

August 30, 2013

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

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

**Tariff Amendment to Further Enhance Cost Recovery by Generating
Resources**

Dear Secretary Bose:

The California Independent System Operator Corporation (“ISO”) submits this tariff amendment to include additional categories of costs eligible for inclusion in proxy cost calculations for start-up and minimum load, generated bids, and variable cost default energy bids, as described below.¹ Specifically, the ISO proposes to include: (1) the volumetric components of the grid management charge in proxy cost calculations for start-up and minimum load costs, generated energy bids, and variable cost default energy bids; (2) the bid segment fee in the minimum load proxy cost calculation, generated energy bids, and variable cost default energy bids; and (3) a major maintenance expense component in the proxy start-up and minimum load costs. In conjunction with these changes, the ISO also proposes to reduce the level of the registered cost cap for scheduling coordinators opting to use the registered cost option rather than the proxy cost option.

The ISO proposes to revise the tariff in two additional respects. First, the ISO proposes to change one of the publications used to calculate the greenhouse gas allowance price. The tariff currently refers to Platt’s Daily, which does not currently publish a greenhouse gas price. Second, the ISO proposes to clarify the definition of

¹ The ISO submits this filing pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d. Capitalized terms not otherwise defined herein have the meanings set forth in the ISO tariff. References to numbered sections are references to sections of the ISO tariff unless otherwise indicated.

the grid management charge to be consistent with the current rate structure and to revise the definition of an independent entity.

This filing is the latest in a series of improvements the ISO has made to its tariff mechanisms providing for the recovery of costs by generating resources participating in its markets, which the Commission has found to be just and reasonable.² Most recently, pursuant to a stakeholder initiative that began in February of 2012 to improve and enhance the tariff provisions pertaining to resource cost recovery mechanisms, the ISO filed and the Commission accepted tariff revisions that allow resources to recover greenhouse gas compliance costs in their commitment costs, default energy bids, and generated bids.³ Like other amendments to include additional costs in cost-based bid calculations, this tariff amendment is just and reasonable and widely supported by the ISO's market participants.

The ISO requests that the Commission issue an order on October 29, 2013 (*i.e.*, 60 days from the date of this filing) that accepts the tariff changes effective as of November 1, 2013. An October 29, 2013 order will provide the ISO with one day to deploy the software so that it can be implemented as of the November 1, 2013 trading day.⁴

I. Background

A. ISO Tariff

Pursuant to its tariff, the ISO performs optimized economic commitment and dispatch of resources in the markets it operates based on the resources' market bids as well as any generated bids and default energy bids and their commitment costs, which consist of the costs of starting up the resources (start-up costs) and the costs of running the resources at their minimum operating levels (minimum load costs). On a 30-day basis, scheduling coordinators for resources may choose either the proxy cost option or the registered cost option for specifying their start-up costs or their minimum load costs

² See *California Independent System Operator Corp.*, 128 FERC ¶ 61,282, at PP 26-30 (2009) (accepting various tariff revisions to "provide resource owners the needed flexibility to choose the option that best enables recovery of their start-up and minimum load costs"); *California Independent System Operator Corp.*, 134 FERC ¶ 61,257, at PP 4, 23-24, 26 (2011) (accepting tariff revisions to "further increase resource owners' flexibility in choosing between the options available to recover start-up and minimum load costs by allowing a resource to select a different recovery option for each type of cost and by introducing a daily bid option").

³ *California Independent System Operator Corp.*, 141 FERC ¶ 61,237 (2012) (conditionally accepting tariff amendment subject to compliance filing to be submitted by the ISO); Commission letter order, Docket No. ER13-219-001 (Feb. 26, 2013) (accepting ISO compliance filing).

⁴ The day-ahead market for the November 1, 2013 trading day will occur on October 31, 2013.

to be used for the resources in the ISO markets.⁵ The proxy cost option uses cost-based information to calculate variable start-up and minimum load costs.⁶ The registered cost option allows scheduling coordinators to register fixed start-up and minimum load cost values of their choosing in the Master File, subject to a registered cost cap currently set at 200 percent of the projected proxy cost.⁷

The ISO tariff also includes rules that specify the ISO's use of generated energy bids and default energy bids. Generated bids are generated by the ISO when a bid is not submitted by a scheduling coordinator and is required for a resource adequacy requirement or scheduling and bidding infrastructure rules as set forth in the ISO tariff and applicable business practice manual.⁸ Variable cost default energy bids are used in the ISO's local market power mitigation process to mitigate bids that are identified as having potential market power.⁹ Like start-up and minimum load costs, generated energy bids and variable cost default energy bids incorporate resource-specific costs.

B. Stakeholder Process

On February 8, 2012, the ISO initiated a stakeholder process called Commitment Costs Refinements 2012 to discuss the following areas for potential modifications to the ISO tariff:

- (1) Inclusion of greenhouse gas compliance costs in the calculations for commitment costs, default energy bids, and generated bids;
- (2) Inclusion of grid management charge components and the bid segment fee in proxy cost calculations for start-up and minimum load costs, default energy bids, and generated bids;
- (3) Inclusion of a major maintenance expense component in proxy start-up and minimum load costs;

⁵ ISO tariff section 30.4

⁶ ISO tariff section 30.4.1.1.

⁷ ISO tariff sections 30.4.1.2, 39.6.1.6. The projected proxy cost includes a gas price component and, if eligible, a projected greenhouse gas allowance price component. ISO tariff section 39.6.1.6.

⁸ ISO tariff sections 30.7.3.4, 40.6.8; ISO tariff Appendix A (definition of generated bid).

⁹ Each scheduling coordinator can choose one of the following three options as its preferred option for calculating default energy bids: (1) the variable cost option, (2) the negotiated rate option, or (3) the locational marginal price option. ISO tariff section 39.7.1. Only default energy bids calculated pursuant to the variable cost option will include the additional costs proposed in this tariff amendment. Such costs can also be included in any negotiated default energy bid.

- (4) Reduction of the level of the registered cost cap for scheduling coordinators opting to use the registered cost option;
- (5) Provisions to allow resources to recover penalty costs for violating natural gas pipeline balancing orders and costs of emissions of nitrogen oxide (NOx) and sulfur oxide (SOx) as part of the bid cost recovery mechanism; and
- (6) Inclusion of costs associated with transitions of multi-stage generating resources in proxy cost calculations.¹⁰

To develop the policy for the changes proposed in the stakeholder process, the ISO issued a series of papers for stakeholder review, held a total of four conference calls with stakeholders to discuss the papers, and provided opportunities for written comments. As a result of the policy stakeholder process, the ISO sought approval by the ISO Governing Board (“Board”) for issues (1) through (5). The ISO dropped issue (6) from the scope of this initiative due to a lack of sufficient stakeholder interest and the potential complications involved in developing an approach for enhancing the proxy cost calculation for inclusion in transition costs for multi-stage generating resources. The stakeholder consensus was that these refinements should be deferred until more experience is gained with the multi-stage generating resource functionality. As the ISO explained in an issue paper posted on April 25, 2013, which announced that the ISO would not proceed in this initiative with developing any enhancements designed for multi-stage generating resources, such resources can rely on the existing structure in the ISO tariff that allows scheduling coordinators to register transition costs up to a cap determined by the costs reflected in the resources’ proxy start-up and minimum load costs.¹¹ In other words, once the additional costs, including major maintenance costs, are reflected in proxy start-up and minimum load costs, the headroom available for scheduling coordinators for registered transition costs increases to allow those costs to be included in registered transition values. At its May 17, 2012 meeting, the Board authorized the ISO to prepare and submit tariff revisions to implement the policies for issues (1) through (5).

¹⁰ Materials relating to this stakeholder process are available on the ISO website at <http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostsRefinement2012.aspx>.

¹¹ The April 25, 2013 issue paper explains: “For situations when a unit is moved to a configuration which is not a start-up configuration, the MSG [multi-stage generating resource] provides the CAISO with the transition costs, subject to certain constraints, so that any major maintenance costs due to a start-up of [a] specific component in transitioning into the configuration can be included in the transition costs.” *Commitment Cost Refinements 2012 Implementation Details* at 10-11 (April 25, 2013) (“Implementation Details Document”). The Implementation Details Document is provided in Attachment E to this filing and is available on the ISO website at <http://www.caiso.com/Documents/ImplementationDetails-CommitmentCostsRefinement2012.pdf>. See also ISO tariff section 30.4.2 (setting forth the structure for registering transition costs up to the cap).

As noted above, last year the ISO filed and the Commission accepted the first of these listed modifications, to include greenhouse gas compliance costs in the specified calculations.¹² The ISO is now filing this tariff amendment to implement issues (2) through (4) after recently deciding to take additional time to develop tariff language to implement issue (5), relating to recovery of natural gas pipeline penalty costs and emissions costs. It has become clear to the ISO in the course of the tariff stakeholder process that this area requires further consideration and development before it is ready to be filed for Commission acceptance. In particular, the development of the proposal has to this point focused on recovery of intrastate gas pipeline penalties. Although the vast majority of generating units are served by intrastate gas pipelines in California and the penalties for violating intrastate gas pipeline operational flow orders inspired this particular tariff change, the ISO has determined that it also needs to review the provisions of interstate gas pipeline tariffs, discuss those provisions with stakeholders, and further refine and develop the proposal. The ISO anticipates that it will be able to file tariff revisions to permit recovery of gas pipeline penalty costs and emissions costs in time for them to be implemented in the ISO's spring 2014 release. Accordingly, although draft tariff language was developed in the tariff stakeholder process in this area, it is not discussed or proposed in this filing.

On April 25, 2013, the ISO initiated a stakeholder process to develop implementation details and tariff language to put into effect the proposals for cost recovery-related improvements contained in this filing.¹³ Recognizing the need to discuss certain implementation options prior to developing the tariff language, the ISO hosted a conference call with stakeholders on May 1, 2013 to discuss implementation options. On June 7, 2013, the ISO issued draft tariff language to implement the proposals, and requested that stakeholders provide written comments by June 17, 2013. The ISO held a conference call on June 26, 2013 to discuss the comments. On July 25, 2013, the ISO published revised draft tariff language based on stakeholder comments and the ISO's own further review. The ISO requested stakeholders' written comments by August 8, 2013, and held a conference call on August 15, 2013 to discuss the revised draft tariff language.¹⁴

¹² The ISO filed the tariff revisions on October 29, 2012, to reflect the fact that the California Air Resources Board was going to implement a cap-and-trade program for greenhouse gas emissions on January 1, 2013. The Commission accepted the tariff revisions effective as of January 1, as requested by the ISO. *California Independent System Operator Corp.*, 141 FERC ¶ 61,237 (2012); Commission letter order, Docket No. ER13-219-001 (Feb. 26, 2013).

¹³ As noted above, the ISO also discussed in this process modifications relating to natural gas penalty costs and emissions costs as well as transition costs for multi-stage generating resources, but elected not to include those topics in this filing in order to allow for further development of these issues.

¹⁴ A list of key dates in the stakeholder process is provided in Attachment H to this filing.

II. Proposed Tariff Revisions

A. Inclusion of Grid Management Charge Components and Bid Segment Fee in Cost-Based Bid Calculations

The ISO proposes to modify the tariff provisions regarding the calculation of cost-based bids – *i.e.*, proxy start-up and minimum load costs, variable cost default energy bids, and generated bids – to include the volumetric components of the grid management charge (the market services charge and the system operations charge) in those calculations. In addition, the ISO proposes to include the bid segment fee in the minimum load proxy cost calculation, variable cost default energy bids, and generated bids.¹⁵

The grid management charge is a monthly charge assessed to scheduling coordinators to enable the ISO to recover the costs of operating the ISO markets and other costs specified in the ISO tariff.¹⁶ The volumetric components of the grid management charge are the market services charge and the system operations charge.¹⁷ Those components are volumetric in that they are based on the megawatt-hour (MWh) quantities that are scheduled, injected into the ISO controlled grid, or withdrawn from the ISO controlled grid. The volumetric components are part of the ISO's marginal costs of operating the ISO markets. The bid segment fee is a flat per-bid-segment charge, which the ISO proposed to convert into a volumetric cost component for inclusion in cost-based bids.¹⁸

The calculation of proxy start-up costs will include the market services charge and the system operations charge but not the bid segment fee. This is because start-up costs do not trigger a bid segment fee as it is not considered a "bid." The calculation of minimum load costs, default energy bids, and generated bids are considered bids and therefore will include the market services charge and the system operations charge, as well as the bid segment fee. Specifically, minimum load cost is treated as one bid segment.

The ISO proposes to include the market services charge and the system operations charge in the calculation of proxy start-up costs and minimum load costs using slightly different formulas. To determine the proxy minimum load cost adder for the volumetric grid management charges, the ISO will simply multiply the rates for the

¹⁵ Specifically, the ISO proposes to modify section 30.4.1.1.1 and 30.4.1.1.2 for proxy start-up and minimum load costs, sections 39.7.1.1, 39.7.1.1.1, and 39.7.1.1.2 for default energy bids, and section 40.6.8 for generated bids.

¹⁶ ISO tariff section 11.22.2; Appendix A to ISO tariff (definition of grid management charge).

¹⁷ See ISO tariff sections 11.22.2.5.1, 11.22.2.5.2, and ISO tariff Appendix F, Schedule 1, Part A.

¹⁸ See ISO tariff sections 11.22.5 and ISO tariff Appendix F, Schedule 1, Part A.

market services charge and system operations charge by the MWhs reflected in the resource's minimum normal capability (PMin). Because proxy start-up costs are calculated based on a resource's fuel consumption in going from off-line to on-line status, the ISO had to develop an approach to estimate MWh in order to determine the volumetric market services charge and system operations charge for proxy start-up costs.¹⁹ Through the stakeholder process, the ISO developed and now proposes a formula under which the rates for the market services charge and system operations charge will be multiplied by an approximation of the amount of start-up MWhs (*i.e.*, the shortest start-up time listed for the resource in the Master File multiplied by the PMin of the resource multiplied by 0.5).²⁰

Stakeholders expressed widespread support for including the volumetric components of the grid management charge in the calculation of cost-based bids. In addition, some stakeholders recommended that administrative (non-volumetric) inputs to the grid management charge also be included in the cost-based calculations.²¹ The ISO determined, however, that it would not be appropriate to include administrative inputs to the grid management charge in the calculation of cost-based bids, because those inputs relate to market participants' general costs of participating in the ISO markets and are not part of the ISO's marginal costs of operating the markets and, therefore, are not appropriately included in volumetric-based adders.²²

B. Inclusion of an Adder for Major Maintenance Expenses in the Calculation of Proxy Start-Up and Minimum Load Costs

The ISO also proposes to modify the tariff provisions regarding the calculation of proxy start-up and minimum load costs to include an adder for major maintenance

¹⁹ The ISO could potentially collect information on the energy produced for each start-up cycle of a resource, but the ISO would have no straightforward way to validate this information. Implementation Details Document at 10-11.

²⁰ *Id.* The ISO does not propose to use the total start-up time of the resource in this calculation because it is appropriate for the proxy start-up cost not to include the cost to heat up boilers before any power is delivered to the grid. Since the grid management charge only applies to megawatts flowing into or off the grid, the resource does not pay the grid management charge until it is synchronized to the grid and is delivering power. The shortest start-up time in conjunction with the 0.5 multiplication factor approximate the energy produced by the resource while it ramps up after synchronization to PMin. *Id.* at 11.

²¹ Examples of administrative inputs to the grid management charge are the inter-scheduling coordinator trade transaction fee and the scheduling coordinator ID charge. See ISO tariff sections 11.22.7 and 11.22.8.

²² *Draft Final Proposal – Commitment Costs Refinements 2012* at 11-12 (Apr. 11, 2012) (“Draft Final Proposal”). The Draft Final Proposal is provided in Attachment C to this filing and is available on the ISO website at <http://www.caiso.com/Documents/DraftFinalProposal-CommitmentCostRefinements.pdf>.

expenses incurred by generators.²³ It is just and reasonable to include this adder in the calculations because major maintenance expenses are marginal costs for a resource that are proportional to the number of times a unit starts up or the number of hours it operates. Further, the calculation of minimum load costs already includes default variable operations and maintenance costs, and scheduling coordinators can negotiate a variable operations and maintenance adder if the default adder is not sufficient.²⁴ This existing variable operations and maintenance adder covers maintenance costs that are proportional to energy output. The purpose of the major maintenance adder proposed here is to capture costs that are not appropriately included in the variable operations and maintenance adder that relate to the costs associated with start-ups and run hours. Thus, the inclusion of adders for major maintenance expenses appropriately recognizes such expenses as another category of maintenance costs that should be included in start-up and minimum load costs.²⁵ Market participants are currently only able to account for these costs as part of the projected proxy cost cap on start-up and minimum load costs under the registered cost option.²⁶

Under the ISO's proposal, a scheduling coordinator may propose adders for major maintenance expenses as a component of start-up costs, minimum load costs, or both. The proposed adders must be based solely on resource-specific information derived from actual maintenance costs, when available, or estimated maintenance costs provided by the scheduling coordinator to the ISO or an independent entity selected by the ISO. The ISO plans to utilize Potomac Economics, which already assists the ISO in the calculation of default energy bids, for this purpose.²⁷

The ISO or independent entity will evaluate the information provided by the scheduling coordinator, and may require the scheduling coordinator to provide additional information, to enable the ISO or independent entity to determine a reasonable adder for major maintenance expenses or to conduct an audit of major maintenance expenses. The proposed tariff provisions set forth the process for evaluation of the information provided by the scheduling coordinator. The tariff provisions also set forth dispute resolution processes, including the right to raise a

²³ Specifically, the ISO proposes to modify tariff sections 30.4.1.1.1, 30.4.1.1.2, and 39.7.1.3.2, and to add new tariff section 30.4.1.1.4, to include the major maintenance expense adder.

²⁴ See ISO tariff sections 30.4.1.1.1(a), 30.4.1.1.2(a), and 39.7.1.1.2.

²⁵ As set forth in the proposed tariff revisions, to the extent that the adder for major maintenance expenses is a component of start-up costs, it will be calculated in dollars per start-up, and to the extent that the adder is a component of minimum load costs, it will be calculated in dollars per operating hour.

²⁶ See ISO tariff section 39.6.1.6. As discussed in the next section of this transmittal letter, the ISO proposes to reduce the level of the registered cost cap from 200 percent of the projected proxy cost to 150 percent of the projected proxy cost.

²⁷ Proposed ISO tariff section 30.4.1.1.4.

dispute with the Commission if it cannot be resolved by the parties, that apply in the event of a disagreement regarding the sufficiency or accuracy of the information provided by the scheduling coordinator and/or the ISO's or independent entity's determination of the adder for major maintenance expenses.²⁸ The proposed dispute resolution processes are based on the existing dispute resolution process that applies to the negotiated rate option for determining default energy bids.²⁹ The ISO will include any adders for major maintenance expenses in the monthly informational filings the ISO submits to the Commission regarding default energy bids and negotiated variable operations and maintenance cost adders.³⁰

Participants in the stakeholder process unanimously supported the inclusion of an adder for major maintenance expenses in the calculation of start-up and minimum load costs. Stakeholders noted that a significant drawback of choosing the proxy cost option under the current tariff is that the calculation of proxy costs does not consider major maintenance associated with operating a resource. Several stakeholders also noted that major maintenance expenses are more closely linked to start-up for some resources and to hours of operation at minimum load for other resources, and that the adder for major maintenance expenses should reflect these resource-specific characteristics.³¹ These differences are reflected in the ISO's proposed tariff revisions, in that the adder can be a component of start-up costs, minimum load costs, or both.

Although the ISO removed the development of specific adders for transition costs for multi-stage generating resources from this initiative during the policy stakeholder process, Pacific Gas and Electric Company ("PG&E") raised the issue of including specific major maintenance values in transition costs. The ISO explained to PG&E that the issue had been de-scoped but that the existing transition cost structure in the tariff allows scheduling coordinators to increase their transition cost values to reflect major maintenance costs once these costs are reflected in the resources' proxy cost calculations, as the headroom for registering transition costs will be increased.³² The ISO reiterated its interest and willingness to take up this issue in a future stakeholder process. The ISO anticipates that this issue will generate more interest as more resources participate as multi-stage generating resources in the future.³³

²⁸ *Id.*

²⁹ See ISO tariff section 39.7.1.3.1.

³⁰ See the proposed revisions to ISO tariff section 39.7.1.3.2.

³¹ Draft Final Proposal at 12.

³² See *supra* note 11 and accompanying text.

³³ The ISO recently submitted a tariff amendment to enable the ISO to require certain resources that are operable in multiple configurations to register as multi-stage generating resources. Implementation of this tariff amendment will likely result in more resources participating as multi-stage generating resources. In the tariff amendment, the ISO also proposes to modify its tolerance band test for bid cost recovery to

C. Reduction of the Registered Cost Cap from 200 Percent to 150 Percent

The ISO proposes to modify tariff section 39.6.1.6 to reduce the level of registered cost cap from 200 percent of the projected proxy cost to 150 percent of the projected proxy cost.³⁴ This reduction in the level of the registered cost cap is just and reasonable for two reasons.

First, as costs are added to the proxy cost calculations for start-up and minimum load costs, the need for headroom to include costs not reflected in proxy costs is reduced. If the cap on registered costs is not reduced, then the ISO would simply be increasing the ability of scheduling coordinators to register values in excess of their actual costs. The registered cost option was implemented to capture potential costs associated with starting up a resource or operating the resource at minimum load that were not captured within the projected proxy cost calculation. Thus, the registered cost option was put into effect to enable market participants to bid in higher start-up and minimum loads costs for resources with non-fuel-related costs not captured in the variable operations and maintenance adder under the proxy cost option, and to account for expected fuel price volatility.³⁵ The ISO has since expanded the types of start-up and minimum load costs that resources can recover under the proxy cost option. The recoverable proxy start-up and minimum load costs now include greenhouse gas compliance costs, and pursuant to this tariff amendment, they will also include the volumetric components of the grid management charge and an adder for major maintenance expenses. Because resources will be able to recover these additional types of costs under the proxy cost option, there will no longer be a need for resources to recover these types of costs under the registered cost option instead. As a result, it is appropriate to lower the level of the current registered cost cap.

Second, lowering the level of the current registered cost cap will decrease opportunities for resources to receive inflated bid cost recovery uplift payments. Resources may bid in such a way as to receive bid cost recovery in the day-ahead

eliminate the possibility that a resource could receive minimum load bid cost recovery payments when the resource is not actually producing at minimum load. See the ISO's July 30, 2013 tariff amendment filing in Docket No. ER13-2063-000. A Commission order on this tariff amendment is pending.

³⁴ The ISO also proposes to modify tariff section 39.6.1.6 to state that the projected proxy cost includes the major maintenance expense and volumetric grid management charge components discussed above.

³⁵ *California Independent System Operator Corp.*, 123 FERC ¶ 61,288, at P 3 (2008); *Addendum to Draft Final Proposal – Commitment Costs Refinements 2012* at 3 (Apr. 27, 2012) (“Addendum to Draft Final Proposal”). The Addendum to Draft Final Proposal is provided in Attachment D to this filing and is available on the ISO website at <http://www.caiso.com/Documents/Addendum-CommitmentCostsRefinementsDraftFinalProposal.pdf>.

market and then not deliver the day-ahead scheduled amount in real-time, or resources may deviate in real-time to avoid shutdown instructions. Both of these strategies could potentially be profitable if a resource can recover minimum load costs through ISO uplift payments that are in excess of its actual minimum load costs. To mitigate this adverse strategic behavior, the ISO proposed and the Commission accepted two expedited tariff amendments in 2011,³⁶ and the ISO recently filed a tariff amendment that includes various bid cost recovery metrics and resulting bid cost recovery adjustments.³⁷ Lowering the registered cost cap will provide an additional safeguard because it will ensure that the bid cost recovery uplift payments the resources receive cannot be inflated above the level of the 150 percent registered cost cap.

In the stakeholder process, the ISO originally proposed to reduce the registered cost cap to 125 percent of the projected proxy cost.³⁸ However, stakeholders expressed concerns about the proposed lowering of the cap to that level. They asserted that a 125 percent cap may not account for intra-day gas price volatility, the exposure of natural gas price risk for low-capacity-factor resources, and natural gas balancing penalties. Stakeholders also contended that the registered cost cap should not be lowered to 125 percent because significant opportunity costs are associated with starting up and running a resource if the resource is subject to contractual or environmental constraints.³⁹ A similar concern was expressed by the ISO Market Surveillance Committee (“MSC”).⁴⁰

Given these concerns, the ISO revised the proposal for lowering the registered cost cap, so that the cap would be reduced to 150 percent rather than to 125 percent.⁴¹ The ISO’s proposal for a 150 percent registered cost cap is supported by the analysis of historical fuel price levels and fuel price volatility, the results of which are described in Appendix A to the Draft Final Proposal. This analysis found that 98 percent of the time during the period from January 2002 to August 2011, the maximum gas spot price was

³⁶ See *California Independent System Operator Corp.*, 135 FERC ¶ 61,110, clarified, 137 FERC ¶ 61,180 (2011); *California Independent System Operator Corp.*, 136 FERC ¶ 61,118 (2011).

³⁷ See *supra* note 33.

³⁸ Draft Final Proposal at 5-6.

³⁹ Addendum to Draft Final Proposal at 4.

⁴⁰ *Opinion on Bid Cost Recovery Mitigation Measures and Commitment Costs Refinement* at 3, 7-8 (May 7, 2012) (“MSC Opinion”). The MSC Opinion is provided in Attachment F to this filing and is available on the ISO website at http://www.caiso.com/Documents/DecisionCommitmentCostsRefinements-MSC_Opinion-May2012.pdf.

⁴¹ Addendum to Draft Final Proposal at 3-4.

150 percent or less of the gas futures price.⁴² Further, 100 percent of the time over that same period, the average spot gas price was 150 percent or less of the gas futures price.⁴³ Thus, based on this historical analysis, the 150 percent cap can be expected to be more than sufficient to cover the expected monthly fuel price risk associated with purchasing natural gas on the spot market. The 150 percent cap should also account for any risk in the intra-day gas markets and any non-fuel costs that will still not be accounted for in the proxy cost calculations. The MSC agrees with this approach, stating that lowering the registered cost cap to 150 percent would be a conservative measure.⁴⁴ Moreover, the ISO does not propose to change the existing tariff provisions that allow a resource with registered costs (start-up or minimum load) to switch from the registered cost option to the proxy cost option if natural gas prices spike such that the calculated proxy value exceeds the resource's registered costs.⁴⁵

D. Other Revisions

The ISO proposes to revise the tariff provisions on incremental cost calculations under the variable cost option to replace Platt's Daily with CME Group as one of the listed publications whose prices the ISO may use to calculate greenhouse gas allowance prices.⁴⁶ The ISO's policy is to use at least two of three daily prices to calculate the greenhouse case cost daily index. Since Platt's Daily does not currently publish a greenhouse gas allowance price, the ISO has had to rely on two prices instead of three. Substituting CME Group will allow the ISO to use three prices, and to rely on only two prices in the event a price from one of the three publications is not available.

The ISO proposes to revise the definition of the term "grid management charge" in Appendix A to the tariff to reflect the three charges that constitute the grid management charge under the current tariff – the market services charge, the system

⁴² Draft Final Proposal at 17-18. The only exceptions were that, for 1 percent of the prices at the PG&E city gate and the Southern California Edison Company border over the period, the maximum gas spot price was 190-200 percent of the gas futures price. *Id.* See also ISO presentation, *Refinements to Commitment Costs, 2012* at slide 5 (May 2, 2012) ("May 2, 2012 Presentation"). The May 2, 2012 Presentation is provided in Attachment G to this filing and is available on the ISO website at <http://www.caiso.com/Documents/Presentation-AddendumCommitmentCostsRefinementsDraftFinalProposal.pdf>.

⁴³ Draft Final Proposal at 18-19; May 2, 2012 Presentation at slide 5.

⁴⁴ MSC Opinion at 8. The MSC also recommended that the registered cost cap could be lowered further to 125 percent if the ISO were to make a finding within the next year that fuel cost variations, opportunity costs, and other omitted costs are highly unlikely to exceed 25 percent of proxy costs for the great majority of generating units. *Id.*

⁴⁵ See ISO tariff section 30.4.1.2.

⁴⁶ Proposed revisions to ISO tariff section 39.7.1.1.1.4.

operations charge, and the congestion revenue rights (CRR) services charge.⁴⁷ When the ISO amended the tariff to revise its grid management charge structure, the ISO neglected to revise the definition at that time. The ISO also proposes to update the definition of the term “independent entity” to accurately describe the current function of that entity and to eliminate an anachronistic reference to “reference prices” no longer used by the ISO in market power mitigation.

III. Effective Date

The ISO requests that the tariff revisions contained in this filing be made effective as of the November 1, 2013 trading day. The ISO will run the day-ahead market for the November 1, 2013 trading day on October 31, 2013. Accordingly, the ISO respectfully requests that the Commission issue its order on October 29, 2013 (*i.e.*, 60 days after this filing was submitted) to provide the ISO with one day – October 30, 2013 – to deploy the software prior to the October 31, 2013 day-ahead market for the November 1, 2013 trading day.

IV. Communications

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

Nancy Saracino
General Counsel
Sidney M. Davies
Assistant General Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel: (916) 351-4400
Fax: (916) 608-7236
E-mail: nsaracino@caiso.com
sdavies@caiso.com

Michael Kunselman
Bradley R. Miliauskas
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004
Tel: (202) 239-3300
Fax: (202) 654-4875
E-mail: michael.kunselman@alston.com
bradley.miliauskas@alston.com

V. Service

The ISO has served copies of this filing on the California Public Utilities Commission, the California Energy Commission, and all parties with Scheduling Coordinator Agreements under the ISO tariff. In addition, the ISO has posted a copy of the filing on the ISO website.

⁴⁷ See ISO tariff section 11.22.2.5 and ISO tariff Appendix F, Schedule 1, Part A.

VI. Contents of this Filing

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

Attachment A	Clean ISO tariff sheets incorporating this tariff amendment
Attachment B	Red-lined document showing the revisions contained in this tariff amendment
Attachment C	Draft Final Proposal
Attachment D	Addendum to Draft Final Proposal
Attachment E	Implementation Details Document
Attachment F	MSC Opinion
Attachment G	May 2, 2012 Presentation
Attachment H	List of key dates in the stakeholder process

VII. Conclusion

For the reasons set forth in this filing, the ISO respectfully requests that the Commission issue an order on October 29, 2013 that accepts the tariff revisions proposed in the filing effective as of the November 1, 2013 trading day.

Respectfully submitted,

Nancy Saracino
General Counsel
Roger E. Collanton
Deputy General Counsel
Sidney M. Davies
Assistant General Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630

/s/ Bradley R. Miliauskas
Michael Kunselman
Bradley R. Miliauskas
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004

Counsel for the California Independent System Operator Corporation

Attachment A – Clean

Amendment to Further Enhance Cost Recovery by Generating Resources

California Independent System Operator Corporation

August 30, 2013

30.4.1.1 Proxy Cost Option

30.4.1.1.1 Natural Gas-Fired Resources

For each natural gas-fired resource, the Proxy Cost option uses formulas for Start-Up Costs and Minimum Load Costs based on the resource's actual unit-specific performance parameters. The Start-Up Cost and Minimum Load Cost values utilized for each such resource in the CAISO Markets Processes will be either (a) or (b) below:

- (a) Formulaic values adjusted for fuel-cost variation on a daily basis as calculated pursuant to a Business Practice Manual.

Start-Up Costs also include: (i) the cost of auxiliary power calculated using the unit-specific MWh quantity of auxiliary power used for Start-Up multiplied by a resource-specific electricity price; (ii) a greenhouse gas cost adder for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, which is calculated for each Start-Up as the product of the resource's fuel requirement per Start-Up, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price; (iii) the rates for the Market Services Charge and System Operations Charge multiplied by the shortest Start-Up Time listed for the resource in the Master File, multiplied by the PMin of the resource, multiplied by 0.5; and (iv) a resource-specific adder, if applicable, for major maintenance expenses (\$ per Start-Up) determined by the CAISO or Independent Entity selected by the CAISO to determine such major maintenance expenses.

Minimum Load Costs also include: (i) operation and maintenance costs as provided in Section 39.7.1.1.2; (ii) a greenhouse gas cost adder for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, which is calculated for each Start-Up as the product of the resource's fuel requirement at Minimum Load, the greenhouse gas emissions rate authorized by the California Air

Resources Board, and the applicable Greenhouse Gas Allowance Price; (iii) the rates for the Market Services Charge and System Operations Charge multiplied by the PMin of the resource; (iv) the Bid Segment Fee; and (v) a resource-specific adder, if applicable, for major maintenance expenses (\$ per operating hour) determined pursuant to Section 30.4.1.1.4.

(b) Values specified by Scheduling Coordinators pursuant to Sections 30.7.9 and 30.7.10.

In the event that the Scheduling Coordinator for a unit does not provide sufficient data for the CAISO to determine the unit's base Proxy Costs or one or more of the additional components of the unit's Proxy Costs, the CAISO will assume that the unit's base Start-Up Costs and Minimum Load Costs, or the indeterminable additional component(s) of the unit's Start-Up Costs or Minimum Load Costs, are zero.

30.4.1.1.2 Non-Natural Gas-Fired Resources

For each non-natural gas-fired resource, Start-Up Cost and Minimum Load Cost values under the Proxy Cost option shall be based on either (a) or (b) below:

(a) The relevant cost information of the particular resource, which will be provided to the CAISO by the Scheduling Coordinator and maintained in the Master File.

Start-Up Costs will include: (i) greenhouse gas allowance costs for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator; (ii) the rates for the Market Services Charge and System Operations Charge multiplied by the shortest Start-Up Time listed for the resource in the Master File, multiplied by the PMin of the resource, multiplied by 0.5; and (iii) a resource-specific adder, if applicable, for major maintenance expenses (\$ per Start-Up) determined by the CAISO or Independent Entity selected by the CAISO to determine such major maintenance expenses.

Minimum Load Costs also include: (i) operation and maintenance costs as provided in Section 39.7.1.1.2; (ii) greenhouse gas allowance costs for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation,

as provided to the CAISO by the Scheduling Coordinator; (iii) the rates for the Market Services Charge and System Operations Charge multiplied by the PMin of the resource; (iv) the Bid Segment Fee; and (v) a resource-specific adder, if applicable, for major maintenance expenses (\$ per operating hour) determined by the CAISO or an Independent Entity selected by the CAISO.

For each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the information provided to the CAISO by the Scheduling Coordinator must be consistent with information submitted to the California Air Resources Board. Adders for major maintenance expenses will be determined pursuant to Section 30.4.1.1.4.

- (b) Values specified by Scheduling Coordinators pursuant to Sections 30.7.9 and 30.7.10.

In the event that the Scheduling Coordinator for a unit does not provide sufficient data for the CAISO to determine one or more components of the unit's Proxy Costs, the CAISO will assume that the indeterminable component(s) of the unit's Start-Up Costs or Minimum Load Costs are zero.

30.4.1.1.3 Multi-Stage Generating Resources

If a Multi-Stage Generating Resource elects the Proxy Cost option, that election will apply to all the MSG Configurations for that resource. The Proxy Cost values for Multi-Stage Generating Resources will be calculated for each specific MSG Configuration.

30.4.1.1.4 Adders for Major Maintenance Expenses

Scheduling Coordinators may propose adders for major maintenance expenses as a component of Start-Up Costs, Minimum Load Costs, or both. Such proposed adders must be based solely on resource-specific information derived from actual maintenance costs, when available, or estimated maintenance costs provided by the Scheduling Coordinators to the CAISO and the Independent Entity. Scheduling Coordinators may submit updated resource-specific major maintenance information for purposes of seeking a change to any major maintenance adder, no sooner than thirty (30) days after a major maintenance adder has been determined. The CAISO or Independent Entity will evaluate the information provided by Scheduling Coordinators, and may require Scheduling Coordinators to provide additional

information, to enable the CAISO or Independent Entity to determine reasonable adders for major maintenance expenses or to conduct audits of major maintenance expenses. Within fifteen (15) days of receipt of the information or any requested additional information, the CAISO or Independent Entity will notify the Scheduling Coordinator in writing whether it has sufficient and accurate information to determine reasonable major maintenance adders to be included in Start-Up or Minimum Load calculations or both. Within ten (10) days after providing written notification to the Scheduling Coordinator that the information is sufficient and accurate, the CAISO or Independent Entity will determine the reasonable adder for major maintenance expenses to be included in Start-Up or Minimum Load Costs or both and will so inform the Scheduling Coordinator in writing.

In the event of a dispute regarding the sufficiency or accuracy of the information provided by the Scheduling Coordinator, the CAISO or Independent Entity and the Scheduling Coordinator will enter a period of good faith negotiations that terminates sixty (60) days after the date the dispute began. If the CAISO or Independent Entity and the Scheduling Coordinator resolve the dispute during the 60-day negotiation period, within ten (10) days of such agreement, the CAISO or Independent Entity will determine the reasonable adder for major maintenance expenses and will provide the adder to the Scheduling Coordinator in writing. If the CAISO or Independent Entity and the Scheduling Coordinator fail to agree upon the sufficiency or accuracy of the information during the 60-day negotiation period, the Scheduling Coordinator has the right to petition FERC to resolve the dispute as to the sufficiency or accuracy of its information.

In the event of a dispute regarding the CAISO's or Independent Entity's determination of adders for major maintenance expenses, the CAISO or Independent Entity and the Scheduling Coordinator will enter a period of good faith negotiations that terminates sixty (60) days after the date the dispute began. If the CAISO or Independent Entity and the Scheduling Coordinator resolve the dispute during the 60-day negotiation period, the agreed-upon values will be effective as of the first Business Day following the resolution date. If the CAISO or Independent Entity and the Scheduling Coordinator fail to agree on the major maintenance values for either Start-Up or Minimum Load Costs following the 60-day negotiation

period, the Scheduling Coordinator has the right to file proposed values and supporting information for major maintenance adders for Start-Up or Minimum Load Costs with FERC pursuant to Section 205 of the Federal Power Act.

In the event of a dispute regarding the reasonableness of the adder for major maintenance expenses determined by the CAISO or Independent Entity, but not a dispute regarding the sufficiency or accuracy of the information provided by the Scheduling Coordinator, the CAISO or Independent Entity will determine a reasonable interim adder for major maintenance expenses until the adder for major maintenance expenses is determined by agreement between the CAISO or Independent Entity and the Scheduling Coordinator or by FERC. Any subsequent agreement or FERC order determining the adder for major maintenance expenses will be reflected in an adjustment to the interim adder for major maintenance expenses in the next applicable Settlement Statement.

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39.6.1.6 Maximum Start-Up Cost and Minimum Load Cost Registered Cost Values

The maximum Start-Up Cost and Minimum Load Cost values registered in the Master File by Scheduling Coordinators for resources that elect the Registered Cost option in accordance with Section 30.4 will be limited to 150% of the Projected Proxy Cost. The Projected Proxy Cost will include a gas price component, a major maintenance expense component, a volumetric Grid Management Charge component, and, if eligible, a projected Greenhouse Gas Allowance Price component calculated as set forth in this Section 39.6.1.6.

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39.6.1.6.3 Major Maintenance Expense Component

The major maintenance expense component is determined based on the process set forth in Section 30.4.1.1.4.

39.6.1.6.4 Volumetric Grid Management Charge Component

The volumetric Grid Management Charge component is set forth in Sections 39.7.1.1.1.1 and 39.7.1.1.1.2.

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39.7.1.1 Variable Cost Option

For natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by adding incremental cost (comprised of incremental fuel cost plus a volumetric Grid Management Charge adder plus a greenhouse gas cost adder if applicable) with variable operation and maintenance cost, adding ten percent (10%) to the sum, and adding a Bid Adder if applicable. For non-natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by summing incremental fuel cost plus ten percent (10%) of fuel cost plus a Bid Adder if applicable.

39.7.1.1.1 Incremental Cost Calculations Under the Variable Cost Option

39.7.1.1.1.1 Natural Gas-Fired Resources

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

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

The unit's final incremental fuel cost curve is calculated by multiplying this incremental

heat rate curve by the applicable natural gas price, and then, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing. Heat rate and cost curves shall be stored, updated, and validated in the Master File.

- (b) Calculation of greenhouse gas cost adder - For each natural gas-fired resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the CAISO will calculate a greenhouse gas cost adder as the product of the resource's incremental heat rate, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price.
- (c) Calculation of volumetric Grid Management Charge adder – For each natural gas-fired resource, the CAISO will include a volumetric Grid Management Charge adder that consists of: (i) the Market Services Charge; (ii) the System Operations Charge; and (iii) the Bid Segment Fee divided by the MW in the Bid segment.

39.7.1.1.1.2 Non-Natural Gas-Fired Resources

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

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

Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator for the resource; and (ii) a volumetric Grid Management Charge adder that consists of: (i) the Market Services Charge; (ii) the System Operations Charge; and (iii) the Bid Segment Fee divided by the MW in the Bid segment. Cost curves shall be stored, updated, and validated in the Master File.

39.7.1.1.1.3 Calculation of Natural Gas Price

To calculate the natural gas price, the CAISO will use different gas price indices for the Day-Ahead Market and the Real-Time Market and each gas price index will be calculated using at least two prices from two or more of the following publications: Natural Gas Intelligence, SNL Energy/BTU's Daily Gas Wire, Platt's Gas Daily, and the Intercontinental Exchange. If a gas price index is unavailable for any reason, the CAISO will use the most recent available gas price index. For the Day-Ahead Market, the CAISO will update the gas price index between 19:00 and 22:00 Pacific Time using natural gas prices published on the day that is two (2) days prior to the applicable Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available. For the Real-Time Market, the CAISO will update gas price indices between the hours of 19:00 and 22:00 Pacific Time using natural gas prices published one (1) day prior to the applicable Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available.

39.7.1.1.1.4 Calculation of Greenhouse Gas Allowance Price

To calculate the Greenhouse Gas Allowance Price, the CAISO will use different greenhouse gas price indices for the Day-Ahead Market and the Real-Time Market and each greenhouse gas price index will be calculated on a daily basis using at least two prices from two or more of the following publications: the Intercontinental Exchange, CME Group, and ARGUS. If a greenhouse gas price index is unavailable for any reason, the CAISO will use the most recent available greenhouse gas price index. For the Day-Ahead Market, the CAISO will update the greenhouse gas price index between 19:00 and 22:00 Pacific Time using prices for greenhouse gas allowances published on the day that is two (2) days prior to the applicable Trading Day, unless prices for greenhouse gas allowances are not published on that day, in which case the CAISO will use the most recently published prices for greenhouse gas allowances that are

available. For the Real-Time Market, the CAISO will update greenhouse gas price indices between the hours of 19:00 and 22:00 Pacific Time using prices for greenhouse gas allowances published one (1) day prior to the applicable Trading Day, unless prices for greenhouse gas allowances are not published on that day, in which case the CAISO will use the most recently published prices for greenhouse gas allowances that are available. The CAISO will calculate each Greenhouse Gas Allowance Price during a year using prices for greenhouse gas allowances from that same year.

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39.7.1.3.2 Informational Filings With FERC

The CAISO shall make an informational filing with FERC of any adders or interim adders for major maintenance expenses determined pursuant to Sections 30.4.1.1.1, 30.4.1.1.2, and 30.4.1.1.4, any Default Energy Bids negotiated pursuant to this section, or any temporary Default Energy Bids established pursuant to Section 39.7.1.5, or any custom operations and maintenance adders negotiated pursuant to Section 39.7.1.1.2, no later than seven (7) days after the end of the month in which the Default Energy or operations and maintenance values were established.

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40.6.8 Use Of Generated Bids

Prior to completion of the Day-Ahead Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Sections 40.5.1 or 40.6.1 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the CAISO Day-Ahead Market. Prior to running the Real-Time Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Section 40.6.2 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the Real-Time Market. If a Scheduling Coordinator for an RA Resource submits a partial bid for the resource's RA Capacity, the CAISO will insert a Generated Bid only for the remaining RA Capacity. In addition, the CAISO will determine if all dispatchable Resource Adequacy Capacity from Short Start Units, not otherwise selected in the IFM or RUC, is reflected in a Bid into the Real-Time Market and will insert a Generated Bid for any remaining dispatchable Resource Adequacy Capacity for which the CAISO has not received notification of an Outage. As provided in the Business Practice

Manuals, a Generated Bid for Energy will be calculated and will include: (i) a greenhouse gas cost adder for a resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation; and (ii) a volumetric Grid Management Charge adder that consists of: (i) the Market Services Charge; (ii) the System Operations Charge; and (iii) the Bid Segment Fee divided by the MW in the Bid segment. A Generated Bid for Ancillary Services will equal zero dollars (\$0/MW-hour). Notwithstanding any of the provisions of Section 40.6.8 set forth above, the CAISO will not insert any Bid in the Real-Time Market required under this Section 40 for a Resource Adequacy Resource that is a Use-Limited Resource unless the resource submits an Energy Bid and fails to submit an Ancillary Service Bid.

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**Appendix A,
Master Definitions Supplement**

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- Grid Management Charge (GMC)

The CAISO monthly charge on all Scheduling Coordinators that provides for the recovery of the CAISO's costs listed in Section 11.22.2 through the service charges described in Section 11.22.2.5 calculated in accordance with the formula rate set forth in Appendix F, Schedule 1, Part A. The charges that comprise the Grid Management Charge consist of: 1) the Market Services Charge, 2) the System Operations Charge, and 3) the CRR Services Charge.

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- Independent Entity

The entity, not affiliated with the CAISO or any Market Participant, that assists the CAISO in the determination of values used in the CAISO's market processes.

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Attachment B – Marked

Amendment to Further Enhance Cost Recovery by Generating Resources

California Independent System Operator Corporation

August 30, 2013

30.4.1.1 Proxy Cost Option

30.4.1.1.1 Natural Gas-Fired Resources

For each natural gas-fired resource, the Proxy Cost option uses formulas for Start-Up Costs and Minimum Load Costs based on the resource's actual unit-specific performance parameters. The Start-Up Cost and Minimum Load Cost values utilized for each such resource in the CAISO Markets Processes will be either (a) or (b) below:

- (a) Formulaic values adjusted for fuel-cost variation on a daily basis as calculated pursuant to a Business Practice Manual.

Start-Up Costs also include: (i) the cost of auxiliary power calculated using the unit-specific MWh quantity of auxiliary power used for Start-Up multiplied by a resource-specific electricity price; ~~and~~ (ii) a greenhouse gas cost adder for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, which is calculated for each Start-Up as the product of the resource's fuel requirement per Start-Up, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price; (iii) the rates for the Market Services Charge and System Operations Charge multiplied by the shortest Start-Up Time listed for the resource in the Master File, multiplied by the PMin of the resource, multiplied by 0.5; and (iv) a resource-specific adder, if applicable, for major maintenance expenses (\$ per Start-Up) determined by the CAISO or Independent Entity selected by the CAISO to determine such major maintenance expenses.

Minimum Load Costs also include: (i) operation and maintenance costs as provided in Section 39.7.1.1.2; ~~and~~ (ii) a greenhouse gas cost adder for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, which is calculated for each Start-Up as the product of the resource's fuel requirement at Minimum Load, the greenhouse gas emissions rate authorized by the

California Air Resources Board, and the applicable Greenhouse Gas Allowance Price; (iii) the rates for the Market Services Charge and System Operations Charge multiplied by the PMin of the resource; (iv) the Bid Segment Fee; and (v) a resource-specific adder, if applicable, for major maintenance expenses (\$ per operating hour) determined pursuant to Section 30.4.1.1.4.

- (b) Values specified by Scheduling Coordinators pursuant to Sections 30.7.9 and 30.7.10.

In the event that the Scheduling Coordinator for a unit does not provide sufficient data for the CAISO to determine the unit's base Proxy Costs or one or more of the additional components of the unit's Proxy Costs, the CAISO will assume that the unit's base Start-Up Costs and Minimum Load Costs, or the indeterminable additional component(s) of the unit's Start-Up Costs or Minimum Load Costs, are zero.

30.4.1.1.2 Non-Natural Gas-Fired Resources

For each non-natural gas-fired resource, Start-Up Cost and Minimum Load Cost values under the Proxy Cost option shall be based on either (a) or (b) below:

- (a) The relevant cost information of the particular resource, which will be provided to the CAISO by the Scheduling Coordinator and maintained in the Master File.

Start-Up Costs will include: (i) greenhouse gas allowance costs for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator; (ii) the rates for the Market Services Charge and System Operations Charge multiplied by the shortest Start-Up Time listed for the resource in the Master File, multiplied by the PMin of the resource, multiplied by 0.5; and (iii) a resource-specific adder, if applicable, for major maintenance expenses (\$ per Start-Up) determined by the CAISO or Independent Entity selected by the CAISO to determine such major maintenance expenses.

Minimum Load Costs also include: (i) operation and maintenance costs as provided in Section 39.7.1.1.2; ~~and~~ (ii) greenhouse gas allowance costs for each resource registered with the California Air Resources Board as having a greenhouse gas compliance

obligation, as provided to the CAISO by the Scheduling Coordinator: (iii) the rates for the Market Services Charge and System Operations Charge multiplied by the PMin of the resource; (iv) the Bid Segment Fee; and (v) a resource-specific adder, if applicable, for major maintenance expenses (\$ per operating hour) determined by the CAISO or an Independent Entity selected by the CAISO.

For each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the information provided to the CAISO by the Scheduling Coordinator must be consistent with information submitted to the California Air Resources Board. Adders for major maintenance expenses will be determined pursuant to Section 30.4.1.1.4.

- (b) Values specified by Scheduling Coordinators pursuant to Sections 30.7.9 and 30.7.10.

In the event that the Scheduling Coordinator for a unit does not provide sufficient data for the CAISO to determine ~~the unit's Proxy Costs one or more components of the unit's Proxy Costs~~, the CAISO will assume that the ~~unit's Start-Up Costs and Minimum Load Costs~~ indeterminable component(s) of the unit's Start-Up Costs or Minimum Load Costs are zero.

30.4.1.1.3 Multi-Stage Generating Resources

If a Multi-Stage Generating Resource elects the Proxy Cost option, that election will apply to all the MSG Configurations for that resource. The Proxy Cost values for Multi-Stage Generating Resources will be calculated for each specific MSG Configuration.

30.4.1.1.4 Adders for Major Maintenance Expenses

Scheduling Coordinators may propose adders for major maintenance expenses as a component of Start-Up Costs, Minimum Load Costs, or both. Such proposed adders must be based solely on resource-specific information derived from actual maintenance costs, when available, or estimated maintenance costs provided by the Scheduling Coordinators to the CAISO and the Independent Entity. Scheduling Coordinators may submit updated resource-specific major maintenance information for purposes of seeking a change to any major maintenance adder, no sooner than thirty (30) days after a major maintenance adder has been determined. The CAISO or Independent Entity will evaluate the information

provided by Scheduling Coordinators, and may require Scheduling Coordinators to provide additional information, to enable the CAISO or Independent Entity to determine reasonable adders for major maintenance expenses or to conduct audits of major maintenance expenses. Within fifteen (15) days of receipt of the information or any requested additional information, the CAISO or Independent Entity will notify the Scheduling Coordinator in writing whether it has sufficient and accurate information to determine reasonable major maintenance adders to be included in Start-Up or Minimum Load calculations or both. Within ten (10) days after providing written notification to the Scheduling Coordinator that the information is sufficient and accurate, the CAISO or Independent Entity will determine the reasonable adder for major maintenance expenses to be included in Start-Up or Minimum Load Costs or both and will so inform the Scheduling Coordinator in writing.

In the event of a dispute regarding the sufficiency or accuracy of the information provided by the Scheduling Coordinator, the CAISO or Independent Entity and the Scheduling Coordinator will enter a period of good faith negotiations that terminates sixty (60) days after the date the dispute began. If the CAISO or Independent Entity and the Scheduling Coordinator resolve the dispute during the 60-day negotiation period, within ten (10) days of such agreement, the CAISO or Independent Entity will determine the reasonable adder for major maintenance expenses and will provide the adder to the Scheduling Coordinator in writing. If the CAISO or Independent Entity and the Scheduling Coordinator fail to agree upon the sufficiency or accuracy of the information during the 60-day negotiation period, the Scheduling Coordinator has the right to petition FERC to resolve the dispute as to the sufficiency or accuracy of its information.

In the event of a dispute regarding the CAISO's or Independent Entity's determination of adders for major maintenance expenses, the CAISO or Independent Entity and the Scheduling Coordinator will enter a period of good faith negotiations that terminates sixty (60) days after the date the dispute began. If the CAISO or Independent Entity and the Scheduling Coordinator resolve the dispute during the 60-day negotiation period, the agreed-upon values will be effective as of the first Business Day following the resolution date. If the CAISO or Independent Entity and the Scheduling Coordinator fail to agree on the

major maintenance values for either Start-Up or Minimum Load Costs following the 60-day negotiation period, the Scheduling Coordinator has the right to file proposed values and supporting information for major maintenance adders for Start-Up or Minimum Load Costs with FERC pursuant to Section 205 of the Federal Power Act.

In the event of a dispute regarding the reasonableness of the adder for major maintenance expenses determined by the CAISO or Independent Entity, but not a dispute regarding the sufficiency or accuracy of the information provided by the Scheduling Coordinator, the CAISO or Independent Entity will determine a reasonable interim adder for major maintenance expenses until the adder for major maintenance expenses is determined by agreement between the CAISO or Independent Entity and the Scheduling Coordinator or by FERC. Any subsequent agreement or FERC order determining the adder for major maintenance expenses will be reflected in an adjustment to the interim adder for major maintenance expenses in the next applicable Settlement Statement.

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39.6.1.6 Maximum Start-Up Cost and Minimum Load Cost Registered Cost Values

The maximum Start-Up Cost and Minimum Load Cost values registered in the Master File by Scheduling Coordinators for resources that elect the Registered Cost option in accordance with Section 30.4 will be limited to 150200% of the Projected Proxy Cost. The Projected Proxy Cost will include a gas price component, a major maintenance expense component, a volumetric Grid Management Charge component, and, if eligible, a projected Greenhouse Gas Allowance Price component calculated as set forth in this Section 396.6.1.6.

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39.6.1.6.3 Major Maintenance Expense Component

The major maintenance expense component is determined based on the process set forth in Section 30.4.1.1.4.

39.6.1.6.4 Volumetric Grid Management Charge Component

The volumetric Grid Management Charge component is set forth in Sections 39.7.1.1.1.1 and 39.7.1.1.1.2.

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39.7.1.1 Variable Cost Option

For natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by adding incremental cost (comprised of incremental fuel cost plus a volumetric Grid Management Charge adder plus a greenhouse gas cost adder if applicable) with variable operation and maintenance cost, adding ten percent (10%) to the sum, and adding a Bid Adder if applicable. For non-natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by summing incremental fuel cost plus ten percent (10%) of fuel cost plus a Bid Adder if applicable.

39.7.1.1.1 Incremental Cost Calculations Under the Variable Cost Option

39.7.1.1.1.1 Natural Gas-Fired Resources

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

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

The unit's final incremental fuel cost curve is calculated by multiplying this incremental heat rate curve by the applicable natural gas price, and then, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing. Heat rate and cost curves shall be stored, updated, and validated in the Master File.

- (b) Calculation of greenhouse gas cost adder - For each natural gas-fired resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the CAISO will calculate a greenhouse gas cost adder as the product of the resource's incremental heat rate, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price.

- (c) Calculation of volumetric Grid Management Charge adder – For each natural gas-fired resource, the CAISO will include a volumetric Grid Management Charge adder that consists of: (i) the Market Services Charge; (ii) the System Operations Charge; and (iii) the Bid Segment Fee divided by the MW in the Bid segment.

39.7.1.1.1.2 Non-Natural Gas-Fired Resources

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

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

greenhouse gas allowance costs for each non-natural gas-fired resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator for the resource; and (ii) a volumetric Grid Management Charge adder that consists of: (i) the Market Services Charge; (ii) the System Operations Charge; and (iii) the Bid Segment Fee divided by the MW in the Bid segment. Cost curves shall be stored, updated, and validated in the Master File.

39.7.1.1.1.3 Calculation of Natural Gas Price

To calculate the natural gas price, the CAISO will use different gas price indices for the Day-Ahead Market and the Real-Time Market and each gas price index will be calculated using at least two prices from two or more of the following publications: Natural Gas Intelligence, SNL Energy/BTU's Daily Gas Wire, Platt's Gas Daily, and the Intercontinental Exchange. If a gas price index is unavailable for any reason, the CAISO will use the most recent available gas price index. For the Day-Ahead Market, the CAISO will update the gas price index between 19:00 and 22:00 Pacific Time using natural gas prices published on the day that is two (2) days prior to the applicable Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available. For the Real-Time Market, the CAISO will update gas price indices between the hours of 19:00 and 22:00 Pacific Time using natural gas prices published one (1) day prior to the applicable Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available.

39.7.1.1.1.4 Calculation of Greenhouse Gas Allowance Price

To calculate the Greenhouse Gas Allowance Price, the CAISO will use different greenhouse gas price indices for the Day-Ahead Market and the Real-Time Market and each greenhouse gas price index will be calculated on a daily basis using at least two prices from two or more of the following publications: the Intercontinental Exchange, ~~CME Group~~Platt's Daily, and ARGUS. If a greenhouse gas price index is unavailable for any reason, the CAISO will use the most recent available greenhouse gas price index. For the Day-Ahead Market, the CAISO will update the greenhouse gas price index between 19:00 and 22:00 Pacific Time using prices for greenhouse gas allowances published on the day that is two (2) days prior to the applicable Trading Day, unless prices for greenhouse gas allowances are not published on

that day, in which case the CAISO will use the most recently published prices for greenhouse gas allowances that are available. For the Real-Time Market, the CAISO will update greenhouse gas price indices between the hours of 19:00 and 22:00 Pacific Time using prices for greenhouse gas allowances published one (1) day prior to the applicable Trading Day, unless prices for greenhouse gas allowances are not published on that day, in which case the CAISO will use the most recently published prices for greenhouse gas allowances that are available. The CAISO will calculate each Greenhouse Gas Allowance Price during a year using prices for greenhouse gas allowances from that same year.

* * * *

39.7.1.3.2 Informational Filings With FERC

The CAISO shall make an informational filing with FERC of any adders or interim adders for major maintenance expenses determined pursuant to Sections 30.4.1.1.1, 30.4.1.1.2, and 30.4.1.1.4, any Default Energy Bids negotiated pursuant to this section, or any temporary Default Energy Bids established pursuant to Section 39.7.1.5, or any custom operations and maintenance adders negotiated pursuant to Section 39.7.1.1.2, no later than seven (7) days after the end of the month in which the Default Energy or operations and maintenance values were established.

* * * *

40.6.8 Use Of Generated Bids

Prior to completion of the Day-Ahead Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Sections 40.5.1 or 40.6.1 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the CAISO Day-Ahead Market. Prior to running the Real-Time Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Section 40.6.2 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the Real-Time Market. If a Scheduling Coordinator for an RA Resource submits a partial bid for the resource's RA Capacity, the CAISO will insert a Generated Bid only for the remaining RA Capacity. In addition, the CAISO will determine if all dispatchable Resource Adequacy Capacity from Short Start Units, not otherwise selected in the IFM or RUC, is reflected in a Bid into the Real-Time Market and will insert a Generated Bid for any remaining dispatchable Resource Adequacy Capacity for

which the CAISO has not received notification of an Outage. As provided in the Business Practice Manuals, a Generated Bid for Energy will be calculated and will include: (i) a greenhouse gas cost adder for a resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation; and (ii) a volumetric Grid Management Charge adder that consists of: (i) the Market Services Charge; (ii) the System Operations Charge; and (iii) the Bid Segment Fee divided by the MW in the Bid segment. A Generated Bid for Ancillary Services will equal zero dollars (\$0/MW-hour). Notwithstanding any of the provisions of Section 40.6.8 set forth above, the CAISO will not insert any Bid in the Real-Time Market required under this Section 40 for a Resource Adequacy Resource that is a Use-Limited Resource unless the resource submits an Energy Bid and fails to submit an Ancillary Service Bid.

* * * *

Appendix A, Master Definitions Supplement

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- Grid Management Charge (GMC)

The CAISO monthly charge on all Scheduling Coordinators that provides for the recovery of the CAISO's costs listed in Section 11.22.2 through the service charges described in Section 11.22.2.5 calculated in accordance with the formula rate set forth in Appendix F, Schedule 1, Part A. The charges that comprise the Grid Management Charge consist of: 1) the ~~Core Reliability Services—Demand Charge~~Market Services Charge, 2) the ~~Core Reliability Services—Energy Exports Charge~~System Operations Charge, and 3) the ~~Energy Transmission Services—Net Energy Charge~~, 4) the ~~Energy Transmission Services—Uninstructed Deviations Charge~~, 5) the ~~Core Reliability Services/Energy Transmission Services—Transmission Ownership Rights Charge~~, 6) the ~~Forward Scheduling Charge~~, 7) the ~~Market Usage Charge~~, and 8) the ~~Settlements, Metering, and Client Relations Charge~~CRR Services Charge.

* * * *

- Independent Entity

The entity, not affiliated with the CAISO or any Market Participant, that assists the CAISO in the determination of values used in the CAISO's market processes.

* * * *

Attachment C – Draft Final Proposal

Amendment to Further Enhance Cost Recovery by Generating Resources

California Independent System Operator Corporation

August 30, 2013



California ISO
Shaping a Renewed Future

Draft Final Proposal

Commitment Costs Refinements 2012

April 11, 2012

Commitment Costs Refinements 2012

Prepared for discussion at a stakeholder meeting – April 18, 2012

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1 Introduction and background

The economic commitment of a generating resource in the ISO markets is based on its market energy and ancillary service bids as well as the cost of starting up the resource and its costs at its minimum operating level (pmin). That is, commitment costs – start-up (SU) and minimum load (ML) costs – are integral to the optimization’s choice to utilize the resource. Furthermore, commitment costs are part of the ISO’s bid cost recovery (BCR) calculation that determines whether or not a resource has a revenue shortfall over the course of a day. If, based on the BCR calculation, the resource does have a shortfall – meaning that its commitment and market bid costs are not covered by its market revenues – then the resource receives a BCR uplift payment. Thus, the accurate specification of a resource’s commitment costs is critical to efficient commitment and fair compensation of generating resources in our market.

Since the implementation of the ISO’s LMP market design on April 1, 2009, the ISO has made several market rule changes to increase the options and flexibility for market participants to specify start-up and minimum load costs. The first effort involved reducing the minimum time period for electing either the proxy cost option or the registered cost option from six months to 30 days. Through a second initiative, which was approved by the ISO Board of Governors in July 2010, the ISO committed (a) to evaluate the default variable operations and maintenance cost adder to minimum load cost values every three years,¹ (b) to allow scheduling coordinators to make independent elections of either the proxy or registered cost option for start-up and minimum load costs, and (c) to permit (non-negative) daily bidding of start-up and minimum load costs on behalf of resources subject to the proxy cost option.

In this current initiative – Commitment Costs Refinements 2012 – the ISO and stakeholders have evaluated additional improvements to the specification of start-up and minimum load costs. In this draft final proposal, the ISO proposes the following changes to the calculation of minimum load and start-up costs:

- The proxy minimum load and start-up costs calculated by the ISO will be modified to incorporate the following :
 - Costs associated with greenhouse gas emissions incurred under California’s upcoming greenhouse gas cap-and-trade program.
 - The cost of the ISO’s grid management charge.
 - A fixed adder to cover major maintenance expenses.
- In conjunction incorporating these additional costs components into the ISO’s proxy cost calculations, the registered cost cap for minimum load and start-up costs will be reduced from 200 percent to 125 percent of the respective projected proxy cost, as calculated by the ISO for the resource every 30 days.

¹ The review and update of O&M values was recently completed and was approved by the ISO Board of Governors in December 2011. The updated O&M values will be effective in April 2012 subject to FERC approval.

This initiative has also evaluated changes to the ISO’s cost-based calculations used for default energy bids (DEB)² and generated bids.³ Consistent, with the changes to the calculation of costs for start-up and minimum load, the ISO proposes that the DEB and generated bid calculation be modified to include (1) greenhouse gas costs, and (2) ISO grid management charge costs.

Finally, the ISO proposes a mechanism for recovery of costs associated with operational flow orders incurred in the natural gas market.

The changes described above will apply to Generating Units, Pseudo Tie Generating Units, and Resource-Specific System Resources. Consistent with existing market design, only variable costs of generation, and not fixed costs, have been considered for inclusion into the ISO’s cost calculations.

2 Process and Timetable

The timeline for this stakeholder initiative culminates in taking a policy recommendation to the ISO Board of Governors in May 2012. The table below summarizes the key steps in the stakeholder process starting with the release of the issue paper and ending with submission of the ISO management proposal to the Board.

February 3, 2012	Issue paper posted
February 8	Conference call
February 17	Comments due *
February 29	Straw proposal posted
March 7	On-site stakeholder meeting
March 14	Comments due *
April 11	Draft final proposal posted
April 18	Stakeholder conference call
April 23	Comments due *
May 16-17	Board of Governors meeting

* Please e-mail comments to comcosts2@caiso.com

² Default energy bids (DEB) are energy bid curves that replace a resource’s submitted bid curve in the event that the resource is mitigated according to the local market power mitigation (LMPM) algorithm. Please see ISO tariff section 39 for additional information.

³ A generated bid is a cost-based bid which can be inserted on behalf of a market participant, for example, pursuant to generally applicable SIBR validation rules, and for Resource Adequacy bidding obligations.

3 Identified opportunities for improvements to bid costs

3.1 Changes to the registered cost option for start-up and minimum load costs

The current structure for generators to specify start-up and minimum load costs allows for two options: (1) the proxy cost option which is variable and tied to the natural gas price index and the heat-rate characteristics of the generating resource, and (2) the registered cost option which is a static value that is fixed for a minimum of 30 days after it is specified by the generator. The cap on the value that may be specified for the registered cost option for either start-up or minimum load is currently equal to 200 percent of the resource-specific projected proxy cost value as calculated by the ISO every 30 days.

The original motivation for providing the registered cost option was the recognition that there were potentially costs associated with starting up a resource and/or operating at minimum load that were not captured within the projected proxy cost calculation. However, the ability to register minimum load costs up to 200 percent of actual costs served as a key mechanism in adverse market behavior that inflated bid cost recovery (BCR) uplift payments in the first half of 2011. This resulted in two emergency filings to revise the tariff's bid cost recovery provisions. Although these filings addressed the observed behavior, there may still be opportunities to exploit this 200 percent cap. This could involve: (1) resources bidding in such a way as to receive BCR in the DA market and then not delivering the DA schedule in real-time, or (2) deviating in real-time to avoid shutdown instructions. Both of these strategies could be profitable if a resource can earn minimum load costs that are in excess of its actual minimum load costs. Consequently, and also because it was proposing to explicitly incorporate additional costs into its calculated proxy costs for resources, the ISO proposed as part of this initiative to examine lowering this 200 percent cap.

Stakeholder feedback

Market participants in favor of changes to the cap on the registered cost option generally focused on the need to prevent generating resources from having incentives to submit high registered cost values to recoup more than their actual costs through bid cost recovery. CDWR-SWP, the CPUC, NCPA, PG&E, SCE, and SDG&E expressed support for lowering the cap for the registered cost option for start-up and minimum load costs. In general, market participants in support of revising the registered cost cap did not recommend eliminating this option altogether, but instead recommended revisions to it. Such feedback included moving the cap closer to 100 percent of the calculated projected proxy cost values for start-up and minimum load, and adding the calculation of additional cost elements to the proxy cost calculation to reduce the need for market participants to rely on the registered cost option to recover these other cost components.

For example, Calpine stated support for maintaining the registered cost option, and recommended changing the registered cost cap to 175 percent of calculated costs to help accommodate for potential volatility in the nascent California GHG allowance market. Several stakeholders propose that the registered cost for start-up and minimum load costs be eliminated altogether. Several market participants expressed significant concerns over lowering the cap on the registered cost option. CalPeak, GenOn Energy, La Paloma, NRG Energy, Wellhead and WPTF are opposed to any change to the 200 percent cap on the registered cost option. Generally, comments by these participants maintain that neither the proxy cost option nor a lowered registered cost option are adequate to recover start-up and minimum load costs in the ISO market. NRG states that cost recovery has provided protection for significant costs related to natural gas procurement, as well as the volatility of natural gas prices. In addition, several of these market participants commented that

the 200 percent registered cost cap is the only means for their units to earn a contribution toward fixed costs when committed by the ISO at minimum load.

Proposal

The original intent of the registered cost option for start-up and minimum load costs was to (1) enable market participants to bid in higher start-up and minimum load costs for resources with non-fuel related costs not captured in the variable operations and maintenance (O&M) adder, and (2) account for expected fuel price volatility. The current 200 percent cap on the static registered cost value was set so as to enable market participants to account for these cost elements.

In this draft final proposal, the ISO proposes to keep the registered cost option, but to lower the registered cost cap to 125 percent of the projected proxy cost. The ISO proposes to keep the registered cost option to accommodate resources that have costs that are not incorporated into the proxy cost calculation. However, these additional costs should in the future be fairly limited. The additional cost components the ISO is also proposing to incorporate into its proxy cost calculations reduce the additional costs that are not explicitly accounted for and would need to be accounted for under the projected proxy cost multiplier. These additional costs – greenhouse gas costs, GMC costs, and major maintenance costs – are described in more detail below.

The ISO's proposal for a 125 percent registered cost cap is also based on the analysis of historical fuel price levels and fuel price volatility, the results of which are described in Appendix A to this paper. This analysis found that average spot natural gas prices exceeded the natural gas projected proxy price by at most 10 percent, and this was at most 10 percent of the time.⁴ Thus the 125 percent cap, over a month, more than covers what would generally be the fuel price risk associated with purchasing natural gas on the spot market. The 125 percent cap should also account for any risk in the intra-day markets for natural gas and any non-fuel costs that will still not be accounted for in the proxy cost calculations.

3.2 Greenhouse gas emissions costs

The California Air Resources Board (CARB) is implementing a cap-and-trade program for greenhouse gas (GHG) emissions starting in January 2013.⁵ Under cap-and-trade, an overall limit on GHG emissions from capped sectors, including electricity generating facilities, will be established and facilities subject to the cap will have to acquire allowances to emit GHGs. By slowly lowering the number of available allowances, the cap-and-trade program is intended to reduce GHG emissions to 1990 levels by the year 2020, and ultimately achieving an 80 percent reduction from 1990 levels by 2050.

Consequently, California's thermal generating resources will bear a per-MWh cost associated with the GHG allowances needed for their energy output. Therefore, there is reason to consider including those costs in the cost-based calculations for minimum load and start-up costs, as well as default energy bids and generated bids. Key considerations in defining how those costs might be determined are (1) determining GHG emission quantities and (2) identifying an appropriate price index to use for the GHG allowance cost.

⁴ The values differed for the different locational gas indices used by the ISO.

⁵ More information on the cap-and-trade program is available at following link:
<http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm>

Stakeholder feedback

Nearly unanimously, stakeholders expressed support for the inclusion of costs associated with the CARB's GHG cap-and-trade program.

Southern California Edison (SCE) is concerned about the liquidity and volatility in the GHG allowance market and recommends additional monitoring and safeguards.

Calpine, La Paloma and Western Power Trading Forum (WPTF) support the inclusion of administrative fees associated with the cap-and-trade program. SCE opposes the inclusion of such administrative fees.

Calpine is concerned by the plan to use CARB rather than EPA emissions rates.

California Department of Water Resources – State Water Project (CDWR-SWP) conveyed their concern that consideration of GHG cap-and-trade compliance costs for cost-based calculations stating that this will lessen the incentive of generating resources to reduce GHG emissions.

San Diego Gas & Electric (SDG&E) recommends that a rolling average of the GHG allowance price be used only if the market lacks liquidity.

SDG&E also requests clarification of the ISO's proposal with respect to resources that emit less than 25,000 mtCO₂ each year, and thus do not have a compliance obligation under the cap-and-trade program. Western Power Trading Forum (WPTF) suggests that the ISO defer to the California ARB's published list of entities covered by the cap-and-trade regulation rather than put in an exemption.

Pacific Gas and Electric (PG&E) recommends a separate stakeholder process to address additional cost allocation issues associated with California's GHG cap, such as potential ISO compliance requirements when it imports emergency power. The ISO clarifies that we will not be registered as a Purchasing-Selling Entity for the purpose of completing e-tags, thus will not have a compliance obligation as an importer under the GHG regulations.

Proposal

The ISO proposes to follow the methodology recommended by the Department of Market Monitoring (DMM) for calculating the cost of greenhouse gas allowances.⁶ In summary, the ISO proposes to calculate each unit's greenhouse gas emissions based on the unit's heat rate characteristics, as registered with the ISO, and the emission rate used by the California ARB in assessing GHG compliance obligations. The standard GHG emission rate for natural gas used by the ARB is that which can be calculated under U.S. Environmental Protection Agency regulations and is 0.053165 mtCO₂/mmBTU.⁷ The ISO also proposes to use a different unit-specific emission rate for a unit if the market participant submits documentation that the unit has a different emission rate for ARB compliance purposes.

⁶ DMM's proposal is available at the following link:
http://www.caiso.com/Documents/WhitePaper_CaliforniaGreenhouseGasCap_GenerationVariableCosts.pdf

⁷ U.S. EPA Greenhouse Gas regulation, Subpart C, Table C-1 and C-2,
http://ecfr.gpoaccess.gov/cgi/t/text/textidx?c=ecfr&sid=f095b41950528f0d4d3090382efcd1ce&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl

Commitment Costs Refinements 2012

The ISO proposes that the cost of greenhouse gas allowances be incorporated into the various elements of generators' variable costs as follows:

- Incremental energy costs used for default energy bids and generated bids : Include greenhouse gas allowance costs as a per MWh incremental cost, which can be calculated as:

Allowance cost per MWh =

incremental CO₂ emissions per MWh (mtCO₂/MWh) * 1 allowance per mtCO₂ *
greenhouse gas allowance price

Where,

Incremental CO₂ emissions per MWh (mtCO₂/MWh) = unit's incremental heat rate
(mmBTU/MWh) * (0.053165 mtCO₂/mmBTU)

- Minimum load energy costs: Include greenhouse gas allowance costs as a per MWh cost for a unit's minimum load output, which can be calculated as:

Allowance cost per MWh =

average CO₂ emissions per MWh at minimum load (mtCO₂/MWh) * 1 allowance per
mtCO₂ * greenhouse gas allowance price

Where,

Average CO₂ emissions per MWh (mtCO₂/MWh) = unit's average heat rate at minimum
load (mmBTU/MWh) * (0.053165 mtCO₂/mmBTU)

- Start-up costs: include greenhouse gas allowance costs as a cost per start-up, which can be calculated as:

Allowance cost per start-up =

CO₂ emissions per start-up (mtCO₂/start-up) * 1 allowance per mtCO₂ * greenhouse gas
allowance price

Where,

CO₂ emissions per start-up (mtCO₂/start-up) = unit's start-up fuel requirement
(mmBTU/start-up) * (0.053165 mtCO₂/mmBTU)

Consistent with the DMM recommendation, the ISO proposes that the only greenhouse gas emissions that should be included in cost-based calculations are those that vary with output. Accordingly, the ISO proposes not to include the administrative fees associated with cap-and-trade program compliance in the calculations of costs associated with resource starts or incremental energy output.

Generating resources that do not emit more than 25,000 mtCO₂ in the previous year do not have a GHG cap-and-trade compliance obligation. The ISO proposes not to include greenhouse gas

allowance costs in its calculation of variable costs for these resources. The ISO proposes to rely on the California ARB's assessment of entities that have a GHG cap-and-trade compliance obligation.⁸

Consistent with the DMM recommendation, the ISO proposed to base the GHG allowance price on publically available indices of GHG allowance futures prices. Similar to the current method the ISO uses for determining natural gas prices, the ISO proposes to use the average of prices from three separate commercially published indices. In the event three prices are not available, the ISO will use the average of the prices from two separate indices. The price used will be the published daily settlement price of the California GHG futures product with the next delivery date.

Several market participants expressed concern that these prices could be volatile and/or that liquidity in the secondary market for GHG allowances could be limited. The experience in the secondary market for GHG allowances under the Eastern states Regional Greenhouse Gas Initiative (RGGI) showed that a relatively stable and liquid secondary market developed within the first year.⁹ Since traders would have the experience of that market, it seems that the secondary market for California GHG allowances would develop even more quickly.

The ISO previously proposed to help mitigate any volatility and lack of liquidity in the GHG allowances market by using a 30-day rolling-average of the published index prices. However, stakeholders pointed out that it would be appropriate for the cost-based calculations to reflect any daily volatility in the GHG allowance market. Consequently, the ISO now proposes to: (1) use a daily GHG allowance price for the costs that the ISO calculates daily, (2) use the average of the daily GHG allowance price over the first twenty days of each month to determine allowance costs to be used in the calculation of registered costs to be fixed for the next month.

Some stakeholders commented that the ISO needs to implement additional monitoring and safeguards to protect against manipulation of allowance prices. The ISO believes that this will be an important protection and notes that, as part of the implementation of the GHG cap-and-trade program, the California ARB will be implementing an active market monitoring program to guard against manipulation of allowance prices and the associated indices.

The GHG cap-and-trade program will go into effect on January 1, 2013. The ISO's plan is to implement the inclusion of GHG allowance costs into cost-based calculations at that time. The other elements of this proposal (including the change to the registered cost cap) are planned for implementation along with the separation of the netting of day-ahead and real-time BCR calculations planned for fall 2013 implementation..

3.3 Operational Flow Orders

Natural gas is generally shipped to generating resources via pipelines. Under some conditions pipeline operators may issue Operational Flow Orders (OFO), under which generators will incur financial penalties if their natural gas usage is more or less than a specified tolerance band. These OFOs are typically issued in circumstances that require controlled flow in an effort to protect pipelines or to maintain reliability of natural gas delivery. If a circumstance arises such that the generator is not able to adjust its use of natural gas, it can be assessed an OFO penalty due to its noncompliance with that OFO.

⁸ http://www.arb.ca.gov/cc/capandtrade/covered_entities_list.pdf

⁹ http://www.rggi.org/docs/MM_2010_Annual_Report.pdf, page 5.

The ISO sought stakeholder input into three general issues listed below, and requested identification of additional issues to be addressed:

- The circumstances under which OFO penalties are assessed vary. In concert with stakeholders, the ISO proposed to develop a proposal as to the circumstances under which OFO penalties would be appropriately recovered through the ISO.
- Since an OFO penalty is a daily cost and not an hourly marginal cost (i.e., a per-MWh cost), the structure of proxy commitment costs, default energy bids, or generated bids is not congruous with that of the OFO penalties. The ISO sought input on what mechanism would best be used for compensating generators for OFO penalties that would be appropriately recovered through the ISO.
- There are situations in which multiple generators bundle their purchases of natural gas such that they appear to the supplier as one customer. As a result, the deviation of some subset of generators in that bundled group can cause an OFO penalty to be assessed to the whole group. The ISO sought input into the manner and extent to which these bundling arrangements should be considered in cost recovery through the ISO.

Stakeholder feedback

CDWR-SWP and SDG&E contend that generators can mitigate for the risk of an OFO penalty within their economic bids.

The California Public Utilities Commission (CPUC) advocates that a generator's OFO penalties should be recoverable only when the ISO dispatches a generator in real time, and the generator has elected the proxy cost option.

GenOn, NRG Energy, Sempra United States Gas and Power (USGP), Wellhead, and the Western Power Trading Forum (WPTF) support the inclusion of OFO penalties accounted for in cost-based calculations.

Six Cities recommends that "winter balancing" penalties also be eligible for *ex post* cost recovery.

SCE suggests that penalties for "over burn" as well as "under burn" be considered.

Proposal

The ISO proposal follows the DMM recommendation closely.¹⁰ In summary, DMM recommends that OFO penalty costs can be recovered by market participants *ex post* under circumstances that are attributable to three pre-specified types of ISO dispatch: exceptional dispatch, real-time commitments, and instances of bid mitigation. Following such events, the ISO proposes that stakeholders apply to the ISO for cost recovery with evidence of their OFO penalty associated with either an "over burn" or an "under burn" of natural gas. The OFO penalty costs will be included in a re-evaluation of the real-time BCR calculation for that day with the OFO costs added into the calculation of the generator's net shortfall or surplus over the day.

In contrast with the DMM recommendation, the ISO does not propose to differentiate between resources under the registered cost and the proxy cost option for minimum load as originally proposed by DMM. This recommendation is based on the proposal made in this initiative to change the cap on the registered cost option.

¹⁰ http://www.caiso.com/Documents/DMMMethodology-Account_OperationalFlowOrderPenaltiesIncurred_EnergyDispatches.pdf

Bundled gas customers that receive an OFO penalty need to determine among themselves which party will submit these costs to the ISO for recovery. A mechanism will be required to make sure that no more than 100 percent of any OFO is being recovered by a bundled group of generators.

The ISO does not propose at this time to include cost recovery for natural gas balancing penalties other than Operational Flow Orders.

The ISO further proposes to modify its treatment of NO_x and SO_x emissions so that recovery of costs penalties associated with these emissions are treated in the same way as the OFO penalty cost recovery described here. In particular, if a generator is assessed a penalty for NO_x or SO_x emissions due to an exceptional dispatch or a real-time ISO commitment, the generation owner should submit documentation of that penalty. The ISO will subsequently re-evaluate the generator's real-time bid cost recovery net surplus or shortfall and make adjustments accordingly.

3.4 Grid management charge line item in cost-based calculations

The ISO's grid management charge (GMC) is a charge assessed market participants, and is the cost-recovery mechanism for the ISO. The GMC calculations and allocation were recently changed and are now assessed based on the methodology described in the GMC draft final proposal an excerpt of which is provided below:¹¹

The ISO proposes that the three GMC charge categories be allocated based on gross MWh (capacity and CRR holdings) and MWh (energy). The Market Services category includes awards of ancillary services, and schedules and dispatch instructions of generation, imports, load, and exports. The System Operations category includes all flow quantities for generation, load, imports, and exports. The CRR Services category includes the total MWh quantity awarded through both the allocation process and auction.

The ISO's draft final proposal to allocate the charges as follows to each user of the ISO's services: The Market Services charge will be applied to the scheduling coordinator's gross absolute value of awarded MWh of energy and MW of AS in the forward and real time markets. The System Operations charge will be applied to the scheduling coordinators gross absolute value of actual MWh of real time energy flows. The CRR Services charge will be applied to each scheduling coordinators total MW holdings of CRR that are applicable to each hour. The three administrative charges will be applied to each scheduling coordinator based on their use of the associated transactions.

The GMC charges that fall into the Market Services and System Operations categories are volumetric, meaning that they are based on the MWh quantities either scheduled or injected/withdrawn from the grid. As such the ISO recognizes that inclusion of these costs in the calculations of cost-based bids – default energy bids, proxy minimum load costs, and generated bids – may be appropriate, and sought stakeholder feedback on this issue.

¹¹ http://www.caiso.com/Documents/DraftFinalProposal-2012GridManagementChargeFeb15_2011.pdf

Stakeholder feedback

Stakeholders who commented on this element of the issue paper expressed nearly unanimous support of including volumetric GMC charges into cost-based calculations. Some stakeholders recommended that administrative charges GMC also be included in cost-based calculations.

Proposal

The ISO proposes to include the volumetric elements of the GMC into the proxy start-up, proxy minimum load, default energy bid, and generated bid calculations. In particular, the ISO will include in those calculations the following elements of the GMC calculation: Market Services, System Operations, and \$0.005/ bid segment charge.

The ISO does not propose to include administrative fees in any of the cost-based calculations mentioned above. Examples of administrative GMC charges are the Scheduling Coordinator fee, inter-SC trade fee, and the interest on invoice true-up. Administrative charges are not associated with per-MWh operation; rather, they are related to general costs of participating in the ISO markets.

3.5 Major maintenance adder to the proxy cost calculations

As noted above, there are two options for specification of start-up and minimum load costs, one of which is the proxy cost option. Generators often find that using the proxy cost option to capture start-up and minimum load costs is preferable to the registered cost option because the proxy start-up costs change daily along with the natural gas price index. Election of the proxy cost option enables generators to avoid potential risk associated with fuel price fluctuations over the 30-day period for which the registered cost option is fixed. However, stakeholders have provided feedback on many occasions that a significant drawback of using the proxy cost option is that the current calculation does not consider major maintenance associated with operating a generating unit.

Stakeholder feedback

Stakeholders unanimously support the inclusion of a major maintenance adder as part of cost based calculations for start-up and/or minimum load costs. The point was brought up by several participants that major maintenance expenses are more closely linked to start-up events for generators with certain attributes, and to run-hours for other generators. Several stakeholders indicated in their feedback that a major maintenance adder component to proxy calculations should be robust to such generator characteristics.

Proposal

The ISO proposes that a major maintenance adder should be included in cost-based calculations. Major maintenance expenses are marginal costs to the extent that the schedule for performing such maintenance is based on: the run-hours for the unit, the number of starts, or the energy output.

In support of this effort, the ISO has engaged Potomac Economics to develop default values for major maintenance costs. Potomac Economics will rely on publically available data, experience with development and monitoring of major maintenance cost adders in other markets, and information provided by the ISO and ISO market participants.

Potomac Economics' paper describing their methodology for determining major maintenance costs will be posted to the Commitment Cost Refinements 2012 webpage separately from this draft final proposal.¹²

3.6 Transition costs

Resources modeled using the multi-stage generating (MSG) modeling functionality define their multiple operating ranges and the costs and constraints associated with transitions between the ranges in their master file registration. Currently, there are rules associated with the specification of transition costs.¹³ Based on the impression that the rules were not adequate to enable MSG resources' transition costs to be fully and accurately specified, the ISO proposed to switch from this rule-based approach to proxy transition costs. The proposal was that proxy transition cost values would be based on specific and defined operating characteristics. Today, cost-based calculations consider resource-specific heat-rate data, an index of the natural gas price and, in the case of minimum load costs, operations and maintenance (O&M) costs. When the ISO presented this straw proposal within the recent stakeholder initiative on MSG Enhancements,¹⁴ stakeholders were unanimously opposed to this change. The feedback we received was that the calculation of proxy costs does not consider all of the costs associated with an MSG resource making a transition from one operating configuration to another.

The ISO sought stakeholder feedback on the specific, quantifiable costs associated with MSG transitions that can be captured and used to reflect transition costs through a defined proxy cost calculation.

Stakeholder feedback

CPUC and CDWR-SWP expressed similar sentiments; namely that the costs not captured under the current rules should be explicitly identified and thereafter refining the manner in which transition costs are specified only as needed.

Both NRG and Calpine support a registered cost option for transition costs.

PG&E, Sempra USGP, and SDG&E advocate that transition costs be handled in a manner consistent with the proxy start-up and proxy minimum load calculations. SDG&E further recommends that the proxy transition costs include a fixed adder.

Wellhead recommends that changes to transition costs be considered in a separate stakeholder initiative.

Proposal

The ISO's Board of Governors recently approved the ISO's recommendations to make multi-stage generating unit modeling registration required for certain types of generating resources. This will

¹² <http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostsRefinement2012.aspx>

¹³ Documents related to the commitment costs initiative in which the transition cost validation rules were developed are available at the following link:
<http://www.caiso.com/informed/Pages/StakeholderProcesses/BiddingMitigationCommitmentCosts.aspx>

¹⁴ Documents related to the policy initiative through which MSG enhancements are available at the following link: <http://www.caiso.com/informed/Pages/StakeholderProcesses/Multi-StageGenerationEnhancements.aspx>

effectively triple the number of generators using the MSG functionality many of which have not been through market simulation. Accordingly, the ISO agrees with the feedback provided by the CPUC and CDWR-SWP that more understanding of precisely what costs are not being captured under the existing rules that govern transition costs is needed. Determining what costs – if any – are not covered, and what the benefits of changing dramatically the specification of transition costs might be is premature at this point. In line with feedback from SDG&E, the ISO proposes to further examine the need for changes to the specification of commitment costs at a later date when the fleet of resources modeled through the MSG functionality is more complete.

4 Conclusion

The ISO will conduct an on-site stakeholder meeting to review this straw proposal on April 18, 2012. The ISO appreciates stakeholder comments and discussion on this straw proposal. Please send your comments by close of business on April 23, 2012 to comcosts2@caiso.com.

5 Appendix

Below are several charts depicting analyses of daily natural gas spot prices and futures prices. Spot prices are for the SoCal City Gate, SoCal Border, and PGE City Gate delivery points. The futures price is the maximum NYMEX contract price for the first 21 calendar days of the prior calendar month. (Thus, for example, the February 2002 future price is the max of NYMEX prices for January 1 – 21 of 2002.) Data for SoCal City Gate prices are not included until 3rd quarter 2008.

In the first chart below, the maximum spot price is the highest daily price for the calendar month. They are shown along with the futures prices which are calculated using the methodology described above. Figure 1 shows summer price spikes in 2005 and 2008, but that the volatility of fuel prices has significantly diminished recently.

Figure 1: Natural gas future and monthly maximum spot prices
January 2002 – August 2011

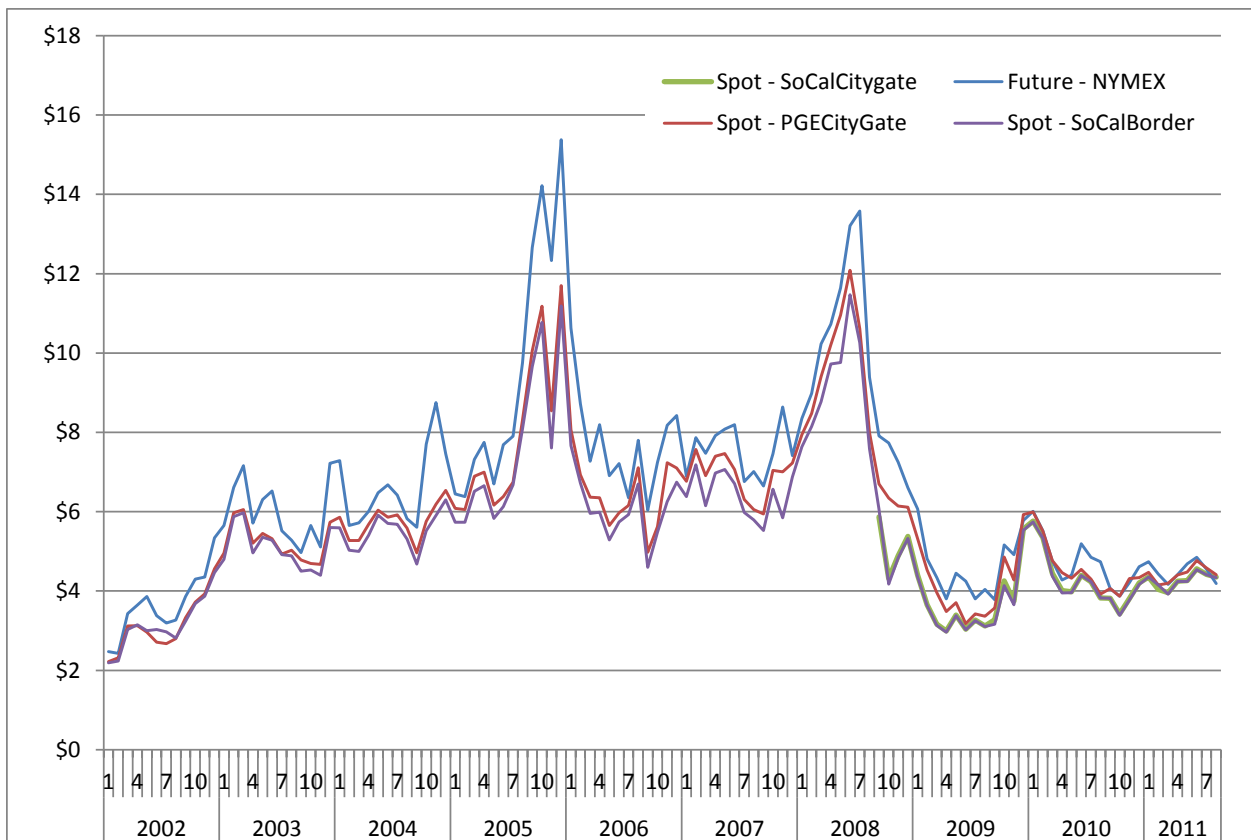
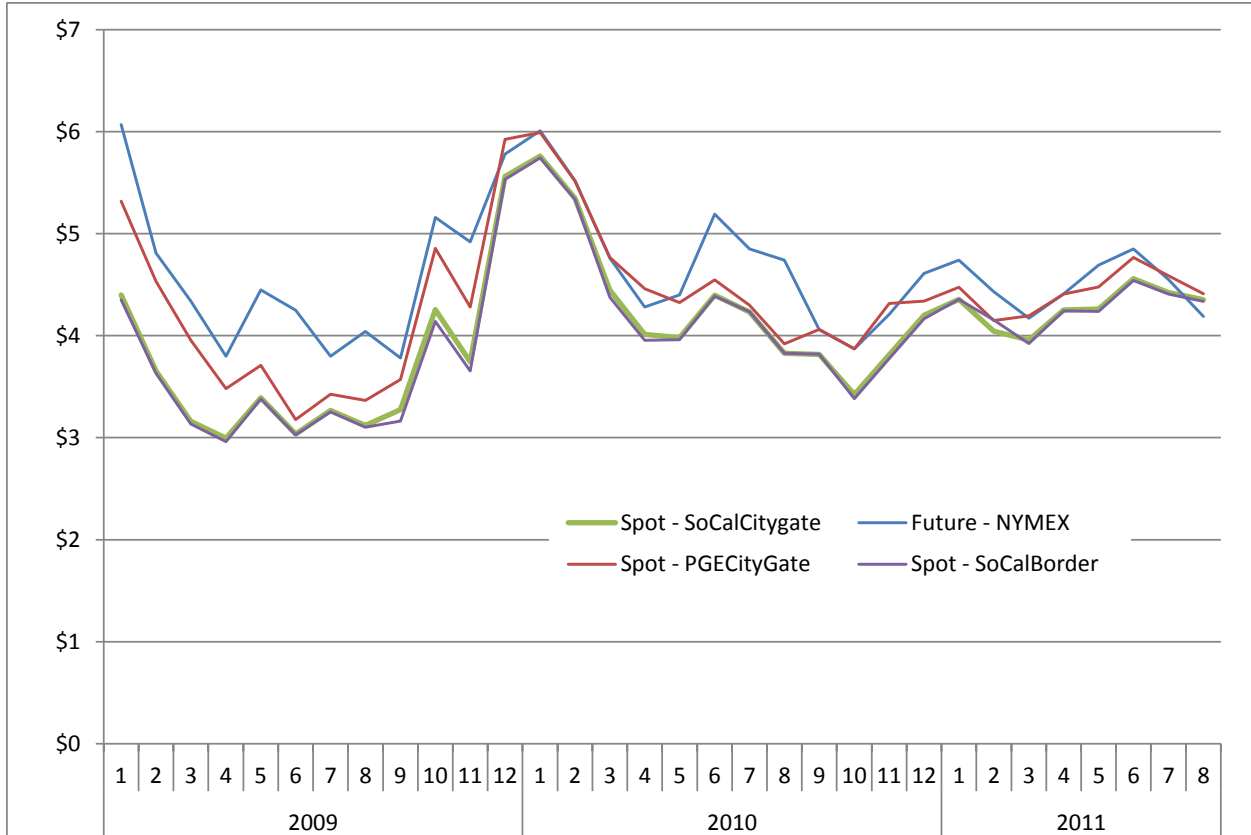


Figure 2, the second of the four charts shows the same data as above, but for a more recent period of time, January 2009 through August of 2011. This chart shows significantly lower price volatility in the last several years.

Figure 2: Natural gas future and monthly maximum spot prices
January 2009 – August 2011

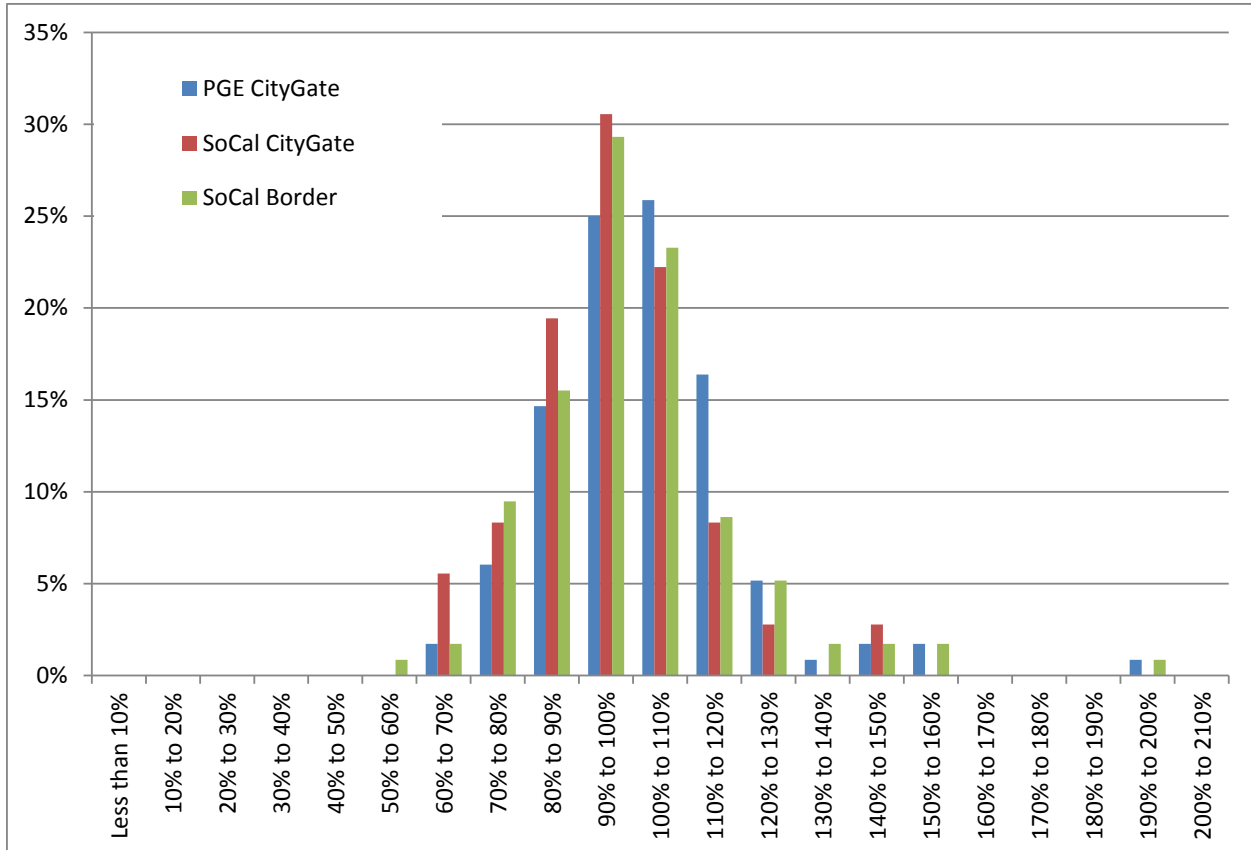


The third and fourth charts below take a different approach to the display of the natural gas prices.¹⁵ To construct Figure 3, first the ratio of the monthly maximum spot price (for each of the three delivery points) as a ratio of the futures price was calculated. Given the sample period, there were 116 observations. The rationale for this calculation is to ascertain the extent to which the futures price is a good instrument by which to hedge against spot price volatility. The percentage differences from each of the monthly maximum spot-to-futures ratio were divided up into bins in 10% increments. For example, if a month's maximum daily spot price were 105% of that same month's futures price, then that would contribute an observation to the "100% to 110%" bin. Also note that the vertical axis is in percentage terms. This describes the percentage of all observations

¹⁵ These analyses follow closely the techniques used by the Department of Market Monitoring when the original registered cost option cap was being developed:
MRTU Market Power Mitigation: Bid Caps for Start-Up and Minimum Load Costs Draft Revised Proposal (August 8, 2007)

that fall into each bin. Again for example, over the entire sample, 25% of the PGE City Gate ratios of maximum spot price to futures price were in “90% to 100%” bin.

**Figure 3: Frequency of maximum spot as a percentage of futures price
January 2002 – August 2011**



The data behind Figure 3 are included below:

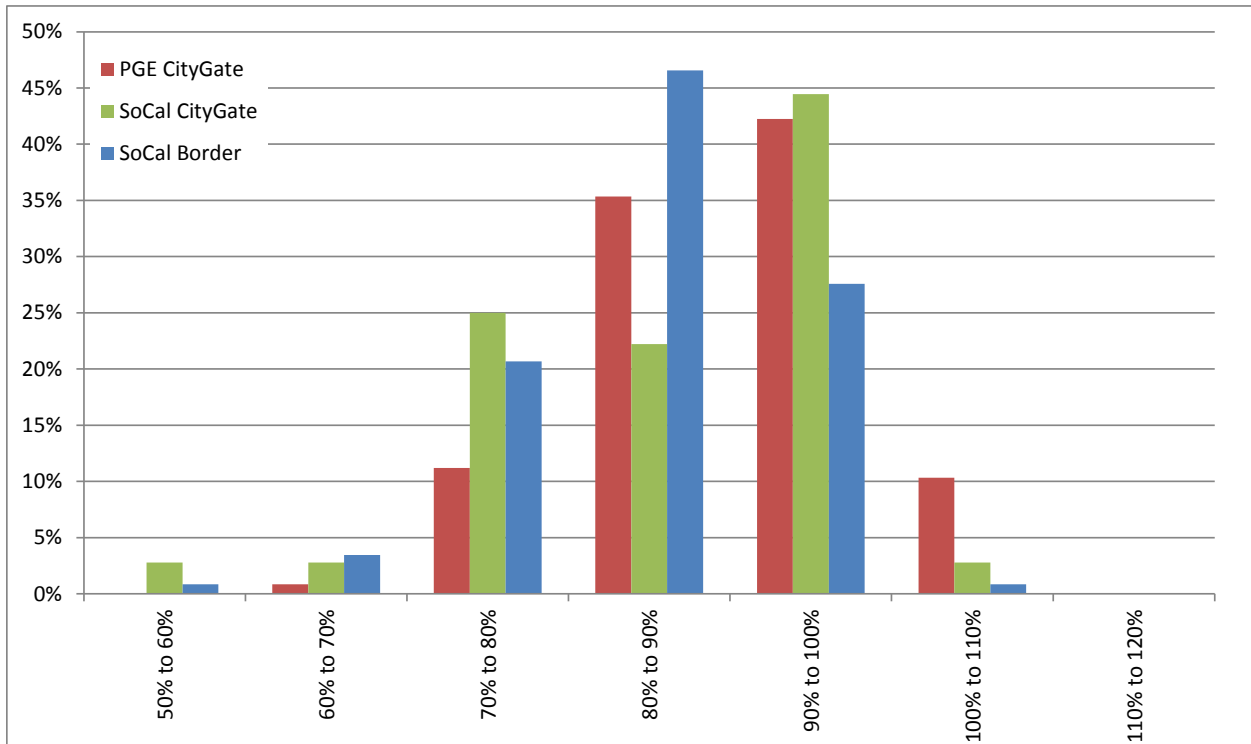
Bin	PGE CityGate	SoCal CityGate	SoCal Border
Less than 10%	0%	0%	0%
10% to 20%	0%	0%	0%
20% to 30%	0%	0%	0%
30% to 40%	0%	0%	0%
40% to 50%	0%	0%	0%
50% to 60%	0%	0%	1%
60% to 70%	2%	6%	2%
70% to 80%	6%	8%	9%
80% to 90%	15%	19%	16%
90% to 100%	25%	31%	29%
100% to 110%	26%	22%	23%
110% to 120%	16%	8%	9%
120% to 130%	5%	3%	5%

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130% to 140%	1%	0%	2%
140% to 150%	2%	3%	2%
150% to 160%	2%	0%	2%
160% to 170%	0%	0%	0%
170% to 180%	0%	0%	0%
180% to 190%	0%	0%	0%
190% to 200%	1%	0%	1%
200% to 210%	0%	0%	0%

Figure 4 shows utilizes the same basic principle as that used for Figure 3, however, the %age differences from each of the monthly average spot-to-futures ratio were divided up into bins in 10% increments. This chart shows what one would expect: that the ratio of average spot-to futures price is skewed reflecting the risk premium associated with buying natural gas in advance. By buying a futures contract, one pays a premium to lock in that monthly price. Still, for over 90% of all three delivery points fall into the bins spanned by 70% to 100%.

**Figure 4: Frequency of average spot as a percentage of future
January 2002 – August 2011**



The data behind Figure 4 are included below:

Bin	PGE CityGate	SoCal CityGate	SoCal Border
50% to 60%	0%	3%	1%
60% to 70%	1%	3%	3%

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70% to 80%	11%	25%	21%
80% to 90%	35%	22%	47%
90% to 100%	42%	44%	28%
100% to 110%	10%	3%	1%
110% to 120%	0%	0%	0%

Attachment D – Addendum to Draft Final Proposal
Amendment to Further Enhance Cost Recovery by Generating Resources
California Independent System Operator Corporation
August 30, 2013



California ISO
Shaping a Renewed Future

Addendum to the Draft Final Proposal

Commitment Costs Refinements 2012

April 27, 2012

Commitment Costs Refinements 2012

Prepared for discussion at a stakeholder conference call – May 2, 2012

1 Introduction and background

The economic commitment of a generating resource in the ISO markets is based on its market energy and ancillary service bids as well as the cost of starting up the resource and its costs at its minimum operating level (pmin). That is, commitment costs – start-up (SU) and minimum load (ML) costs – are integral to the optimization’s choice to utilize the resource. Furthermore, commitment costs are part of the ISO’s bid cost recovery (BCR) calculation that determines whether or not a resource has a revenue shortfall over the course of a day. If, based on the BCR calculation, the resource does have a shortfall – meaning that its commitment and market bid costs are not covered by its market revenues – then the resource receives a BCR uplift payment. Thus, the accurate specification of a resource’s commitment costs is critical to efficient commitment and fair compensation of generating resources in our market.

Since the implementation of the ISO’s LMP market design on April 1, 2009, the ISO has made several market rule changes to increase the options and flexibility for market participants to specify start-up and minimum load costs. In the Commitment Costs Refinements 2012 initiative, the ISO and stakeholders have evaluated additional improvements to the specification of start-up and minimum load costs. Specifically, the ISO proposed costs associated with greenhouse gas emissions, the volumetric elements of the ISO’s grid management charge, and a fixed adder to cover major maintenance expenses be included in cost-based calculations.

In conjunction with incorporating these additional costs components into the ISO’s proxy cost calculations, the registered cost cap for minimum load and start-up costs was proposed to be reduced from 200 percent to 125 percent of the respective projected proxy cost, as calculated by the ISO for the resource every 30 days.

In this addendum to the draft final proposal for the commitment costs refinements initiative, the ISO proposes to modify the proposed level of the registered cost option cap from 125 percent of the projected proxy cost value to 150 percent of the projected proxy cost value.

2 Process and Timetable

The timeline for the brief stakeholder process associated with this addendum is included below:

April 27	Draft final proposal posted
May 2	Stakeholder conference call
May 7	Comments due *
May 16-17	Board of Governors meeting

* Please e-mail comments to comcosts2@caiso.com

3 Change to the draft final proposal with respect to the cap for registered start-up and minimum load costs

The current structure for generators to specify start-up and minimum load costs allows for two options: (1) the proxy cost option which is variable and tied to the natural gas price index and the heat-rate characteristics of the generating resource, and (2) the registered cost option which is a static value that is fixed for a minimum of 30 days after it is specified by the generator. Currently, the cap on the value that may be specified for the registered cost option for either start-up or minimum load is currently equal to 200 percent of the resource-specific projected proxy cost value as calculated by the ISO every 30 days.

The original motivation for providing the registered cost option was the recognition that there were potentially costs associated with starting up a resource and/or operating at minimum load that were not captured within the projected proxy cost calculation. Thus, the original intent of the registered cost option for start-up and minimum load costs was (1) to enable market participants to bid in higher start-up and minimum load costs for resources with non-fuel related costs not captured in the variable operations and maintenance (O&M) adder, and (2) to account for expected fuel price volatility. The current 200 percent cap on the static registered cost value was set so as to enable market participants to account for these cost elements while mitigating exposure to some – but not all – fuel price risk.

However, the ability to register minimum load costs up to 200 percent of actual costs served as a key mechanism in adverse market behavior that inflated bid cost recovery (BCR) uplift payments in the first half of 2011. This resulted in two emergency filings to revise the tariff's bid cost recovery provisions. Although these filings addressed the observed behavior, there may still be opportunities to exploit this 200 percent cap. This could involve: (1) resources bidding in such a way as to receive BCR in the DA market and then not delivering the DA schedule in real-time, or (2) deviating in real-time to avoid shutdown instructions. Both of these strategies could be profitable if a resource can earn minimum load costs that are in excess of its actual minimum load costs. Additionally, the ISO has recognized the ability and incentive to exploit these and other opportunities to increase bid cost recovery would be increased under the separation of the netting of day-ahead and real-time bid cost recovery calculations. As a result, the ISO is proposing bid cost recovery mitigation measures that are designed to mitigate the potential to increase bid cost recovery payments by not following ISO dispatch instructions and will also scale bid cost recovery payments to account for undelivered energy. Consequently, and also because we have proposed to explicitly incorporate additional costs into its calculated proxy costs for resources, the ISO has proposed as part of this initiative to lower this 200 percent cap.

The ISO proposes to keep the registered cost option to accommodate resources that have costs that are not incorporated into the proxy cost calculation. However, these additional costs should in the future be more limited as a result of this proposal. The additional cost components the ISO is also proposing to incorporate into its proxy cost calculations reduce the additional costs that are not explicitly accounted for and would need to be accounted for under the projected proxy cost multiplier. These additional costs – greenhouse gas costs, GMC costs, and major maintenance costs – are described in the draft final proposal and no changes are proposed to these elements of that proposal.

In this addendum to the draft final proposal, the ISO maintains the proposal to keep the registered cost option, but is now proposing a more measured approach to lowering the registered cost cap and is revising the proposal reduce the current 200 percent cap to 150 percent of the projected

proxy cost instead of lowering the registered cost cap to 125 percent of the projected proxy cost as previously proposed.

Stakeholder and Market Surveillance Committee feedback

Many stakeholders who provided feedback on the commitment costs refinements policy initiative had significant concerns about the proposed lowering of the cap for registered start-up and minimum load costs. Specific concerns included intra-day gas price volatility, the exposure of natural gas price risk for low-capacity factor resources, and natural gas balancing penalties (other than operational flow orders, which are addressed in the draft final proposal).

The ISO does not proposal to change the “safety valve” that allows a resource with registered costs (start-up or minimum load) to switch from registered costs to proxy costs if natural gas prices spike such that the calculated proxy value exceeds the resource’s registered costs.¹

Stakeholders also contended that there are significant opportunity costs associated with starting up and running a resource if that resource is subject to contractual or environments constraints. This concern was strongly echoed by the Market Surveillance Committee in the March 30, 2012 meeting of that committee.

Stakeholders also raised some concern about the potential volatility and illiquidity of the GHG market upon its initial start-up in January of next year. The timing of the current anticipated implementation dates for all the other commitment costs proposal elements (that is, all but the GHG allowance cost adder) gives 9 months for the GHG market prices to settle before the registered cost cap is dropped.

Given these concerns, the ISO is revising the proposal for lowering the registered cost cap. The ISO believes that this will enable generators with costs not included in the new proxy cost calculation to have more flexibility to account for them through the registered cost option. Moreover, the new bid cost recovery mitigation measures being proposed by the ISO will mitigate current adverse incentives to increase bid cost recovery payments by not following ISO dispatch instructions.

Addendum to the Draft Final Proposal

In this addendum to the draft final proposal, the ISO maintains the proposal to keep the registered cost option, but revises the proposal to change the registered cost cap to 150 percent of the projected proxy cost. This change is made in light of the stakeholder and MSC feedback described above.

4 Conclusion

The ISO will conduct a stakeholder conference call to review this addendum to the draft final proposal on May 2, 2012 from 10:00 to 11:00 a.m. The ISO appreciates stakeholder comments and discussion on this addendum. Please send your comments by close of business on May 7, 2012 to comcosts2@caiso.com.

¹ Please see CAISO Tariff section 30.4.1.2.

Attachment E – Implementation Details Document
Amendment to Further Enhance Cost Recovery by Generating Resources
California Independent System Operator Corporation
August 30, 2013



Commitment Cost Refinements 2012 Implementation Details

April 25, 2013

Commitment Cost Refinements 2012 Implementation Details

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Introduction

This document provides details of the CAISO's proposed approach for implementing components of the policy developed as part of the *Commitment Costs Refinements 2012* stakeholder initiative:

- Including generator major maintenance costs in start-up and/or minimum load costs
- Providing generators with the opportunity to recover the costs of natural gas pipeline operational flow order penalties under certain circumstances
- Making reimbursement of NOx and SOx emission penalties consistent with the method used for operational flow order reimbursement
- Including costs for the ISO grid management charge (GMC) in generator start-up costs

The CAISO previously committed to providing additional information, prior to developing tariff language, regarding how market participants will submit the cost information that will be used to develop generator-specific major maintenance costs to be included in start-up and/or minimum load costs. In addition, the CAISO has determined that the details of implementing (1) operational flow order penalty cost reimbursement, (2) modifying reimbursement of NOx and SOx emission penalties, and (3) including GMC costs in generator start-up costs would benefit from further discussion with stakeholders prior to developing tariff language.

As background, the CAISO Board of Governors authorized the ISO In May 2012 to submit tariff language to the Federal Energy Regulatory Commission to implement the policy developed in the *Commitment Costs Refinements 2012* stakeholder initiative. The ISO plans to begin developing this tariff language in May, and plans to submit the tariff amendment to the Commission in mid-July to become effective October 1, 2012. In addition to the topics listed above, the Commitment Costs Refinements 2012 stakeholder initiative also provided for (1) a reduction to the registered cost cap for minimum load and start-up costs, (2) including greenhouse gas allowance costs in the CAISO market, and (3) including GMC charges in default energy bids, proxy minimum load costs, and generated bids., . The greenhouse gas allowance costs have already been incorporated into CAISO markets. The other changes discussed in this paper, along with the straightforward inclusion of GMC costs into minimum load costs and bids, will improve proxy cost estimation, making the reduction in the registered cost cap possible, and these will be incorporated into the ISO tariff at the same time.

Major Maintenance Cost Adder

Under the Commitment Costs Refinements 2012 policy changes, the proxy minimum load and start-up costs the ISO calculates for generation resources will include an adder for major maintenance costs that are related to the number of hours a unit is operated or the number of times it is started. The CAISO has contracted with the independent entity that calculates default energy bids and greenhouse gas adder, Potomac Economics, to develop a template for resources to submit the relevant data, and to undertake the calculations of the major maintenance adder. Along with this paper the CAISO is posting the

template, instructions, and examples developed by Potomac Economics at <http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostsRefinement2012.aspx>. The CAISO had previously committed to providing this additional information before developing tariff language for including generator major maintenance costs in start-up and/or minimum load costs so that market participants could consider it during their review of the tariff language.

The ISO has realized that previously there has not been a discussion of how major maintenance adders would be calculated for multi-stage generating plants which may have several different configurations specified in the Master File. Since the different configurations may use different combinations of the various components of the MSG unit, there may be different major maintenance costs for the various configurations. For example, a combined cycle plant with two combustion turbines and a steam heat recovery unit might have a configuration that is only one combustion turbine running, and a second configuration that has both combustion turbines and the steam heat recovery unit running. The first configuration only impacts the major maintenance associated with the first combustion turbine, while the second configuration impacts major maintenance on all three elements.

The CAISO proposes to implement the major maintenance adder for MSG units in the following manner. For each configuration of a MSG which is a start-up configuration, Potomac Economics will calculate the major maintenance adder related to the number of start-ups for inclusion in the calculation of proxy start-up costs, and the major maintenance adder related to the number of hours a unit is operated for use in the proxy minimum load cost calculation. For those configurations which are not start-up configurations, only the major maintenance adder related to the number of hours a unit is operated will be calculated for use in the proxy minimum load cost calculations. For situations when a unit is moved to a configuration which is not a start-up configuration, the MSG provides the CAISO with the transition costs, subject to certain constraints, so that any major maintenance costs due to a start-up of specific component in transitioning into the configuration can be included in the transition costs.

The template developed by Potomac Economics should provide sufficient flexibility to allow MSGs to include the necessary cost information to determine the major maintenance adders for all the configurations specified in the Master File. Potomac Economics will be able to speak to this during the stakeholder conference call, and in the future will provide an example of how an MSG would submit its data on the template.

Operational Flow Order Penalties

The *Commitment Costs Refinements 2012* policy changes include provisions for the costs incurred by generators as a result of natural gas pipeline Operation Flow Order (OFO) penalties to be included in the calculation of real-time bid cost recovery under certain limited circumstances. These are circumstances in which the operational flow order penalty costs could not reasonably be avoided by the resource and where the potential penalty costs are not considered in the energy bids submitted for a generator:

- Exceptional dispatch
- Real-time commitment to minimum load

- Instances of bid mitigation.

The policy included provisions for market participants to provide the actual costs of OFO penalties to the ISO, which will then verify them before including them in the bid cost recovery calculations. This section describes how the ISO intends to implement this policy. The paper discusses in detail the circumstances in which generators will be eligible to have OFO penalty costs included in their bid cost recovery, how they will submit the data on the costs, and how these costs will be verified.

The intent of the policy is that market participants will be eligible to seek recovery of OFO penalties costs when they were caused by ISO actions and were unavoidable and not anticipated by the market participant. This is important so that CAISO cost recovery does not undermine the purpose of OFOs, which is to keep the natural gas pipeline system within certain bounds in stressed conditions. This general policy has several more detailed implications, which are described below:

1. The ISO will reimburse for OFO costs due to exceptional dispatch only in circumstances only when the price paid for the exceptional dispatch is mitigated to its default energy bid or when a resource is dispatched without a submitted real-time bid. This is because market participants have the opportunity to include the costs of potential OFO penalties in their real time energy bids and presumably would do so.

OFOs are typically known the day before the operating day, and certainly before real time bid submission deadlines. If generators are subject to an OFO, their real-time bids would presumably include the costs of potential OFO penalties. Consequently, if a resource is dispatched in real-time, including through exceptional dispatch, it is reasonable to assume that its bids are sufficient to cover potential OFO penalty costs.

2. If a generator receives an exceptional dispatch instruction without a submitted energy bid then it is paid its default energy bid. Since the default energy bids do not include OFO penalty costs, it is reasonable to provide for OFO cost reimbursement if a resource is exceptionally dispatched without a bid. As included in the policy changes resulting from the *Commitment Costs Refinements 2012* policy, a generator would be eligible for OFO cost reimbursement if it is not dispatched in the IFM, but in real-time is dispatched to its minimum load level. In this case, the costs of an OFO penalty would be included in the minimum load and start-up costs used to calculate the real-time bid cost recovery. This is simply an extension of the existing rules for start-up and minimum load costs which recognize that these costs may not be fully recovered by the bid price if the generator is run at minimum load, and includes these costs in the calculation of real-time bid cost recovery. This does not apply if the unit was dispatched in IFM, is exceptionally dispatched beyond the minimum load level, or, as explained in the next section, the exceptional dispatch is at such a time that the market participant can avoid OFO penalties by changing its gas nominations.
3. The ISO will not include OFO penalties in real time bid cost recovery when market participants could have adjusted natural gas nominations to avoid the penalty. This includes making use of the 3pm intra-day nomination opportunity to adjust natural gas schedules.

The CAISO will not include OFO penalties in real time bid cost recovery if a generator would have been able to adjust the scheduled gas flow to avoid the OFO penalty. Since there is an opportunity at 3pm to adjust the intra-day gas flows, any exceptional dispatch occurring sufficiently before 3pm to allow the generator to adjust the nominated gas flow will not cause the CAISO to consider OFO penalties costs in real-time bid cost recovery. The CAISO's initial assumption is that 1 hour is sufficient time. The CAISO seeks comments from stakeholders on whether this is an appropriate time period. Thus, only exceptional dispatch, or real-time dispatch, occurring after 2pm on a gas day will be eligible for consideration of OFO penalties in the real-time bid cost recovery. The CAISO recognizes that currently the gas day does not coincide with the calendar day, so the period when OFO penalties can be considered in real-time bid cost recovery is actually after 2pm through the start of the next gas day at 7am the following morning.

4. Similar to exceptional dispatches, units that receive real-time dispatch will only be eligible to include OFO penalty costs in their real-time bid cost recovery if their energy bid cleared in the market is mitigated.

Since market participants will know that an OFO is in effect before real-time bids are due, they will have the opportunity to include any potential OFO penalty costs in those bids. Thus, for real-time dispatch, unless the bids from a generator are mitigated to the default energy bid, OFO penalty costs will not be eligible for inclusion in real-time bid cost recovery.

5. Real-time bid cost recovery only applies to OFO penalties, not to other natural gas balancing penalties, such as for violating Emergency Flow Orders or Curtailment Orders.

The CAISO recognizes the critical importance of the reliability of the natural gas delivery systems, and does not wish to provide potential incentives that might cause generators to undertake actions which would jeopardize the reliability of the natural gas transmission and distribution systems. Thus, the CAISO wishes to clarify that it will only consider the costs of penalties for violation of OFO orders. It is the understanding of the CAISO that OFOs are issued when pipelines expect that they may incur additional costs if customers fail to properly balance their deliveries and burns, but that this doesn't generally threaten the reliability of the system. As such, the penalties are meant to discourage customers from being out of balance, and to compensate the system, and other customers, for costs of balancing. The situation is different when the pipeline issues an order to curtail usage on specific pipeline, or issues Emergency Flow Orders. In these cases, the reliability of the natural gas pipeline system may be risk and the CAISO will not allow penalties under these conditions to be considered for real-time bid cost recovery so as not to provide any possible incentive for generators to violate these orders. In these situations the generators should communicate to the CAISO that they are under a curtailment or emergency flow order so that the CAISO will be aware of these restrictions, and if necessary for the reliability of the electric grid, the CAISO can coordinate with the natural gas pipelines' control centers to ensure the best reliability for both systems.

6. Scheduling Coordinators seeking to have OFO penalties included in the calculation of real-time BCR will be required to submit proof of the OFO penalties.

In order for the CAISO to consider OFO penalties in the calculation of real-time bid cost recovery, the scheduling coordinator for the generator will be required to submit to the CAISO the bill from the natural gas supplier for the generator indicating the charges for the OFO penalty for the specific gas day attributable to the specific generator. If the bill is not directly from the pipeline to the generator, but instead a bill from a balancing agent responsible for providing gas and balancing services to a group of gas customers, the scheduling coordinator submitting the OFO penalties for inclusion in the BCR recovery must indicate how the OFO penalty costs are attributed to the generator, and indicate any other generation included in the balancing group. Additionally, the scheduling coordinator must submit a copy of the OFO order clearly indicating the tolerance band and penalty rate for the OFO order. The CAISO will propose that it will have the right to audit any of these submissions. The CAISO also proposes that these requests for consideration of OFO penalties must be received within 60 calendar days of the penalty date.

Due to the potential large number of different billing entities, the CAISO requests stakeholders provide input, prior to developing the tariff language for the OFO policy, on the form of the bills and how they might best be submitted. The CAISO specifically requests input from stakeholders on how OFO penalties are displayed on the bills and whether this includes information on the specific day of the penalty and which generator is responsible for the penalties.

If the natural gas is provided by a balancing agent with several generators included in the balancing group, an OFO penalty that meets all other requirements may have appropriate portions assigned to more than one specific generator. These portions may be included in the real-time bid cost recovery calculations for all specific generators with eligibility, if those generators have requested recovery of their share of the OFO penalty. In no case will the total of these portions included in the real-time bid cost recovery exceed the overall OFO penalty for the balancing agent.

7. The CAISO will include in the BCR Calculation the lesser of the actual penalty shown on the bill submitted by the Scheduling Coordinator for the generator, or the estimated OFO penalty amount.

Using the information provided by the Scheduling Coordinator, along with the generator's day-ahead dispatch MW amounts, the heat rate curve for the generator, and the real-time dispatch for the resource, the CAISO will calculate an estimated OFO penalty amount. The calculation will be as follows.

First, the amount of gas throughput from the day-ahead schedule is calculated. The formula uses a short-hand notation for calculating the natural gas through-put from the heat rate curve by showing this as a simple multiplication.

$$\text{DADT} = \text{DAMW} * \text{AHR}$$

Where DADT = day ahead gas throughput in dekatherms

DAMW = day ahead dispatch in MW. Note this includes MW from 2 different day ahead CAISO market runs to match the 7am to 7am gas day

AHR = heat rate curve for the generator

Second, the amount of gas throughput from real-time dispatch for which the generator can adjust his gas nominations is calculated:

$$RTADT = RTAMW * AHR$$

Where RTADT = real time adjustable dekatherms - real time dispatch gas throughput which the generator can adjust for by using intraday nominations

RTAMW = real time adjustable MW

The total amount of gas throughput which was able to be nominated is then calculated. This is the assumed to the amount of gas which the generator should have scheduled.

$$BDT = DADT + RTDT$$

Where BDT = Balancing level of gas throughput

Real-time dispatched MW can be split into three categories. The first are the MWs for which the generator can adjust its gas nominations. The remaining MW of real time dispatch is further split into those MW which are the responsibility of the generator because they were dispatched and/or paid based on an unmitigated bid, even if they were from exceptional dispatch, and those MW of real-time dispatch or exceptional dispatch which are paid either at a mitigated bid price or which were exceptionally dispatched when there was no bid.

$$RTMW = RTAMW + RTGMW + RTCMW$$

Where RTGMW = real time dispatch which cannot be adjusted for through the intra-day nominations, but which are not to be included in the BCR calculation and are the responsibility of the generator.

RTCMW = real time dispatch MW which cannot be adjusted for through intra-day nominations and are eligible to be included in the BCR calculation.

$$RTGDT = RTGMW * AHR$$

$$RTCDDT = RTCMW * AHR$$

The estimated OFO penalty is calculated using the two types of real-time MW for which gas nominations could not be adjusted, the total amount of gas throughput which was assumed nominated, and the tolerance level and penalty rate from the OFO. In addition, the CAISO is proposing to adjust the real-time MW for which gas nominations could not be adjusted up by 10% to account for any inaccuracies in using the average heat rates.

Estimated OFO penalty =

If $RTGDT + RTCDT > 0$

$$\{ [RTGDT + RTCDT] * (1.1) - [BDT * Tolup] \} * Pen$$

Where

Tol = under-delivery tolerance level for the OFO

Pen = penalty rate for OFO

If $RTGDT + RTCDT < 0$

$$\{ [BDT * (1 - Tol\down)] - [RTGDT + RTCDT] * (1.1) \} * Pen$$

Where

Tol\down = over-delivery tolerance level for the OFO

The amount of the Estimated OFO penalty which would be included in the BCR calculation would be

$$BCR\text{amount} = [RTCDT / (RTCDT + RTGDT)] * (\text{estimated OFO penalty})$$

The lesser of BCRamount or the actual OFO penalty shown on the bill can be included in the BCR calculation, subject to a check that the total OFO penalty shown on the bill is not being over collected by multiple generators within the balancing group.

8. If an OFO penalty from a balancing natural gas supplier is submitted by more than one generator, the sum of the amounts included in BCR calculations for all eligible generators must be less than or equal to the OFO penalty.

This recognizes that sometimes an OFO penalty may not just be attributable to one generator, but may actually have resulted from dispatches of more than one generator in the same gas balancing group. This allows more than one generator to request the inclusion of the appropriate share of the OFO penalty in its BCR calculation, but limits the overall amount included in all BCR calculations to no more than the actual penalty.

The inclusion of these costs in the calculation of the bid cost recovery amounts does not necessarily mean that generators will see their CAISO settlement revenue increased; if the total revenue received from the CAISO real-time markets is sufficient to cover the BCR amount, there is no need for additional recovery and no adjustments are made.

Emissions Penalties

The CAISO will change its process for providing generators with recovery for SO_x and NO_x emission penalties incurred due to CAISO dispatch or exceptional dispatch. The CAISO is proposing this change in procedure to make the recovery of these costs correspond to the recovery of the OFO penalty costs. Similar to how OFO penalties will be treated, generators which incur penalties for emissions of NO_x and SO_x from being dispatched in real-time with their bid mitigated, or from being exceptionally dispatched and not paid at least their as-bid price, and will be able to seek recovery of these costs through their inclusion in the real-time bid cost recovery

As with the OFO penalties, generators will only be eligible to submit emission penalties for inclusion in the calculation of real-time bid cost recovery when the generator is unable to recover the costs through its bid price. For real-time dispatch this would only occur when the generator's bids have been mitigated. In the absence of bid mitigation the CAISO assumes that the generator has incorporated the costs of any possible emission penalties into its bids. For exceptional dispatch this could occur if the resources was exceptionally dispatch and had not submitted a real-time bid, or again, where the price paid for the exceptional dispatch is mitigated.

In order for these costs to be considered in the bid cost recovery calculations, the generator will be required to submit the bill from the air pollution control district, demonstrate how the penalty is related to the CAISO dispatch or exceptional dispatch, and demonstrate that the conditions for inclusion are met. The CAISO will retain the authority to audit any such submission. The CAISO also proposes that these requests for consideration of emission penalties must be received within 60 calendar days of the penalty date. If the emissions covered by the penalty are only partially eligible for recovery, the proportion of the penalty relating to the eligible MWs will be calculated and used. If approved, the costs will be included in the real-time bid cost recovery calculation.

The adoption of these rules for recovery of emission costs will mean that the current method for recovery of these costs, detailed in section 11.18 of the CAISO tariff, will be removed and replaced. The existing Emission Cost Charge and Emission Cost Trust Account will be phased out. If emissions costs are recoverable through the bid cost recovery, they will be recovered in a similar fashion to other cost recovered through the bid cost recovery process.

CAISO GMC Costs Inclusion in Generator Start-up Costs

The policy changes resulting from the Commitment Cost Refinements 2012 initiative also will modify proxy minimum load costs, start-up costs, generated energy bids, and proxy energy bids to include the volumetric elements of the CAISO's grid management charge, i.e. the amounts charged per MWh of energy production. This is straight-forward for the minimum load costs and energy bids, since these elements can easily incorporate the per MWh volumetric elements. However, the ISO calculates start-up costs based on fuel consumption so it is not possible to directly apply the volumetric grid management charges to start-up costs. The ISO could potentially collect information on the energy produced per each start-up cycle, but there would be no straightforward way to validate this

information. Consequently, the ISO proposes to calculate volumetric GMC charges per start-up based on the simple methodology described below.

The volumetric grid management charges which are to be included in these costs are market services, system operations, and \$0.005 per megawatt hour bid segment charge. The rate effective for 2013 for these three charges is \$0.3880 /MWh. For most generators it is anticipated that including these costs into start-up costs will result in only a small change in start-up costs. Because of this small anticipated impact, the CAISO proposes to implement the inclusion of the GMC costs into start-up costs in a simple and easy method, which makes use of data already available to the CAISO. First, a simple estimate of start-up energy is calculated. This is multiplied by the appropriate GMC rate to determine the GMC start-up cost estimate:

$$\text{Startup Energy} = (\text{Pmin} / 2) * \text{Startup Time Period}$$

$$\text{GMC startup cost} = \text{Startup Energy} * \text{GMC rate}$$

Where:

$$\text{Startup Time Period} = \text{period from initial sync with the grid to Pmin}$$

The CAISO does not propose using the total start-up time to avoid paying generators for the time to heat up boilers before any power is delivered to the grid. Since the GMC only applies to megawatts flowing into or off the grid, the generator does not pay the GMC until its unit is synced to the grid and delivering power, so these costs should not be included in the start-up costs.

The CAISO seeks stakeholder comments on the appropriateness of this estimate of GMC costs to be included in start-up costs. Stakeholders are encouraged to suggest modifications which would improve the accuracy of the calculation, but are also encouraged to consider the complexity of their proposed modifications relative to the potential financial impacts.

Next Steps

The CAISO will hold a stakeholder call on May 1st, from 10am to 12 pm to discuss these issues. Representatives from Potomac Economics will be available to discuss the template and calculations for the Major Maintenance Adder. Specific information on this conference call is available on the CAISO website.

The CAISO will also post a comment template for stakeholders, and comments will be due on May 10th. If necessary, the CAISO will issue a revised Implementation Detail Proposal as part of the tariff development process, which will begin in May.

Attachment F – MSC Opinion

Amendment to Further Enhance Cost Recovery by Generating Resources

California Independent System Operator Corporation

August 30, 2013

**Opinion on
Bid Cost Recovery Mitigation Measures and Commitment Costs Refinement**

by

**James Bushnell, Member
Scott M. Harvey, Member
Benjamin F. Hobbs, Chair
Shmuel S. Oren, Member**

Members of the Market Surveillance Committee of the California ISO

May 7, 2012

1. Introduction and Summary

The Market Surveillance Committee (MSC) of the California Independent System Operator has been asked to provide an opinion on the ISO's proposals on bid cost recovery (BCR) mitigation¹ and commitment costs.² Earlier versions of the BCR and commitment cost proposals have been discussed during MSC meetings in 2011 and, most recently, at the March 30, 2012 MSC meeting. In addition, MSC members have participated in stakeholder calls and have reviewed stakeholder comments submitted to the ISO.

These proposals are part of the ISO's initiative to provide incentives for increased flexibility in real-time markets to facilitate integration of variable renewable power sources into the ISO markets. As part of that initiative, the ISO Board approved two elements of Phase I of the Renewable Integration: Market and Product Review³ at the December 2011 board meeting. These elements included lowering of the bid floor in two stages and revision of the bid cost recovery mechanism (BCR) to allow for separate calculation of BCR in the day-ahead and real-time markets. Among other features, the proposal included a feature to detect and disqualify persistent uninstructed energy deviations from BCR. This is because the current ISO BCR design can offer incentives for generators to offer very high bids for part of their capacity output range and then to deviate from real-time instructions in a way that would result in high energy as-bid costs and BCR.

¹ *Bid Cost Recovery Mitigation Measures, Draft Final Proposal*, CAISO, April 6, 2012, www.caiso.com/Documents/DraftFinalProposal-BidCostRecoveryMitigationMeasures.pdf; *Addendum to Bid Cost Recovery Mitigation Measures Draft Final Proposal*, CAISO, April 27, 2012, www.caiso.com/Documents/Addendum_BidCostRecoveryMitigationMeasuresDraftFinalProposal.pdf

² *Commitment Costs Refinements 2012, Draft Final Proposal*, California ISO, April 11, 2012, www.caiso.com/Documents/DraftFinalProposal-CommitmentCostRefinements.pdf; *Addendum to Commitment Costs Refinements Draft Final Proposal*, CAISO, April 27, 2012, www.caiso.com/Documents/Addendum-CommitmentCostsRefinementsDraftFinalProposal.pdf

³ www.caiso.com/Documents/DraftFinalProposal-RenewableIntegrationMarket-ProductReviewPhase1.pdf

The MSC submitted an opinion to the Board in December offering general support for those proposals.⁴ In the opinion, the MSC cautioned that the performance of the revised BCR mechanism would depend on specific parameter choices, and that the system should be subjected to extensive testing before parameter values are selected and the system is implemented. In particular, we were unable at that time to conclude with confidence that the Performance Measure and Persistent Uninstructed Energy Check features of the proposal would function as intended. We stated that additional detail regarding the parameter values that would be used in applying these features along with additional testing data would be needed to allow us to reach a conclusion about their functioning. We also said that it would be important to ascertain that those features are (1) effective in discouraging strategic behavior aimed at increasing BCR payments, (2) while not inadvertently yielding large decreases in BCR payments for normal deviations from dispatch instructions. Such decreases would undermine the goal of encouraging more resources to participate in the real-time dispatch. We noted that testing might indicate that significant changes to the basic features as proposed would be necessary to accomplish these goals.

In the April 6 draft final BCR mitigation proposal, the ISO presents details of the mechanism, including parameters to be used in its implementation. In the present opinion, we comment on that implementation. In particular, we express our support for its major features, including the modified day-ahead metered energy adjustment factor; the real-time performance metric; and the persistent uninstructed energy (PUIE) check.

However, we believe that further examination is needed to determine the particular threshold values to be used to determine whether persistent uninstructed energy would be disqualified. In particular, although the analysis of historical data in the draft BCR proposal is very helpful in understanding the potential frequency of mitigation, it is not presently clear whether the instances in which generators would have had bid costs disqualified actually represent abuse or not. Nor is it clear whether or not significant cases of abuse might pass the proposed threshold and avoid mitigation. The MSC also recommends that the criteria used to determine whether mitigation will take place also include consideration of a total dollar or dollar/MW of capacity threshold.

Turning to the commitment cost proposal, as a general principle, we support the recovery of legitimate and verifiable start-up (SU) and minimum-load (ML) costs when they are incurred as part of the least-cost operation of the ISO market. We have addressed in past opinions the design of the limitations imposed by the ISO on how such fixed costs can be bid.⁵ Our recommendations attempted to balance the need for responsiveness to changing fuel and other costs, while

⁴ Market Surveillance Committee of the CAISO, *Final Opinion on Renewable Integration: Market Product Review, Phase 1*, www.caiso.com/Documents/MS_C_Final_Opinion_RenewableIntegrationMarketProductReviewPhase1.pdf

⁵ Market Surveillance Committee of the California ISO, *Comments on Changes to Bidding Start-Up and Minimum Load*, July 16, 2009, www.caiso.com/Documents/FinalOpiniononStart-UpandMinimumLoadBiddingRules.pdf; Market Surveillance Committee of the California ISO, *Opinion on Changes to Bidding and Mitigation of Commitment Costs*, June 4, 2010, www.caiso.com/Documents/FinalOpiniononChanges-BiddingandMitigation-CommitmentCosts.pdf

limiting opportunities to take advantage of local market power to recover inflated as-bid levels of these costs. We expressed explicit support for accounting not only for fuel cost portion of SU and ML costs, but also the increased wear-and-tear costs to the generation unit due to the increased number of starts and the opportunity cost of a start due to maintenance contract and environmental restrictions on the total annual number of starts or run-hours. The ISO's present commitment cost proposal is certainly a step in the right direction on this issue. We noted previously that developing a reasonably accurate methodology for determining what these costs are for each generation unit is difficult to achieve, and that it is desirable to have a local market power mitigation methodology that focuses the application of mitigation on generators at locations where generators may have the ability to submit inflated SU and ML bids that will clear in the market.

The present proposal offers an improved methodology for estimating certain components of SU and ML costs that are not presently included in proxy bid and registered cost calculations, which we strongly support. In particular, the proposal would allow for inclusion of grid management charges, CO₂ costs, and maintenance costs in SU and ML proxy bids, which we support, as well as ex post recovery of operational flow order costs. This permits the lowering of the cap upon registered SU and ML costs to 150% of the proxy value, which we believe could be lowered further within a year to 125% if experience indicates that actual costs are generally below that value. Presently, we lack the information necessary to determine whether one or the other, or some different value, would be best.

We identify two further enhancements to the commitment costs proposal that we believe could improve the efficiency of system operations by allowing bids to more fully reflect costs. The complexity of these enhancements means that it is not practical to implement these enhancements in the commitment costs proposal at this time. Therefore we recommend that the ISO initiate, at an appropriate time, a stakeholder process that would move towards developing and implementing a follow-up proposal.

The first enhancement whose consideration we recommend concerns SU and ML opportunity costs due to limitations upon starts and run-hours. These can be significant for some units, but are not provided for in this proposal. At previous MSC meetings addressing the topic in 2009 and 2010, such costs were mentioned as important, and we have previously recommended consideration of their inclusion.⁶ We repeat that recommendation here.

Second, we recommend that consideration be given in a future stakeholder process to including costs associated with operational flow orders (OFOs) in SU and ML bids used in the real-time market software if those costs can be reasonably anticipated with enough lead-time so that reasonably verifiable values can be included. If possible, this is much preferable to recovery based upon after-the-fact calculations because it is important for market efficiency that unit commitment decisions be based on all known costs. Otherwise, units might be committed which would not otherwise have been if their SU and ML costs had included OFO costs, thereby unnecessarily increasing costs. We recommend that a study be undertaken of the potential magnitude of OFO costs under alternative market conditions with the objective of determining whether they could

⁶ Ibid.

be large enough to be relevant to commitment decisions, and if significant efficiency improvements could then result from including them in SU and ML bids.

Finally, we also make a long-term recommendation that the ISO consider possibilities for more tailored mitigation of market power in commitment costs. This would involve relaxing constraints on allowable bids where markets are likely to be highly contested (for example, by allowing them to change bids more often than monthly) and having tighter constraints where exceptional dispatch, load pocket conditions, or other constraints limit contestability. However, we were not able at this time to identify a transparent, readily implemented, and defensible basis for such a refined system, and so recommend that such tailored mitigation not be included in this proposal, but that it be studied for possible implementation in future BCR revisions.

2. BCR Mitigation

2.1 General Comments

As we explained in our December 2011 opinion on Phase 1, the BCR mitigation procedure would apply a performance metric that would scale certain components of the bid cost recovery calculation based upon deviations from ISO dispatch instructions. This prorating process is intended to remove the incentive, for instance, for a generating unit to receive a day-ahead BCR payment based on a day-ahead commitment, and then to declare an outage so that the unit would not actually run but would still receive the payment, or for a unit to receive BCR for generation in excess of ISO dispatch instructions.

However, the performance metric only considers uninstructed deviations within a single real-time interval. Because of the way the ISO calculates dispatch instructions relative to a resource's actual metered output at the time the real-time dispatch software begins its calculations, uninstructed deviations that continue over time can impact ISO real-time dispatch instructions in future intervals. This means that uninstructed deviations calculated solely relative to the dispatch instructions for the current interval will not accurately reflect the *cumulative* deviations by the resource. In other words, a unit may only narrowly deviate from a dispatch order in a current interval, but that order might only be necessary because of additional non-compliance in previous intervals. In some cases a unit can force the dispatch, through previous non-compliance, to provide instructions it can profit from through bid-cost recovery and other mechanisms.

Therefore, the ISO proposed to augment the performance metric with a real-time calculation of a persistent uninstructed energy index (PUIE) that would disqualify real-time energy from the real-time BCR calculations in the case where generators choose to deviate consistently over several periods, yielding a greater deviation between actual operation and system cost-minimizing dispatch than can result from just one interval's deviation. The check would construct a "counterfactual" or hypothetical series of operating levels that would have occurred if the generator had adhered to the operators' instructions.

In our previous opinion, we expressed our support for the need for the proposed performance metric and persistent deviations check, and the general philosophy behind their calculation and

application. They are likely to be more effective than the previous BCR procedures in avoiding potential BCR payment inflation from intentional deviations. We reiterate that general support here.

We support the proposed metered energy adjustment factor and performance metric. Although it has been suggested that more generally applicable uninstructed deviation penalties should be used instead, we prefer the more tightly focused proposal made by the ISO. We believe that in the vast majority cases, the appropriate “penalty” is just the real-time cost of energy, which represents the market’s cost of making up for a market party’s imbalance. We support this proposal’s narrow applicability of adjustments to situations involving BCR payments. In the below comments, we focus on the persistent uninstructed energy check and its use for disqualifying certain as-bid energy cost shortfalls from eligibility for BCR, since this is the item that has attracted the most stakeholder attention.

2.2 Persistent Deviation Criteria for Disqualifying Energy Bid Cost Recovery

In our December 2011 opinion, we also noted that the revised BCR mechanism represents a significant departure from the previous BCR procedures at the ISO, and indeed at any other RTO or ISO. For this reason, we argued that it is important that the procedures, as well as the particular parameter values to be used to implement them, be subject to careful testing to ensure that they will work as intended. In particular, will they effectively guard against intentional inflation of BCR payments arising from unscheduled output, i.e., deviations from the ISO’s dispatch instructions? And, at the same time, will they avoid penalizing innocent behavior by prorating BCR payments in response to normal scheduling inaccuracies or errors in a way that would undermine the goal of encouraging more resources to participate in the real-time dispatch? At the time that opinion was written, the specific triggers for mitigating persistent uninstructed deviations had not been defined.

In the ISO draft final proposal, specific triggers are provided, along with statistics based on historical data on how often they would have been violated in the past. There are two indices that are proposed for use in determining whether mitigation of persistent uninstructed deviations would occur (measures A and B, defined on p. 16 of the proposal). The final draft proposal has proposed that the following combinations of A and B would not trigger mitigation:

1. A less than 3%;
2. B less than 3 \$/MWh; or
3. Combinations of A and B that satisfy both A less than 10% and B less than 10 \$/MWh.

The first two criteria represent revisions to the previous proposal, and provide an additional safe harbor for generators whose deviations are small and quite possibly due to normal operational variations. In particular, if A is positive but B is small (or B is positive and A is zero), we do not believe it is necessary to adjust BCR, since BCR is close to zero anyway. Such points lie on or very near the A and B axes in Figures 3.3.4-1 (p. 17) and 3.3.2-5 (p. 23) of the proposal. The set of combinations in the third criterion was proposed in earlier versions of the BCR proposal.

On the other hand, there might be cases where A and B are both barely satisfy criterion 3 (e.g., $A = 9\%$ and $B = \$9/\text{MWh}$), but the total dollar amount is large. Therefore, we recommend that the ISO examine these cases from the historical record to determine the magnitude of BCR associated with persistent uninstructed deviations. If the amounts are significant in some cases, we recommend that the above criteria be modified so that if the total dollar amount is above some total $\$/\text{interval}$ threshold that mitigation be triggered even if any of the above criteria are satisfied. Alternatively, to account for the fact that generators can be very different in size, this threshold could instead be phrased in terms of $\$/\text{interval}$ per MW of installed capacity, with some de minimus total $\$/\text{interval}$ amount below which mitigation would not be triggered.

In particular, we are concerned that the reasons for observed persistent deviations in the past are not understood, and as a result the thresholds might be set at levels that result in disqualification of BCR in cases where deviations are the result of normal operating variations. Several stakeholders share this concern. If the loss of BCR would then be significant and frequent, that could act to discourage real-time bidding by needed resources. We recommend that the data analysis conducted in Section 3.3.5 of the proposal be extended in order to inform possible adjustments to the proposed parameters. In particular, the possibilities of false positives and negatives should be examined by, first, determining, if possible, the reasons for a sample of historical instances that violate the proposed deviation criteria; second, doing the same for instances that come close, but do not violate the criteria; and, third, assessing the resulting impact on BCR for those units. We believe that such an analysis will provide useful information for fine-tuning the parameters to ensure that an appropriate balance is struck between reducing incentives for the inefficient bidding and generation output strategies that are the concern of the PUIE check, and the risk of discouraging participation in the real-time market by resources that would likely require BCR. We note that as output by variable renewable energy sources increases, instances of very low or negative real-time prices will happen more often, which could increase the frequency of BCR for thermal resources.

2.3 What Energy Bid Costs Should be Disqualified if Persistent Deviations Occur?

During the March 30, 2012 MSC meeting, we expressed support for revising the draft proposal so that the only energy bid costs that would be excluded from the BCR calculations would be those that were identified as persistent uninstructed deviations during intervals that the performance measures were violated. The draft proposal at that time would have resulted in disqualification of all energy bid costs from those intervals, which we believed would have been overly severe and perhaps would discourage resources from participating in the real-time dispatch. We support the change represented by the revised proposal of April 6, in which only the deviations identified as persistent uninstructed deviations would be excluded. This makes the penalty more proportionate to the impact of the potentially intentional over-generation, and will avoid the possible problem that might arise from incenting generators to skew somewhat towards undergenerating in order to avoid the risk of losing all energy bid BCR.

3. Commitment Costs

3.1 General Comments

Presently, market participants can choose between two methods for bidding their start-up and minimum load costs. Under the Proxy Cost option the market participant submits its start-up and minimum load costs on a daily basis, with the bids capped by the ISO's proxy cost calculation. Under the registered cost option, the start-up and minimum load cost bids submitted by the market participant must remain constant for 30 days and are required to be no more than twice a cost-based measure calculated by the ISO. This 100% head-room allows for volatility of spot fuel costs and for SU and ML costs that are excluded from the proxy. Regarding volatility, the ISO's analysis shows that spot fuel costs rarely exceed 110% of the monthly gas price used to calculate gas costs under the registered cost option. Although spot prices for individual days might be significantly higher than the monthly gas price, the single highest day is not the relevant measure under the registered price option for high capacity factor units that would operate many or most days (and be required to submit the same bids on all of those days under the registered cost option). For such units the amount of headroom needed for that reason is well below 100%. However, for low capacity factor units, their fuel costs can be significantly above average monthly levels, especially if periods of high electricity demand coincide with higher daily gas prices, so somewhat more head room can be justified in those cases. Intraday gas costs can also be higher than daily price indices. Finally, volatility may be higher in future months and years than it has been over the past few years during the recession. Thus, headroom of more than 10% could perhaps be justified on volatility grounds alone, especially for lower capacity factor units.

It would normally be more efficient for a gas-fueled generator in particular to vary its start-up and minimum load offer costs on a daily basis to reflect variations in gas prices as permitted under the ISO's Proxy Cost methodology. However, the ISO's Proxy cost measure has historically not included all costs. Hence, generators for whom those costs are substantial might prefer to submit bids based on the registered cost option, despite the inefficiency of being constrained to submit the same offers for 30 days. Hence, the present 100% headroom also allows for miscellaneous SU and ML costs that are not captured in the proxy; presently, these include maintenance costs, opportunity costs of start-ups, emissions costs, grid management charges, and possibly others. To the extent that those costs can be explicitly included in the proxy cost, the need for market participants to bid using the registered cost method is reduced. Further, to the extent that those costs can be explicitly included in the registered cost, the allowed percentage headroom over the ISO calculated costs can be decreased. Therefore, given the ISO's proposal to include many more categories of costs in the base registered costs, we agree with the ISO that the allowed head room above these estimated costs under the registered cost option can be decreased. If it was possible to allow inclusion of opportunity costs and operational flow order costs in bids (as we suggest below should be considered in future revisions of the commitment cost rules), then we would be comfortable with the percentage of headroom being lowered from 100% to 25%. However, the present proposal excludes opportunity costs from calculations of proxy costs, and provides no means for their recovery. For this reason, somewhat more headroom could be justified in the registered cost option.

However, we do not make a recommendation for a particular value for amount of head-room, since we do not have estimates of the likely magnitudes of opportunity costs. We do note that if maintenance costs typically amount to approximately one-third of the presently allowed proxy cost, then the ISO's proposal to allow 50% head-room would result in the same total allowable bid under the registered cost option as the previous 100% head-room. If maintenance costs are typically less than 33%, then a 50% head-room would generally result in lower total allowable bids than under the present head-room. However, we do not have information on typical maintenance costs and so cannot assess whether the ISO's proposed change would result in a significant decrease, on average, in the overall allowable SU and ML bids under the registered cost option.

As information is lacking that would definitively support one or another cap, we therefore suggest proceeding cautiously by lowering the cap, as proposed by the ISO, to 150% immediately. We recommend that then within a year it be lowered further to 125% if the ISO makes a finding that fuel cost variations, opportunity-costs, and other omitted costs are highly unlikely to exceed 25% of proxy costs for the great majority of generating units.

If all significant categories of costs are included in SU and ML proxy bids, then we would find merit in the suggestion that the head-room percentage be applied just to the fuel cost portion of the proxy. On the other hand, if potentially important categories are omitted, such as opportunity costs, then the purpose of the headroom is not just to insure against gas price volatility risks, but also to accommodate other categories of SU and ML costs that are not captured in the proxy. This is the case with the ISO's proposal. Therefore, we believe that the proposal's application of the percentage to the entire SU and ML cost, and not just the fuel cost portion, is appropriate.

3.2 Focusing Mitigation on Units with Local Market Power

The philosophy of mitigation in the energy market is to focus mitigation on units possessing local market power. In contrast, the mitigation system for SU and ML bids is system-wide. However, we expect that generating units that are not in locations that would confer local market power would have a strong market incentive to submit bids reflecting their actual SU and ML costs to the extent permitted by ISO rules. On the other hand, units located in load pockets or other areas in which they possess local market power might be able to inflate their SU and ML offers to levels well above their costs yet still clear in the market. We believe that it is desirable to focus mitigation on those resources having locational market power, including that due to the various minimum on-line rules. In the long run, therefore we recommend that mitigation efforts be focused upon areas with persistent local market power, while giving more flexibility to generators outside such areas. The MSC has previously recommended a dynamic local market power mitigation (LMPM) procedure similar to that used for energy bids.⁷

For instance, this proxy cost approach would be made more focused, and could eventually be turned into a cap on start-up and minimum load bids with the market participant allowed to vary its bids every day as long as they were under the cap. Also, areas with persistent market power

⁷ Footnote 5, supra.

could have tighter head-room percentages for the registered cost option, and other areas could have looser percentages.

However, implementation of such a system would mean that the occurrence of persistent market power would have to be defined. The procedure would have to be dynamic (responsive to changing market conditions), transparent, and a valid reflection of local market power. Unfortunately, the new local market power mitigation procedure (LMPM), based upon the contribution to locational marginal prices (LMPs) of shadow prices of uncompetitive transmission constraints, is not applicable to lumpy decisions to commit generating units. This is because commitment of units needed to resolve uncompetitive constraints will often result in those constraints becoming nonbinding and having a zero shadow price. Because of such conceptual challenges, as well as practical considerations, development of such a LMPM-like system for SU and ML bids is not possible within the context of this proposal, but should be considered in the future.

3.3 Negotiated Maintenance Costs

In general, procedures involving negotiation to determine which costs can be recovered have poor incentive properties. If (1) a generator faces relatively little competition in a locally constrained area, so that higher SU costs would not lower the frequency of commitment, and (2) the generator usually obtains BCR for its SU costs, then incentives to minimize costs are dampened. The expense and relative lack of transparency of negotiated costs are further disadvantages.

To the extent that (1) most start-ups are not subjected to BCR, and (2) maintenance costs are non-discretionary, involving standard contracts with vendors, then we are less concerned with the incentive effects of negotiations. It would be useful to have data on the percentage of incurred SU costs for various classes of units that are recovered through BCR. If the percentages are small, then our concern over the negotiated cost option is less. However, this percentage may increase in the future as more renewable capacity comes on line, and episodes of very low or negative prices become more frequent.

Nonetheless, we recognize the need for negotiation given the great variations in types of generators and maintenance contracts. Therefore, we urge the ISO to put into place procedures for identifying benchmarks for classes of units; for identifying cases in which maintenance costs are considerably above benchmark levels; and for providing incentives for lowering those costs, such as allowing recovery of only a portion of costs that are above identified benchmarks.

3.4 Opportunity Costs of Start Ups

Opportunity costs for start-ups arise as follows. A generating unit that has a limited number of starts per year due to maintenance contract requirements incurs an opportunity cost for starting up if there is a positive probability that the generator will run out of starts before the end of the summer high load season; that is, a start now results in foregoing net revenue later in the year. The amount of this opportunity cost depends on the probability of using up all the allowable starts, and the gross margin (price minus variable cost, including SU and ML costs) that would have been earned in the later start.

Opportunity costs can also arise for operating hours if a unit has a limited number of run-hours because of environmental or other limitations. In that case, a similar opportunity cost arises that should legitimately be reflected in ML bids.

Although such opportunity costs are difficult to estimate, they can be large for some units in some years. If disregarding those costs results in units burning through all their allowable starts or run-hours early in the summer, this can significantly hurt market efficiency by decreasing the availability of needed resources later in the summer. A possible approach to correcting this problem would be to allow generators to negotiate an opportunity cost component in their SU or ML costs, and if such a component is included, have it be updated throughout the high demand season to reflect changing expectations concerning probability of running out, fuel costs, and prices.

Clearly, this calculation would be complex, costly, and relatively difficult to monitor and verify. To calculate opportunity costs, a generator would have to make a showing of a binding constraint that can reasonably be expected to bind. Then it would be necessary to approximate the probability of lost opportunities and the gross margin (prices minus variable costs) associated with them based upon reasonable expectations of future energy prices. This calculation would consider the number of starts or run-hours available versus the rate at which the unit has been committed. The relevant gross margin would be for the 'marginal' start - the future start that would be precluded because a start was instead scheduled today.⁸

The ISO is not recommending such a procedure for estimating and including opportunity costs in SU and ML proxy bids at this time because of the practical challenges involved in its design and implementation in the timeframe available. Therefore, we recommend that consideration be given to inclusion of opportunity costs in proxy costs in a new stakeholder process in the near future.

If no provision is eventually made for including opportunity costs in SU and ML bids, this could result in significant inefficiencies. An obvious inefficiency would be if a unit runs out of available starts or run-hours early in the season. A less obvious, but also potentially important inefficiency, can arise if a generator tries to prevent that outcome by choosing designation as a "use limited resource" in order to be exempt from the all-hours must-offer requirement. This would prevent commitment during certain hours. However, as wind penetration increases, the times

⁸ Such a calculation of opportunity costs could in theory take place through a negotiation process, based on some standardized procedure. This is not an easy calculation, but some standard and conservative values might be agreed upon that would be better than zero (the present value). Once quantified, then one approach to including opportunity costs in SU or ML bids could be to have a separate daily or weekly changing registered cost component to SU or ML costs.

Another alternative for calculating opportunity costs could rely more on historical data. The purpose would be to estimate the gross margin for the marginal start in the relevant time windows in past years. A rough approximation might be the margin that is exceeded some X% of the time in the, for instance, the last month of the time window. The procedure could then adjust this margin for differences in fuel costs between the historical period and the present season, and also account for how binding the constraint is (the number of starts or run-hours used relative to those available) if that affects the likelihood of running out of starts or run-hours.

when that generator would optimally be dispatched might occur more frequently during off-peak hours which cannot be anticipated by inflexible monthly use plans. Large inefficiencies are likely to arise if a significant amount of capacity withdraws itself from the market during many hours in this manner. It would be more efficient to instead allow high SU and ML bids that reflect opportunity costs of operation, which then gives flexibility to the market software to determine whether or not it is worthwhile to run the units. We recommend that a study be conducted to determine if inefficiencies of this type are resulting from monthly use plans, and if so, what their significance is. Development of a procedure to include opportunity costs in SU and ML proxies would help avoid this potential inefficiency.

3.5 Operational Flow Order Costs

We agree with the premise of the commitment cost proposal that it is important to enable generators to recover significant operational flow order (OFO) costs, since they have the potential to materially affect SU and ML costs. Although OFO costs have recently been very minor, there were much higher levels on occasion in previous years according to PG&E data.⁹ Also, changes in pipeline pressure rules and the possibility of tight electricity supplies in the coming months might cause such charges to become larger and more frequent than in the recent past.

As a general principle, it is desirable that any costs that can materially contribute to SU and ML costs be reflected in SU and ML bids so that the costs can actually influence unit commitment decisions, and so improve market efficiency. After-the-fact recovery of such costs can help to make generators whole, and by lowering the risk of non-recovery of costs, can encourage participation in the real-time market, which is desirable. However, after-the-fact recovery could distort unit commitment choices. As a result, costs may be incurred that the market software would have chosen to avoid, if those costs had been fully reflected in SU and ML bids.

In the particular case of OFO costs, their inclusion in SU and ML bids are also desirable from a gas and electric system reliability standpoint. This is because OFO's can be pipeline specific and if it would be much better to meet load with a gas-fired generator served by a pipeline that has not imposed an OFO than one that has.

Application of this general principle in the case of OFO costs would require an ability to adjust reference bids for real-time SU and ML bids daily in response to OFO costs, or the creation of a registered cost component to those SU and ML bids. A requirement would be that it would be practical to anticipate OFO costs in time for such a procedure; because OFO costs are usually known at the time the bid is submitted, in which case this inclusion seems reasonable. It would also be necessary to reasonably expect that OFO costs are fully marginal for the unit (i.e., are part of the incremental cost of starting up and running a unit). Although there are ambiguities in allocating OFO costs among multiple units coming under a single gas contract, it appears likely that OFO costs are fully felt for marginal decisions.

⁹ www.pge.com/pipeline/operations/fo/foarch.shtml. For instance, as recently as July 10, 2010, there were days with charges amounting to \$5/mmBTU, and during the crisis, charges as high as \$25/mmBTU occurred.

If these conditions are met, and if the costs of implementation are reasonable relative to anticipated market efficiency benefits, we would recommend that consideration be given to instituting a procedure to include reasonably anticipatable OFO costs in the proxy, rather than after the fact. On the other hand, reasons for not including OFO costs in SU and ML can include the complexity of implementing such a procedure; uncertain or minor efficiency improvements in commitment; and ambiguities in assigning costs to particular units and possible opportunities for strategic behavior that these ambiguities might present.¹⁰

We do not have data that would allow us to compare the efficiency benefits of including OFO costs in SU and ML bids to the expense of implementing such a procedure. Because of the uncertain possibilities for strategic bidding that inclusion of OFO costs in bids might open up, we support for now the ISO's proposal for after-the-fact recovery.

However, if there is a potential for OFO costs to become more important in the future, so that disregarding them in real-time unit commitment decisions would result in significant inefficiencies, then this issue should be addressed in a stakeholder process and further consideration given to including OFO costs in allowable real-time SU and ML bids.

4. Conclusion

In summary, we support the goals and most of the specific elements of the commitment cost and BCR mitigation proposals. In the case of the commitment cost proposal, it is an important step towards inclusion of all relevant costs in start-up and minimum-load bids, which is desirable for both cost-recovery and market efficiency reasons. For this reason, we support the proposed lowering of the cap upon registered SU and ML costs to 150% of proxy costs, and further recommend that it be lowered to 125% a year later if the ISO finds that total SU and ML costs are very likely to fall under that tighter cap. We recommend that consideration be given in a future stakeholder process to address inclusion of an additional category in proxy costs (opportunity costs of start-ups and run-hours). We also recommend that consideration be given in the future to including operational flow order costs in real-time SU and ML bids, rather than recovering such costs after the fact if such costs have the potential to be large enough to significantly affect commitment decisions and market efficiency.

For the BCR mitigation proposal, there remains uncertainty over whether the criteria for identifying persistent uninstructed deviations will indeed catch most circumstances in which such deviations are deliberate actions intended to inflate BCR payments, will avoiding penalizing inadvertent and unintentional deviations. Further analysis is desirable of historical patterns of deviation.

¹⁰ We note that opportunities for strategic behavior can also arise if OFO costs are recovered after-the-fact as proposed. If OFO costs cannot be included in the SU and ML bids and have to be recovered in an ad hoc reimbursement later, then allocation among units can become an issue. This is because there are revenues and costs for a group of units, and some will have had profits and others will not in a particular day before the OFO costs are accounted for. As a result, how OFO costs are allocated could impact the total BCR. Allocation rules could also affect efficiency; for instance, if the ISO allocates all the OFO costs to the profitable units, this will lead to undesirable incentive problems. Therefore, strategic behavior considerations do not necessarily favor after-the-fact recovery of OFO costs.

FINAL

In the long run, we would prefer a BCR mitigation system that, like the local market power mitigation procedure for energy, focuses on locations where competition cannot be relied upon to incent efficient bidding for start-up and minimum load costs.

Attachment G – May 2, 2012 Presentation

Amendment to Further Enhance Cost Recovery by Generating Resources

California Independent System Operator Corporation

August 30, 2013

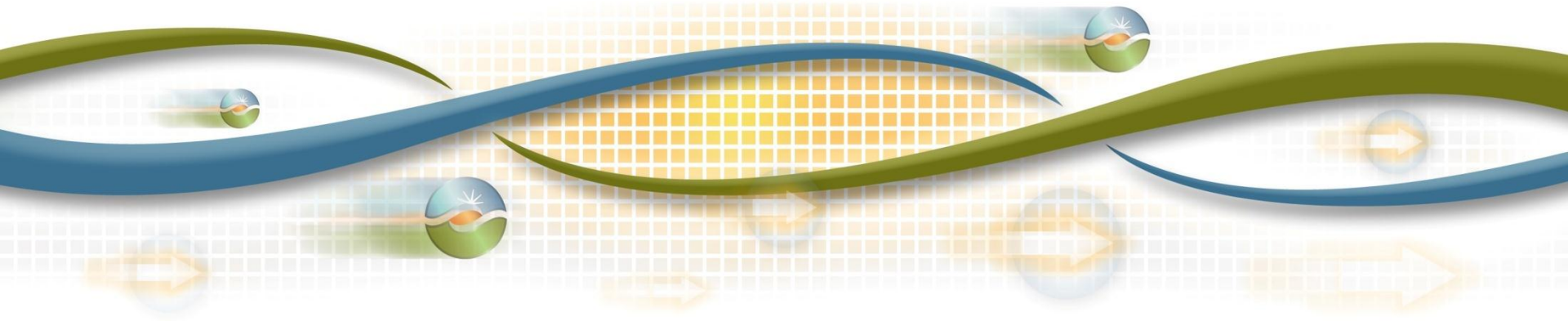
Refinements to Commitment Costs, 2012

Stakeholder Conference Call

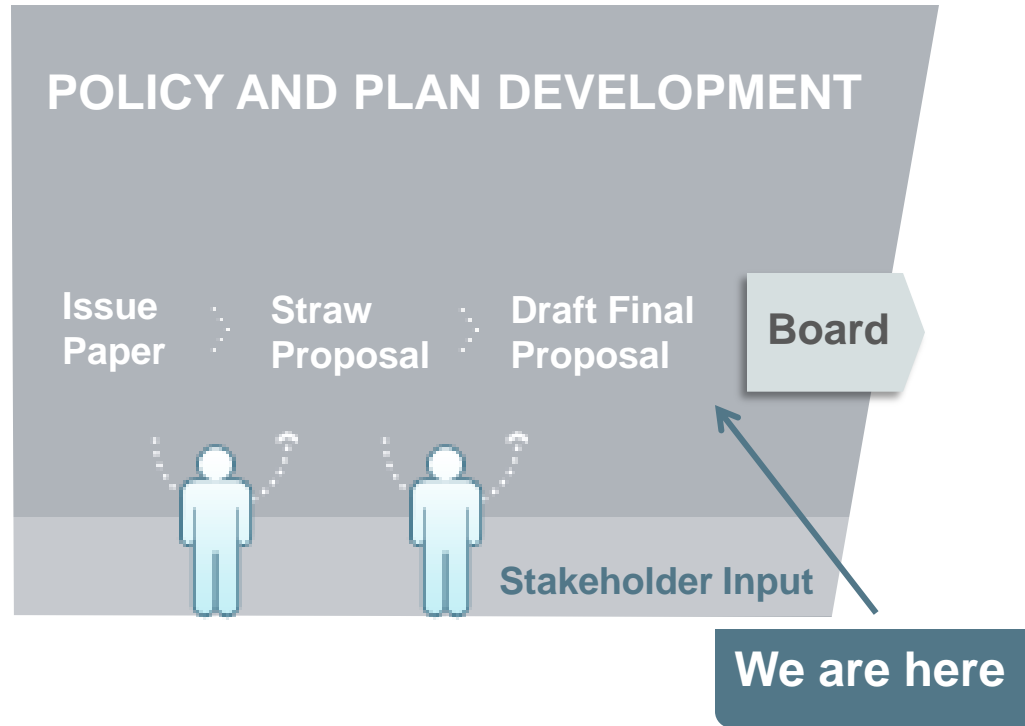
May 2, 2012

Gillian Biedler

Senior Market Design & Policy Specialist



ISO Policy Initiative Stakeholder Process



Background on the registered cost option for start-up and minimum load costs

- The cap on the registered cost option for either start-up or minimum load is equal to 200% of the resource's calculated SU and/or MLC
- The 200% cap was established to enable recovery of costs not captured in the proxy cost calculation
- Checks put in place to balance motivation to choose the registered cost option
 - Cap was intended to account for some – but not all – fuel price volatility
 - Fixed for 30 days

Motivation for lowering the registered cost option cap

- 200% cap served as a mechanism and incentive for market behavior that inflated BCR uplift payments
- The need for headroom is diminished as the proxy cost option is made more robust
 - Greenhouse gas allowance costs
 - Grid management charge costs
 - Major maintenance adder

Additional information in support of a lower registered cost cap

- Safety valve allows resources with registered costs to switch out of registered and into proxy if proxy exceeds registered
- Some concern regarding potential volatility and illiquidity of the new GHG cap-and-trade program
 - 9 months of the GHG program before the registered cost cap is changed
- Historical natural gas prices (2002 – 2011)
 - 98% of the time, $(\text{max spot})/(\text{futures}) < 150\%$
 - 100% of the time, $(\text{avg spot})/(\text{futures}) < 150\%$

Feedback on the proposed registered cost option cap

- Some stakeholders favor reducing the cap or eliminating registered cost option due to adverse incentives
- Many stakeholders expressed concerns
 - Intra-day fuel price volatility
 - Natural gas price hedging for low-capacity factor units
 - Natural gas balancing risk
- The Market Surveillance Committee
 - opportunity costs for use-limited or start-limited resources may not be covered by the 125% cap

ISO proposal – registered cost option cap

- The ISO proposes that the registered cost cap be set at 150% of the projected proxy cost
- The projected proxy cost used for the cap will include the enhancements in this proposal
 - Greenhouse gas allowance costs
 - Grid management charge costs
 - Major maintenance adder

Next steps...

Date	Activity
April 27	Addendum posted
May 2	Conference call
May 7	Comments due
May 16-17	Presentation to ISO Board

Contact information

Gillian Biedler

gbiedler@caiso.com

Desk: (916) 608-7203

Mobile: (916) 337-7485

Send comments to comcosts2@caiso.com

Attachment H – Stakeholder Process Key Dates

Amendment to Further Enhance Cost Recovery by Generating Resources

California Independent System Operator Corporation

August 30, 2013

List of Key Dates in the Stakeholder Process for this Tariff Amendment

Date	Event/Due Date
February 3, 2012	ISO issues paper entitled "Issue Paper – Commitment Costs Refinements 2012"
February 8, 2012	ISO hosts stakeholder conference call that includes presentation entitled "Refinements to Commitment Costs, 2012" and discussion of paper issued on February 3
February 10, 2012	ISO Department of Market Monitoring issues paper entitled "California Greenhouse Gas Cap and Generation Variable Costs White Paper"
February 17, 2012	Due date for written stakeholder comments on paper issued on February 3
February 21, 2012	Potomac Economics issues paper entitled "Major Maintenance Adders Plan"
February 27, 2012	ISO Department of Market Monitoring issues paper entitled "Potential Methodology to Account for OFO Penalties Incurred Due to Real-Time Energy Dispatches"
February 29, 2012	ISO issues paper entitled "Straw Proposal – Commitment Costs Refinements 2012"
March 7, 2012	ISO hosts stakeholder conference call that includes presentation entitled "Refinements to Commitment Costs, 2012" and discussion of paper issued on February 29
March 14, 2012	Due date for written stakeholder comments on paper issued on February 29
April 11, 2012	ISO issues paper entitled "Draft Final Proposal – Commitment Costs Refinements 2012"
April 18, 2012	ISO hosts stakeholder conference call that includes presentation entitled "Refinements to Commitment Costs, 2012" and discussion of paper issued on April 11
April 24, 2012	Due date for written stakeholder comments on paper issued on April 11
April 27, 2012	ISO issues paper entitled "Addendum to the Draft Final Proposal – Commitment Costs Refinements 2012"
May 2, 2012	ISO hosts stakeholder conference call that includes presentation entitled "Refinements to Commitment Costs, 2012" and discussion of papers issued on April 11 and 27
May 7, 2012	Due date for written stakeholder comments on paper issued on April 27
April 25, 2013	ISO issues paper entitled "Commitment Cost Refinements 2012 Implementation Details"
May 1, 2013	ISO hosts stakeholder conference call that includes presentation entitled "Commitment Cost Refinements 2012 Implementation Details" and discussion of paper issued on April 25

Date	Event/Due Date
May 6, 2013	Potomac Economics issues paper entitled “Instructions for Major Maintenance Template” and examples of major maintenance templates
May 10, 2013	Due date for written stakeholder comments on paper issued on April 25
June 7, 2013	ISO issues draft tariff language to implement commitment costs refinement initiative
June 17, 2013	Due date for written stakeholder comments on draft tariff language issued on June 7
June 26, 2013	ISO hosts stakeholder conference call that includes discussion of draft tariff language issued on June 7
July 25, 2013	ISO issued revised draft tariff language to implement commitment costs refinement initiative
August 8, 2013	Due date for written stakeholder comments on revised draft tariff language issued on July 25
August 15, 2013	ISO hosts stakeholder conference call that includes discussion of revised draft tariff language issued on July 25