and regulation service procured for real-time operations and units committed for energy in the fifteen-minute unit-commitment process lack sufficient ramping capability and flexibility to meet operational needs in the five-minute market interval. This occurs due to changing conditions from the forecast conditions used to commit resources during the prior procurement procedures. To address this issue, the ISO proposes to implement a new constraint in the fifteen-minute real-time unit commitment process and the five-minute real-time dispatch that will ensure sufficient resources are committed to meet five-minute operational needs.

The implementation of this new constraint could result in lost revenues to supply resources that are committed to meet this constraint in lieu of providing ancillary services. To address this issue, Management proposes to compensate resources providing the ramping capacity needed to meet the flexible ramping constraint for any associated opportunity cost. Management further proposes to allocate the costs associated with payment of the opportunity cost to real-time metered load and exports.

Management proposes the following motion:

> ***Moved, that the ISO Board of Governors approves the proposed tariff change regarding the compensation provisions of the flexible ramping constraint, as described in the memorandum dated August 18, 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.***

DISCUSSION AND ANALYSIS

The ISO's real-time procedures are designed to ensure sufficient capacity is committed to allow for efficient and economic load following during each five-minute dispatch interval. A fundamental goal of the ISO is to commit resources through its market and produce awards, commitments, and dispatches that are feasible and sufficient to address a reasonable range of unexpected outcomes. As discussed below, the ISO has observed numerous instances in which awards and commitments are rendered infeasible due to load forecast error, generation variability, and changes in intertie flows. These instances pose reliability concerns. If there is insufficient committed resource flexibility, the ISO may be forced to draw on operating reserves, regulation, or the interconnection through increases in the area control error. To address this issue, the ISO proposes a flexible ramping constraint designed to ensure that sufficient upward ramping capability is available in the five-minute real-time dispatch to follow load efficiently and reliably over an estimated range of potential variability around the load forecast.

Operational Need

The real-time unit-commitment and real-time dispatch processes optimize resources based on a single imbalance energy forecast amount for an operating interval (i.e., a 15-minute or 5-minute period, respectively). The current processes assume a perfect load forecast, generation resources acting in accordance with their dispatch, and constant conditions over the interval. As a result, there are times when the real-time unit-commitment process will optimize resources so efficiently that there is little or no additional on-line and available unscheduled capacity for five-minute dispatch to meet any variation from the assumed conditions in the real-time unit commitment. Changes in the imbalance energy needs for real-time dispatch after real-time unit-commitment runs are frequent and often trigger imbalance shortages. This issue is more prominent when the load is increasing in the morning and evening ramps. Shortages of ramping capability are an existing operational issue that is expected to become more pronounced as additional intermittent renewable resources are integrated into the ISO grid.

When real-time imbalance-energy changes occur and available dispatch ramping capability is exhausted, leaning on regulation or the interconnection, biasing the load or exceptional dispatch are the only tools left for operators to manage the system. If an imbalance shortage persists or is larger than what can be satisfied by available regulation and non-contingent reserves,[1] the ISO may be forced to lean on neighboring balancing authority areas or be forced to dispatch and potentially deplete its operating reserves. This could jeopardize the ISO's ability to meet NERC operating criteria. In the most extreme circumstances, imbalance shortages can result in the ISO being forced to consider firm load curtailment or be subject to reliability compliance actions from WECC and NERC. Therefore, it is necessary to ensure that the ISO has the tools to manage varying and uncertain imbalance conditions to operate the grid consistent with prudent utility practice.

[1] Operating reserves are designated by suppliers as either contingent or non-contingent. Contingent reserves can only be dispatched when contingency conditions occur, such as an unplanned outage, transmission contingency event, or an imminent or actual system emergency. Non-contingent reserves can be dispatched in real-time to meet imbalance energy needs.

Flexible Ramping Constraint

The flexible ramping constraint provides the ISO dispatch flexibility to follow variations in balancing needs efficiently in the event the actual need is higher than forecast. The flexible ramping constraint enforces an ISO-specified quantity of upward-ramping capability requirement in the real-time unit commitment and the real-time dispatch. The flexible-dispatch capability resulting from the flexible-ramping constraint is obtained from capacity that has not been designated to provide regulation or contingency reserves (*i.e.*, spinning or non-spinning reserve). This capacity will then be available for five-minute dispatch instructions from the real-time dispatch, and if dispatched above minimum load will be eligible to set real-time locational marginal prices.

The quantity of the flexible dispatch capability will be determined using a variety of tools. These tools will estimate the expected level of imbalance variability, the uncertainty due to forecast error, and the differences between the hourly, 15-minute average and actual 5-minute load levels. The expected level of historical imbalance variability is determined by considering the statistical pattern of supply variation. Uncertainty due to forecast error also factors into the historical differences between the hour-ahead forecast level and the actual load. The ISO will publish the quantity of upward needs used in the constraint for each relevant market process.

Real-time Unit Commitment Opportunity Cost and Compensation

The ISO procures incremental ancillary service in the real-time unit-commitment process. The awarded ancillary services are settled at the ancillary service marginal price from the first 15-minute interval resulting from the real-time unit-commitment market optimization over the horizon. The flexible ramping constraint can result in an opportunity cost in the real-time unit-commitment process if a resource is not awarded ancillary services in order to reserve sufficient upward ramping capability in any interval across the real-time unit-commitment horizon. The resource-specific opportunity cost attributed to ancillary services is the difference between the ancillary services marginal price and the resource's ancillary services bid price.

For example, assume the spinning reserves ancillary services marginal price was $5.00. If a resource had a $3.00 bid for spinning reserves, but was not awarded incremental spinning reserves in order to resolve the flexible ramping constraint, the resource incurred an opportunity cost of $2.00. However, if the resource had a $7.00 bid for spinning reserves, even though the upward ramping capability of the resource resolved the flexible ramping constraint, the resource did not incur an opportunity cost because the resource would not have been economically awarded incremental spinning reserves due to its bid price. It is reasonable to assume that the bid price represents the price at which the resource is indifferent to being awarded ancillary services. The example above illustrates that an opportunity cost arises only when awards are financially binding. However, since the real-time unit commitment co-optimizes energy and ancillary services across the horizon, the implementation of a pure opportunity cost compensation mechanism cannot be easily implemented.

Since it is difficult to isolate the ancillary services opportunity cost for generating units that are reserved to meet projected ramping needs under the flexible ramping constraint, Management proposes to compensate resources that are providing the flexible ramping capability at a price that represents the marginal value of such capacity, which in optimization terms is referred to as the "shadow price." This will fully compensate generating units for any ancillary-services opportunity cost incurred due to the flexible ramping constraint.

All resources providing capacity to meet the flexible ramping constraint will be compensated based on the product of the ramping MW quantity of capacity that the resource has been awarded and the flexible ramping constraint shadow price. All resources used to meet the flexible ramping constraint will be compensated even if a specific resource does not have a resource specific opportunity cost. This is because the shadow price reflects the marginal unit's opportunity cost, similar to how the locational marginal price for energy is based upon the marginal unit and not an individual resource's energy bid.

Real-time Dispatch Opportunity Cost and Compensation

The enforcement of the flexible ramping constraint in the real-time dispatch process allows the ISO to manage the flexible ramping capacity provided by the real-time unit commitment process due to changes between the 15-minute real-time pre-dispatch run and the 5 minute real-time dispatch run. The resources which resolve the flexible ramping constraint in the real-time dispatch process will only come from the resources used to resolve the constraint in the real-time unit commitment process. Therefore, no opportunity cost can arise for resources in the real-time dispatch process which were not previously compensated through the real-time unit commitment shadow price.

POSITIONS OF THE PARTIES

Stakeholders widely recognize the operational need for the flexible ramping constraint to ensure sufficient resources are available for dispatch to meet fluctuations in real-time conditions. Early in the stakeholder process, Management proposed to also include the flexible ramping constraint in the residual unit commitment process in the day-ahead market. However, based on stakeholder comments, Management agreed to enforce the flexible ramping constraint only in real-time market processes.

Several stakeholders highlighted that the upward ramping operational need could be met by non-contingent spinning reserves the ISO already procures. However, this option is not likely to be as effective because the ISO does not have separate requirements for non-contingent and contingency-only spinning reserves. The ISO market identifies only a single operating reserve requirement for each procurement interval, which can be met by any combination of contingency-only and non-contingent reserves, the designation of which is elected by market participants. Since the market optimization would have no control over how much non-contingent reserve is procured, simply increasing the operating reserve requirement may not result in sufficient non-contingent spinning reserves to meet ramping needs.

The shortcoming identified above could be addressed by modifying the market software to procure non-contingent spinning reserve as a separate market product. However, the intent of the flexible ramping constraint is to meet the operational needs in the more immediate term without creating a new market product. The need for new market products is currently being evaluated in the renewable integration market and product review phase 2 stakeholder initiative.

Several stakeholders question the allocation of costs to measured demand. The proposal to allocate to measured demand aligns with the existing allocation of ancillary services and simplifies implementation of the compensation mechanism. The allocation of renewable integration costs is also being addressed in the renewable integration market and product review phase 2 stakeholder initiative within the broader scope of renewable integration costs. A stakeholder matrix is provided at Attachment A. In addition, the Market Surveillance Committee issued an opinion in support of Management's proposal. The final opinion is provided as Attachment B.

MANAGEMENT RECOMMENDATION

Management respectfully requests Board approval for the implementation and compensation of the flexible ramping constraint as described in this memorandum. The flexible ramping constraint is necessary to ensure sufficient upward ramping capability to reliably manage the grid. Since enforcement of the flexible ramping constraint can result in opportunity costs for resources that resolve the constraint, Management believes it is appropriate to compensate those resources for the opportunity costs incurred due to the implementation of the new constraint.

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

Flexible-Ramping Constraint Compensation Amendment

Attachment D – Market Surveillance Committee Opinion

October 7, 2011

Final Opinion on Payment for Provision of Flexible Ramping

James Bushnell, Member
Scott M. Harvey, Member
Steven Stoft, Member
Benjamin F. Hobbs, Chairman
Market Surveillance Committee of the California ISO

August 16, 2011

1. Introduction

This opinion comments on the ISO's "Opportunity Cost of Flexible Ramping Constraint" proposal ("Flexiramp Proposal").[1] This proposal would implement a new set of constraints in the Real-Time Pre-Dispatch (RTPD) and Real-Time Dispatch (RTD) processes. The goal of these constraints is to reserve unloaded rampable capacity ("flexiramp") to meet ramping needs in the real-time market. The proposal would also provide for payments to reserved capacity based on calculated marginal opportunity costs from the RTPD market. The proposal is meant to be an interim measure, to be superseded by a ramp-related product to be defined as part of the ISO's Renewable Integration Market & Product Review, Phase 2 ("Renewable Integration Review").[2]

In preparing this opinion, we benefited from interaction with ISO staff and from the written comments made by stakeholders and the questions and concerns raised in the public calls on the proposal.

We support the proposal as a strictly interim measure to increase the supply of upward ramp in the real-time market, pending market reforms resulting from the Renewable Integration Review that better address the fundamental issues.

We have assessed the proposal against seven criteria that we propose for evaluating such interim market proposals. First, we anticipate that the proposal will generally be effective in committing more rampable capacity in real time in the RTPD, and that this flexiramp will be useful to the market. The ISO has performed market simulations of the flexiramp proposal that provide some indication of the likely cost and impact on the real-time availability of ramp. We have not have the opportunity to study these results, but have been informed by ISO staff that the simulations indicate that more ramping capability will result. Some adjustment of parameters used in implementing the flexiramp constraint in RTPD and RTD may be necessary in order to strike an appropriate balance between the risk of too little flexiramp and the excessive payments that may occur if much more than is needed is acquired. It is also possible that at some point in the future there will be insufficient commitable capacity in real-time to meet the need for flexiramp, and

[1] Draft Final Proposal, July 20, 2011, foliweb7.caiso.com/2bc1/2bc1e2b53ba90.pdf

[2] www.caiso.com/informed/Pages/StakeholderProcesses/RenewablesIntegrationMarketProductReviewPhase2.aspx

the possibility of acquiring flexiramp in the day-ahead market will need to be revised. Finally, flexiramp is to be acquired on a system-wide basis; therefore, the ISO will need to monitor where flexiramp is acquired to determine whether it is being obtained in, for instance, generation pockets where it cannot be accessed if needed due to transmission constraints.

Second, we are satisfied that the proposal is reversible. It does not tie the ISO's hands concerning development in the Renewable Integration Review of a ramp product that will better address the fundamental issues. Third, the proposal has the advantage of being simple to implement, and the opportunity cost-based settlement price is automatically calculated in RTPD. However, because of complicated interactions of energy, ancillary services, and flexiramp in different intervals, the causes that contribute to the flexiramp price in particular intervals will inevitably less than transparent. This is, however, a generic problem with energy and ancillary services pricing as well. Fourth, interim measures should avoid large shifts in costs, and ISO staff have stated that the market simulations indicate that this will likely not be a problem. If, however, large costs are incurred without corresponding benefit, then the flexiramp feature can be modified or turned off relatively easily.

Fifth, price signals should be efficient, bearing a relationship to the costs incurred in supplying flexiramp, with costs being allocated to responsible parties. In the interests of simplicity of implementation and reversibility, this criterion is somewhat sacrificed, which we believe is justified for an interim measure. We have two main concerns that lead to us to conclude that the settlement method used should not be made a permanent feature of the ISO markets. First of all, it is not clear what level and form of compensation is needed to incent investments in efficient amounts of upward ramp capability, or its short-run provision in the ISO's markets. Second, we believe that in most cases, the opportunity cost-based payment from RTPD is likely to be greater than the actual opportunity costs, as MW capacity that is designated as flexiramp by RTPD will be free to sell energy in the first (binding) interval of RTD (subject to the need to provide flexiramp in later intervals). Thus generators will receive a payment based on RTPD's estimate of opportunity cost, but in most cases actually incur little or no such cost. If flexiramp prices indeed turn out to be very low, as the market simulations indicate they are likely to be, then we believe that their interim nature makes this possible overpayment an acceptable risk in exchange for providing needed upward ramp capacity. We also note that this is also analogous to the situation with payments for non-contingent spinning reserves to the extent that such reserves can be dispatched for energy, and so the proposal has the advantage of treating those reserves and flexiramp in a broadly consistent manner. The issue of efficient and appropriate payment for ramping capability will be addressed, we hope, in the Renewable Integration Review.

Sixth, we see some potential for unexpected consequences. The potential is not great because of the finite life of this interim measure, and its restrictive scope relative to alternatives that would involve creation of a product that would be acquired both day-ahead and in real-time or which requires submission of bids. Further, we have been told that the ISO's market simulations of the flexiramp proposal indicate that flexiramp prices will be low. However, we believe that the inconsistency between how the RTPD process calculates opportunity costs for flexiramp and the likely smaller opportunity costs that will actually be experienced by generators in the RTPD and RTD processes may lead to unexpected changes in bidding behavior. For example, since spinning reserves will be paid for opportunity costs in RTPD based both on energy and flexiramp opportunities, while only energy opportunity costs are considered in the day-ahead market, this may alter day-ahead spin bidding behavior.

The seventh and last criterion is consistency in philosophy with existing market features. This is not achieved by this proposal because flexiramp is treated differently from ancillary services involving bidding and both day-ahead and real-time markets. We believe that this is acceptable for an interim proposal, given the need for simplicity, reversibility, and limited potential for unexpected consequences. We further believe that the Renewable Integration Review is a more appropriate forum for fundamental consideration of the relationship of any ramp product to other products in the market, and the appropriate design of the market.

The remainder of the Opinion is structured as follows. In Section 2, we characterize in general terms the problem that the flexiramp proposal is addressing, and possible fundamental solutions to the problem. Because this is an interim measure that may be greatly changed as a result of the Renewable Integration Review, it is not feasible or desirable to implement a fundamental solution. In Section 3, we summarize several criteria for evaluating interim measures to provide flexiramp, and we assess this proposal against those criteria. Section 4 presents conclusions.

2. Problem Description and Fundamental Solutions

2.1 The Physical Source of the Problem Addressed

Balancing load and generation is difficult because of unexpected events on both sides of the market. The day-ahead market (IFM) relies on a forecast of load that is implicitly assumed to contain no surprises and purchases generation based on an assumption that generators will perform as bid or self-scheduled. But the IFM does not consider only generation capacity when scheduling generation, it also considers the ramping ability of generators. So if the average hourly load is expected to increase by, say, four GW from one hour to the next, the IFM makes sure the committed generators can increase their output by that amount.

The IFM also purchases ancillary services (AS), regulation and operating reserves. The purchase of operating reserves are designed to take account of unexpected events—"contingencies."[3] But "contingencies" evaluated with regard to operating reserves pertain to the availability of enough capacity to meet forecast load, mainly considering the possibilities of generators and lines going out of service due to failures, not to whether there is enough ramping capability to enable generation to meet load in each dispatch interval. As noted in the flexiramp proposal, many other kinds of "non-contingent" events can disrupt the system's balance—eight are listed. These include fluctuations in load and in non-dispatchable supply, such as wind, solar and run-of-river.

Because operating reserves are by-and-large held in reserve for contingencies,[4] no product is specifically procured to cover the eight "non-contingencies," although regulation is used to meet them within 5-minute dispatch intervals. Fortunately, the generators providing energy have ramping capability available to handle non-contingent events adequately under most circums-

[3] Regulation, in contrast, balances supply and demand within five-minute intervals, since dispatch of generation by RTD is unable to do so.

[4] In the Eastern Interconnection, operating reserves are also times also used to meet ACE when there is so much dragging that regulation is unable to do so. Page 5 of the CAISO's flexiramp proposal suggests that the CAISO also uses its operating reserves to balance load and generation when it is ramp constrained or there is such dragging.

tances. However, particularly during the morning ramp, when many generators are at their maximum up-ramp limits, there are regular shortages of the extra ramping capacity needed to handle non-contingencies. Just under 1% of all five minute real-time intervals suffer power balance violations due to inadequate upward ramp capacity in the second quarter of 2011, according to the most recent DMM Quarterly Report.[5] That same report indicates, however, that the system power balance constraint is violated in RTD due to lack of upward ramp in many hours of the day. In the future, this problem is anticipated to get worse and to occur more often outside of the morning ramp period partly because of the increasing penetration of variable renewable energy sources.

2.2 The Consequences of the Problem Addressed

A shortage of ramping capability to handle non-contingencies results in a number of problems. However, mild shortages of rampable capacity in RTD do not endanger reliability as long as either sufficient regulation is available or, if regulation cannot maintain the desired CAISO Area Control Error (ACE), California can import more power. California is well connected to the Western Interconnection (WI) with uncontrollable AC lines. As a result, if the ISO generators provide 100 MW less than its load (including scheduled imports and the response of regulation), an extra 100 MW will flow into the ISO from the WI. This is a matter of physics and it happens instantly. Moreover generation remains equal to load for the entire WI. However, the WI will not be "in balance." Instead that 100 MW shortfall means that there will be a tiny reduction in voltage and frequency throughout the system. This will force a (slightly) undesirable reduction in load, although generation outside the ISO will quickly adjust to rebalance the WI as a whole. The frequency reduction is uniform throughout the WI, but voltage reductions will be more localized to the ISO. The main point here is that a short-term ACE imbalance in the ISO does not directly impose a high cost. No real problem may be noticeable.

However, unscheduled imports from the WI (leaning on the system) are undesirable and so there are NERC rules, limiting ACE, and there are penalties if ACE limits are violated too often by too much. (These rules are designed both to limit ACE and to maintain the frequency of the WI.) So the first cost to the ISO of imbalances comes from ACE-violation penalties.[6] A much less likely, but more dramatic cost is associated with reliability problems. If it happens that the extra imports due to an ISO imbalance overload a tie-line, that overload must be corrected. The choices are then to (1) use up operating reserves, (2) dispatch emergency demand response, or (3) shed load.

[5] CAISO Department of Market Monitoring, Quarterly Report on Market Issues and Performance, August 2011, Figure 1.7 (www.caiso.com/Documents/QuarterlyReport_MarketIssues-Performance-August 2011.pdf) shows that the power balance constraint is relaxed on average in about 1% of the hours, and that these violations are well dispersed (with 12 of the 24 hours equaling or exceeding that 1% frequency). However, regulation may have been used in these instances to bring CAISO supply and demand closer to balance. The CAISO market design sets the energy price at the power balance constraint penalty when it must use regulation to balance load and generation.

[6] Consistent ACE violations with excess imports when the price of power is above average would make the ISO deservedly unpopular in the WI. However this problem could easily be remedied by extra exports in the afternoon when the price is generally higher than in the morning. Even revenue-neutral ACE violations are thought to provoke disapproval in dispatching circles, but this might not by itself provide sufficient reason for spending much ratepayer money.

The first is undesirable and could endanger reliability, the second is costly, and the third is much more costly.

So there are five apparent sources of cost from the present lack of non-contingent operating reserves, use of regulation for imbalances, use of operating reserves, penalties for ACE violations, purchases of emergency demand response, and load shedding. We have not heard that any of the latter three have actually occurred as a result of this problem, perhaps because regulation has been sufficient. However, we understand from ISO staff that high prices have sometimes been paid—generally out of market—for generator performance that prevents the occurrence of these problems. Presumably, those payments are less than the costs that would otherwise be borne if these problems occur, though we have seen no information about either payments or avoided costs. Assuming the payments are reasonable, then flexiramp can be partially evaluated by asking if it will reduce total financial costs. Again, we have seen no estimates, but if flexiramp turns out not to be cheaper than other alternatives, it has been designed by the ISO to be easy to turn off—even in real time.

2.3 The Market-Design Sources of Problem Addressed

Unexpected balancing events (non-contingencies) are to be expected. In fact, they are certain to occur, but at unpredictable times. The fact that the market design does not sufficiently account for them now and therefore acquires too little ramping capacity therefore cannot be attributed to their unexpected nature.[7] It appears that there are two main flaws in the present market design that flexiramp is designed to address. Because this market patch is being made under considerable time pressure, flexiramp does not fix either flaw, but instead, implements a compensating measure.

The first market flaw is that non-contingent imbalance events are dealt with only by regulation, and are disregarded by the real-time commitment and dispatch market for energy and operating reserves. As wind penetration increases, using regulation alone will become an increasingly inefficient way of dealing with those imbalance events. That the energy market ignores non-contingent imbalance events is easily explained. Taking them into account explicitly in the market dispatch would require the software to look at not just one possible future—the forecast load—but at a great many possible futures. This sort of stochastic-programming approach, though theoretically ideal and the subject of significant research and development by universities and vendors, is simply out of reach at this time. It is quite possible that even if it could be implemented, it would provide only small savings compared with a heuristic approach similar to what is now used for ancillary services. So the market flaw of using a non-stochastic energy dispatch should likely remain, though a heuristic correction to increase the market's procurement of ramping capability might make sense.

That leaves the flaw in the operating reserves markets. Jumping ahead a bit, we note that flexiramp is simply another way of buying non-contingent reserves, a product that the ISO already purchases in its AS markets. The problem is that the ISO has no control over the amount of non-contingent reserves that it purchases. It simply buys reserves and lets the sellers designate them as contingent or non-contingent. The ISO could buy more reserves, but much or most of these

[7] Regulation is acquired for these contingencies within dispatch intervals.

would likely be contingent reserves, as is now the case. Fixing this flaw is non-trivial (but not particularly difficult) because, if the ISO required a specific quantity of non-contingent reserves, it would need to price them separately as they would at times be a more expensive product than the less-frequently used contingent reserves. This would occur when the contingency reserve requirement is binding, resulting in price separation between contingent and non-contingent reserves.

From an economic perspective, there is little difference between contingencies and non-contingent events that cause sudden imbalance problems. Standard contingencies tend to be quicker and so they require more regulation, but after regulation (and some very temporary leaning on interconnections[8]), both types of surprises are handled the same way by 10-minute spinning and non-spinning reserves.[9] Since the basic approach to AS is well established and largely implemented, it is likely to make more sense in the long run (probably in the Renewable Integration Review) to fix the AS market rather than to invent a new flexiramp market. However, in the short-run, flexiramp is the more practical approach.

2.4 The Flexiramp Design

Flexiramp is described by the proposal as a constraint, but as usual, the constraint simply determines the ISO's demand for the flexiramp product. The capacity providing flexiramp functions, in essence, as a form of non-contingent reserves procured at a different price than standard spin, and at a price that is not set by offers from the generators providing the service.[10] The amount of capacity scheduled to meet this constraint (the demand for flexiramp) is the <u>M</u>inimum online <u>R</u>equired Upward ramping <u>C</u>apability requirement (MRUC).[11] This value will be determined by a simple heuristic formula involving recent ramping needs as modified by the system operator's input.

Flexiramp will be priced in RTPD. Generators providing flexiramp in the first (binding) interval of RTPD will be paid a price equal to the shadow price (or dual variable) of the RTPD flexiramp constraint (MRUC). This shadow price equals the opportunity cost of devoting capacity to provide flexiramp rather than to providing some other product.[12] Bids for flexiramp do not set the

[8] The response to an outage contingency generally involves such leaning in the seconds after a large outage, as allowed by reliability standards. These standards accept that neither the CAISO nor any other balancing authority area would carry enough regulation to cover a large outage by itself.

[9] Another difference is that the loss of a unit results in a persistent loss of capacity that can be replaced by starting a unit, whereas, variations in wind or load can be shorter in duration for which starting a unit with a minimum run time might not be appropriate.

[10] Note, however, that despite the similarity in function, flexiramp is defined as a separate product from noncontingent spin. Capacity designated as flexiramp cannot also be designated as spinning reserve in the same interval.

[11] No downward ramping capacity is being required at this time, although the DMM Quarterly Report on Market Issues and Performance for the second quarter of 2011 (op. cit.) indicates that more intervals suffer power balance relaxations (violations) due to inadequacies in downward ramp capacity than because of inadequate upward ramp capability (see Figs. 1.5 and 1.6 and the accompanying discussion).

[12] For instance, a generator might provide 20 MW of flexiramp in interval 1 of RTPD. If it could instead have provided 20 MW of spin, priced at \$5/MWh and if it had bid \$2/MWh to provide that spin, then it

price of flexiramp, as there are no bids. The RTPD market in essence assumes that all available rampable capacity can be used for flexiramp up to the limits imposed by capacity constraints and ramp constraints; generators cannot otherwise limit the amount of its capacity that can be scheduled in the RTPD process for this purpose.

In each 15-minute real-time pre-dispatch (RTPD), generation will be scheduled to the end of the hour in such a way that MRUC MW of flexiramp would be available in each 5-minute interval if everything went as planned. This is accomplished by dispatching some off-line generators and by backing off some generators that are near or at maximum capacity. Backing off these generators will be costly if other generators need to be dispatched or if more expensive generators need to be ramped up to take up the slack. This cost is the market's opportunity cost of flexiramp, and for intervals in which it is non-zero this opportunity cost will be paid to all MRUC MW of flexiramp that is planned in the RTPD. Of course in the real time dispatch (RTD), some of this flexiramp will not be provided. This is because it may be used to cover non-contingent balancing events and because RTD relaxes some of the requirements for flexiramp relative to RTPD. In particular, no flexiramp is required in the first (binding) 5 minute interval, while reduced amounts (relative to RTPD's MRUC) are acquired in the non-binding intervals immediately after the binding interval.

The provision of flexiramp will in most intervals likely be supported by RTPD committing generation that would otherwise be off-line. After the initial (binding) 5-minute interval in RTD, flexiramp is maintained by RTD by positioning some generators below their maximum output. However the flexiramp constraint is reduced in the first few non-binding 5-minute interval in RTD, as just mentioned. Hence, generators that were projected to incur an opportunity cost of providing flexi-ramp in RTPD have a high likelihood of being dispatched to provide energy in RTD, thereby incurring no opportunity cost. For this reason, and because of thermal generation needs arising from non-contingencies, the actual opportunity cost in RTD will often turn out differently than anticipated in RTDP. The result is that the actual market cost of flexiramp can be quite difficult to predict. However, there can be no doubt that the flexiramp mechanism will procure an increased level of what is, in effect, non-contingent spin that can be used for solving the ramping problems that are currently plaguing the ISO.

The RTPD's process for acquiring flexiramp can be viewed as an interplay of a demand curve for flexiramp with supply. In particular, the MRUC requirement in combination with the penalty price on the flexiramp constraint defines the ISO's demand curve (shown as D-Flexi in Figure 1) for the flexiramp product.

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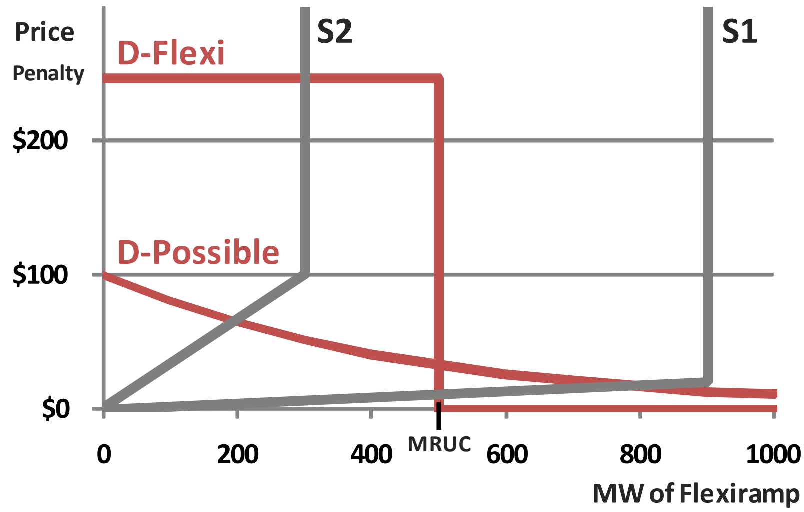
bears a \$3/MWh opportunity cost for providing flexiramp rather than spin. The RTPD optimization will then automatically yield a flexiramp shadow price of at least \$3/MWh. Alternatively, the opportunity cost might instead result from diverting that unit's capacity from profitable energy production, in which case the opportunity cost would be the difference between the energy price and the unit's energy bid. (Note, however, energy is not settled in RTDP, so this is a surrogate for possible opportunity costs in the RTD market where energy is actually sold.) The opportunity cost calculation can become more complicated by intertemporal ramp constraints, which means that the shadow price for flexiramp in interval 1 might be determined by foregone opportunities for AS or energy in later RTPD intervals.

Figure 1. Possible Supply and Demand Curves for Flexiramp



The higher, step-function demand curve, labeled D-Flexi is the demand curve determined by the flexiramp proposal, although MRUC will vary from hour to hour. The lower, smooth demand curve, labeled D-Possible, is one possibility for what an optimal demand curve might look like. (It is possible, of course, that the optimal curve might be higher than D-Flexi for some values of flexiramp to the left of 500 MW; we do not mean to prejudge the marginal value of flexiramp.) In one respect, D-Possible is more reflective of the value of flexiramp than D-Flexi because it is smooth. It is unrealistic to think that MRUC could be worth $247/MWh (its penalty price) when 499 MW is available and $0/MWh when 501 MW is available. Such an on-off demand curves makes sense when complying with a black-and-white regulatory requirement, such as NERC's requirement for operating reserves, but they make little sense (except as operational compromises) when they are meant to reflect the value of a physical hedge against random contingencies. The penalty level of the D-Flexi demand curve is also unlikely to reflect the economic value of flexiramp since it was determined with little regard for the value of flexiramp.

Fortunately, based on reports of the ISO's market simulations of flexiramp, the supply curve for flexiramp seems to be frequently most similar to S1. In other words, flexiramp is anticipated to be usually very inexpensive. In this case the D-Flexi curve will demand too little, but will pay a lower price, often zero, for a fairly generous supply of flexiramp. However if the system runs into conditions under which flexiramp is not cheap, perhaps as shown by supply curve S2, then using the wrong demand curve will likely cause significant over procurement at an uneconomic cost. Since the ISO's reported simulations indicate that a generous supply of flexiramp is currently available, we do not recommend a change in the current design. However, for the ISO's Renewable Integration Market & Product Review, Phase 2 ("Renewable Integration Review"), we suggest that the demand side of the market be seriously considered in a manner consistent with scarcity pricing for other market products.

3. Criteria for Evaluation of an Interim Solution

The fundamental solutions presented above are either impractical in general (as is an explicitly stochastic IFM) or they are practical for consideration in the Renewable Integration Review, but not so for a short-lived interim measure. Thus, if the problem is to be addressed in the interim, a temporary fix would need to be implemented. We suggest the following general criteria for evaluating such temporary market changes:

1. Cost effectiveness (economic efficiency) in addressing the problem.
2. Reversible, so as to avoid constraining the ISO from implementing a fundamentally different approach as a result of the Renewable Integration Review.
3. Simplicity and transparency.
4. Avoidance of large shifts in costs among market parties.
5. Efficient price signals: compensates market parties for costs incurred, and is paid for by market parties responsible for the costs
6. Limited potential for unexpected consequences.
7. Consistency in philosophy with existing market features.

Below we offer our assessment of the flexiramp proposal in light of these criteria.

3.1 Effectiveness

In those RTPD intervals when there would otherwise be insufficient ramp, the formulation of the flexiramp constraint in RTPD will increase the amount of unloaded capacity that could provide energy at short notice. This is anticipated to occur by increasing the amount of committed capacity. We have confirmed this possibility by undertaking our own simplified simulations (without data) of the impacts of imposing the flexiramp constraint in the RTPD and RTD processes, including extensions of the examples presented in the Technical Bulletin.[13]

There are three circumstances we identified in which the flexiramp constraint may be ineffective. First, it is possible that in some circumstances that load (net of wind generation) will be appreciably higher than anticipated in the first interval of RTD, using most or all of the scheduled flexiramp. In that case it may be difficult for RTD to meet flexiramp constraints in subsequent intervals, even though the amounts of flexiramp required in the advisory intervals immediately after the first interval are reduced relative to the RTPD requirement. In these cases, the flexiramp constraint may be unsatisfied. We understand that this did not occur often in the ISO's market simulations of the flexiramp constraint. However, if this situation occurs with some frequency, then adjustments to the amount of flexiramp acquired in RTPD and in advisory intervals of RTD are likely to correct the problem.

The second circumstance is where inadequate capacity is committed in the day-ahead (IFM) and residual unit commitment processes such that there is too little committable capacity available for RTPD, so that less flexiramp can be acquired than is desired by the ISO. Again, this did not appear to be a problem in the market simulations. However, it could arise under conditions other

[13] "Flexible Ramping Constraint", Technical Bulletin 2011-02-01, April 19, 2011, www.caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraint_UpdatedApr19_2011.pdf

than those considered in the simulations. It is also possible that the cost of commitment and energy might be higher than if additional commitment to accommodate flexiramp could take place day-ahead. If either circumstance occurs, it is possible that the problem could be partially solved if relatively high prices for flexiramp in RTPD encourage generators who otherwise would not be available to self-commit and make themselves available.

This possibility would have at least partially been dealt with by the ISO's original proposal, which proposed that flexiramp also be obtained in RUC. However, the ISO believes that this additional complicating feature is not needed to provide sufficient flexiramp at this time.[14] Therefore, we suggest that the sufficiency and cost of supply of flexiramp in RTPD be monitored and if there problems occur frequently that some day-ahead version of the flexiramp constraint be revisited. Meanwhile, we anticipate that the Renewable Integration Review will result in a proposal in which a product that provides flexiramp functionality would be acquired both day-ahead and in real-time, avoiding the latter problem.

The third possibility arises because flexiramp is acquired on a system-wide basis, unlike energy which is acquired nodally or AS which are acquired zonally. A difficulty may arise in that it might be acquired in places where it would be ineffective. As an extreme case, flexiramp might all be scheduled in a generation pocket which has lots of extra generation and ramp precisely because it cannot be dispatched. Locational flexiramp constraints have not been included in the flexiramp design for the sake of simplicity. Therefore, the ISO should monitor where flexiramp is acquired so that if inaccessibility of flexiramp occurs frequently, then appropriate fixes can be implemented relatively quickly.[15]

3.2 Reversibility

The concern here is that the particular flexiramp constraint formulation and settlement procedure would restrict the range of alternatives that would be considered in the Renewable Integration Review, perhaps raising an obstacle to a more fundamental solution. We understand that the Review has been considering several possibilities for providing flexiramp functionality in the ISO markets unrestrained by the interim flexiramp design, most involving definition of a product that

[14]Opportunity Cost of Flexible Ramping Constraint Issue Paper & Straw Proposal, June 24, 2011, www.caiso.com/Documents/Flexible%20ramping%20constraint%20-%20papers%20and%20proposals/OpportunityCost_FlexibleRampingConstraint_IssuePaper_StrawProposal.pdf

[15]A third situation does not involve inadequate amounts of flexiramp, but rather payment might be made in RTPD without any change in the amount of resources or their schedules in binding intervals of RTD. In particular, it is possible that in some intervals, the flexiramp constraint in the first interval of the RTPD constraint might be binding with a positive shadow price, but without changing unit commitment or the distribution of operating reserves among generators. As a result, generator schedules and prices might not be changed in the first interval of the RTD compared to the situation. In that situation, there will be opportunity cost-based payments to generators without changing actual dispatch or commitment. However there is no reliability concern in that situation as the system will have enough rampable capacity in this case. We note however that the ISO's market simulations indicate that in many or most cases when there is a significant payment, there will also be more capacity committed, resulting in more ramp capability..

would be bid for and settled in both day-ahead and real-time markets. Therefore, there does not seem to be a concern with respect to this criterion.

3.3 Simplicity and Transparency

The proposal has two basic aspects. First, it adds sets of constraints to the RTPD and RTD processes to reserve rampable capacity to accommodate unexpected changes in RTD load, and to ensure that ramp rate limitations for generation units are still satisfied should the flexiramp be called upon. Second, it uses the shadow price the binding interval's flexiramp supply constraint in RTPD to determine payments for sources of flexiramp in that interval. Payments are made by load. Market participants are not asked to submit bids, and no changes are made in the day-ahead markets. Therefore, from a mathematical perspective, the flexiramp constraints are the minimum necessary to ensure feasibility, and the payment rule has the appeal of being based upon a single price that is automatically provided by RTPD, which is RTPD's estimate of the marginal cost to the market of the provision of flexiramp.[16]

However, the simple use a shadow price does present transparency problems, in that it can be challenging to understanding how opportunity costs arise any particular interval. Because RTPD schedules energy (non-binding), ancillary services (binding), and flexiramp simultaneously, opportunity costs can arise in very complicated ways, even in simplistic cases. As can often happen in such cases, the price of any one of these commodities can reflect the complex movements, both up and down, of supply of more than one commodity from several generators that are necessary to ensure that capacity, ramp, and transmission constraints remain satisfied.[17] We support the use of opportunity cost calculated in this way not only because of its mathematical convenience, but also because it correctly reflects the physical interactions of how the energy, AS, and flexiramp are supplied.[18] Unfortunately, in complicated electricity markets, it will not always be transparent how shadow prices originate in a particular circumstance, and sometimes unexpected extremes can occur. The examples in the Technical Bulletin[19] are helpful, and additional ones reflecting, for instance, changes in commitment and significant changes in load between RTPD and RTD would be helpful in informing stakeholders.

3.4 Avoidance of Large Shifts in Costs

This is desirable in an interim measure because, in general, an interim measure will involve compromises in market design in the interest of simplicity and reversibility that may result in

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[16]An alternative payment schemes that might be as easy or easier to understand is to instead have a fixed $/MW/hour payment. But such a payment would violate our other criteria by being arbitrary, unreflective of market conditions, and inconsistent with how energy and ancillary services are paid.

[17] See the Technical Bulletin, op. cit. In one simple three generator simulation we considered with just energy and flexiramp, the price of flexiramp was determined by a complex reshuffling of energy and flexiramp among two different generators that arose because of a binding ramp constraint.

[18] A partial exception is when a product or flexiramp is in shortage in the RTPD scheduling run, so that the prices in that run reflect constraint violation penalties, such that the pricing run of RTPD yield different prices than the scheduling run.

[19] Op. cit..

payments not satisfying the next market design criterion (cost compensation and responsibility). As a result, if large payments are made, they may not be made to those who bear the costs or in proportionate to those costs, and payments may be made by parties who are not responsible for the need for flexiramp. In theory, the amounts of flexiramp to be acquired (hundreds of MW) and the potential for prices in the tens of $/MW/hr means that there is potential for significant cash flows. However, the market simulations conducted by the ISO show zero or very low flexiramp prices in most intervals; if this turns out to be actually the case when flexiramp is implemented, then this criterion will be satisfied. Because the constraints for flexiramp are similar in many respects to those for spinning reserve, while the amount of MWs involved is much less, we anticipate that the aggregate payments over time will be much less than for operating reserves.

If, contrary to expectation, it turns out flexiramp settlement expenses are much higher than anticipated, the relationship of these costs to the actual opportunity costs (in terms of AS and energy rescheduling) should be verified.

3.5 Efficient Price Signals: Cost Compensation and Cost Responsibility

Efficient price signals impose two requirements. First, the prices paid should reflect benefits (price should equal marginal benefit). Second, prices should reflect the costs of what is purchased (price should equal marginal cost). The result in this case, if both requirements were satisfied, would be that the marginal cost of flexiramp would equal the marginal benefit of flexiramp. This would mean the procurement was cost effective (economically efficient). To our knowledge, no estimate has been made of benefits, although we agree with the ISO's view-that the benefits could be substantial. This means that efficient price signals, those equal to the marginal benefit of additional flexiramp to the system, are currently out of the question. However, it is still desirable to achieve supply-side efficiency (minimize the cost to the market) by ensuring that all providers face the same price, and the current proposal takes a useful step in that direction.

As a general market design principle, minimizing the cost to the market of acquiring flexiramp is desirable for an interim solution. However, it may be compromised because of the need for quick implementation, and the cost of implementing more complex designs that would send more efficient prices to the market parties that can provide or reduce the requirements for a commodity. This is the situation with flexiramp. On the supply side, a more efficient design would involve, as noted above, acquisition both day-ahead and in real-time. Also, to ensure cost reflectivity of prices, a bidding procedure would be preferable so that suppliers can reveal their opportunity costs of providing flexiramp. However, in interests of simplicity, day-ahead acquisition and a bidding procedure has been omitted.

One simple step that could contribute to flexiramp payments being more cost reflective is to use the the capacity bid for spinning reserve as the bid price for flexiramp in the objective functions of RTPD and RTD. This idea has appeal because of some similarities between spinning reserve and flexiramp from the generators' point of view. However, there is a key difference: flexiramp is more likely to be used to produce energy in RTD, and so opportunity costs should, on average, be less than for spin, especially non-discretionary spin. There are not obviously other significant costs associated with provision of flexiramp (although more frequent ramping itself may impose costs[20]), so we support the use of a zero bid price for the interim flexiramp process.

We note that there is an aspect of this proposal that, like ancillary services, can result in divergence of payments from actual costs. This largely arises from differences between the RTPD and RTD designs and prices. In particular, the opportunity costs that would be paid to flexiramp in RTPD are based, in part, upon energy prices that are not actually paid; actual energy payments occur in RTD. The lack of convergence, on average, of RTPD and RTD prices in practice means that the actual opportunity cost of flexiramp (if arising from foregone RTD energy revenues) is not paid. Because RTPD prices have tended to be less than RTD prices, this could imply a downward bias for payments. Note, however, that this is true also of other ancillary services acquired in RTPD. On the other hand, unlike contingency-only spinning reserve and regulation, capacity reserved for flexiramp can be dispatched for energy and paid in RTD, and indeed has a reasonably high likelihood of doing so. Therefore the opportunity cost of flexiramp calculated in RTPD may overstate the actual lost opportunity in the ISO's real-time markets.[21,22] This could affect bidding behavior for spin, because capacity scheduled for flexiramp would generally have more opportunity than spin to earn a gross margin from energy revenues in RTD.

However, we note that this possible overstatement of opportunity costs for flexiramp is also analogous to the situation with payments for non-contingent spinning reserves. Non-contingent spin, which is only acquired in the day-ahead market, is paid the shadow price of the spin constraint, but that may overstate opportunity costs since non-contingent spin can, under some conditions, be dispatched in RTD. Therefore the proposal has the advantage of treating flexiramp opportunity costs in a manner broadly consistent with non-contingent spin opportunity costs. The issue of the correct estimation of opportunity costs for ancillary services and how they are compensated should be addressed in the Renewable Integration Review.

On the demand side, identification and allocation of costs to responsible parties, which could include both suppliers and consumers of energy, would in theory be preferable to charging all flexiramp costs to load. One approach would be to charge flexiramp costs to parties with imbalances in RTD. However, this would be imperfect, because it is not imbalances that create the need for flexiramp but large variations of load and generation within the five minute RTD intervals. Another approach would be to identify the relative contribution of load and supply (especially

[20] C. Wang, S. M. Shahidehpour, "Effects of Ramp-Rate Limits on Unit Commitment and Economic Dispatch", *IEEE Trans. Power Systems*, Vol. 8, No. 3, 1993.

[21] Some opportunity cost can occur in RTD because the flexiramp constraint in later (nonbinding) intervals of RTD could result in changes in dispatch in the first interval in order to position generators who would be providing flexiramp in nonbinding RTD intervals.

[22] A fundamental fix would be to include an energy settlement in RTPD and then only settle imbalances from that position in RTD, but this would be a large and fundamental departure from the present market design. Another approach would be to estimate the actual opportunity costs incurred in RTD rather than use the RTPD shadow price. This might possibly be estimated based, for instance, on the shadow price of ramp rate constraints that limit energy production in the first (binding) RTD interval for units that provide flexiramp in later (nonbinding) intervals, considering the amount of energy provided in the first RTD interval relative to that scheduled in the corresponding RTPD interval. However, implementation of such a procedure would require significant study and would complicate the proposal.

variable uncontrollable supply) to those fluctuations, and to charge accordingly; however, this is a topic more suited for the Renewable Integration Review. Therefore, in the interest of simplicity, we support charging all flexiramp costs to load, while looking forward to the results of the Review for definition of a more complete and cost-reflective charging mechanism for ramping capability.

3.6 Limited Potential for Unexpected Consequences

Almost by definition, this criterion is difficult to assess, since it requires anticipation of the unanticipated. However, large changes to a market design in both philosophy and implementation details are more likely to yield unexpected problems than circumscribed changes.

The limited duration of the mechanism (until the results of the Renewable Integration Review are implemented) and its limited scope (no bidding mechanism, scheduling only in the real-time market) suggests that unintended consequences are less likely than they would be for more permanent measures involving broader changes to the market. However, we believe that two elements of the flexiramp design that appear at present to have the potential for troublesome unintended consequences. One is that setting payments based on an opportunity cost in RTPD that is due to a constraint that will not be enforced in the same way in RTD; as we pointed out, the actual opportunity costs experienced by resources devoted to flexiramp will differ from (and likely be less than) the payments made, even on average. The second is the impact of flexiramp opportunity cost payments on the day-ahead spinning reserve market; it is possible spinning reserve prices might be higher in RTPD than in the day-ahead market due to the presence of the flexiramp constraint in the former but not in the latter. Hence it would be desirable for the California ISO both to evaluate in testing the practical potential for such unintended consequences and to also carefully monitor this aspect of flexiramp performance when it is in operation.

3.7 Consistency in Philosophy with Existing Market Features

In the interest of simplicity, the flexiramp process has not been proposed as a full-fledged product with bidding and both day-ahead and real-time markets. Thus, it differs in philosophy with the processes for acquiring and paying for ancillary services, which we believe is undesirable in the long run. However, because it is interim, we accept that the need for simplicity in the proposal. We look forward to participating in the Renewable Integration Review where a more fundamental examination of the need for and alternatives for acquisition of ramp products is underway.

4. Conclusion

We conclude that the flexiramp proposal is likely to be an effective and reversible measure to address a need for more upward ramp capability in the real-time ISO market. The ability to tune the parameters of the flexiramp constraints, including the RTPD requirements and the amounts acquired in nonbinding intervals of RTD, give considerable flexibility to respond to unforeseen problems. We look forward to more detailed reporting of market simulations designed to confirm the anticipated effectiveness and price impacts of the flexiramp proposal.

However, the flexiramp proposal only partially addresses the fundamental reasons for the inadequate amount of upward ramping capacity. Furthermore, the payment based on opportunity costs in RTPD may overstate actual opportunity costs that providers of flexiramp will experience in the ISO's real-time markets. Therefore, we anticipate that any ramping product design that emerges from the ISO's Renewable Integration Review will likely have a very different structure and settlement procedure. That Review will need address the issues we have identified concerning appropriate incentives for short- and long-term provision of upward ramp and consistency with other products in the ISO's day-ahead and real-time markets. Among these issues are whether and when to pay capacity payments for ramp and (other) ancillary services; how they interact in the operational constraints in the day-ahead and real-time markets; assignment of responsibility for the costs of ancillary services; and the design of scarcity payments.