California Independent
System Operator Corporation

June 6, 2016

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. ER16- ___-000

Tariff Amendment to Implement Pricing Enhancements

Dear Secretary Bose:

The California Independent System Operator Corporation (CAISO) submits this tariff amendment to implement components of its pricing enhancements initiative.[1] Specifically, the CAISO proposes to: (1) modify contingency modeling in the CAISO's market optimization so that prices will reflect the cost of congestion associated with the most limiting contingency under transmission constraint relaxation conditions; and (2) eliminate conditions that can lead to multiple pricing solutions for the same problem, resulting in unique pricing solutions to transmission constraints. These revisions will enhance market outcomes and provide more accurate and appropriate price signals in the CAISO markets.

Stakeholders generally support the proposed changes and raised only a minor issue regarding the mathematical formulation used to implement the second of the changes. As explained below, the CAISO has already taken steps to address these questions.

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[1] The CAISO 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 CAISO tariff, and references to specific sections are references to existing sections in the current CAISO tariff or to tariff sections as revised in this filing, unless otherwise indicated.

The CAISO requests that the Commission issue an order by September 1, 2016 that accepts the tariff revisions contained in this filing effective September 7, 2016.

I. Background

A. Existing Process for Formulating Contingency-Related Constraints

The CAISO market software enforces transmission constraints that protect the transmission system in the event of a contingency or the outage of a transmission element. The market software enforces the transmission constraints for both base cases and contingency cases,[2] treating each base case and contingency case as a separate transmission constraint. The market software also uses a set of pricing parameters to indicate the cost associated with relaxing any of the transmission constraints.[3] Currently, prices in the integrated forward market and real-time market reflect the costs of one or more transmission constraints being relaxed based on a set of penalty prices equal to the maximum energy bid price.[4]

Since 2013, the increased number of contingency-related transmission constraints that are being modeled as well as tighter conditions on the transmission system have resulted in a number of instances where a transmission constraint has been binding for the base case and/or multiple contingency cases.[5] In those instances, the market software may produce a solution in which the transmission constraint cannot be resolved and therefore must be relaxed due to the multiple contingencies. Because the market software treats each base case and contingency case as a separate transmission

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2 Contingency cases consist of limitations imposed on the transmission grid that reflect possible or eventually probable outage contingencies in operating the CAISO balancing authority area consistent with requirements and reliability standards issued by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC).

3 Existing tariff section 27.4.3. For the sake of clarity, this transmittal letter distinguishes between existing tariff provisions (*i.e.*, provisions in the current CAISO tariff) and revised tariff provisions (*i.e.*, tariff provisions that the CAISO proposes to revise in this filing).

4 Existing tariff section 27.4.3.2. The current maximum energy bid price is $1,000/MWh. Existing tariff section 39.6.1.1. The corresponding pricing parameter used in the residual unit commitment is set at the maximum residual unit commitment availability bid price, which is currently set at $250/MWh. Existing tariff sections 27.4.3.2, 39.6.1.2.

5 *See* Pricing Enhancements Final Proposal at 27 ("Final Proposal"). The Final Proposal, which was one of the materials provided in the stakeholder process that led to this tariff amendment, is contained in attachment C to this filing.

constraint, each such case has a congestion cost that is compounded in the marginal cost of congestion component of the locational marginal price (LMP) for energy.[6] This congestion cost is compounded for the various locations on the transmission system impacted by the transmission constraint, based on shift factors.[7] As a result, in cases where multiple transmission constraints are relaxed, the market solution reflects a compounded price based on the cumulating impacts of the penalty prices. This pricing approach reflects all contingencies equally without regard to the relative impact of each contingency.

Applying existing market rules in these circumstances does not result in an optimal pricing of energy because the compounding of penalty prices does not provide any further congestion relief than merely setting the congestion component of the locational marginal price based on the pricing of the most relaxed contingency. Although this issue was less of concern in the past, with the inclusion of an increased number of contingencies, the compounded pricing becomes more problematic. The compounding of pricing results in increased congestion costs. When there are few contingencies modeled, the inefficiency is of less concern. However, as the number of contingencies modeled increases, the CAISO has determined that it is appropriate to address this inefficiency.

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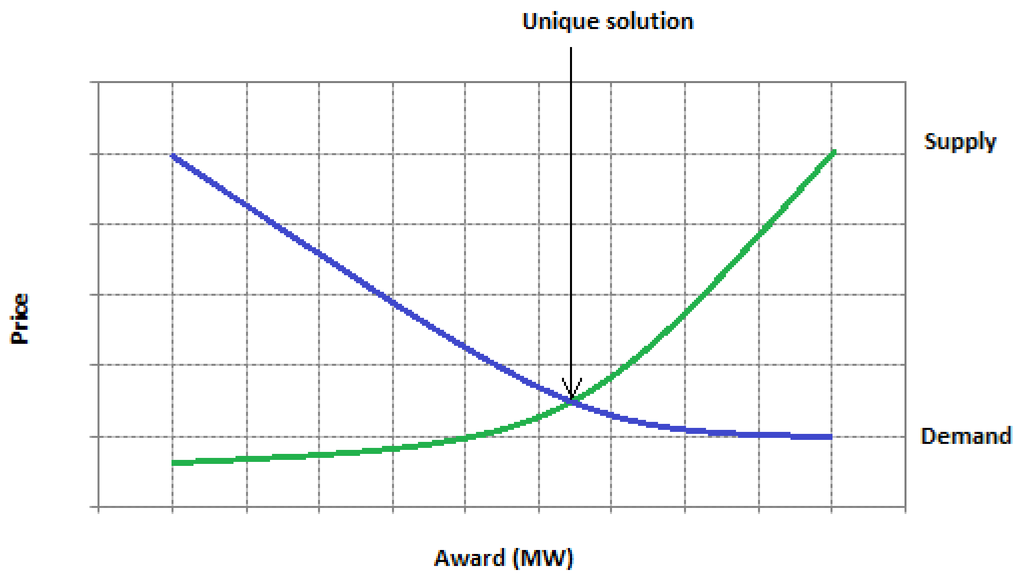
6 Existing tariff section 27.1 and existing tariff appendix C set forth how the CAISO calculates locational marginal prices for energy for the CAISO day-ahead and real-time markets. The locational marginal price at any given pricing node (PNode) for the day-ahead and real-time markets is comprised of three cost components: (1) the system energy marginal cost; (2) marginal cost of losses; and (3) marginal cost of congestion. In addition, Energy Imbalance Market (EIM) participating resources in the real-time market may receive an EIM bid adder to enable them to recover costs to comply with greenhouse gas regulations issued by the California Air Resources Board. Existing tariff section 27.1.1; existing tariff appendix C, sections A-B.

7 The optimization algorithms used in the CAISO markets calculate and utilize shift factors as an essential part of the process of determining resource schedules and prices. For any given PNode in the full network model (FNM), the shift factors associated with that PNode describe the resulting flows across all network lines when one additional MW of energy is injected at the PNode and withdrawn at the specified slack bus or buses.

B. Existing Conditions that Can Lead to Multiple Pricing Solutions

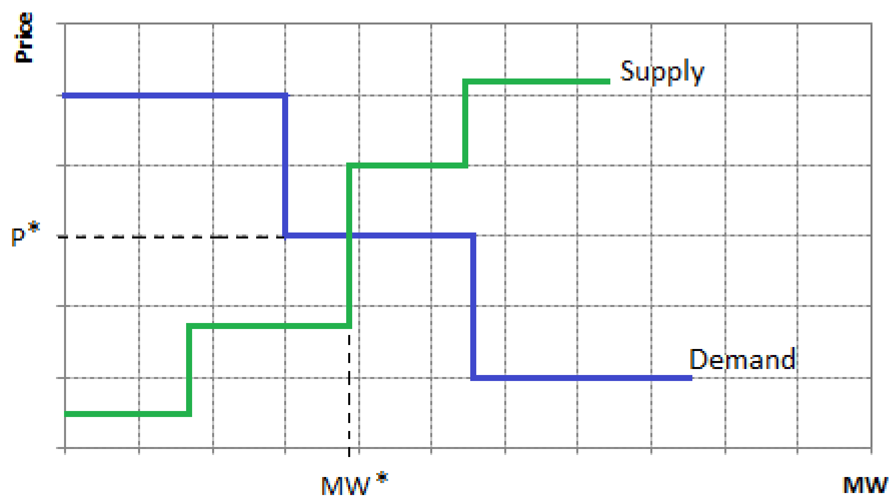
In an ideal market clearing process for an LMP-based market, prices are set optimally at the point where the upward sloping supply curve and downward sloping demand curve intersect. Each such price is unique in cases where the curves intersect at a single point. Figure 1 below illustrates such an ideal intersection:

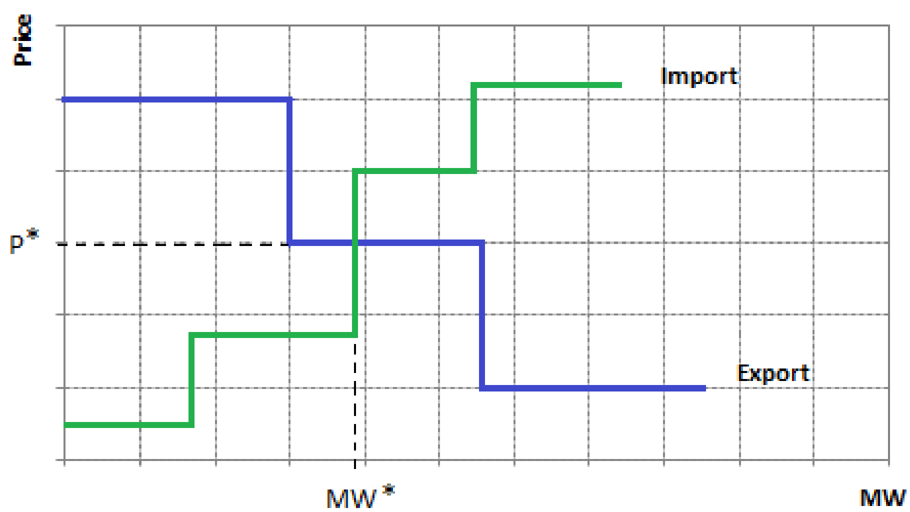
Figure 1: Supply and Demand Curves with a Unique Market Clearing Point



However, this ideal intersection of supply and demand curves does not realistically capture electricity market operations in which the bids are typically in the form of step-wise bidding curves, as is the case in the CAISO markets. These step-wise bid curves provide market participants the flexibility to submit multi-segment bids (usually multi-step-wise bids) for the full range of a resource's capacity and to vary bid prices along the steps. These step-wise bid curves better reflect the nature of generation costs and benefits for demand in electricity markets. The use of step-wise bid curves with multiple steps unavoidably breaks the smoothness of ideal supply and demand curves. As illustrated in Figures 2 and 3 below, even with monotonically increasing supply step-wise curves and monotonically decreasing step-wise demand curves, the market may clear at points where there is a unique price and megawatt (MW) solution.

Figures 2 and 3: Unique Market Solutions





However, these principles do not hold true in all cases, and it is possible for the market to clear at a location where there is an array of optimal market solutions that continue to be optimal at a multiplicity of prices (*i.e.*, at more than one price). Even with bids that are monotonically increasing for supply and decreasing for demand, conditions may occur when the intersecting point of stepwise supply and demand curves may lie at a horizontal or vertical segment of the curves, or may not intersect at all. Looking at the diagrams in Figures 2 and 3, one can visualize multiple scenarios in which the market could clear in portions of the bid curves where both curves are vertical, which would produce a case where all prices along the intersecting vertical ranges are optimal. Although these solutions continue to be optimal from a market-clearing perspective, such solutions are often referred to as "degenerate solutions," and their economic significance has further implications for the market overall.

Such degenerate pricing conditions are not limited to wholesale electricity markets. Degeneracy is rooted in the mathematical formulation and pricing optimization of a wide range of physical problems. In the case of wholesale electricity markets, degenerate cases can lead to a multiplicity of possible pricing solutions for the same dispatch of resources, and any of these solutions is "optimal" from a market clearing perspective. From this perspective, any of the multiple optimal solutions will achieve the same least-cost dispatch, and the cleared awards will be the same regardless of which of the multiple prices the market clears. Additionally, the overall cost of the market at any of the multiple solutions will be the same, regardless of which of the multiple prices the market clears. This holds for the cases where there is degeneracy of solutions with multiplicity of prices with only one set of optimal dispatches. Conceptually, there may also be degeneracy of solutions with multiplicity of dispatches with only one set of optimal prices.

The CAISO is proposing to change its market software so that it can specifically address degeneracy with multiplicity in prices arising from constraints, such as those arising from intertie constraints, that impact locational marginal prices. This proposal does not address degeneracy of solutions with multiplicity of dispatches. Under scenarios of degeneracy, linear programming commercial software products, such as the product used as part of the CAISO market software, often produce only one of the many optimal solutions. While the one solution attained is mathematically optimal, the fact that the resulting price could be one from a multiplicity of prices is problematic because the price attained may reflect a higher marginal cost of congestion at a particular location than is appropriate to reflect the congestion that actually exists at that location. This issue is not a problem when no schedules clear at such locations and no party pays for energy at that price. However, when used for settling other products such as congestion revenue rights, this creates an opportunity for changes of congestion revenue rights payouts that are not tied to the actual system conditions.[8]

The current approach also creates pricing uncertainty because the optimization software as currently configured can reach an optimal solution at any price from the range of mathematically optimal prices. This result is not under the CAISO's control, and the result instead is solely based on the optimization outcome. Consequently, there are no specific criteria the CAISO is instructing the market software to employ. While the price is optimal from a mathematical perspective, there is a wide range of price variation under the same conditions among degenerate solutions that are equally optimal. The enhancement proposed in this filing will eliminate the conditions of multiplicity of

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8 *See* existing tariff section 11.2.4.

price and ensure market clearing prices that are consistent with least-cost dispatch principles while continuing to be mathematically optimal. This will provide better price certainty for all market conditions.

The CAISO enforces multiple constraints in its market software to reflect the physical and scheduling limitations of the system under various possible conditions. One such constraint is the intertie constraint to limit import/export schedules between the CAISO and neighboring balancing authority areas.[9] Certain systems conditions, such as circumstances where an intertie is de-rated to a zero limit in one direction but not in the other direction, can produce degenerate pricing conditions. Under such circumstances, it is possible for an intertie bid to set the price through a bid that creates artificial congestion even though no net megawatts actually clear.[10]

Figure 4 below illustrates this possibility. In this case, the market clears at a partially open intertie where the capacity is derated to 0 MW in the export direction only, but is closed in the import direction with an import limit that exceeds 0 MW. In such cases, bids may still be submitted at the intertie, and the CAISO clears the market based on the import stack represented in green and the export stack represented in blue. As show in Figure 4, the market solution attains a system marginal energy cost of $30. Given that the import bid is higher than the system energy marginal cost, no imports would be awarded on this intertie, and no exports would be awarded in the export direction because it is derated to 0 MW.

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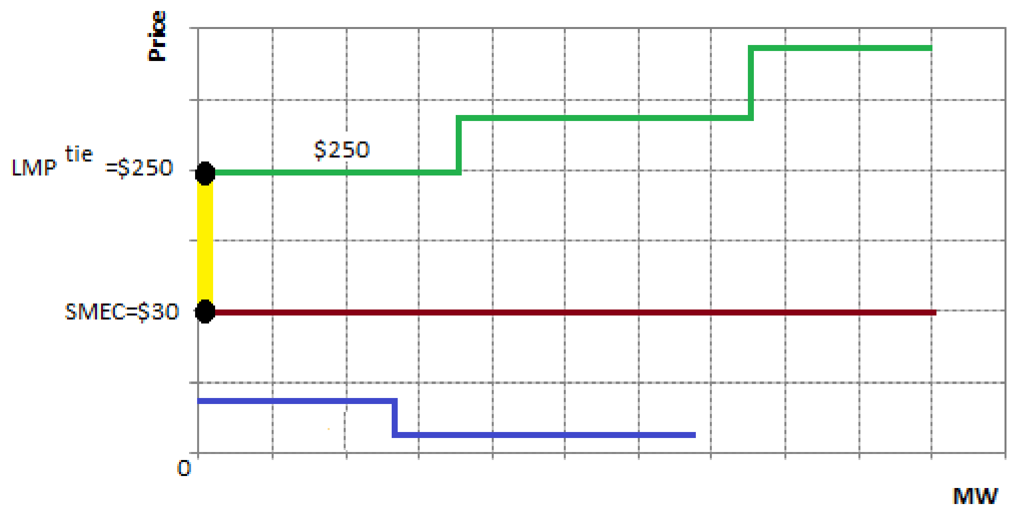
9 *See* existing tariff section 31.8.1.

10 For instance, in some circumstances there are outages that may cause load to be stranded. Depending on the scenarios, bids can still be allowed in the market. CAISO Operating Procedure 35301 provides an explanation of the CAISO's procedures for dealing with stranded load available at: http://www.caiso.com/Documents/3530I.pdf.

Figure 4: Degeneracy Solution with Multiple Optimal Prices



In terms of MW awards, this is an expected and optimal outcome under such scenarios. This condition leads to a degenerate solution where there are a multiplicity of prices that would be optimal, but the CAISO must settle market transactions based on a single market clearing price through the market clearing process. Figure 4 illustrates this scenario for the bids at a given scheduling point. The import bids set the price at the intertie location at $250/MWh, and the shadow price for the intertie constraint is set at negative $220/MWh (*i.e.*, $30 minus $250) in the export direction to balance with the system energy price of $30.[11] This means the intertie constraint is binding in the export direction at the 0 MW limit. The set of multiple prices is bounded on one end when the export constraint is binding at negative $220 and on the other end when such constraint is binding at a zero shadow price. For any price in this range, the optimal dispatch remains the same – 0 MW awards for both imports and exports. For the actual market solution, the software optimization feature independently selects the value at the upper bound of the shadow price for the market solution. As currently configured, the market optimization software does not have prescribed rules for selecting a specific price from the many possible prices. Rather, the market optimization software essentially converges on one of the solutions.

An outcome where it is possible to have multiple prices that are mathematically optimal does not pose a complication in the context of this energy market solution because there are 0 MW awards to settle at such prices, whatever the prices turn out to be. Any of the prices within the indicated range are equally optimal, and they all have their root in the mathematical formulation

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[11] The shadow price represents the marginal value of relieving a particular constraint. Existing tariff appendix A, definition of "Shadow Price."

and marginal pricing of the constraint. However, as discussed above, this does create pricing uncertainty because, under the same market conditions, the market clearing process may attain a locational marginal price at that scheduling point that can be either $30/MWh, or $250/MWh or any other price in between. For instance, assume the optimization converges to a locational marginal price of $100.28/MWh or to a price of $190.67/MWh, each of which are plausible outcomes since these prices are within the range of optimal prices.

Although these prices are optimal from a mathematical perspective, these prices would have little economic significance. The $30/MWh price can reflect the system-wide price, which has economic significance as it represents the system marginal energy cost. On the other hand, the $250/MWh price could reflect the economic bid submitted at that location and cleared in the market as marginal. Such a price might also have economic significance. However, the prices can also clear at any point in between $30/MWh, or $250/MWh, but some of these alternative prices would not reflect either of these market conditions (*i.e.*, system-wide price or the bids at that location). These prices simply meet the conditions of an optimal price in the market and could consequently lead to difficult conditions to hedge for the congestion implied by these prices if these prices materialized in the energy market solutions. This could lead to possible adverse market outcomes in other markets, such as the congestion revenue right market, that rely on this pricing and in which one price or another will have different settlements implications. For these reasons, as described below, the CAISO proposes a tariff amendment to ensure that the market clearing process produces a solution with a unique price consistent with the least-cost market dispatch principles already embodied in the existing tariff.[12]

C. Stakeholder Process

Beginning in 2014, the CAISO launched a stakeholder initiative to consider refinements to its market rules to increase price certainty and efficiency of prices cleared through the CAISO markets. This pricing enhancements initiative included:

- The CAISO issuing a series of three papers;
- Stakeholder conference calls to discuss the CAISO papers and opportunities to submit comments on the papers;
- The development of draft tariff provisions;

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12 *See* existing tariff sections 27.4.2, 27.4.3.

- A further conference call and opportunity for stakeholders to submit written comments on the draft tariff provisions; and

- Market simulations to show results with the proposed solution for addressing compounding of pricing for contingencies and for multiplicity of prices. [13]

The pricing enhancements initiative resulted in four proposed revisions to enhance market outcomes and provide more accurate and appropriate price signals in the CAISO markets:

(1) Revisions to the validation process for self-schedules supported by existing transmission contracts and transmission ownership rights to avoid creating artificial congestion and to ensure efficient use of the CAISO-controlled transmission grid.

(2) Modifications to the mathematical formulation the CAISO's market software uses for pricing the relaxation of transmission constraints to eliminate the current potential compounding effect of multiple contingencies on the price for relaxing transmission constraints.

(3) Revisions to the CAISO's market solution formulation to eliminate conditions that can lead to multiple pricing solutions for the same problem, ensuring that the market application produces a unique price if a market-clearing problem is limited by any constraint that affects the energy prices.

(4) Revisions to the CAISO's administrative pricing rules.[14]

The CAISO Governing Board ("Board") voted unanimously to authorize this filing during its public meeting held on December 18, 2014.[15]

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[13] Materials regarding this stakeholder process (including the Final Proposal) are available on the CAISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/PricingEnhancements.aspx. A list of key dates in the stakeholder process that are relevant to this tariff amendment is provided in attachment F to this filing.

[14] After the September 8, 2011, outage in the southwestern United States, the CAISO committed to revise its administrative pricing rules that would apply in the event of similar system emergencies or market disruptions. The CAISO launched this effort in 2012 and resumed it in June 2014 as part of the pricing enhancements initiative.

[15] Materials related to the Board's authorization are available on the CAISO website at http://www.caiso.com/informed/Pages/BoardCommittees/BoardGovernorsMeetings.aspx. These materials include a memorandum to the Board on the pricing enhancements proposal from Mark

This tariff amendment solely concerns the second and third sets of revisions listed above.[16] All stakeholders either support or do not oppose the proposed tariff revisions.[17]

II. Proposed Tariff Revisions

A. Enhanced Formulation of Contingency-Related Constraints

As explained above, in cases where multiple transmission constraints are relaxed, the market solution reflects a compounded price based on the totality of applicable penalty prices. Establishing prices under these circumstances does not result in an optimal pricing of energy. As discussed above, under current market rules, the compounding of penalty prices related to the multiple contingencies can increase the congestion costs at a particular location. However, the increased cost resulting from the compounding effect does not provide any further congestion relief than would be provided if the congestion component of the locational marginal price was instead based on the penalty price of the most relaxed contingency.

To address the non-optimal pricing of energy resulting from multiple contingencies, the CAISO proposes to modify provisions in its tariff regarding contingency modeling in the market optimization software so that the price will reflect the cost of congestion associated with the most limiting contingency under constraint relaxation conditions.[18]

With this modification, the CAISO will continue to enforce all credible contingencies determined by operations studies in the market clearing process, just as the CAISO does under the existing market rules.

Rothleder, Vice President, Market Quality & Renewable Integration ("Board Memorandum"), which is also provided in attachment D to this filing.

[16] The Commission has already accepted a tariff amendment to implement the first set of revisions listed above. *Cal. Indep. Sys. Operator Corp.*, 152 FERC ¶ 61,195 (2015). The revisions went into effect on November 4, 2015. *See Cal. Indep. Sys. Operator Corp.*, 153 FERC ¶ 61,138 (2015). The CAISO will submit a tariff amendment to implement the fourth set of revisions from the pricing enhancements initiative listed above in the future

[17] See pages 7-8 of the summary of submitted stakeholder comments included with the Board Memorandum in attachment D to this filing. The CAISO provided additional details and examples related to these two proposals in the Final Proposal in response to stakeholder requests. Section IV of this transmittal letter explains how the CAISO addressed one question raised by stakeholders.

[18] Revised tariff section 27.4.3.2.

Just like today, the CAISO will continue to establish the set of contingencies it will use in each market run based on operations engineering studies. The CAISO conducts a pre-screening process to determine which set of contingencies to enforce in each market run. Therefore, the proposed change does not impact the CAISO's ability to operate the system reliably consistent with NERC/WECC requirements. From the perspective of system reliability, if the CAISO could identify *ex ante* the single most limiting or severe contingency, it could enforce that contingency alone, which would cover all the other contingencies. However, *ex ante* it is not possible to identify exactly which of the possible or probable contingencies will occur. Which contingency becomes the most limiting in any market interval depends on the specific system conditions observed at the time. Because this is an inherently dynamic process, from a practical perspective it is not feasible to determine *ex ante* the contingency that will be the most limiting. Therefore, the CAISO must enforce all the contingencies it believes are possible or probable.

The proposed change will only impact the pricing of congestion when a constraint is relaxed. Rather than compounding the effect of the penalty prices associated with multiple contingencies being relaxed, the proposed pricing application will produce market outcomes based on the most limiting contingency case.[19] The CAISO determined that, by pricing at the most limiting contingency case, the CAISO's software is able to capture the congestion impact associated with the most limiting congestion.

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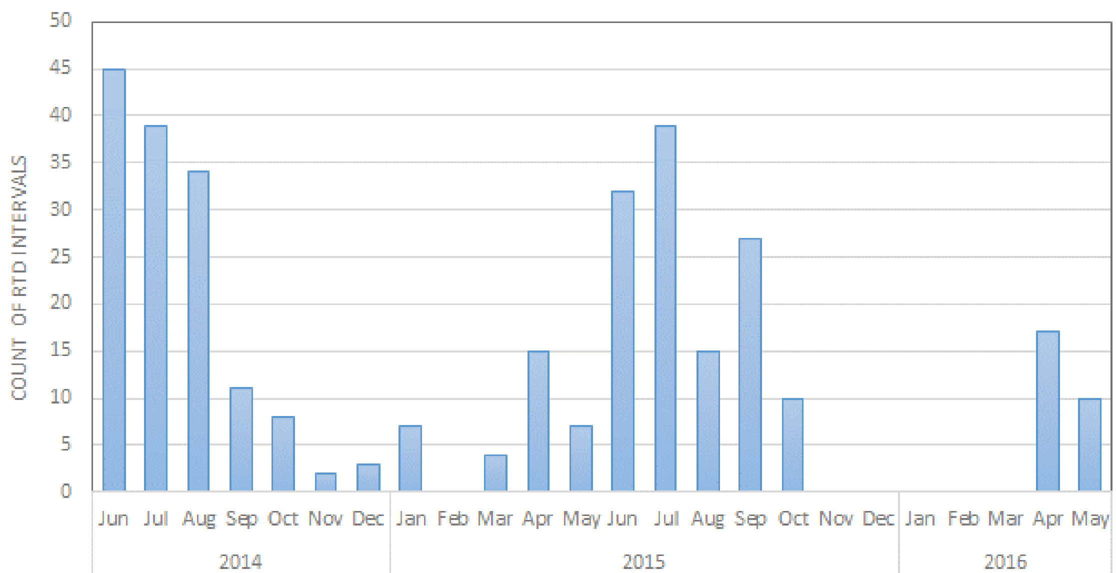
[19] The Final Proposal (at pages 27-29) contains a detailed mathematical discussion of the benefits the revision will provide.

The CAISO evaluated the historical data for the last two years and found several instances where concurrent contingencies were binding with constraints being relaxed. For example, Figure 5 below shows the number of intervals (frequency) in the real-time dispatch (RTD) interval of constraints binding concurrently for the last 24 months.

Figure 5: Frequency of RTD Intervals Experiencing Concurrent Binding of Contingencies



To implement this change, the CAISO will enhance the market application logic so it will effectively result in pricing only the most limiting contingency under constraint relaxation conditions. As discussed above, just like today, all contingencies will still be enforced in the market but only the most limiting constraint will be priced. Under the current market software, when a constraint is relaxed there are multiple slack variables per constraint due to the enforcement of multiple contingencies. With the software enhancements to be implemented when this tariff amendment becomes effective, the market software logic will only use one common slack variable for each transmission constraint associated with different contingencies.

For purposes of illustrating in detailed mathematical terms how this enhancement would be implemented, consider the current formulation of a transmission constraint related to contingencies:

$$\sum_j a_{kj}^c x_j \le b_k^c, \quad \forall k, c$$

In the current CAISO market formulation, this standard problem is expanded for the scheduling run to account for potential relaxation of transmission constraints by introducing a slack variable *k* to each transmission constraint.

$$\sum_j a_{kj}^c x_j - s_k^c \le b_k^c, \quad \forall k, c$$

The slack variables are penalized in the objective cost function with the corresponding constraint parameters prices as defined in section 27.4.3 of the CAISO tariff and section 6.6.5 the CAISO business practice manual for market operations. The amount of constraint relaxation from the scheduling run is denoted with s and the constraint with the largest relaxation is denoted with the index *m*. Pursuant to the proposed change, the transmission constraints will be modelled as follows:

$$\sum_j a_{kj}^m x_j - s_k \le b_k^m - \hat{s}_k^m - \varepsilon \quad \forall c = m$$

$$\sum_j a_{kj}^c x_j - s_k \le b_k^c - \hat{s}_k^c + \varepsilon \quad if \quad \hat{s}_k^c > 0 \quad \forall c \ne m$$

$$\sum_j a_{kj}^m x_j \le b_k^c \quad if \quad \hat{s}_k^c = 0 \quad \forall c \ne m$$

The difference between the two is the treatment of the slack variable, which is indicated by s_k in the equations above. Under the current design, there is one slack variable per constraint, including one slack variable per contingency constraint. The modified approach uses only a single slack variable for the base constraint and all the associated contingency constraints. This common slack variable also will be appended in the objective function only once, which means the relaxation will be priced only once. The limit for case *k* is further reduced by a small tolerance (ε) to force the common surplus variable to take value, whereas the limit for other violated cases is increased by a small tolerance to force price discovery. This formulation is more descriptive than the formulation provided in the policy discussion during the initial stages of the stakeholder process because more details came to light once the model was further evaluated in the implementation stage. This more detailed formulation implements the proposal discussed during the stakeholder process and approved by the CAISO Board.

Under the CAISO market software enhancements, even though the CAISO will model a transmission constraint individually for each contingency, there will be a common slack variable for transmission relaxation. Therefore, when a relaxation occurs, only the most limiting constraint will determine the amount of required relaxation. Any other contingency-related constraint that is less severe will be covered by this relaxed limit and, thus, will not be binding. The most limiting constraint is determined based the amount of relaxation applied on the transmission constraint limit.

This change will result in a different solution only when the market relaxes a transmission constraint associated with contingencies and not under any other type of transmission constraint. If the market solution is solving within the economical range, the market solution attained with this enhancement will be no different than the solution attained with the current market software since there are no slack variables or change in the limit for feasible cases.

This approach is just and reasonable because the pricing of all the enforced contingencies will no longer be compounded unnecessarily. Instead, prices will be based on the most limiting constraint. The CAISO models and enforces the contingencies in the market run so the market optimization can produce a commitment, schedule, or dispatch solution that considers the possibility that certain conditions may arise in actual operations. In reality, all of these conditions may not arise, but the solution is sufficiently robust to address any of the contingencies should they materialize. The prices produced as part of the solution reflect the cost of ensuring sufficient resources are available to address the modeled contingencies. Pricing all of them in the current approach compounds the pricing of contingencies unnecessarily when there may be little or no further congestion relief. The proposed approach prices the most limiting contingency, which ensures the worst-case contingency is managed and priced. For instance, if there were ten contingencies binding concurrently for the same protected element, with the current formulation, there would be ten shadow prices of $1,000 reflecting each one the penalty price for constraint relaxation. If there were a location with a 100 percent effectiveness for these ten constraints, effectively its marginal congestion component will be about $10,000, reflecting the compounding effect of the multiple contingencies. With the proposed formulation, only the most limiting constraint would be priced with a shadow price of $1,000 and for the location with 100 percent effectiveness. As a result, the marginal congestion component will be about $1,000 because the proposed formulation will eliminate the compounding pricing.

The CAISO proposes to adopt this approach to address the instances of compounded pricing for multiple contingencies like those that have been historically observed in the CAISO markets as illustrated in Figure 5 above. It is important to emphasize that the proposed enhancement will only target instances when there is a constraint relaxation; for instances where there are economical solutions or the contingencies are not binding, the market outcome will not change with the proposed formulation. In addition, this solution is relatively easy to implement under the existing market design and does not require major redesign of the market optimization engine. It only requires minor changes to the formulation of transmission constraints associated with contingencies and will provide the needed improvement to obtain a more appropriate price.

B. Revised Market Solution Formulation to Attain Unique Prices

As discussed above, degenerate pricing conditions can result in multiple market clearing prices due to the economic dispatch of generating resources. The range of solutions produced by the CAISO's linear programming commercial software in degenerate cases creates the potential for a scheduling coordinator to set the price through a bid that creates artificial congestion even though no megawatts actually clear.

The CAISO proposes to revise the market solution formulation set forth in its tariff (and implemented by its software) to eliminate the conditions leading to multiple prices and to enable the market optimization to obtain a unique-price solution. Pursuant to the proposed enhancement, if the market clearing problem is limited by any constraint, the market clearing process will create a shadow price for the constraint (*i.e.*, the price that represents the marginal value of relieving the constraint) only when relaxation of the constraint would reduce the total cost to operate the transmission system.[20] To accomplish this, the CAISO will change the existing linear programming model to be a quadratic programming model that uses a new slack variable in both the objective cost function and the constraint definition. Making this change will guarantee the uniqueness of prices associated with the various constraints in the transmission system, including intertie constraints.

The new formulation is consistent with existing least-cost dispatch principles already embodied in the tariff.[21] The new formulation will also ensure that, for those cases in which an intertie is de-rated to a zero limit in only one direction, the resulting price will not produce artificial congestion that creates complications for other products (such as congestion revenue rights that are settled on the basis of the cost of congestion at the applicable locations on the transmission system.[22]

The proposed solution does not, however, include specific rules to be incorporated in the market application to identify and select *ex ante* one price over others from the feasible set of prices in degeneracy cases. Currently, the market optimization solver converges into one price out of the many feasible

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20 Revised tariff section 27.1.1.3; tariff appendix C, revised sections C, D, and F.

21 *See* existing tariff sections 27.4.2, 27.4.3.

22 The Final Proposal (at pages 34-41) contains a detailed mathematical discussion of the benefits these modifications will provide.

prices and produces that as the final outcome, without following any specific selection rules. As previously noted, this does not mean the price is erroneous, because all of the prices are optimal in cases where there is degeneracy. As explained above, this is characteristic of linear programming-based optimization problems. The CAISO proposes to address this issue by enhancing the pricing formulation so that the conditions for multiplicity of prices are eliminated. The proposed formulation is still consistent with the CAISO's least-cost dispatch principles and will also produce accurate prices

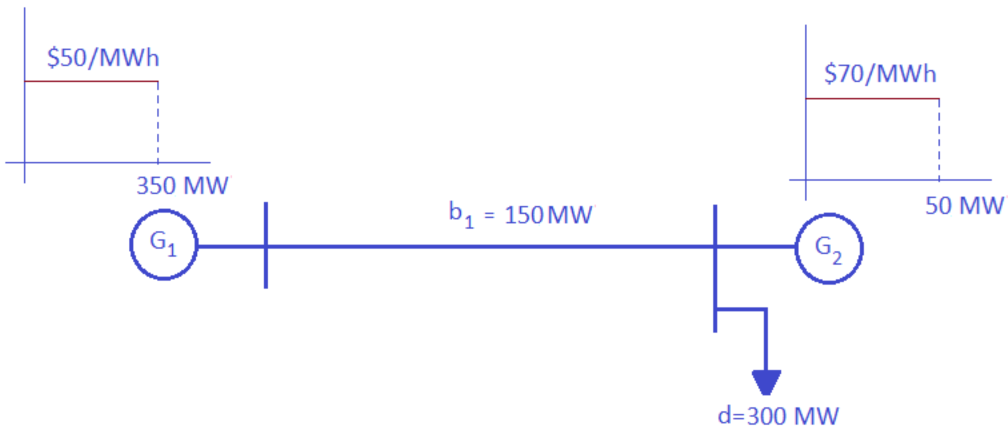
The CAISO and its vendor developed an alternative for effectively addressing such degenerate cases that relies on modifications to the mathematical structure of the linear programming security constrained economic dispatch currently used in the CAISO markets to ensure convexity of the objective function and uniqueness of prices. Attachment E to this filing provides a detailed mathematical description of the current structure and the proposed enhancements.

The CAISO would apply the proposed formulation in both the day-ahead and real-time markets and only in the pricing run of these markets because the pricing run generates the binding schedules and prices. Also, the CAISO intends to apply this formulation to constraints that impact the locational marginal prices for energy, including the power balance constraint and transmission constraints such as interties, branch group flowgates, nomograms, and EIM-related transmission constraints (EIM) transfer and greenhouse gas constraints). This formulation will be applied to these constraints because degeneracy in prices may conceptually happen in any of these constraints similar to the way it happens with intertie constraints.

Similar to how the CAISO models existing slack variables for transmission relaxation, under the proposed formulation the CAISO will model the new slack variable in the constraints in all market intervals, regardless of the potential scenarios of constraints binding or being slack or whether the constraint may be binding or not in the scheduling run. Essentially, the CAISO would treat these no differently than any of the existing constraints variables, and their enforcement would not be based on any specific *ex ante* defined rules. In cases where the constraint is under the defined limit, the slack variable makes no difference under the new design, just as it does not under the existing design, because it does not become meaningful until the system conditions are such that the flows are at the limit.

For purposes of illustrating how the proposed change in the mathematical function will determine prices, consider the two-node example in Figure 6 below, where the local generation is not sufficient to meet 300 MW of demand and the transmission constraint also imposes a limit on generator 1 to meet the load. In the market clearing process, the transmission constraint is relaxed in order to meet the demand and obtain a solution.

Figure 6: Two-Node Example of How the Proposed Change Will Determine Prices



By relaxing the transmission constraint, the slack variable in the scheduling run will allow the flow on line 1 to violate the limit at a penalty price of $5,000 per megawatt-hour (MWh). The solution to the scheduling run results in generator 1 producing 250 MW and generator 2 producing 50 MW. This represents a flow on line 1 of 250 MW, which is feasible by allowing a relaxation of the transmission constraint of 100 MW, and means the slack variable s_1 has a value of 100 MW. In terms of prices, the shadow price μ_1 associated with the transmission constraint of line 1 is negative $5,000/MWh and the shadow price of the power balance, which is the system marginal energy component, is $5,050/MWh. This means the locational marginal price at the locations of generators 1 and 2 is $50/MWh and $5,050/MWh, respectively. These resulting prices reflect the relaxation of the transmission constraint at the penalty price.

With respect to the pricing run formulation, the problem becomes:

$$\begin{aligned} min \quad & 50G_1 + 70G_2 + 1000s_1^s + 1000s_1^p \\ s.t. \quad & G_1 + G_2 = 300 \qquad (\lambda) \\ & G_1 - s_1^s - s_1^p \leq 150 \qquad (\mu_1) \qquad (7) \\ & 0 \leq G_1 \leq 350 \\ & 0 \leq G_2 \leq 50 \\ & 0 \leq s_1^s \leq 100 \\ & 0 \leq s_1^p \leq 0.1 \end{aligned}$$

In this example, the variable s_1^s is limited by the amount of the relaxation from the scheduling run. That is, the 100 MW of relaxation that made the flow feasible, and s_1^p is limited by an epsilon amount. The cost of moving one unit of either of these slack variables is set to $1,000 based on the current values of penalty prices used in the markets for transmission constraint relaxation in the pricing run. The solution of this problem is G_1 = 250 MW, G_2 = 50 MW, flow on line 1= 250 MW, s_1^s = 100 MW, s_1^p=0 MW. The system marginal energy price is $1,050/MWh, the shadow price on the flow constraint with the slack is negative $1,000/MWh. The LMP at the locations of generators 1 and 2 are $50/MWh and $1,050/MWh, respectively. The prices reflect the fact that the flow constraint on line 1 cannot be satisfied and the penalty cost of violating the constraint, which is based on the administrative transmission relaxation price of $1,000/MWh.

The proposed formulation will cast the problem into a quadratic programming program. Assuming that the weight ω^q is set to a very small positive value of, say, 0.0001, the solution to this problem is G1 = 250 MW, G2 = 50 MW, flow on line 1 = 250 MW. The system marginal energy price is $1,050/MWh, the shadow price on the flow constraint with the slack is negative$1,000/MWh. The LMP at the locations of generators 1 and 2 are $50/MWh and $1,050/MWh, respectively. This is the expected result consistent with the goal to set shadow prices for infeasible transmission constraints according to the transmission relaxation price of the pricing run, *i.e.*, $1,000/MWh.

In order to illustrate how the epsilon affects the market solution, consider the summary of market results using different values for the weight as shown in Table 1:

Table 1: Comparison of Market Solutions with Different Weight Values

ω^q	G_1	G_2	LMP_1	LMP_2	λ	μ_1
10	300	0	50	65	65	-15
1	250	50	50	150	150	-100
0.1	250	50	50	1050	1050	-1000
0.01	250	50	50	1050	1050	-1000
0.001	250	50	50	1050	1050	-1000

In the first two cases where the weight is set to a large value, the relaxation relies on the slack variable of the quadratic term and defines prices that do not reflect the relaxation condition. Only in the cases with the weight set to a value of 0.1 or lower will the shadow price and locational marginal prices reflect the actual conditions of constraint relaxation.[23]

Figure 7 below illustrates the market solution using the proposed formulation in which the locational marginal price at the intertie scheduling point is equal to the system marginal energy cost, which in turn results in no congestion on the intertie in the export direction. These numerical examples are from actual market cases observed in the past. The specific bid values were modified so they do not reflect the actual bids.

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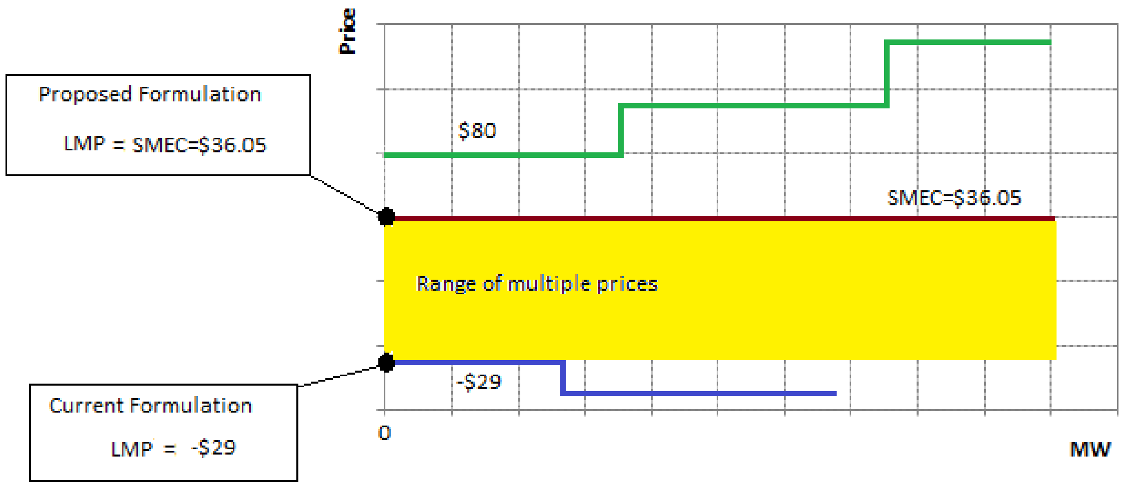
23 This proposed mathematical formulation is coordinated with the change the CAISO proposes in section II.A of this transmittal letter above to address pricing related to the enforcement of multiple contingencies. Under the current treatment of the slack variable, both the definition of the constraint and the objective cost function will remain the same. However, there will be only one slack variable for the set of base case and contingencies appended into the objective cost function, which will be priced once at the penalty price of the most limiting constraint as proposed in section II.A above.

Figure 7: Market Solution at the Intertie with Alternate Pricing



As illustrated in Figure 7, the proposed optimization formulation actually solves to a single market outcome, thereby eliminating degeneracy. The outcome is not based on any new logic requiring the software to pick any particular solution of the set of multiple optimal solutions. Rather, the no-congestion outcome results in the same optimal dispatch as the old formulation, but eliminates the multiplicity of prices. This solution is also consistent with economic dispatch principles where a resource is not dispatched based on the locational marginal price not supporting the dispatch and also the system constraints are enforced and preserve within its limits.

In contrast, consider an alternative scenario where an intertie is de-rated to 0 MW in the import direction and the export limit is non-zero. The bid setup is represented in Figure 7 with the import stack represented in green and the export stack represented in blue. In this case, there are no awards in either the import or export direction. Under the current formulation, the price at the intertie location is set by the export at negative $29. With the system price at $36.05, the price differential between the system price and the tie price is defined by the congestion on the intertie at a shadow price of negative $65.05. Like the previous example, this case also leads to degeneracy and multiplicity of prices. The current formulation provides a market solution at the lower bound of the set of degenerate prices, which is the maximum level of congestion on the intertie in the export direction. The proposed formulation would clear the price at the intertie location equal to the system price of $36.05, leading to no congestion on the intertie. The optimal dispatches in either case are still 0 MW for both imports and exports.

C. Other Tariff Revisions Related to the Revisions Discussed Above

In connection with the tariff revisions discussed above, the CAISO also proposes to make other clarifying and clean-up changes to the existing tariff. These include changes to align the existing tariff with the above-described tariff revisions and to specify the applicability of the tariff provisions on the calculation of locational marginal prices to the energy imbalance market.

Specifically, with regard to the enhanced formulation of contingency-related constraints described above, the CAISO proposes to revise tariff section 27.4.3.1 to delete the words “internal and Intertie” from the phrase “will relax an enforced internal and Intertie Transmission Constraint,” because the deleted words are superfluous. The CAISO also proposes to revise the definition of the term “Contingency” in tariff appendix A to clarify that a contingency can arise while operating not only the CAISO balancing authority area but also an EIM entity balancing authority area. Further, the CAISO proposes to revise the definition of the term “Transmission Constraints” in tariff appendix A to specify that transmission constraints include contingencies and nomograms, while deleting similar provisions from tariff section 27.5.6 because that revised definition renders the deleted tariff provisions unnecessary.

In connection with the revised market solution formulation to obtain unique prices described above, the CAISO proposes to clarify the provisions in existing tariff sections 27.1 and 27.1.1 and existing tariff appendix C to describe more specifically how the CAISO calculates locational marginal prices and their cost components, consistent with the revised market solution formulation. These revisions will update the tariff language and make it easier to understand.

With regard to the energy imbalance market, the CAISO proposes to clarify in section C of tariff appendix C that the system-level power balance constraint is enforced over the CAISO balancing authority area for the day-ahead market and over the EIM area (*i.e.*, the combined CAISO balancing authority area and all EIM entity balancing authority areas) in the real-time market. The CAISO also proposes to clarify in section E of tariff appendix C that the marginal cost of losses component of the locational marginal price at PNodes in an EIM entity balancing authority area in the real-time market includes additional contributions from the shadow price of the power balance constraint for that balancing authority area and the shadow price of the net imbalance energy export allocation constraint for greenhouse gas regulation. Further, the CAISO proposes to clarify in section F of tariff appendix C that, in the real-time market, the CAISO will determine the marginal greenhouse gas component of the locational marginal price at a PNode in an EIM entity balancing authority area and LMPs for imports and exports between that EIM entity balancing authority area and a non-EIM entity balancing authority area as the negative of the shadow price of the net imbalance energy export allocation constraint. These provisions will make it clear how the CAISO will calculate the locational marginal price when an EIM balancing authority area is involved in a day-ahead or real-time market transaction.

III. Market Simulation Results

In order to verify that the software changes produced results consistent with the proposed rule changes, the CAISO conducted market simulations during August and September 2015 to test specific scenarios for the proposed enhancements of compounded pricing of multiple contingencies and multiplicity of prices due to degeneracy. The CAISO provided to participants the plan for the simulation,[24] and once the simulation was completed participants were able to see the market results under these simulated scenarios; the CAISO held a conference call to explain the simulation results. This simulation allowed participants to see and evaluate market results for these enhancements.

The first scenario tested the proposed changes that would apply when the market experiences multiple binding contingencies as described above in section II.A. The CAISO tested a specific scenario at a single flow gate that has existing multiple outage contingencies defined that would cause the flow gate to bind for multiple contingencies when there are no resources available and the emergency limit was decreased to force the condition to happen. The CAISO generated this scenario to replicate as close as possible the actual scenarios observed historically in the market.

During the market simulation, the CAISO enabled the software feature with the proposed rule change one day in both the day-ahead and real-time markets. Then the CAISO disabled the feature on another day to test and demonstrate the differences in pricing under the proposed changes. With the feature disabled, each contingency was priced at the pricing run penalty price for an overloaded constraint, resulting in compounded pricing of multiple contingencies. When the feature was enabled, each contingency was equally overloaded but the pricing run penalty price was equally distributed between the contingencies. In this case, the pricing on the flow gates or relevant locations was reflective of only one single time the penalty price, which was a lower price than under the scenario with the penalty price compounded multiple times when the feature was turned off.

In the second scenario, the CAISO tested the proposed enhancement to address multiplicity of prices in a structured scenario as described above in

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[24] The document is available on the CAISO website at: http://www.caiso.com/Documents/PricingEnhancementsStructuredScenarios.pdf.

section II.B. Again, the CAISO conducted the scenarios with the proposed market feature on and off for scenarios replicating the historical occurrences of multiplicity of prices. The CAISO built a scenario with similar conditions to the cases observed historically in the actual market where the intertie constraint was partially open to trigger a scenario of price degeneracy. Only the bids for the intertie locations were adjusted with respect to the original bids from the actual market. In this scenario, the CAISO set an import or export limit at 0 MW. When the proposed feature was not enabled and, with the 0 MW limit, a high-priced bid was created in the opposite direction. In a degeneracy case, no schedules would be created but, the intertie constraint would bind on the 0 MW limit with the high price from the opposite direction bid.

When the feature was enabled, the market solution attained a $0 shadow price for the intertie constraint. This was simulated in both the day-ahead market and the real-time markets.

IV. Stakeholder Issues

Stakeholders generally support the proposed changes. Some stakeholders indicated that they desired to review the detailed mathematical formulation that will be used in the algorithm and implementation of the solution to eliminate the multiplicity of pricing solutions. The CAISO's Market Surveillance Committee raised a similar issue. In response, the CAISO explained that its software vendor deems this to be proprietary information and thus the CAISO was unable to release such information. However, to address the concerns of both stakeholders and the Market Surveillance Committee, the CAISO provided additional level of detail to stakeholders as to how the mathematical formulation will be adjusted. As discussed above, the CAISO also conducted market simulations to test the software, verified that the software works as intended, and provided the results of the market simulations to stakeholders.

V. Effective Date

The CAISO requests that the Commission issue an order by September 1, 2016 that accepts the tariff revisions contained in this filing effective September 7, 2016. Issuance of the Commission order by September 1 is necessary so that the CAISO has enough time to prepare its systems for the September 1 go-live date.

VI. Communications

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

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VII. Service

The CAISO 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 CAISO tariff. In addition, the CAISO has posted a copy of the filing on the CAISO website.

VIII. Contents of Filing

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

Attachment A	Clean CAISO tariff sheets incorporating this tariff amendment
Attachment B	Red-lined document showing the revisions contained in this tariff amendment
Attachment C	Final Proposal
Attachment D	Board Memorandum (including matrix of stakeholder comments)
Attachment E	Mathematical description of existing pricing formulation and enhanced pricing formulation
Attachment F	List of key dates in the stakeholder process

IX. Conclusion

For the reasons set forth in this filing, the CAISO respectfully requests that the Commission issue an order by September 1, 2016 that accepts the tariff revisions proposed in the filing effective as of September 7, 2016.

Respectfully submitted,

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Attachment A – Clean Tariff

Tariff Amendment to Implement Pricing Enhancements

California Independent System Operator Corporation

June 6, 2016

27.1 LMPs And Ancillary Services Marginal Prices

Through the workings of CAISO Market Processes, the CAISO produces: 1) Locational Marginal Prices as provided in Section 27.1.1 and its subparts, and as further provided in Appendix C; and 2) Ancillary Services Marginal Prices as provided below in Section 27.1.2, and its subparts.

27.1.1 Locational Marginal Prices for Energy

As further described in Appendix C, the LMP for Energy at any PNode is the marginal cost of serving the next increment of Demand at that PNode calculated by the CAISO through the operations of the CAISO Markets considering, as described further in the CAISO Tariff, among other things, modeled Transmission Constraints, transmission losses, the performance characteristics of resources, and Bids submitted by Scheduling Coordinators and as modified through the Locational Market Power Mitigation process. The LMP at any given PNode is comprised of three marginal cost components: the System Marginal Energy Cost (SMEC); Marginal Cost of Losses (MCL); and Marginal Cost of Congestion (MCC). Through the IFM the CAISO calculates LMPs for each Trading Hour of the next Trading Day. Through the FMM the CAISO calculates distinct financially binding fifteen-minute LMPs for each of the four fifteen-minute intervals within a Trading Hour. Through the Real-Time Dispatch, the CAISO calculates five-minute LMPs for each of the twelve (12) five (5) minute Dispatch Intervals of each Trading Hour. The CAISO uses the FMM or RTD LMPs for Settlements of the Real-Time Market. In the event that a Pricing Node becomes electrically disconnected from the market model during a CAISO Market run, the LMP, including the SMEC, MCC and MCL, at the closest electrically connected Pricing Node will be used as the LMP at the affected location.

* * *

27.1.1.3 Marginal Cost of Congestion

The Marginal Cost of Congestion at a PNode reflects a linear combination of the Shadow Prices of the binding Transmission Constraints in the network, multiplied by the corresponding Power Transfer Distribution Factor (PTDF) and coefficient relevant to the transmission segment within that constraint, which is described in Appendix C. The Marginal Cost of Congestion for a Transmission Constraint may be positive or negative depending on whether a power injection at that Location marginally increases or decreases Congestion.

* * *

27.4.3.1 Scheduling Parameters for Transmission Constraint Relaxation

In the IFM, the enforced internal and Intertie Transmission Constraint scheduling parameter is set to $5,000 per MWh for the purpose of determining when the SCUC and SCED software in the IFM will relax an enforced Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.12 to relieve Congestion on the constrained facility. This scheduling parameter is set to $1,500 per MWh for the RTM. The effect of this scheduling parameter value is that if the optimization can re-dispatch resources to relieve Congestion on a Transmission Constraint at a cost of $5,000 per MWh or less for the IFM (or $1,500 per MWh or less for the RTM), the Market Clearing software will utilize such re-dispatch, but if the cost exceeds $5,000 per MWh in the IFM (or $1,500 per MWh for the RTM) the market software will relax the Transmission Constraint. The corresponding scheduling parameter in RUC is set to $1,250 per MWh.

27.4.3.2 Pricing Parameters for Transmission Constraint Relaxation

For the purpose of determining how the relaxation of a Transmission Constraint will affect the determination of prices in the IFM and RTM, the pricing parameter of the Transmission Constraint being relaxed is set to the maximum Energy Bid price specified in Section 39.6.1.1. In the case of Contingency-related Transmission Constraints, the CAISO will determine the amount of relaxation required to clear the market using the most limiting condition among the applicable Contingencies and the base case. The CAISO will establish prices based on the parameter pricing specified in this Section as it applies to the most limiting Contingency and base case. The corresponding pricing parameter used in the RUC is set at the maximum RUC Availability Bid price specified in Section 39.6.1.2.

* * *

27.5.6 Management & Enforcement of Constraints in the CAISO Markets

The CAISO operates the CAISO Markets through the use of a market software system that utilizes various information including the Base Market Model, the State Estimator, submitted Bids including Self-Schedules, Generated Bids, Transmission Constraints, and transmission and generation Outages. The market model used in each of the CAISO Markets is derived from the most current Base Market Model available at that time. To create a more relevant time-specific network model for use in each of the CAISO Markets, the CAISO will adjust the Base Market Model to reflect Outages and derates that are known and applicable when the respective CAISO Market will operate, and to compensate for observed discrepancies between actual real-time power flows and flows calculated by the market software. Through this process the CAISO creates the market model to be used in each Day-Ahead Market and each process of the Real-Time Market. The CAISO will manage the enforcement of Transmission Constraints, consistent with good utility practice, to ensure, to the extent possible, that the market model used in each market accurately reflects all the factors that contribute to actual Real-Time flows on the CAISO Controlled Grid and that the CAISO Market results are better aligned with actual physical conditions on the CAISO Controlled Grid. In operating the CAISO Markets, the CAISO may take the following actions so that, to the extent possible, the CAISO Market solutions are feasible, accurate, and consistent with good utility practice:

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

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

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

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

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

(f) The CAISO may adjust Transmission Constraints for the purpose of reserving internal transfer capability in the Day-Ahead or Real-Time Markets, based on anticipated conditions on the natural gas delivery system, to reliably serve load in specific geographic regions of the CAISO Balancing Authority Area, or to assure deliverability of Ancillary Services. The CAISO may or may not release such reserved internal transfer capability based on natural gas and electric system conditions, or observed market inefficiencies. Upon determining that an adjustment is necessary, the CAISO will issue a notification specifying the amount of the adjustment.

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

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Appendix C

Locational Marginal Price

The CAISO shall calculate the price of Energy at Generation PNodes, Scheduling Points, and Aggregated Pricing Nodes, as provided in the CAISO Tariff. The CAISO establishes Trading Hub prices and LAPs as provided in the CAISO Tariff. The LMPs at PNodes, including Scheduling Points, and Aggregated Pricing Nodes include separate components for the marginal cost of Energy, Marginal Cost of Congestion, and Marginal Cost of Losses. As provided in Sections 6.5.3.2.2 and 6.5.5.2.4, Day-Ahead Market LMPs are calculated and posted on a Day-Ahead basis for each hour of the Day-Ahead Market and for each interval of the Real-Time Market.

A. LMP Composition in the Day-Ahead Market

The CAISO calculates the LMP for each PNode, which is based on the Bids of sellers and buyers selected in the Day-Ahead or Real-Time Market and are calculated as described below. The CAISO designates a distributed Reference Bus, r, for calculation of the Locational Marginal Prices. The Locational Marginal Prices are not determined by resources that are not eligible to set the Locational Marginal Price as defined in Sections 31.3.1.4 and 34.20.2.3. For each bus other than the Reference Bus, the CAISO determines separate components of the LMP for the System Marginal Energy Cost, Marginal Cost of Congestion, and Marginal Cost of Losses relative to the Reference Bus, consistent with the following equation:

$LMP_i = SMEC_r + MCC_i + MCL_i$

$LMP_r = SMEC_r$

where:

- $SMEC_r$ is the LMP component representing the marginal cost of Energy at the Reference Bus, r (System Marginal Energy Cost).

- MCC_i is the LMP component representing the Marginal Cost of Congestion at bus *i* relative to the Reference Bus.
- MCL_i is the LMP component representing the Marginal Cost of Losses at bus *i* relative to the Reference Bus.

B. LMP Composition in the Real-Time Market

In each 15-minute interval and each 5-minute interval of the Fifteen Minute Market and Real-Time Dispatch, respectively, the CAISO calculates the LMP for each PNode, based on the Bids of sellers and buyers selected in those markets as specified in the FMM Schedule and 5-minute Real-Time Dispatch Instructions. The CAISO designates a Reference Bus, r, for calculation of the System Marginal Energy Cost (SMECr), which is the shadow price of the system power balance constraint. The CAISO uses the distributed load in the EIM Area as the Reference Bus to calculate loss sensitivities and shift factors used to linearize the power balance and Transmission Constraints. Resources that have constraints that prevent them from being marginal are not eligible to set the Locational Marginal Price. For each bus other than the Reference Bus, the CAISO determines separate components of the LMP for the marginal cost of Energy, Marginal Cost of Congestion, Marginal Cost of Losses, and EIM Bid Adder relative to the Reference Bus, consistent with the following equation:

$$LMP_i = SMEC_r + MCC_i + MCL_i + MCG_i$$

$$LMP_r = SMEC_r$$

where:

- MCG_i is the LMP component representing the marginal cost of the EIM Bid Adder in dispatching Energy from the relevant EIM Participating Resources to serve load in the CAISO Balancing Authority Area (Marginal Greenhouse Gas Cost).

For each PNode within an EIM Entity Balancing Authority Area, the LMP shall include a fourth component, the EIM Bid Adder component.

C. The System Marginal Energy Cost Component of LMP (Day-Ahead and Real-Time Market)

The SMEC shall be the same for each location throughout the system. SMEC is the sensitivity of the power balance constraint at the optimal solution. The power balance constraint ensures that the physical law of conservation of Energy (the sum of Generation and imports equals the sum of Demand, including exports and Transmission Losses) is accounted for in the network solution. This system level power balance constraint is enforced over the CAISO Balancing Authority Area for the Day-Ahead Market and over the EIM Area in the Real-Time Market. For the designated reference location the CAISO will utilize a distributed Load Reference Bus for which constituent PNodes are weighted using the Reference Bus distribution factors. The Load distributed Reference Bus distribution factors are based on the Load Distribution Factors at each PNode that represents cleared Load in the Integrated Forward Market or forecast Load for MPM, RUC and RTM. In the Integrated Forward Market, in the event that the market is not able to clear based on the use of a distributed load Reference Bus, the CAISO will use a distributed generation Reference Bus for which the constituent nodes and the weights are determined economically within the running of the Integrated Forward Market based on available economic bids. In the event that the CAISO employs a distributed generation Reference Bus, it will notify Market Participants of which Integrated Forward Market runs required the use of this backstop mechanism. A distributed Load Reference Bus will be used for RUC and RTM regardless of whether a distributed Generation Reference Bus were used in the corresponding Integrated Forward Market run. If the market-clearing problem is limited by the system-level power balance constraint, the market clearing process would create a Shadow Price for the power balance constraint only when the relaxation of the constraint would result in a reduction in the total cost to operate the system.

D. Marginal Congestion Component Calculation (Day-Ahead and Real-Time)

The CAISO calculates the Marginal Costs of Congestion at each bus as a component of the bus-level LMP. The Marginal Cost of Congestion (MCCi) component of the LMP at bus i is calculated in the Day-Ahead Market using the equation:

$$MCC_i = -\sum_k \sum_j C_{j,k}\, PTDF_{i,j}\, FSP_k$$

where:

- *K* is the Transmission Constraint index.

- j is the transmission component index of Transmission Constraint k. When Transmission Constraint k is a Nomogram, there can be more than one transmission component. When Transmission Constraint k is any other Transmission Constraint, there shall be only one transmission component. $PTDF_{i,j}$ is the Power Transfer Distribution Factor for the bus *i* on transmission component j of the Transmission Constraint *k* which represents the flow across that transmission component j when an increment of power is injected at bus *i* and an equivalent amount of power is withdrawn at the Reference Bus. The CAISO does not consider the effect of losses in the determination of PTDFs.

- $C_{j,k}$ is the constraint coefficient for the transmission component j in constraint k. When constraint k is a Nomogram, this represents the relevant coefficient for that component. When constraint k is any other Transmission Constraint, this coefficient will always be 1.
- FSP_k is the constraint Shadow Price on constraint *k* and is equivalent to the reduction in system cost expressed in $/MWh that results from a marginal increase of the capacity on constraint *k*. If the market-clearing problem is limited by any Transmission Constraint including Interties, branch groups, flowgates, nomograms, and Energy Imbalance Market-related transmission constraints (EIM Transfer constraint and power balance constraint for a Balancing Authority Area), the market clearing process would create a Shadow Price for the Transmission Constraint, only when the relaxation of the constraint would result in a reduction in the total cost to operate the system.

The MCC at PNodes in an EIM Entity Balancing Authority Area *j* in the Real Time Market includes an additional contribution from the shadow price of the power balance constraint for that Balancing Authority Area, λ_j, as follows:

$$\text{MCC}_i = \lambda_j - \sum_{k=1}^{K} PTDF_{jk}\, FSP_k$$

A power balance constraint is not formulated for the CAISO Balancing Authority Area alone in the RTM. The shadow price of the power balance constraint for EIM Entity Balancing Authority Area *j* (λ_j) has the following contributions:

a) the shadow price of the EIM Transfer distribution constraint (φ_j), which distributes the EIM Transfer for Balancing Authority Area *j* to Energy transfers on interties with other Balancing Authority Areas in the EIM Area; and

b) the shadow price of the EIM Transfer scheduling limit for Balancing Authority Area *j*, upper (ν_j) or lower (ξ_j):

$$\lambda_j = \varphi_j - \nu_j + \xi_j$$

Where λ_j is zero for the CAISO Balancing Authority Area since the power balance constraint is not formulated for it.

The difference between the shadow prices of the EIM Transfer distribution constraints for two Balancing Authority Areas *j* and *k* in the EIM Area has the following contributions from any intertie *l* used for energy transfers between these two Balancing Authority Areas:

a) the EIM Transfer schedule cost that applies to that intertie *l* (c_l);

b) the shadow price of the Energy transfer schedule limit from Balancing Authority Area *j* to Balancing Authority Area *k* that applies to that intertie *l*, upper limit (ρ_l) or lower limit (σ_l); and

c) the shadow price of the scheduling limit that constrains both Energy transfers and additional schedules to Balancing Authority Area *j* on that intertie *l*, upper limit (ζ_l) or lower limit (η_l):

$$\varphi_j - \varphi_k = -c_l - \rho_l + \sigma_l + \zeta_l - \eta_l$$

There may be multiple scheduling limits under (c) above that constrain schedules on a given EIM Intertie.

E. Marginal Losses Component Calculation

The CAISO calculates the Marginal Cost of Losses (MCLi) at each bus i as described in Section 27.1.1.2. The MCL component of the LMP at any bus i within the CAISO's Balancing Authority Area is calculated using the equation:

$$MCL_i = MLF_i * SMEC_r$$

Where:

- MLFi is the marginal loss factor for PNode i to the system Reference Bus, based on an AC power flow solution. The marginal loss factor at a PNode is the incremental change in the quantity (MW) of transmission losses in the network resulting when serving an increment of Load at the PNode from the Reference Bus.
    - MLFi is equal to $-\partial L/\partial G_i$, where: L is system losses, G_i is "generation injection" at PNode *i*, $\partial L/\partial G_i$ is the partial derivative of system losses with respect to generation injection at bus *i*, that is, the incremental change in system losses associated with an incremental change in the generation injections at bus *i* holding constant other injection and withdrawals at all buses other than the Reference Bus and bus *i*.
- SMECr is the marginal cost of Energy at the Reference Bus r (System Marginal Energy Cost).

The MCL at PNodes in an EIM Entity Balancing Authority Area *j* in the Real Time Market includes additional contributions from the shadow price of the power balance constraint for that Balancing Authority Area (λ_j) and the shadow price of the net imbalance energy export allocation constraint for greenhouse gas regulation (ψ):

$$MCL_i = MLF_i * (SMEC_r + \lambda_j - \psi)$$

F. Marginal Greenhouse Gas Cost Component Calculation

For EIM Participating Resources within an EIM Entity Balancing Authority Area and Energy imported to or exported from an EIM Entity Balancing Authority Area, the CAISO will include the marginal cost of the EIM Bid Adder in dispatching Energy from the relevant EIM Participating Resources to serve load in the CAISO Balancing Authority Area. The CAISO will allocate the Net Imbalance Energy Export optimally to EIM Participating Resources. This allocation does not depend on the location of the EIM Entity Participating Resource; i.e. the CAISO does not use a shift factor in the allocation. If the Net Imbalance Energy Export from all EIM Entity Balancing Authority Areas as a group is negative or zero, there is no associated Net Imbalance Energy Export allocation. Otherwise the net imbalance energy export allocation constraint is binding with a Shadow Price (ψ). If the market-clearing problem is limited by any Marginal Greenhouse Gas Cost constraint, the market clearing process would create a Shadow Price for the Marginal Greenhouse Gas Cost constraint only when the relaxation of the constraint would result in a reduction in the total cost to operate the system. The CAISO determines the Marginal Greenhouse Gas Cost component of the LMP at a PNode in an EIM Entity Balancing Authority Area and LMPs for imports and exports between that EIM Entity Balancing Authority Area and a non-EIM Entity Balancing Authority Area as the negative of the Shadow Price of the net imbalance energy export allocation constraint,

$$MCG_i = -\psi$$

* * *

Appendix A

Master Definition Supplement

* * *

- Contingency

A potential Outage that is unplanned, viewed as possible or eventually probable, which is taken into account when considering approval of other requested Outages or while operating the CAISO Balancing Authority Area or EIM Entity Balancing Authority Area.

* * *

- Transmission Constraints

Physical and operational limitations on the transfer of electric power through transmission facilities, which include Contingencies and Nomograms.

Attachment B – Marked Tariff

Tariff Amendment to Implement Pricing Enhancements

California Independent System Operator Corporation

June 6, 2016

27.1 LMPs And Ancillary Services Marginal Prices

Through the workings of~~The~~ CAISO Market Processes, the CAISO produces~~s are based on~~: 1) Locational Marginal Prices as provided ~~below~~ in Section 27.1.1 and its subparts, and as further provided in Appendix C; and 2) Ancillary Services Marginal Prices as provided below in Section 27.1.2, and its subparts.

27.1.1 Locational Marginal Prices for Energy

As further described in Appendix C, the LMP for Energy at any PNode is the marginal cost of serving the next increment of Demand at that PNode calculated by the CAISO through the operations of the CAISO Markets~~consistent~~ considering, as described further in the CAISO Tariff, among other things, modeled ~~with existing~~ Transmission Constraints, transmission losses, ~~and~~ the performance characteristics of resources, ~~also considering, among other things,~~and ~~Energy~~ Bids~~ Curves~~ submitted by Scheduling Coordinators and as modified through the Locational Market Power Mitigation process. The LMP at any given PNode is comprised of three marginal cost components: the System Marginal Energy Cost (SMEC); Marginal Cost of Losses (MCL); and Marginal Cost of Congestion (MCC). Through t~~T~~he IFM the CAISO calculates LMPs for each Trading Hour of the next Trading Day. Through t~~T~~he FMM the CAISO calculates distinct financially binding fifteen-minute LMPs for each of the four fifteen-minute intervals within a Trading Hour. ~~The Real-Time Dispatch runs every five (5) minutes throughout each Trading Hour and~~ Through the Real-Time Dispatch, the CAISO calculates five-minute LMPs for each of the twelve (12) five (5) minute~~the next~~ Dispatch Intervals of each Trading Hour. The CAISO uses the FMM or RTD LMPs for Settlements of the Real-Time Market. In the event that a Pricing Node becomes electrically disconnected from the market model during a CAISO Market run, the LMP, including the SMEC, MCC and MCL, at the closest electrically connected Pricing Node will be used as the LMP at the affected location.

* * *

27.1.1.3 Marginal Cost of Congestion

The Marginal Cost of Congestion at a PNode reflects a linear combination of the Shadow Prices of the binding Transmission Constraints in the network, multiplied by the corresponding Power Transfer Distribution Factor (PTDF) and coefficient relevant to the transmission segment within that constraint, which is described in Appendix C. The Marginal Cost of Congestion for a Transmission Constraint may be positive or negative depending on whether a power injection ~~(i.e., incremental Load increase)~~ at that Location marginally increases or decreases Congestion.

* * *

27.4.3.1 Scheduling Parameters for Transmission Constraint Relaxation

In the IFM, the enforced internal and Intertie Transmission Constraint scheduling parameter is set to $5,000 per MWh for the purpose of determining when the SCUC and SCED software in the IFM will relax an enforced ~~internal and Intertie~~ Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.12 to relieve Congestion on the constrained facility. This scheduling parameter is set to $1,500 per MWh for the RTM. The effect of this scheduling parameter value is that if the optimization can re-dispatch resources to relieve Congestion on a Transmission Constraint at a cost of $5,000 per MWh or less for the IFM (or $1,500 per MWh or less for the RTM), the Market Clearing software will utilize such re-dispatch, but if the cost exceeds $5,000 per MWh in the IFM (or $1,500 per MWh for the RTM) the market software will relax the Transmission Constraint. The corresponding scheduling parameter in RUC is set to $1,250 per MWh.

27.4.3.2 Pricing Parameters for Transmission Constraint Relaxation

For the purpose of determining how the relaxation of a Transmission Constraint will affect the determination of prices in the IFM and RTM, the pricing parameter of the Transmission Constraint being relaxed is set to the maximum Energy Bid price specified in Section 39.6.1.1. In the case of Contingency-related Transmission Constraints, the CAISO will determine the amount of relaxation required to clear the market using the most limiting condition among the applicable Contingencies and the base case. The CAISO will establish prices based on the parameter pricing specified in this Section as it applies to the most limiting Contingency and base case. The corresponding pricing parameter used in the RUC is set at the maximum RUC Availability Bid price specified in Section 39.6.1.2.

* * *

27.5.6 Management & Enforcement of Constraints in the CAISO Markets

The CAISO operates the CAISO Markets through the use of a market software system that utilizes various information including the Base Market Model, the State Estimator, submitted Bids including Self-Schedules, Generated Bids, ~~and~~ Transmission Constraints, ~~including Nomograms and Contingencies~~ and transmission and generation Outages. The market model used in each of the CAISO Markets is derived from the most current Base Market Model available at that time. To create a more relevant time-specific network model for use in each of the CAISO Markets, the CAISO will adjust the Base Market Model to reflect Outages and derates that are known and applicable when the respective CAISO Market will operate, and to compensate for observed discrepancies between actual real-time power flows and flows calculated by the market software. Through this process the CAISO creates the market model to be used in each Day-Ahead Market and each process of the Real-Time Market. The CAISO will manage the enforcement of Transmission Constraints, ~~including Nomograms and Contingencies,~~ consistent with good utility practice, to ensure, to the extent possible, that the market model used in each market accurately reflects all the factors that contribute to actual Real-Time flows on the CAISO Controlled Grid and that the CAISO Market results are better aligned with actual physical conditions on the CAISO Controlled Grid. In operating the CAISO Markets, the CAISO may take the following actions so that, to the extent possible, the CAISO Market solutions are feasible, accurate, and consistent with good utility practice:

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

(b) The CAISO may enforce or not enforce Transmission Constraints~~, including~~

~~Nomograms and Contingencies,~~ if the CAISO has determined that non-enforcement or enforcement, respectively, of such Transmission Constraints may result in the unnecessary pre-commitment and scheduling of use-limited resources.

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

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

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

(f) The CAISO may adjust Transmission Constraints for the purpose of reserving internal transfer capability in the Day-Ahead or Real-Time Markets, based on anticipated conditions on the natural gas delivery system, to reliably serve load in specific geographic regions of the CAISO Balancing Authority Area, or to assure deliverability of Ancillary Services. The CAISO may or may not release such reserved internal transfer capability based on natural gas and electric system conditions, or observed market inefficiencies. Upon determining that an adjustment is necessary, the CAISO will issue a notification specifying the amount of the adjustment.

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

***

Appendix C

Locational Marginal Price

The CAISO shall calculate the price of Energy at Generation PNodes, Scheduling Points, and Aggregated Pricing Nodes, as provided in the CAISO Tariff. ~~LMPs can be set by Bids to sell or purchase Energy.~~ The CAISO establishes Trading Hub prices and LAPs as provided in the CAISO Tariff. The LMPs at PNodes, including Scheduling Points, and Aggregated Pricing Nodes include separate components for the marginal cost of Energy, Marginal Cost of Congestion, and Marginal Cost of Losses. As provided in Sections 6.5.3.2.2 and 6.5.5.2.4, Day-Ahead Market LMPs are calculated and posted on a Day-Ahead basis for each hour of the Day-Ahead Market ~~for Energy~~ and for each interval of ~~for each Dispatch Interval for~~ the Real-Time Market ~~LMPs~~.

A. LMP Composition in the Day-Ahead Market

~~In each hour of the Day-Ahead Market for Energy, t~~The CAISO calculates the LMP for each PNode, which is ~~equal to the marginal cost of Energy available at the PNode in the hour,~~ based on the Bids of sellers and buyers selected in the Day-Ahead or Real-Time Market ~~for Energy as specified in the Day-Ahead Schedule~~and are calculated as described below. The CAISO designates a distributed Reference Bus, r, for calculation of the Locational Marginal Prices~~System Marginal Energy Cost (SMECr). The CAISO uses a distributed Reference Bus to define an aggregate value of Energy for the CAISO Balancing Authority Area~~. The Locational Marginal Prices are not determined by resources that are not eligible to set the Locational Marginal Price as defined in Sections 31.3.1.4 and 34.20.2.3~~, which includes resources that have constraints that prevent them from being marginal~~. For each bus other than the Reference Bus, the CAISO~~Transmission Provider~~ determines separate components of the LMP for the

System Marginal Energy Cost~~marginal cost of Energy~~, Marginal Cost of Congestion, and Marginal Cost of Losses relative to the Reference Bus, consistent with the following equation:

$LMP_i = SMEC_r + MCC_i + MCL_i$

$LMP_r = SMEC_r$

where:

- $SMEC_r$ is the LMP component representing the marginal cost of Energy ~~(also referred to as λ)~~ at the Reference Bus, r (System Marginal Energy Cost).
- MCC_i is the LMP component representing the Marginal Cost of Congestion ~~(also referred to as ρ)~~ at bus *i* relative to the Reference Bus.
- MCL_i is the LMP component representing the Marginal Cost of Losses ~~(also referred to as γ)~~ at bus *i* relative to the Reference Bus.

B. LMP Composition in the Real-Time Market

In each 15-minute interval and each 5-minute interval of the Fifteen Minute Market and Real-Time Dispatch, respectively, the CAISO calculates the LMP for each PNode, based on the Bids of sellers and buyers selected in those markets as specified in the FMM Schedule and 5-minute Real-Time Dispatch Instructions. The CAISO designates a Reference Bus, r, for calculation of the System Marginal Energy Cost (SMECr), which is the shadow price of the system power balance constraint. The CAISO uses the distributed load in the EIM Area as the Reference Bus to calculate loss sensitivities and shift factors used to linearize the power balance and Transmission Constraints. Resources that have constraints that prevent them from being marginal are not eligible to set the Locational Marginal Price. For each bus other than the Reference Bus, the CAISO determines separate components of the LMP for the marginal cost of Energy, Marginal Cost of Congestion, Marginal Cost of Losses, and EIM Bid Adder relative to the Reference Bus, consistent with the following equation:

$LMP_i = SMEC_r + MCC_i + MCL_i + MCG_i$

$LMP_r = SMEC_r$

where:

- MCG_i is the LMP component representing the marginal cost of the EIM Bid Adder in dispatching Energy from the relevant EIM Participating Resources to serve load in the CAISO Balancing Authority Area (Marginal Greenhouse Gas Cost).~~representing the EIM Bid Adder at bus *i* relative to the Reference Bus.~~

For each PNode within an EIM Entity Balancing Authority Area, the LMP shall include a fourth component, the EIM Bid Adder component.

C. The System Marginal Energy Cost Component of LMP (Day-Ahead and Real-Time Market)

The SMEC shall be the same for each location throughout the system. SMEC is the sensitivity of the power balance constraint at the optimal solution. The power balance constraint ensures that the physical law of conservation of Energy (the sum of Generation and imports equals the sum of Demand, including exports and Transmission Losses) is accounted for in the network solution. This system level power balance constraint is enforced over the CAISO Balancing Authority Area for the Day-Ahead Market and over the EIM Area in the Real-Time Market. For the designated reference location the CAISO will utilize a distributed Load Reference Bus for which constituent PNodes are weighted using the Reference Bus distribution factors. The Load distributed Reference Bus distribution factors are based on the Load Distribution Factors at each PNode that represents cleared Load in the Integrated Forward Market or forecast Load for MPM, RUC and RTM. In the Integrated Forward Market, in the event that the market is not able to clear based on the use of a distributed load Reference Bus, the CAISO will use a distributed generation Reference Bus for which the constituent nodes and the weights are determined economically within the running of the Integrated Forward Market based on available economic bids. In the event that the CAISO employs a distributed generation Reference Bus, it will notify Market Participants of which Integrated Forward Market runs required the use of this backstop mechanism. A distributed Load Reference Bus will be used for RUC and RTM regardless of whether a distributed Generation Reference Bus were used in the corresponding Integrated Forward Market run. If the market-clearing problem is limited by the system-level power balance constraint, the market clearing process would create a Shadow Price for the power balance constraint only when the relaxation of the constraint would result in a reduction in the total cost to operate the system.~~Once the Reference Bus is selected, the System Marginal Energy Cost is the cost of economically providing the next increment of Energy at the distributed Reference Bus, based on submitted Bids.~~

D. Marginal Congestion Component Calculation (Day-Ahead and Real-Time)

The CAISO calculates the Marginal Costs of Congestion at each bus as a component of the bus-level LMP. The Marginal Cost of Congestion (MCCi) component of the LMP at bus i is calculated in the Day-Ahead Market using the equation:

$$\cancel{MCC_i = -\left(\sum_{k=1}^{k} PTDF_{ik} * FSP_k\right)}$$

$$MCC_i = -\sum_k \sum_j C_{j,k}\, PTDF_{i,j}\, FSP_k$$

where:

- *K* is the ~~number of thermal or interface~~ Transmission Constraint~~s~~ index.

- j is the transmission component index of Transmission Constraint k. When Transmission Constraint k is a Nomogram, there can be more than one transmission component. When Transmission Constraint k is any other Transmission Constraint, there shall be only one transmission component.

~~PTDF*ik*~~ $PTDF_{i,j}$ is the Power Transfer Distribution Factor for the ~~generator at~~ bus *i* on transmission component j of the Transmission Constraint ~~interface~~ *k* which represents the~~limits~~ flow~~s~~ across that ~~constraint~~ transmission component j when an increment of power is injected at bus *i* and an equivalent amount of power is withdrawn at the Reference Bus. The CAISO does not consider~~The industry convention is to ignore~~ the effect of losses in the determination of PTDFs.

- $C_{j,k}$ is the constraint coefficient for the transmission component j in constraint k. When constraint k is a Nomogram, this represents the relevant coefficient for that component. When constraint k is any other Transmission Constraint, this coefficient will always be 1.
- ~~FSPk~~ FSP_k is the constraint Shadow Price on ~~interface~~ constraint *k* and is equivalent to the reduction in system cost expressed in \$/MWh that results from a~~n~~ marginal increase ~~of 1MW~~ of the capacity on ~~interface~~ constraint *k*. If the market-clearing problem is limited by any Transmission Constraint including Interties, branch groups, flowgates, nomograms, and Energy Imbalance Market-related transmission constraints (EIM Transfer constraint and power balance constraint for a Balancing Authority Area), the market clearing process would create a Shadow Price for the Transmission Constraint, only when the relaxation of the constraint would result in a reduction in the total cost to operate the system.

The MCC at PNodes in an EIM Entity Balancing Authority Area *j* in the Real Time Market includes an additional contribution from the shadow price of the power balance constraint for that Balancing Authority Area, λ_j, as follows:

$$\cancel{MCC_i = \lambda_j - \left(\sum_{k=1}^{K} PTDF_{ik} * FSP_k\right)}$$

$$\mathrm{MCC}_i = \lambda_j - \sum_{k=1}^{K} PTDF_{jk}\, FSP_k$$

A power balance constraint is not formulated for the CAISO Balancing Authority Area alone in the RTM. The shadow price of the power balance constraint for EIM Entity Balancing Authority Area *j* (λ_j) has the following contributions:

a) the shadow price of the EIM Transfer distribution constraint (φ_j), which distributes the EIM Transfer for Balancing Authority Area *j* to Energy transfers on interties with other Balancing Authority Areas in the EIM Area; and

b) the shadow price of the EIM Transfer scheduling limit for Balancing Authority Area *j*, upper (ν_j) or lower (ξ_j):

$$\lambda_j = \varphi_j - \nu_j + \xi_j$$

Where λ_j is zero for the CAISO Balancing Authority Area since the power balance constraint is not formulated for it.

The difference between the shadow prices of the EIM Transfer distribution constraints for two Balancing Authority Areas *j* and *k* in the EIM Area has the following contributions from any intertie *l* used for energy transfers between these two Balancing Authority Areas:

a) the EIM Transfer schedule cost that applies to that intertie *l* (c_l);

b) the shadow price of the Energy transfer schedule limit from Balancing Authority Area *j* to Balancing Authority Area *k* that applies to that intertie *l*, upper limit (ρ_l) or lower limit (σ_l); and

c) the shadow price of the scheduling limit that constrains both Energy transfers and additional schedules to Balancing Authority Area *j* on that intertie *l*, upper limit (ζ_l) or lower limit (η_l):

$$\varphi_j - \varphi_k = -c_l - \rho_l + \sigma_l + \zeta_l - \eta_l$$

There may be multiple scheduling limits under (c) above that constrain schedules on a given EIM Intertie.

E. Marginal Losses Component Calculation

The CAISO calculates the Marginal Cost of Losses (MCLi) at each bus i as described in Section 27.1.1.2. The MCL component of the LMP at any bus i within the CAISO's Balancing Authority Area is calculated using the equation:

~~$MCLi = MLFi * SMECr$~~

$$MCL_i = MLF_i * SMEC_r$$

Where:

- MLFi is the marginal loss factor for PNode i to the system Reference Bus, based on an AC power flow solution. The marginal loss factor at a PNode is the incremental change in the quantity (MW) of transmission losses in the network resulting when serving an increment of Load at the PNode from the Reference Bus.

  - MLFi is equal to ~~1 -~~ -∂L/∂G*i*, where: L is system losses, G*i* is "generation injection" at PNode *i*, ∂L/∂G*i* is the partial derivative of system losses with respect to generation injection at bus *i*, that is, the incremental change in system losses associated with an incremental change in the generation injections at bus *i* holding constant other injection and withdrawals at all buses other than the Reference Bus and bus *i*.

- SMECr is the marginal cost of Energy at the Reference Bus r (System Marginal Energy Cost)~~the SMEC at the Reference Bus, r~~.

The MCL at PNodes in an EIM Entity Balancing Authority Area *j* in the Real Time Market includes additional contributions from the shadow price of the power balance constraint for that Balancing Authority Area (λ_j) and the shadow price of the net imbalance energy export allocation constraint for greenhouse gas regulation (ψ):

$$MCL_i = MLF_i * (SMEC_r + \lambda_j - \psi)$$

F. Marginal Greenhouse Gas Cost~~EIM Bid Adder~~ Component Calculation

For EIM Participating Resources within an EIM Entity Balancing Authority Area and Energy imported to or exported from an EIM Entity Balancing Authority Area, the CAISO will include the marginal cost of the

EIM Bid Adder in dispatching Energy from the relevant EIM Participating Resources to serve load in the CAISO Balancing Authority Area. The CAISO will allocate the Net Imbalance Energy Export optimally to EIM Participating Resources. This allocation does not depend on the location of the EIM Entity Participating Resource; i.e. the CAISO does not use a shift factor in the allocation. If the Net Imbalance Energy Export from all EIM Entity Balancing Authority Areas as a group is negative or zero, there is no associated Net Imbalance Energy Export allocation~~ or EIM Bid Adder cost~~. Otherwise the net imbalance energy export allocation constraint is binding with a Shadow Price (ψ)~~ and it may have a nonzero EIM Bid Adder price~~. If the market-clearing problem is limited by any Marginal Greenhouse Gas Cost constraint, the market clearing process would create a Shadow Price for the Marginal Greenhouse Gas Cost constraint only when the relaxation of the constraint would result in a reduction in the total cost to operate the system. The CAISO determines the Marginal Greenhouse Gas Cost component of the LMP at a PNode in an EIM Entity Balancing Authority Area and LMPs for imports and exports between that EIM Entity Balancing Authority Area and a non-EIM Entity Balancing Authority Area as the negative of the Shadow Price of the net imbalance energy export allocation constraint, ~~will include the marginal EIM Bid Adder in the LMP charged to the Net Imbalance Energy Export for each PNode within the EIM Entity Balancing Authority Areas.~~

$$MCG_i = -\psi$$

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Appendix A

Master Definition Supplement

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- Contingency

A potential Outage that is unplanned, viewed as possible or eventually probable, which is taken into account when considering approval of other requested Outages or while operating the CAISO Balancing Authority Area or EIM Entity Balancing Authority Area.

* * *

- Transmission Constraints

Physical and operational limitations on the transfer of electric power through transmission facilities, which include Contingencies and Nomograms.

Attachment C – Final Proposal

Tariff Amendment to Implement Pricing Enhancements

California Independent System Operator Corporation

June 6, 2016

Pricing Enhancements

Final Proposal

October 30, 2014

Table of Contents

1 Background and Scope

The ISO has resumed the initiative for Administrative Pricing rules and broadened its scope to include other pricing enhancements. Through its continued effort to improve the efficiency of its markets, the ISO has identified three items related to pricing in the ISO markets. These three items, together with the scope of the initial administrative pricing initiative compose this stakeholder initiative identified as *Pricing Enhancements,* which was launched in August 2012. Specifically, the items considered in this initiative are:

1. Scope set forth in initial administrative pricing initiative
    a. Administrative pricing rules,
    b. Emergency tariff authority, and
    c. Force Majeure.

2. Scheduling priority for existing transmission rights schedules.

This issue concerns the bidding rules for existing transmission rights and transmission ownership rights (ETC/TOR). The ISO is proposing an enhancement to avoid instances where market participants may be exposed to congestion costs created by a bid error.

3. Compounding pricing methodology in the event of multiple contingencies.

This item concerns the compounding effect on pricing for a constraint concurrently binding for multiple contingencies when the constraint needs to be relaxed. Currently, when such cases arise, locational marginal prices reflect a compounded congestion cost component that is proportional to the number of contingencies the constraint is binding for.

4. Multiplicity of prices under “degenerate” conditions.

This enhancement will address the multiplicity of prices that may arise in the ISO markets under certain scenarios. Historical cases of multiplicity of prices have been observed on intertie constraints. The ISO is proposing an enhancement that can lead to a unique pricing outcome.

In this final proposal, the ISO has further elaborated on the administrative pricing rules along the comments provided in the previous round, including some numerical examples. It has also clarified the description of the use of a weight associated with the new slack variable used in the reformulation of the problem to deal with multiplicity of prices.

2 Plan for Stakeholder Engagement and Scope

The proposed schedule for stakeholder engagement is listed below. ISO management expects to present any proposed changes and policy recommendations to the CAISO Board of Governors in December 2014.

Date	Event
Tue 7/01/14	Issue Paper and Straw Proposal Posted
Thu 07/10/14	Stakeholder Call
Tue 7/22/14	Stakeholder Comments Due
Wed 9/26/14	Revised Straw Proposal Posted
Wed 10/03/14	Stakeholder Call
Wed 10/10/14	Stakeholder Comments Due on Straw Proposal
Tue 10/230/14	Draft Final Proposal Posted
Tue 11/06/14	Stakeholder Call
Tue 11/13/14	Stakeholder Comments Due on Draft Final Proposal
December 2014	BOG

The following sections introduce each of the four items of this expanded stakeholder initiative.

3 Administrative pricing rules

3.1 Issue

Administrative Pricing

On June 13, 2012, FERC granted the ISO's petition to waive tariff provisions related to setting administrative prices and settling real-time market transactions in response to the September 8-9, 2011 southwest power outage.[1] FERC found that the administrative prices established by the ISO to set price signals in order to manage the emergency (initially $250, which was later reduced to $100 per MWh) were not authorized by the tariff, but granted the ISO's waiver request. Section 7.7.4(3) explicitly sets the administrative price at the level of the applicable price for the last valid settlement period which, in the SDG&E area, for example, would have been $54 per MWh. FERC disagreed with the ISO that the discretion provided in section 7.7.2 to take any action it "considers necessary" relieves the ISO of its requirement to comply with section 7.7.4(3) when setting the administrative price. FERC concluded that section 7.7.4(3) should be read in conjunction with section 7.1.3(h) that confers upon the ISO general authority to operate resources in a system emergency and that, if section 7.7.2 could be read as expansively as the ISO argued, then the ISO would have virtually unfettered discretion to justify any action or behavior in an emergency situation.

FERC also granted a tariff waiver to permit the ISO to hold tripped load and resources harmless;[2] however, FERC declined to decide whether the September 8 southwest power outage constituted a force majeure event or whether ISO had tariff authority to hold resources harmless in the event of a force majeure event. FERC acknowledged the ISO's commitment to consider tariff changes to avoid confusion in the event of a similar emergency or market disruption in the future through an upcoming stakeholder process, will address this issue going forward. The proposed scope of the initiative for administrative pricing includes:

1. What conditions justify market suspension?
2. Should the ISO have the ability to split the market into regions so that the entire market does not need to be suspended during a regional event?
3. Should the ISO have the authority to establish an administrative price that is different from the current default value which is the last valid price in the market prior to intervention or suspension?
4. If so, how should the ISO determine the appropriate administrative price?

[1] The FERC order is available at http://www.ferc.gov/EventCalendar/Files/20120613122539-ER12-205-000.pdf

[2] The "hold harmless" remedies reversing out the day-ahead schedules and awards for loads and resources.

5. What considerations warrant adjustments to the administrative price rather than returning to the default administrative price?
6. What hold harmless provisions should be established for tripped load, physical resources and convergence bidders during market suspension or force majeure events?
7. Is there a need to provide more clarity concerning the definition of a force majeure event and any actions the market participant or ISO must take and the settlement consequences?
8. Does the ISO need to improve its communication protocols to scheduling coordinators and resource owners and operators?
9. Should the ISO impose penalties on owners, operators and/or scheduling coordinators for failing to respond in a timely manner to exceptional dispatches or operating orders in emergency conditions?
10. Should convergence bidding be suspended until some period of time after system restoration?
11. What other changes to the ISO's emergency tariff provisions should be considered?
12. Other clarifications based on stakeholder comments to issue item.

Table 1 shows a summary of the administrative pricing rules among other ISOs.

Table 1: Summary of Administrative Pricing at Other ISOs

ISO/RTO	Administrative Pricing Protocols
PJM	Manual 11, Section 2.10 PJM Real-time Locational Marginal Price Verification Procedure In the event of a data input or program failure, LMP replacements will be performed as outlined below: 1. If the stale data or program failure exists for less than 6 intervals within the same hour then the affected intervals will be replaced with data from the last successful interval. 2. If the stale data or program failure exists for more than six intervals within the same hour then: If the hour is unconstrained, the hourly LMP will be replaced with the hourly integrated dispatch rate, or if the system is constrained, the LMP values will be recalculated using data from the best available sources. If the stale data or program failure exists for less than 6 intervals within the same hour but the previous hour had 12 failures then: If the hour is unconstrained, the hourly LMP will be replaced with the

ISO/RTO	Administrative Pricing Protocols
	hourly integrated dispatch rate, or If the system is constrained, the LMP values will be recalculated using data from the best available sources.
New England ISO	Manual 11, 2.5.10 ISO Real-Time Price Verification Procedure In the event of a data input or program failure and LMPs, RCPs or Real-Time Reserve Clearing Prices cannot be recalculated as described above, replacements will be performed as outlined below: (a) If the stale data or program failure exists for 11 intervals or less within the same hour then the affected intervals will be replaced with data from the last successful interval or the next successful interval, as appropriate. (b) If the stale data or program failure exists for all intervals within the same hour then the replacement values will be recalculated using data from the best available sources.
New York ISO	OATT Attachment Q Procedures for Reserving and Correcting Erroneous Energy and Ancillary Services Prices 23.2 Methodology for Correcting Prices In the event of a catastrophic failure of the ISO's price calculation software, the ISO shall provide notice of the problem to the Commission and Transmission Customers as soon as possible, but in no event later than the next business day. Following consultation with Transmission Customers regarding the procedures to be used, the ISO shall construct prices as close as possible to the prices that should have resulted from the application of the market rules established in the tariffs to prevailing system conditions.
Midwest ISO	Energy and Operating Reserve Markets Business Practices Manual 9.1.4 LMP/MCP Replacements In the event of a data input failure or program failure that make Ex-Post LMPs and MCPs unavailable, 'replacement' values are calculated in the following way:

ISO/RTO	Administrative Pricing Protocols
	- Where the stale data or program failure exists for eleven or fewer intervals within the same Hour, the affected intervals are replaced with data from the last successful interval or the next successful interval, as appropriate, as described in Section 9.1.5.1. - Where the stale data or program failure exists for all intervals within the same Hour, the following occurs: 1. Where the Hour is unconstrained and Scarcity Prices have not been applied, the Ex-Post LMP is replaced with the Ex-Ante LMP and the Ex-Post MCP is replaced with the Ex-Ante MCP; 2. Where the system is constrained, the Ex-Post LMP values and Ex-Post MCP values are recalculated using data from the best available sources. The Ex-Post LMP and MCP values are recalculated for each five-minute Dispatch Interval and then integrated and weighted in accordance with the calculations under Sections 9.1.5 and 9.1.6 of this BPM.
ERCOT	Protocol Section 6.5.9.2 Failure of the SCED Process (1) When the SCED process is not able to reach a solution, ERCOT shall declare an Emergency Condition. (2) For the intervals in which no solution was reached due to an SCED process failure are equal to the LMPs in the most recently solved interval. For Settlement Intervals that the Real-Time Settlement Point Prices are identified as erroneous and ERCOT sets the SCED intervals as failed in accordance with paragraph (3)(b) of Section 6.3, Adjustment Period and Real-Time Operations Timeline, then the LMPs for the failed SCED intervals are equal to the LMPs in the most recently solved SCED interval that is not set as failed. ERCOT shall notify the market of the failure by posting on the MIS Public Area

Market Suspension during System Emergency

Tariff section 7.7 outlines the management of system emergencies. The ISO proposes to amend this tariff section and other sections, if necessary, to clarify and supplement the ISO's authority during significant system emergencies that require the ISO to suspend the market to take the actions it took on September 8-9 and to clarify authority or to take such additional actions, including the assessment of penalties, as may be necessary to manage the grid to maintain reliable operations during increasingly worsening conditions. The ISO will consider stakeholder comments submitted to FERC in response to the ISO's waiver petition[3] as well as stakeholder comments submitted in the administrative pricing and pricing enhancement stakeholder processes.

Among the items to be explored are the following:

- Are additional criteria needed, beyond those already included in section 7.7.1, to determine when the market can be suspended? Should the ISO clarify section 7.7.2 regarding both the ISO and market participant responsibilities during market suspensions?
- What changes are necessary to section 7.7.4, regarding administrative prices, in order to allow the ISO to set the administrative price different from the last valid interval market price?
- When and what criteria should be used to set the administrative price when the market is not producing prices or when the prices produced are not consistent with actual market and grid conditions?
- Should administrative prices be set regionally and/or should ISO apply administrative prices in regions where a market result is infeasible?

Settlement during Market Suspension or Force Majeure Events

There are several embedded issues that need to be considered in reaching a proposal:

1) What is a force majeure event under the CAISO tariff?

2) Since the ISO tariff provides for no settlement relief from paying for real-time uninstructed deviations in the event of a force majeure event, should the ISO amend the tariff to afford relief in the event of force majeure and, if so, what should those rules be—a settlement rule that excuses financial responsibility for uninstructed deviations or would excuse any additional penalty for uninstructed deviations.

[3] Substantive comments were filed in Docket ER12-205-00 by Powerex Corp., NRG Companies, Morgan Stanley Capital Group Inc., Financial Marketers, Western Power Trading Forum, California Department of Water Resources State Water Project, and Macquarie Energy LLC. The comments are available at http://www.ferc.gov/docs-filing/elibrary.asp.

3) Should the ISO tariff be clarified to specify the conditions that justify the ISO suspending the market?

4) What additional administrative pricing authority should the ISO have when the market is suspended?

5) Should the market be settled differently when the market is suspended and administrative pricing is in place?

6) The factual circumstance that existed on September 8, 2011 and which caused the ISO to hold both physical loads and resources harmless was because both loads and resources tripped; should the hold harmless rule always apply when load and resources trip and only apply when load and resources trip?

7) Are there any other circumstances when day-ahead transactions should be liquidated at the day-ahead price, *i.e.*, the hold harmless settlement?

8) If hold harmless settlement is not appropriate, should additional costs be eligible for recovery through the ISO's bid cost recovery mechanism?

This stakeholder process will also consider new provisions for the settlement of load, physical supply, interties, and virtual bids when the market is suspended during system emergencies. Should market rules remedy inconsistencies between the administrative price and market participants' bid prices? If a remedy is required, should the remedy be implemented through the bid cost recover mechanism or some other mechanism? Should bid cost recovery rules change during market suspension such that both imports and exports are eligible for bid cost recovery?

In reviewing other ISOS in the United States, none of the other five ISOs appear to have any additional documentation other than their respective Tariff languages regarding force majeure. With the similarity of all of the Tariff sections, none appear to offer relief from imbalance energy charges that result from a force majeure event. The Midwest ISO seems to have some provisions for exemptions of energy settlements during events or conditions beyond the control of the market participant.

Communication Improvements

Stakeholders stated that CAISO needs clearer communication channels or standing default tariff provisions so that market participants know whether the information the ISO releases during a similar system emergency is valid. For example, are verbal dispatch instructions mandatory or voluntary during market suspension when the instruction may be inconsistent with the entities' bids? Assuming the market rules are sufficiently explicit should penalties be considered for not following instructions during a market suspension? The communication improvements should result in additional tariff provision as well as improvement to BPM documentation.

3.2 Straw Proposal

3.2.1 Administrative Pricing

The current administrative pricing implementation in real-time markets uses the price from the interval immediately preceding the interval in which the market disruption occurred or the ISO has effectuated a market suspension. The ISO experiences minor market disruptions in the real-time market due to software maintenance (such as database updates and software releases) or unexpected software issues, these occur under normal and non-emergency situations. The ISO can also intervene in the ISO markets during system emergencies or to prevent system emergencies and suspend or disrupt the market and operate the system manually, in which case the Administrative price will also apply for purposes of settling imbalance energy. The administrative pricing can apply to any market or product, including the day-ahead market, fifteen- and five-minute markets.

3.2.1.1 Day-Ahead Markets

PJM has recently taken the additional step to define what pricing and scheduling would be used for their day-ahead market, in case they cannot publish results by 23:59 on the day prior to the trade date.[4] If the day-ahead run cannot be produced and published then all day-ahead schedules and prices will be set to zero.[5] PJM's proposal and filing were the result of a business continuity exercise which identified that if there were, for example, an extraordinary internet-related outage, its ability to produce and publish day-ahead results could be impacted. The CAISO has five years of experience with the nodal market and has not failed to publish day-ahead market results, but is not immune to extraordinary technical

[4] FERC Docket No. ER13-2285-000
[5] PJM Open Access Tariff Section 1.10.8 (d)

issues, and administrative pricing for the day-ahead market should be considered in this initiative as well.

Section 31.6 provides the ISO with sufficient authority to delay the publication of the day-ahead market results to preserve system reliability or prevent a system emergency, to deal with errors or delays that require additional time to run the market, data problems etc. Delayed postings do not constitute a complete failure of the market. Only in more extreme circumstances would the ISO completely abort the day-ahead market (see Section 31.6.3). Although the day-ahead market results only matter for the effective trade date, the latest the ISO needs to produce day-ahead market results is by 20:00 hrs due to real time processes. However, there is a more stringent timeframe imposed by the fact of letting participants know of their schedules and have enough leading time to be able to meet commitment instructions. For this reason, the ISO is proposing that if by 18:00hrs the day-ahead solution is not available, the ISO will need to trigger its provision proposed below.

For the day-ahead market, the ISO is proposing that in the case of a market disruption or market suspension, such as a software issue that results in a complete failure to clear the market and post results for that day, to use either of two approaches:

i) Use the day-ahead results -both awards and prices- from the previous day Taking this option will depend on the evaluation of expected system conditions and the schedules from previous day ahead to determine that the previous day dispatches are within a reasonable scope to be used for the missing day; the health of the real-time market will also need to be considered to make this determination. For the works case, this approach needs to work also for conditions where there is no real-time market functioning.

ii) Based on expected system conditions it is found that using the previous day will not provide a reasonable profile of schedules to meet the needs of the real time (such the missing day is a Monday and previous day, Sunday, is too different in load profile or transmission conditions) and the real time market is operating well then leave the entire market up to the real-time market, with the need to manually dispatch long start unit, and other units as needed, adjust conditions based on manual instructions.

This approach of either-or will provide with the flexibility required to make a determination based on actual factors impacting the trading date. This either-or proposal is aiming on leveraging on using a day ahead solution; there are several factors to consider for this. If such an event is also impacting the real-time market, the real time market also defaults to use the day-ahead results. If the day-ahead results are simply set to zero and the real time market is running, everything would be left up to the real time market, and one of the complications is that the real time market could not project beyond 4.5 hours of the day and for instance long-start resources could not be committed through the real-time market. Second, there are some data inputs coming into the real-time market from the day-ahead market and under ideal conditions, the real-time market will need to rely on some form of day-head information. Third, using the day-ahead market solution will also provide clarity and certainty to resources. If some resources need to align and get fuel prior to the trading date, it is better for resources to in advance of the day the expected generation requirements for the entire day, instead of relying hour by hour of the real time market.

There was a concern that using the previous day solution for the missed day-ahead could result in unreasonable settlements obligations to resources that could not deliver, specifically for cases of resources on outages. This proposal recognizes that the option of using previous day needs to reconcile for this outliers instances. For resources on outage, there is an expectation that such outages will be already logged in the ISO systems by the time the decision is made to use previous day (otherwise, even a normal run of the day-ahead market would potentially still commit resources) and during the evaluation of conditions for the next day the ISO will identify such resources on outages and they will not be subject to the schedules from previous days. If a resource happens to have an outage in the real-time, this would not be different to the normal operation and process of any normal day. For both physical and intertie resources and if the real time market is functioning, they still have the opportunity to bid in the real time.

3.2.1.2 Real-Time markets

The current requirement of using last valid price for a limited number of missing FMM or RTD intervals may be the most reasonable pricing to use given a minor market disruptions. The ISO needs to consider market disruptions of longer duration in the real-time market where the last available price may not provide the right price signal when system conditions change from hour to hour. Through this stakeholder process, the ISO is proposing to apply administrative pricing based on the nature of events as well as relying on the number of intervals impacted. This tiered approach aligns with practices in other ISOs. The generic option of setting the price using the best data available, which is included in several ISO/RTO tariffs is not under consideration as it does not provide sufficient details of steps and considerations used. When the ISO reaches the point of having a market disruption or suspension, there is a high likelihood that the ISO may not be able to rerun the markets in a manner that would reflect a realistic solution; under such conditions, a rerun of the market will usually not be possible or would require the ISO making assumptions and approximations which will potentially lead to have the results of the market reruns being challenged after the fact. This would actually be detrimental to the market certainty required under these conditions. Notice that the ISO pricing is an *ex post* mechanism, unlike other ISOs that rely on ex ante pricing, for which there may be an option of adhering to use the best available data.

As described in section 7.7.15.1 of the ISO tariff, administrative pricing applies to market disruptions, including software failures that results in no market outcomes and blocked intervals. The market disruptions are properly classified and reported to the Commission on a monthly basis. A market suspension, however, may be triggered when the ISO invokes its authority of section 7.7.4. In both instances, under the current tariff, an administrative price is used. Currently, the administrative pricing is unique and relies on using the latest available price that was properly produced by the market software.

The proposal for an administrative price for the real time set forth in this initiative considers a three-tier approach; specifically,

i) if 15-minute market prices are missing for less than four consecutive intervals or if the 5-minute interval dispatch market prices are missing for less than 12 consecutive intervals, then the ISO will preserve the current administrative pricing of using the last best price for each market accordingly.
ii) If the 15-minute market prices are missing for more than three consecutive intervals or the 5-minute market prices are missing for more than 11 consecutive intervals under normal system conditions, then
    a) If the real-time interval (RTD) dispatches prices are not available but the 15-minute market prices are available, then missing RTD prices will be filled in with the 15-minute markets, regardless of how many intervals (for greater than 11 RTD or 3 FNM) are missing as long as the missing prices are related to a market disruption and the market is unable to produce prices. Conversely, if the 15-minute market prices are missing but the 5-minute market prices are available, the 5-minute market prices will be used to fill in the 15-minute prices by using the simple average of the three RTD prices. This approach is proposed based on the fact that if one real-time market is missing but the other one is available, the market being available will reflect the closest conditions to the missing market prices and if this persist for a longer period of time using the prices available from the other real-time sub-market will still capture the nature of prices changing over time during the period of the event.

       This alternative has the benefit of allowing market participants to know just on time what price will be used as the administrative price. Additionally, defaulting to using prices from the other real-time market would minimize the participants' exposure to imbalance charges between the 15-minute market and the 5-minute market.
    b) There may be other conditions where both the 15-minute nor 5-minute market prices are not available and the replacement process described above cannot be

implemented. When both the 15- and 5-minute real-time prices are not available, one can use either a reference of either similar day(s) for real time or day-ahead prices for same period. Using an average price for the last few days of the real time may be a viable option; for instance, a logic could be built upon using the average of the last two similar days (weekdays or weekends) for the same time period; one caveat is that with the inherent dynamic and volatile nature of the real time, there might be conditions where the resulting prices could not be reflective of similar conditions; say, if the previous days had an event that resulted in persistent and extreme low or high prices, this price would heavily influence the administrative price for the subsequent day. The price would also be subject to calculation and subject to change from the price correction process because is calculated based on real-time prices from previous days which are subject to potential price corrections. For practical purposes, using the day-ahead price for the same trading date and hours would provide certainty of what prices are being used if administrative pricing is triggered, and will also minimize imbalances charges across markets when a real-time market disruption happens; this approach will still capture the time-based changing nature of the market prices in case a market disruption spans over multiple hours.

Tier I and tier II do not combine; it is always one or the other methodology.

Let's consider a few examples to illustrate this process. The following table illustrates two hours of the market with all prices available:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	60	59	59	55	35	36	38	39	44	43	43	48	50	55	57	59

Scenario 1: RTD prices are missing for five intervals, then use last available RTD price:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62						36	38	39	44	43	43	48	50	55	57	59

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	62	62	62	62	62	36	38	39	44	43	43	48	50	55	57	59

Scenario 2: Both FNM and RTD prices are missing, each one, for less than 12 and 4 intervals respectively. Then use last available price for each market:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50				40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65							36	38	39	44	43	43	48	50	55	57	59

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	50	50	50	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	65	65	65	65	65	65	36	38	39	44	43	43	48	50	55	57	59

Scenario 3: RTD prices are missing for more than 11 intervals and FNM prices are available, then use FNM prices for corresponding intervals:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62															57	59

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	51	40	40	40	45	45	45	39	39	39	53	53	53	60	57	59

Scenario 4: FNM prices are missing for more than 3 intervals, the use simple average of RTD prices for corresponding intervals:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48																53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	60	59	59	55	35	36	38	39	44	43	43	48	50	55	57	59

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	60.6	60.6	60.6	62.3	62.3	62.3	57.6	57.6	57.6	36.3	36.3	36.3	42	42	42	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	60	59	59	55	35	36	38	39	44	43	43	48	50	55	57	59

Scenario 5: Both FNM and RTD prices are missing for more than 3 and 11 intervals, accordingly, then use DAM prices

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50																			60	60
RTD Price	44	46	47	47																			57	59

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	40	40	40	40	40	40	40	40	50	50	50	50	50	50	50	50	50	50	60	60
RTD Price	44	46	47	47	40	40	40	40	40	40	40	40	50	50	50	50	50	50	50	50	50	50	57	59

iii) The logic described in items *a* and *b* above will cover non-emergency instances of market disruptions where prices are missing and an administrative price is required. The third tier goes beyond these typical market events and touches the core of the discussion that took place with the ISO requesting a waiver for the September 8, 2011. This tier is designed to address instances where an administrative price is required to deal with atypical scenarios not covered in the previous two tiers described above. Consequently, it is expected that this tier is triggered in very few exceptional circumstances. First, this approach will be triggered only under the condition where the ISO has suspended the market. This could occur under two scenarios: (1) the market could fail as a result of catastrophic software failure; or (2) the market results are of such poor quality that system operations cannot rely on them for reliable operation of the grid. The September 8, 2011 event involve a large scale system emergency where generation and load tripped. Although the ISO's market software continued to function, the market results did not reflect the major system changes resulting in dispatches that were not reflective of actual conditions. Accordingly, the ISO suspended the market and set an administrative price to establish an appropriate market signal. In the absence of conditions justifying a market suspension, the administrative pricing described in the previous two sections would apply to any market disruptions that require administrative pricing.

During a market suspension, it is of paramount importance to have an administrative price that will suffice to provide a price signal and incentive for resources to help the ISO manage grid conditions reliably, such as having generation capacity to remain online to meet demand under prevailing conditions and to enable the restoration of the system in the case of outages. One of the options explored was to use the day-ahead prices times a premium factor. This factor could either be defined *a priori* and be applicable for any instances where a market suspension is triggered, or could be estimated by the ISO once there is an event requiring this administrative pricing. The complication turns out to be the basis to use any premium factors. Another complication envisioned by using a premium factor would be the settlements complications. In some instances, a price different than the DAM price will result in imbalance charges to participants in the real time market. For this reason, the ISO's proposal for this third tier is to simply use the day-ahead prices. Since there will be no real-time market functioning, for purposes of any settlements the bid from the day-ahead market will be used as well.

Another concern raised about the market suspension of September 8, 2013 was the triggers and factors used to suspend the market; defining a threshold for when the market should be suspended would be a futile exercise with all the potential factors and interplays that may impact the system and market at any given time. Section 7 of the ISO tariff provides general guidelines of when to call upon for a system emergency and allows for the ISO to make the determination if a market suspension is required. Some participants commented in the direction of using a hard-defined threshold, like the system losing a percentage of load. A hard threshold or trigger fails to capture the inherent complexity of the system and the myriad of potential scenarios. For instance, if a threshold of 10% of tripped load were used, does that mean that a loss of load of 9% would not require a market suspension even when there are grounds indicating that the market is not producing an outcome in alignment with the system conditions? What if the load loss was 11 percent but the market is producing reasonable results and there is no need to suspend the market? For any practical purposes, what would the gain be of having such a threshold under these two scenarios? For this reason the ISO believes it is important to maintain the operational discretion to call a market suspension based on actual events and conditions. After the fact, the ISO commits to provide a description of the conditions led to the ISO to intervene or suspend the market. This, together with the certainty of the administrative price to be used and the settlements provisions defined through this stakeholder process will provide the required certainty and transparency of the ISO actions during a system emergency leading to a market suspension.

Some participants raised concerns of using price thresholds for deciding whether a market suspension is applicable or not. As elaborated in the material related to the September 8, 2011 event, the determination for the market suspension was not due to the prices exceeding certain levels; instead, it was because the actual system conditions were not reflected in the prices being generated by the market, which was using an inconsistent network topology information with respect to the load and generation being connected to the system. Thus, dispatches and prices aligning with the overall system conditions are the primary elements for the ISO to consider when calling upon for a market suspension.

Another element to consider in the discussion is whether the administrative price triggered by a market suspension needs to apply across the entire system or be confined to specific regions of the system. Ideally, if the condition exists in a region of the system, the administrative pricing would be required only for that specific region. The split of the system in regions to apply the administrative pricing poses some practical challenges. First, it would be difficult to define *a priori* what regions in the system should be applied to. If an emergency and market suspension occur, the likelihood of having the issue confined to a pre-defined and existing region would be minimal. One of the complications arising during the September 8, 2011 was the operation of the market under islanding, which eventually led to the market suspension. Therefore, once the market suspension is in place it would be a matter of how to split the system among regions with the risk of having a discriminatory treatment of resources. Furthermore, another concern would be the potential for congestion management among regions with the complication of how to arrive to the congestion prices among the interfaces among the potential different regions. For these reasons and for simplicity in the practical implementation of the administrative pricing, the ISO is proposing to keep only a system-wide administrative pricing. Currently, the administrative pricing used for market disruption is applied system-wide and it there was any congestion observed in the day-ahead market, such congestion and its prices will be preserved with the administrative price.

Another option also suggested in the first round of comments for the administrative pricing under market suspension was to use a pay-as-bid approach. The main challenge for using this approach is the lack of a price for settlements of default load aggregation points since there are no real-time bids for load; the real-time market clears against load forecast not for bid-in demand. Second, one may consider scenarios where no bid information can be readily available to use. One may consider on using the last available bid set but that may lead to similar limitations of the current administrative price of using the last available price. Bids may change across the day and bids in the early morning may not be reflective of the bids for later parts of the bid of the day. The administrative price proposed in this revised version aims to make the process simple and transparent about what price would be used to provide more certainty and transparency in the market place.

Another option suggested in the second round of comments was to define administrative price based on constructing a price that preserves the prevailing conditions. This option would turn out to be quickly intractable because it would require a meaningful set of assumptions to infer that the prevailing conditions would have been. For the time immediately after the suspension, one may think on deriving a price based on the quasi conditions using available last conditions. But this becomes quickly unworkable once a longer period has elapsed because the snapshot from the beginning will no longer reflect the later conditions. Then ISO would have to come with set of assumptions of what the prevailing conditions and dispatches would have been for that time. It is also important to mention that any price, high or low and different from the day-ahead price, will create collateral implications for settlements. A high price is not the perfect solution because depending on the conditions of an event, the requirement could actually be to decrement generation or shutdown resources.

Finally, with the implementation of the Energy Imbalance market (EIM), there needs to be a consideration for the rules for the areas under the EIM. The rules described here apply only for the California balancing area; the specific rules applicable to any other balancing area under EIM will we scoped and defined in the upcoming stakeholder process for EIM enhancements scheduled to start in November 2014.

3.2.2 System emergencies, Force majeure and settlements implications

Through the discussion of the September 8, 2011 event, there has been some intertwined discussion of system emergencies, market suspension and force majeure. For the sake of clarity in the scope of this initiative, it is important to distinguish such conditions accordingly. A market suspension or system emergency is not necessarily dependent or driven by a force majeure event. Through the discussion in the previous section about the administrative pricing in the context of market disruption and the need for a different approach for administrative pricing for a market suspension. A resource can encounter a force majeure event that is not associated with any system emergency or market disruption.

Force majeure in general refers to conditions beyond the own control of a party. The ISO tariff refers to force majeure as

Force Majeure" shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

The only relief that Section 14 for uncontrollable forces (force majeure) provides is that in case of performing a physical obligation due to force majeure, that failure will not result in a “default” under the ISO tariff. The market participant remains financially responsible and there is no provision in the ISO tariff that would alter the settlement in such circumstances. The ISO market design at its core relies on a two-step settlements between the financially binding day-ahead and real time markets; the day- ahead market is financially binding. It imposes financial obligations to parties to pay or be paid based on the day-ahead award; if deviations from such awards take place in the real time, uninstructed deviations are settled accordingly. Such mechanism builds the framework for allocating price risk between the day-ahead and real-time markets. If a participant does not deliver its day-ahead award, it has the financial obligation to pay for the uninstructed deviation. When such deviation occurs, the system will rebalance and other resources will move accordingly to supply the undelivered power. When a market participant submits bids into the day-ahead market based on its location, economical strategy and risk premium, among other factors, participants are taking on the risk and consequences of participating in the market under such settlements terms. This rationale is important to consider for the efficient economical operation of a market. The inherent nature of the power system makes outages over which a market participant may not have any control a typical occurrence. The California ISO is no exception to this and on a routine basis the ISO faces transmission outages, including derates, that may disrupt the delivery of power in certain locations of the system. From the point of view of the supplier, some of these outages and derates might be considered beyond the participant's control. The ISO does not believe the ISO tariff should be amended to excuse the settlement impact of settling deviations at the real-time energy price. Doing so would be burdensome to the ISO and undermine the efficiency of the market. First, the ISO would have to consider each instance of failure to deliver on a case-by-case basis. Most importantly, providing settlement relief for non-delivery for circumstances beyond the supplier's control, would render the overall market operation inefficient, because this after-the- fact resettlement would introduce a high level of uncertainty into the market and shift the risk of non-performance to load serving entities that purchased power in the day-ahead market. Even if the ISO were to attempt to craft a very limited set of force majeure circumstances, the complexity is about the factual investigation for each case invoking the force majeure provisions. If a resource participates in the market it is under the known risk associated with it, including the potential risk to not deliver based on its location.

A further degree of complication arises when one considers who should bear the cost of the no delivery. When typical outages impact specific resources, the system will rebalance by requiring other resources to meet the undelivered power and charging any imbalances to the entity that did not deliver. If a resource is excused of its financial obligation for not delivering, then the system will have to absorb the cost of the imbalance. The market already re-dispatched other resources and they were paid accordingly. If the resource that did not deliver is financially excused, then who should bear the cost of the imbalance?

As part of the discussion related to the September 8, 2011 and the reason of the administrative pricing initiative to exist, the ISO committed to clarify the definition of a force majeure event and the settlement consequences. Accordingly, the ISO proposes to make explicit that force majeure events do not excuse any financial obligation to resources participating in the market.

Furthermore, for the cases where the ISO is suspending the real-time market like the one observed on September 8, 2011 and regardless of whether the system emergency is due to a force majeure or not, there need to be the proper conditions and incentives for resources responding to the conditions and helping to resolve the system emergency. The administrative pricing used under such conditions is a driver for this, and the settlements implications need to be defined. Specifically,

i) For the real-time market, for physical resources and with the proposal to use day-ahead prices, there will be no imbalance charges as the real time market prices will match the day-ahead prices. For resources being impacted by the event, such as tripped load and generation, the use of the day-ahead prices will wash out any imbalance charges. For those resources receiving specific operating order they will get the standard bid or better payment used currently for exceptional dispatches, which is no more than the better of either the market price, bid-in price or default energy bid. Since the real-time market will be suspended the proposal is to use also the bids and default energy bids from the day-ahead market for this purpose. These bids will naturally align with the prices also used to settle the real-time market. Resources elsewhere in the system that will not be affected by the event leading to the market suspension will be able to fulfill their obligations, and to the extent they do it they will be able to manage their financial positions with respect to the day-ahead obligations. If there are resources that are not able to recover their costs due to the administrative price imposed, they will receive standard bid cost recovery using the bids from the day-ahead market. When the day-ahead market is not available, but the real-time market is running, and the ISO defaults to use previous day, such day-ahead awards and prices will be used to settle accordingly the day ahead, and real-time prices and schedules produced from the real time market will be settled with real-time prices, like any standard day for settlements. When both the day-ahead and real-time markets are suspended, the ISO defaults to use previous day for schedules and awards for the real time and then in real time manual operating instructions will be followed. This means that day-ahead and real-time prices will be the same and there will be no imbalance charges.

ii) When the market is suspended and an administrative price is being used, administrative prices will have an impact on financial products. The approach proposed below is to recognize that during a market suspension, an administrative price is being used, and such purely financial products may observe unintended settlement effects –either gains or losses- that have no relationship to their positions. The proposed settlement considerations aim to target the various financial products, including

a. Congestion revenue rights. Congestion revenue rights are settled on the marginal congestion component produced in the integrated forward market. If the ISO was unable to produce a market solution for the day-ahead market, and as indicated above, and the ISO default to use previous day-ahead schedules and prices, CRR will be settled on previous day-head prices because the energy market will still be settled at the day-ahead prices and therefore CRRs are need to complement the exposure to the day-ahead congestion. If on the other hand, the ISO takes the option of not having the day-ahead solution but rather leave fully up to the real-time market, the ISO will fully settle the market based on the real time market. This means that effectively the prices and awards of the day-ahead market will be zero. The settlement implications for congestion revenue rights are that this will effectively neutralize the congestion revenue right transactions. Effectively, all congestion revenue rights will be settled at zero prices. This is needed because the CRRs are released ahead of the day-ahead market and, therefore, there will be CRRs to be settled for.
b. Virtual bids. There may be two different scenarios impacting convergence bids. Since convergence bids are cleared within the day-ahead market, in the case of a day-ahead market suspension there will be no convergence bids cleared -nor will physical bids be cleared-, i.e., awards and prices for convergence bids will be zero. Depending on the actions taken by the ISO for the real time purpose, there is a consideration to make for convergence bids. As described above, the ISO is proposing to either use previous day-ahead results or leave all up to the real-time market depending on the conditions and challenges determine by operations of the system. In case the ISO determines that the DAM results from previous day will be used, the intention is to provide the real time market with a starting point to dispatch physical resources; this needs to be complemented for physical resources with the corresponding settlements. However, there is no operational need to have virtual transactions copied from previous day and then settled them with real-time prices. For this reason if there is a day-ahead market suspension and the ISO defaults to use previous day-ahead results, convergence bids will be suspended for that day, and only physical resources will be settled using awards and prices from previous day-ahead and the schedules and prices produced by the real time, like the settlements under any normal day. IF the ISO determines that instead there will be effectively no day-ahead results and leave everything up to the real time market, for convergence bids there are no

settlement implications because for that day, there will be no awards for convergence bids to settle. Thus, there will be no further settlement implications. In the case of a market suspension for the real time market, the convergence bid transactions will be neutralized by equalizing the real time prices to the day-ahead prices.

4 Priority of self schedules with existing transmission rights

4.1 Issue

Currently, all existing transmission contract (ETC) and transmission ownership rights (TORs) are exempt from any congestion charges for their schedules in the day-ahead and real-time market. The ISO does not reserve the capacity associated with such rights on internal locations but does so for such rights at the interties. Scheduling coordinators must submit specific types of self-schedules in order to be eligible for such treatment. These ETC/TOR self-schedules are validated through a market application in SIBR, which ensures that only holders of such rights receive the exemption from congestion charges by validating that the ETC/TOR self-schedules are associated with specific contract reference numbers. In the past, the ISO has observed cases where a market participant submitted an ETC/TOR self-schedule but used an erroneous contract reference number, in which case the wheel through becomes unbalanced and the ETC/TOR self-schedule loses its scheduling priority and are treated as the self-schedules are passed to the market system as regular price taker self-schedules, producing unintended consequences for the market as well as the ETC/TOR holder.

If a self-schedule is passed on to the market as a price taker when it was intended to be an ETC/TOR, the price taker bid may clear with high prices when the available capacity is not sufficient to accommodate such price taker self schedules in addition to the reserved capacity from ETCs/TORs. Depending on the self-schedule and available capacity, the clearing price (which in some instances may be extreme) may expose other market participants to congestion charges or congestion revenue rights charges simply because of an error by another participant.

The ISO does not implement price corrections in such instances because it was a bid-in error from a participant, and this is a category for which the ISO does not correct prices. This unintended outcome creates an issue for some other participants that now have to absorb high congestion costs, creating uncertainty in the market.

4.2 Straw Proposal

ISO market participants with ETCs or TORs are entitled to use their rights but must comply the ISO bidding and scheduling practices set forth in the ISO tariff and business practice manual. When an error occurs during the bid submission, the SIBR application provides participants with the errors and flags to identify the bid submission issues to correct. Participants therefore are responsible for ensuring the correctness of their bids. The ISO intends to modify this logic in SIBR so that if a scheduling coordinator submits an erroneous contract reference number (CRN) or fails to pass the SIBR validation rules due to a zero entitlement, the ETC/TOR self-schedule will be rejected rather than being passed through like a regular self schedule. The CRN is validated before any entitlement is accepted. CRN's are registered with the ISO for each contract and SIBR validates that the proper CRN is used for the resources designated to the contracts and applicable CRNs with the TOR/ETC self-schedule. There is also a validation for the TOR/ETC self-schedule not to exceed a registered maximum for the resource. Going forward, the new procedure would reject the ETC/TOR self-schedule if either the CRN is misused or if the maximum amount for the applicable contract is exceeded. As part of the process of not considering an invalid ETC/TOR self-schedule, the ETC/TOR rights will not be released. Participants will be notified that the scheduled is rejected and can fix the error if they so choose. This will both provide a clearer signal to the bidder that an error has occurred as well as mitigate the issue of potential congestion associated with erroneous the ETC/TORs self-schedules when later during the market clearing the ISO determines that there isn't sufficient market capacity to clear the price taker self-schedules. In some historical cases the market had to curtail such self-schedules to enforce the feasibility of the tie limits. This change will take place only in the SIBR application and will not require any change in the upstream market application.

5 Compounded pricing of multiple contingencies

5.1 Issue

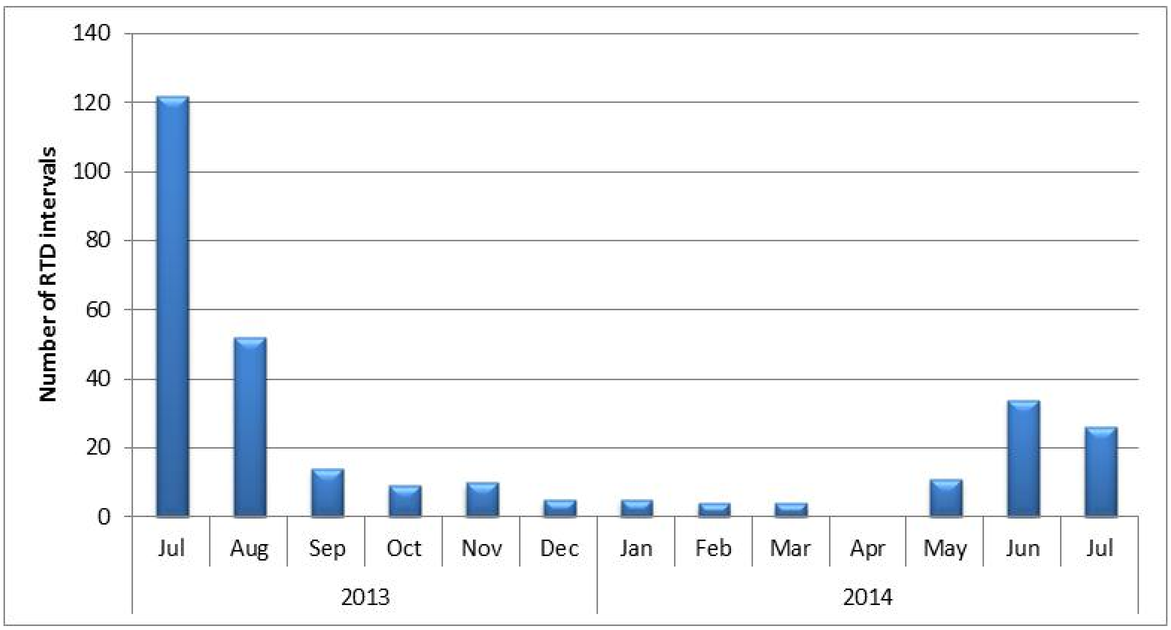
The ISO market systems contain a number of transmission constraints that are enforced in the through the formulation of its security constraint dispatch for both the base and contingency cases. The market system makes use of a series of pricing parameters that when they are binding indicate the cost associated with relaxing these constraints. Since 2013, with the introduction of more contingency-related constraints and with tighter conditions in the system, there have been several instances where a transmission constraint is binding for base case and/or multiple contingency cases. The ISO has observed cases where the solution is the constraint-relaxation region because there are insufficient economic controls (variables) to manage the congestion on the transmission constraints using only economic bids. When this occurs, the same constraint may be binding and relaxed for the base case and/or multiple contingencies cases. Each of these cases will reflect a shadow price associated with the relaxation. Since each contingency case is treated as a separate constraint, each contingency and base case will have a shadow price that will in turn be reflected accordingly in the marginal congestion component of the various locations based on the shift factors thereby compounding the cost of the congestion component of the LMP. For the instances where the solution is based on the administrative constraint relaxation parameters, such pricing of compounded congestion may not be sending a proper price signal. Rather, it is a by-product pricing of the multiple relaxations based on the administrative relaxation parameters prices. Under these conditions, it is expected that only the most severe contingency would be binding and priced.

5.2 Straw Proposal

The ISO establishes the set of contingencies to be used in each market run based on operations engineering studies. The ISO conducts a pre-screening process to determine which contingencies to enforce and it is challenging in that process to determine the single limiting/severe contingency that should be enforced when in most cases a set of contingencies are all credible and which one becomes the most limiting in any market interval depends on the specific system conditions, which is inherently dynamic. Therefore, in several of the instances observed in the past, it turns out that all enforced contingencies were valid and equally credible and the most limiting cannot be identified *ex-ante*. Intuitively, one can consider a mechanism within the market application to programmatically pre-screen and identify the most severe contingency so that the market would enforce only that specific contingency. Under such a construct, any other contingency would not be enforced at all in the market and, therefore, any redispatch for its management would not materialize.

Conceptually, there may be scenarios where the controls (resources) to manage one contingency may be basically the same effective controls to manage another contingency for the same protected element. From a practical perspective, such a construct could not be developed without a major redesign of the ISO market software because. Based on historical occurrences observed in the California ISO market, the cases of concurrent contingencies binding with constraint relaxation have been the most frequent occurrence. Figure 1 shows the number of intervals (frequency) in the real time interval dispatch of constraints binding concurrently for the last 12 months.

Figure 1: Frequency of RTD intervals experiencing concurrent binding of contingencies



Because of these observations and the potential major changes to the market software, the ISO is proposing to confine the scope of this enhancement only to instances where a constraint relaxation occurs for multiple contingencies. In the future, the ISO may explore the cost-benefit of further expanding this application to other scenarios of multiple contingencies binding in the absence of constraint relaxation.

The enhancement in this proposal consists of a modified logic in the market application that would effectively result in pricing only the most limiting contingency under constraint relaxation conditions. All contingencies would still be enforced as usual; however, the current logic which requires that a constraint to be relaxed as a result of multiple contingencies using a slack variable per constraint will be modified so that only one common slack variable is used in the definition of a transmission constraint associated with different contingencies. For illustration, let us consider a cost-minimization problem in its simplest expression to capture the core of the modified logic,

$$
\begin{aligned}
\min \quad & \sum_j c_i(x_i) \\
s.t. \quad & \sum_i x_i = d \\
& \sum_j a_{kj}^c x_j \le b_k^c, \quad \forall k, c \\
& 0 \le x_i \le \overline{x}_i, \qquad \forall i
\end{aligned} \tag{1}
$$

where injections at location *i* are defined by variables x_i and upper limits $\overline{x}_i$; parameter *d* stands for demand, parameter a_{kj}^c stands for the shift factor associated with transmission constraint *k* and location *j* for contingency case *c*; the base case is generally enumerated with c=0, while any other contingency are enumerated starting with c=1. Transmission limit for constraint *k* is defined with parameter b_k^c; the limit for constraint *k* will take only either of two values, one for the base case c=0 and another for the contingency cases, which refers to the emergency limit, *i.e.*, $b_k^{c=1} = b_k^{c=2} = b_k^{c=3} \dots$.

In the current ISO market formulation, this standard problem is expanded for the scheduling run to account for potential relaxation of transmission constraints by introducing a slack variable s_k to each transmission constraint and then appending these slack variables into the objective function which yields the following LP problem:

$$
\begin{aligned}
\min \quad & \sum_j c_i(x_i) + \sum_{k,c} \delta_k s_k^c \\
s.t. \quad & \sum_i x_i = d \\
& \sum_j a_{kj}^c x_j - s_k^c \le b_k^c, \quad \forall k, c \\
& 0 \le x_i \le \overline{x}_i, \qquad \forall i \\
& s_k^s \ge 0, \qquad \forall k
\end{aligned} \tag{2}
$$

The slack variables are penalized in the objective cost function with the corresponding constraint parameters prices as defined in the ISO tariff and the Business Practice Manual for Market Operations. The modified definition of the transmission constraints with the proposed enhancement will now be as follows:

$$
\begin{aligned}
\min \quad & \sum_j c_i(x_i) + \sum_k \delta_k s_k \\
s.t. \quad & \sum_i x_i = d \\
& \sum_j a_{kj}^c x_j - s_k \le b_k^c, \quad \forall k, c \\
& 0 \le x_i \le \overline{x}_i, \qquad \forall i \\
& s_k^s \ge 0, \qquad \forall k
\end{aligned}
\tag{3}
$$

The only difference is in the treatment of the slack variable; currently, there is a slack variable per constraint, including one slack variable per contingency constraint; the modified approach uses only one single slack variable for the base constraint and all the associated contingency constraints. This common slack variable will be also appended in the objective function only once, which means the relaxation will be priced only once.

Even though a transmission constraint will be modeled individually for each contingency, they will have a common slack variable for transmission relaxation. So when a relaxation occurs, only the most limiting constraint will determine the amount of required relaxation and any other contingency related constraint that is less severe will be under this relaxed limit and, thus, will not be binding. It is important to note that this will make a difference only when the market relaxes a transmission constraint associated with contingencies; if the market solution is solving within the economical range, the market solution attained with this enhancement will be no different from the solution attained with the current logic. The ISO is proposing to adopt this approach as this option will address the majority of instances observed in production at a relatively easy to implement solution.

6 Multiplicity of prices

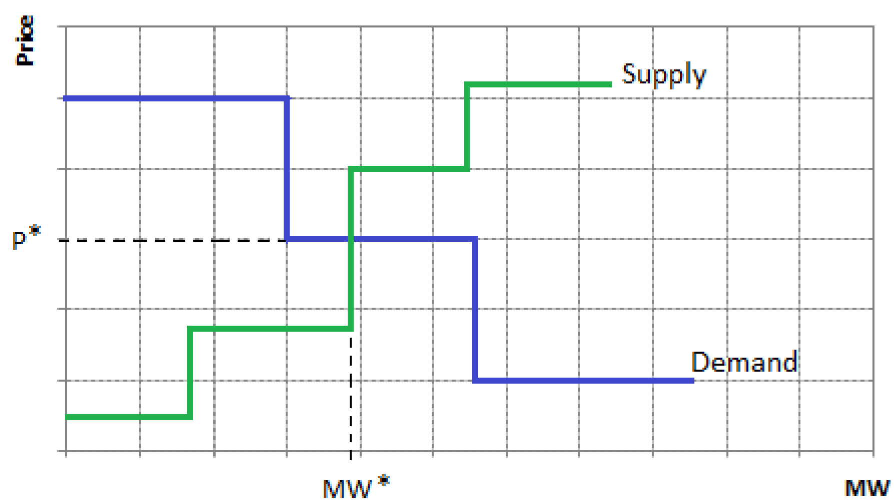
6.1 Issue

The California ISO LMP market design, like many other successful electricity market designs in the United States and elsewhere, is founded on a bid-based security constrained unit commitment and multi-interval economic dispatch. The economic dispatch produces optimal schedules (megawatts) and locational marginal prices (LMPs) that clear the electricity market. The prices arise as a natural by-product of the optimization, and have a traditional economic interpretation of the market clearing prices. The optimization produces a least-cost solution considering not only bid-in information from participants but also system, resources and operational constraints, including power balances, inter-temporal constraints and transmission limits, as well as co-optimizing energy and ancillary services.

Locational marginal prices (LMPs) contain three components: system marginal cost of energy, marginal cost of congestion and marginal cost of losses. Marginal cost of congestion originates from the various transmission-related constraints enforced in the system, including nomograms, flowgates, branch groups and interties. The core of the optimization relies on a security constraint unit commitment (SCUC) and is solved with a mixed integer programming (MIP) methodology. The use of the MIP technique allows the ISO to effectively deal with numerous market design elements of the California ISO markets. Both the tariff and the various business practice manuals of the ISO provide details and descriptions of the basic economic and market principles in which prices are based on the clearing of supply and demand.

In an ideal market clearing process, prices are optimally set at the point where the downward sloping demand curve and upward sloping supply curves intersect. Ideally, such supply curves are smooth and their intersecting point defines the market equilibrium point with the cleared price and quantity. This point maximizes the market surplus. In this typical situation, the marginal cost ($/MWh) of meeting the next increment of demand can be identified by moving along the upward sloping supply curve. However, this simplistic characterization of supply and demand curves does not hold for electricity markets with step-wise bidding structure. A common feature of electricity markets is the flexibility to use multi-segment bids, usually multi-step-wise bids. This is needed to reflect closer the nature of generation costs and benefits for demand. This step-wise format breaks the smoothness of the price curves even when they are monotonically increasing for supply and decreasing for demand that may lead to singular conditions when defining the market clearing point because the intersecting point of stepwise curves may lie at a horizontal or vertical segment of the curves, or may not intersect at all. Figure 2 shows a typical step-wise supply and demand curves and the market clearing point where both curves nicely intersect at one single point *(MW*,P*).*

Figure 2: **Supply and demand curves with a unique market clearing point**



These stepwise curves are not smooth but they are monotonically increasing for supply and monotonically decreasing for demand. In this particular case where such curves intersect the market equilibrium results in unique clearing price and quantity obtained through an economic dispatch. Simply looking at the figure, it is clear that there may be other instances where the supply and demand curves intersect at more than one point, such as intersecting at the vertical or horizontal sections where there can be multiplicity of possible prices or quantity solutions, all of which may be mathematically optimal based on the market clearing process.

The usual emphasis in discussions of locational market-clearing prices focuses on the sometimes counterintuitive nature of network interactions. However, there are other features of bid-based markets that can create counterintuitive results for market prices even without the impact of network interactions. An example, but not the only one, of such solutions is the so-called "degenerate" pricing conditions that can arise with bids and offers expressed as step functions and result in multiple market-clearing prices under economic dispatch.

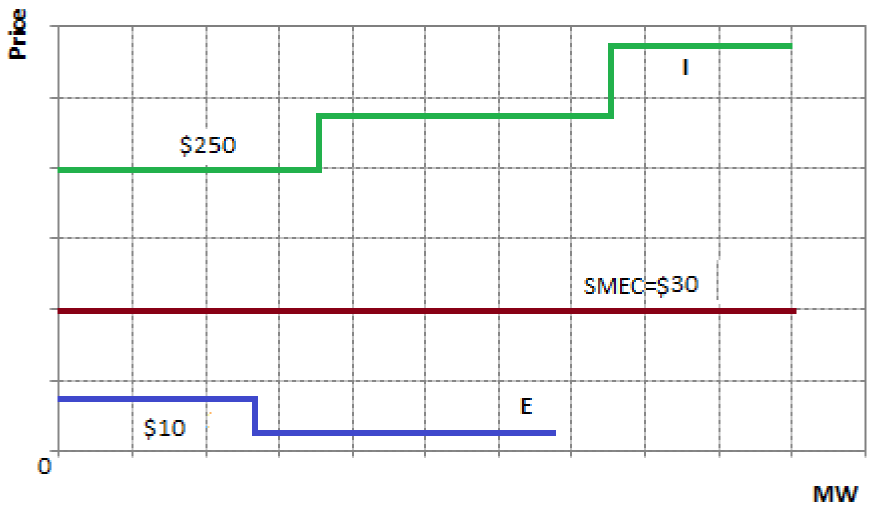
The security constrained economic dispatch is an optimization problem of maximizing the benefits defined by sum of demand bids costs minus the cost of supply offers subject to a number of operational, system and transmission constraints. Mathematically the optimization takes the form of a linear programming problem. In linear programming (LP) applications, marginal or shadow prices are as economically important to calculate as the optimal values of decision variables and the objective function. In mathematical terms, the shadow price represents how much the objective function will change if we relax a given constraint. This is often called the *marginal value*, *shadow price* or *dual variable*, associated with the constraint. The market clearing prices are obtained from the solution of the linear programming problem as shadow prices of the energy and ancillary services requirements, inter-tie, and other transmission and operational constraints.

Although degenerate cases lead to multiplicity of possible solutions, any of these solutions is still optimal. Degeneracy cases are not unique to electricity markets. Degeneracy is rooted to the mathematical formulation and (pricing) optimization of a physical problem and is a well-known and understood condition regardless of the industry in which the condition may arise. Linear programming commercial software products often produce only one of the optimal solutions but many others may also exist, and in the case of electricity markets, only one solution can be used and is desirable.

Among the various constraint considered in the California ISO's market model, there is one set of constraints incorporated to monitor and enforce imports and exports through the various interfaces connecting the ISO system with adjacent balancing authorities, known as *interties (i.e.,* the Intertie Constraint or ITC). The constraints on these interties are in place to enforce scheduling limits rather than power-flow limits. Each intertie has a constraint associated with the capacity in the import direction and another with the export direction. Imports and exports for energy are netted with each other. These constraints are enforced through the market and when binding (i.e., the schedules equal the constraint limit) they may have associated shadow prices. These shadow prices are reflected in the marginal congestion components at specific scheduling point locations for the given intertie. Under certain system conditions, the intertie limits may be at 0 MW in either or both directions. When both directions are set to 0 MW, the instance is referred to as *open tie* condition and no schedules can come through in either direction. There may be other instances where only one direction is derated to 0 MW, which means that the other direction may still have a non-zero limit and thus schedules may still come through; these instances are referred to as *partially open tie*. Although degeneracy may arise from various interplays and forms, this stakeholder effort focuses on the particular cases of interties in the California ISO markets.

Figure 3 illustrates a specific scenario observed in historical outcomes for an instance of a partially open tie derated at 0 MW in the export direction while the import limit is greater than 0 MW. This case is selected for this discussion to illustrate the interplay between the partially open tie situation and the bids submitted to the market in those hours. For the sake of simplicity the MW break points in the stacks are omitted, and only the bid-in prices for the first segment of the imports and exports are shown. These numbers are not real but preserve the structure and interplay of the real cases. The import stack for this intertie is represented in green while the export stack is represented in blue.

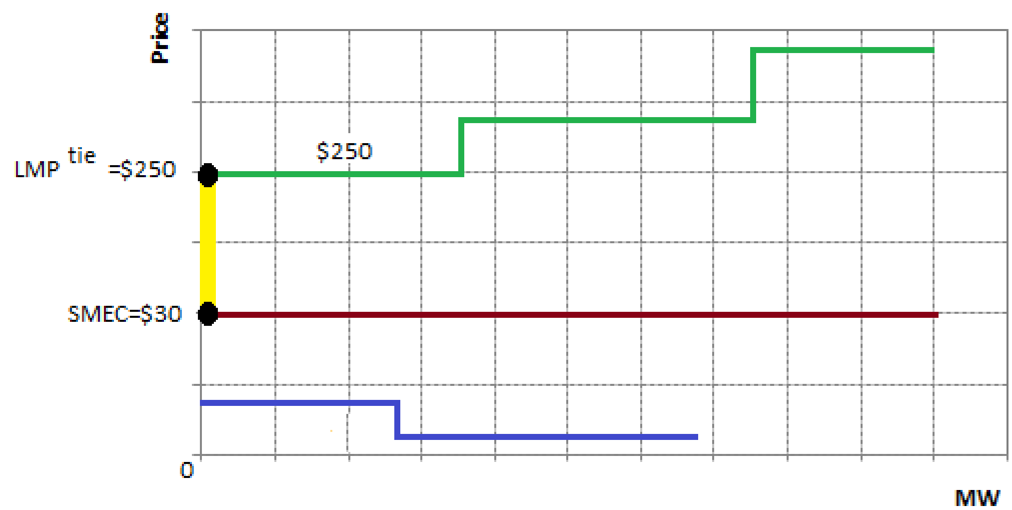
Figure 3: **Bid stack for imports and export for an intertie with to 0 MW in the export direction**



The market solution attained a system marginal energy cost of $30. Given that the import bid is higher than the system energy marginal cost, no imports were awarded on this intertie, and no exports are awarded in the export direction because it is derated to 0 MW and they are not in merit order. In terms of awards this is an expected optimal MW dispatch; however, in terms of prices, this condition leads to a degenerate solution with multiplicity of prices. The import bids set the price at the intertie location at $250 and the shadow price for the intertie constraint is set at ($30-$250)= -$220 in the export direction in order to balance with the system energy price of $30. This means the intertie constraint is binding in the export direction at the 0 MW limit. The set of multiple prices is bounded on one end by this outcome where the export constraint is binding at -$220, the other bound would be when such constraint is binding at a zero shadow price6. This is shown graphically in Figure 4. For any price in this range, the optimal dispatch still holds the same, which is at 0 MW awards for both imports and exports. For the actual market solution, the optimization solver independently selected the value at the upper bound of the shadow price for the market solution.

[6] The 0 MW limit creates conditions for a weak complementarity slackness. Under strict complementarity, if the constraint is binding its associated shadow price will be non zero; for weak complementarity, if the constraint is binding it shadow price may be non zero or zero (J. Nocedal and S. Wright, Numerical Optimization, Springer, 1992).

Figure 4: **Multiplicity of prices for an intertie constraint derated at 0 MW in the export direction**



This degenerate outcome with a multiplicity of prices does not pose a complication in the context of this energy market solution as there are no awards to settle at such prices, whatever the prices turn out to be. Any of the prices within the indicated range are equally optimal and have their root in the mathematical formulation and marginal pricing of the constraint. Any of the prices within the indicated range are equally optimal and have their root in the mathematical formulation and marginal pricing of the constraint. The complication arises when such prices are used outside of the physical energy market. In the case of the day-ahead market, for instance, such prices may have an impact on the settlement of congestion revenue rights (CRRs).

6.2 Straw Proposal

The ISO did not contemplate or adopt specific rules to be incorporated in the market application to identify and select *ex ante* one price over the others from the feasible set of prices in degeneracy cases. The optimization solver of the market selects one price out of the many feasible prices and produces that as the final outcome. It is important to note that the multiplicity of prices and the choice of one of them as the solution is not an erroneous result and does not mean the market application or its solver are working incorrectly. This is simply the inherent nature of the pricing model and optimization, and the only way to overcome this outcome is to use an enhanced pricing formulation. Given the concerns with degenerate solutions and multiplicity of prices under the traditional formulation for pricing constraints with a security constraint economic dispatch, the ISO has worked with its software vendor and developed a possible alternative for addressing such degenerate cases.

The proposed approach relies on modifications to the mathematical structure of the linear programming security constrained economic dispatch currently used in its markets to ensure convexity of the objective function and uniqueness of prices. To put in context the proposed modifications, let's define first the current formulation in its simplest expression with the following linear programming problem:

$$
\begin{aligned}
\min \quad & \sum_j c_i(x_i) \\
s.t. \quad & \sum_i x_i = d && (\lambda) \\
& \sum_j a_{kj} x_j \le b_k, \quad \forall k && (\mu_k) \\
& 0 \le x_i \le \overline{x}_i, \quad \forall i && (\overline{\pi}_i)
\end{aligned}
\tag{4}
$$

This LP problem stands for the minimization of bid-in cost for supply subject to constraints of power balance, transmission limits and supply limits, respectively. Supply is defined with variables x_i and upper limits $\overline{x}_i$; parameter *d* stands for demand, parameter a_{kj} stands for the shift factor associated with transmission constraint *k* and location *j*; transmission limit for constraint *k* is defined with parameter b_k; the variables in brackets in the right hand side of each constraint are their associated dual variables. In the current ISO formulation, this standard problem is expanded for the scheduling run to account for potential relaxation of transmission constraints by introducing a slack variable s_k^s to each transmission constraint and then appending these slack variables into the objective function which yields the following LP problem:

$$
\begin{aligned}
\min \quad & \sum_j c_i(x_i) + \sum_k \delta_k^s s_k^s \\
s.t. \quad & \sum_i x_i = d && (\lambda) \\
& \sum_j a_{kj} x_j - s_k^s \le b_k, \quad \forall k && (\mu_k) \\
& 0 \le x_i \le \overline{x}_i, \quad \forall i && (\overline{\pi}_i) \\
& s_k^s \ge 0, \quad \forall k &&
\end{aligned}
\tag{5}
$$

The slack variables are penalized in the objective cost function with the corresponding constraint parameter prices as defined in the Business Practice Manual for Market Operations.

Similarly, in the pricing run the problem is expanded to account for any potential relaxation that took place in the scheduling run.

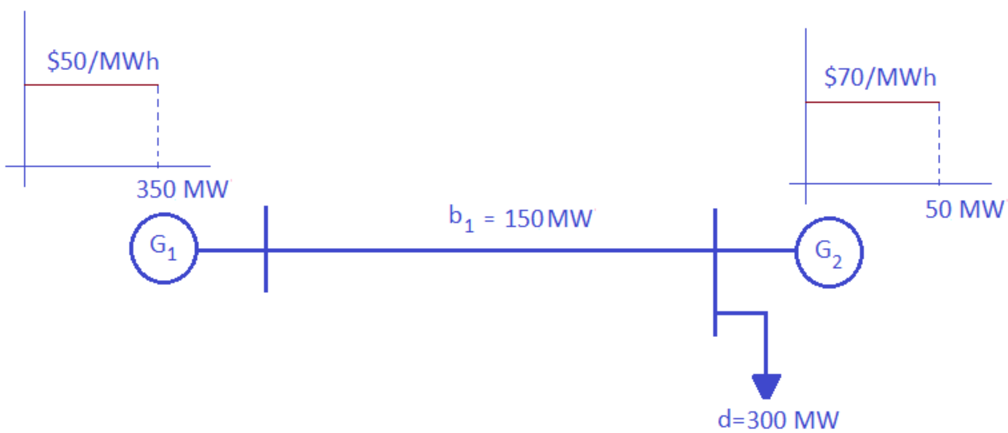
$$\begin{aligned}
\min \quad & \sum_j c_i(x_i) + \sum_k \left(\delta_k^p s_k^s + \delta_k^p s_k^p\right) \\
s.t. \quad & \sum_i x_i = d && (\lambda) \\
& \sum_j a_{kj} x_j - s_k^s - s_k^p \le b_k, \quad \forall k && (\mu_k) \\
& 0 \le x_i \le \overline{x}_i, \quad \forall i && (\overline{\pi}_i) \\
& 0 \le s_k^s \le \hat{s}_k^s, \quad \forall k \\
& 0 \le s_k^p \le \varepsilon^l, \quad \forall k
\end{aligned} \tag{6}$$

where $\hat{s}_k^s$ is the amount of relaxation determined in the scheduling run for transmission constraint *k* that now serves as an upper bound to the first-segment slack variable in the pricing run; additionally, the pricing run uses a second-segment slack variable s_k^p which is limited by an epsilon amount ε^l. The cost of moving these slack variables to regain feasibility in the system by relaxing the transmission constraint is defined by the corresponding penalty prices used currently in the ISO markets system.

The alternate formulation proposed by the ISO relies on expanding the current formulation with another slack variable with an associated weight ω^q ,casting the problem as a quadratic programming problem. The linear transmission constraints are expanded with a penalized slack variable while a quadratic penalized term is added to the objective cost. With these modifications, the traditional security constraint economic dispatch casted as a linear programming problem is converted into a quadratic (convex) programming problem. The problem is strictly convex and separable with respect to the slack variable and, therefore, it can guarantee the uniqueness of prices. In addition, the resulting prices are continuous functions of the problem parameters. Thus, small changes in the problem parameters, such as the constraint limits, will only result in smooth changes in prices. This alternate formulation addresses the multiplicity of shadow prices and also eliminates the potential steep changes in prices when there are small changes in the requirements or conditions.

The additional slack variable introduced in the formulation will compete with the existing slacks s_k^s, s_k^p to fulfill the relaxation required. The slack variables s_k^s, s_k^p contribute linearly to the relaxation of the constraint limit, but their impact on the objective cost function also grows at a constant rate as defined by the penalty price for transmission relaxation. Additionally, with a weight ω^q associated with the slack variable, the growth of new slack variable's contribution to the objective cost function is also limited even if it increases quadratically. If the weight is relatively large, the slack variable effect will be cheaper to use than the slack variables for the linear terms priced at the high penalty price, and the optimization will lean more on that slack for small relaxations. This outcome, however, will result in the slack variable for the quadratic term setting the price potentially at prices that will not reflect the conditions of constraint relaxation. In order to preserve the price signal of constraint relaxations, the weight needs to be sufficiently small. The ISO has done preliminary testing of this proposal pricing mechanism and has found that a weight in the order of 1.E-5 preserves the proper pricing.

Consider the following set-up of a two-node system where the demand of 300 MW cannot be met with the local generation; the transmission constraint also imposes a limit on generator 1 to meet the load. Under this scenario consider that the transmission constraint is allowed to be relaxed in order to meet the demand.



The slack variable in scheduling run will allow the flow on line 1 to violate the limit at a penalty price of $5000/MWh. The solution to the scheduling run results in generator 1 producing 250 MW, generator 2 producing 50 MW; this represents a flow on line 1 of 250 MW, which is feasible by allowing a relaxation of the transmission constraint of 100 MW, and means the slack variable s_1 has a value of 100 MW. In terms of prices, the shadow price μ_1 associated with the transmission constraint of line 1 is -$5000/MWh and the shadow price of the power balance, which is the system marginal energy component, is $5050/MWh; this means the locational marginal price at the locations of generators 1 and 2 is $50/MWh and

\$5050/MWh, respectively. These resulting prices reflect the relaxation of the transmission constraint at the penalty price.

Turning into the pricing run formulation, the problem becomes

$$\min \quad 50G_1 + 70G_2 + 1000s_1^s + 1000s_1^p$$

$$\begin{aligned} s.t. \quad & G_1 + G_2 = 300 && (\lambda) \\ & G_1 - s_1^s - s_1^p \leq 150 && (\mu_1) \\ & 0 \leq G_1 \leq 350 \\ & 0 \leq G_2 \leq 50 \\ & 0 \leq s_1^s \leq 100 \\ & 0 \leq s_1^p \leq 0.1 \end{aligned} \qquad (7)$$

where s_1^s is limited by the amount of the relaxation from the scheduling run; i.e. 100 MW, and s_1^p is limited by an epsilon amount. The cost of moving one unit of either of these slack variables is set to \$1000 based on the current values of penalty prices used in the markets for transmission constraint relaxation in the pricing run. The solution of this problem is G_1 = 250 MW, G_2 = 50 MW, flow on line 1= 250 MW, s_1^s = 100 MW, s_1^p=0 MW. The system marginal energy price is \$1050/MWh, the shadow price on the flow constraint with the slack is -\$1000/MWh. The LMP at the locations of generators 1 and 2 are \$50/MWh and \$1050/MWh, respectively. The prices reflect the fact that the flow constraint on line 1 cannot be satisfied and the penalty cost of violating the constraint, which is based on the administrative transmission relaxation price of \$1000/MWh.

The proposed formulation will cast the problem into a quadratic programming program. Assuming that the weight ω^q is set to a very small positive value of, say, 0.0001, the solution to this problem is G1 = 250 MW, G2 = 50 MW, flow on line 1 = 250 MW. The system marginal energy price is \$1050/MWh, the shadow price on the flow constraint with the slack is -\$1000/MWh. The LMP at the locations of generators 1 and 2 are \$50/MWh and \$1050/MWh, respectively. This is the expected result consistent with the goal to set shadow prices for infeasible transmission constraints according to the transmission relaxation price of the pricing run, i.e. \$1000/MWh.

In order to illustrate the discussion of the effect of the epsilon on the market solution, consider the summary of market results using different values for the weight as shown in Table 2.

Table 2: Comparison of market solutions with different weight values

ω^q	G_1	G_2	LMP_1	LMP_2	λ	μ_1
10	300	0	50	65	65	-15
1	250	50	50	150	150	-100
0.1	250	50	50	1050	1050	-1000
0.01	250	50	50	1050	1050	-1000
0.001	250	50	50	1050	1050	-1000

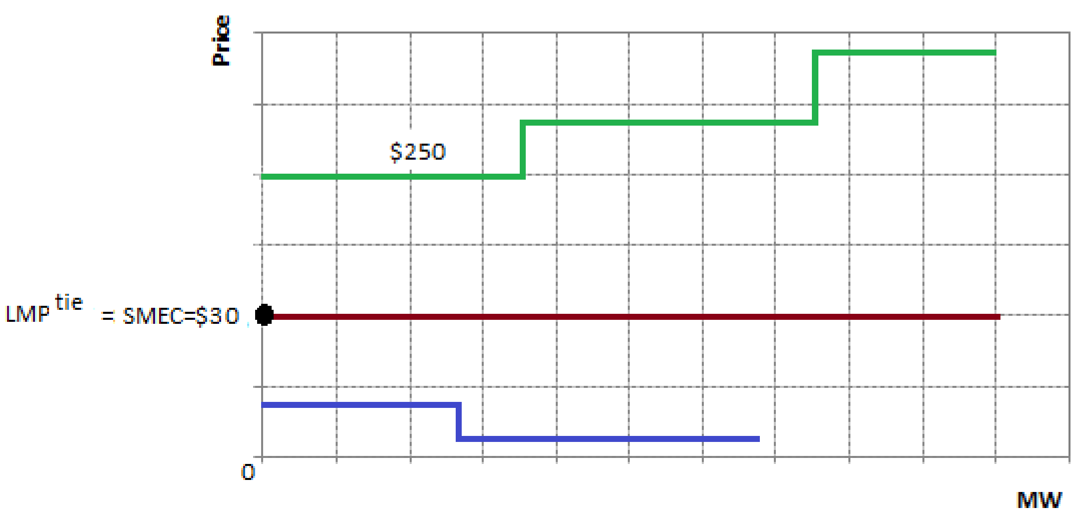
In the first two cases where the weight is set to a large value, the relaxation relies on the slack variable of the quadratic term and also defines prices that do not reflect the relaxation condition. Only in the cases with the weight set to a value of 0.1 or lower the shadow price and LMPs reflect the actual conditions of constraint relaxation.

The proposal for using this alternate formulation is applicable to both the day-ahead and real-time markets and only in the pricing run of the markets because this is the run that generates the binding schedules and prices. Also, the ISO intends to apply this formulation to constraints that impact the locational marginal prices for energy, including power balance constraint and transmission constraints such as interties, branch groups flowgates, nomograms, and energy imbalance market related transmission constraints (EIM transfer, GHG and NSI constraints) . Similar to the treatment of the existing slack variables for transmission relaxation, the expanded model with the new slack variable will always be modeled in the constraints regardless of the potential scenarios of constraints binding or being slack or whether the constraint may be binding or not in the scheduling run. There is no differentiated treatment of constraints due to specific conditions between runs or constraints. The formulation is expanded systematically for all constraints as part of the static model and will always model the existing slack variable and the new added slack variables. In cases where the constraint is slack (under the limit), having the new slack variable, or even the existing slack variable, will make no difference in the outcome.

With respect to how this proposed change interacts with the other enhancement for compounded congestion to price only the most limiting constraint, the only change to the slack variable set-up is the use of a common slack variable; the current treatment of the slack variable in both the constraint definition and objective cost function will remain the same, and with the enhancement for contingencies there will be only one slack variable for the set of base case and contingencies appended into the objective cost function which will be priced once at the penalty price. All this while the enhanced formulation for multiplicity of prices will have a new slack variable in addition to the current use of the existing slack variables.

Figure 5 illustrates the market solution using the alternate formulation in which the LMP at the intertie scheduling point is equal to the system marginal energy cost, which in turn results in no congestion on the intertie in the export direction. These numerical examples are from actual production cases observed in the past; only the specific bid values were modified to not reflect the actual bids.

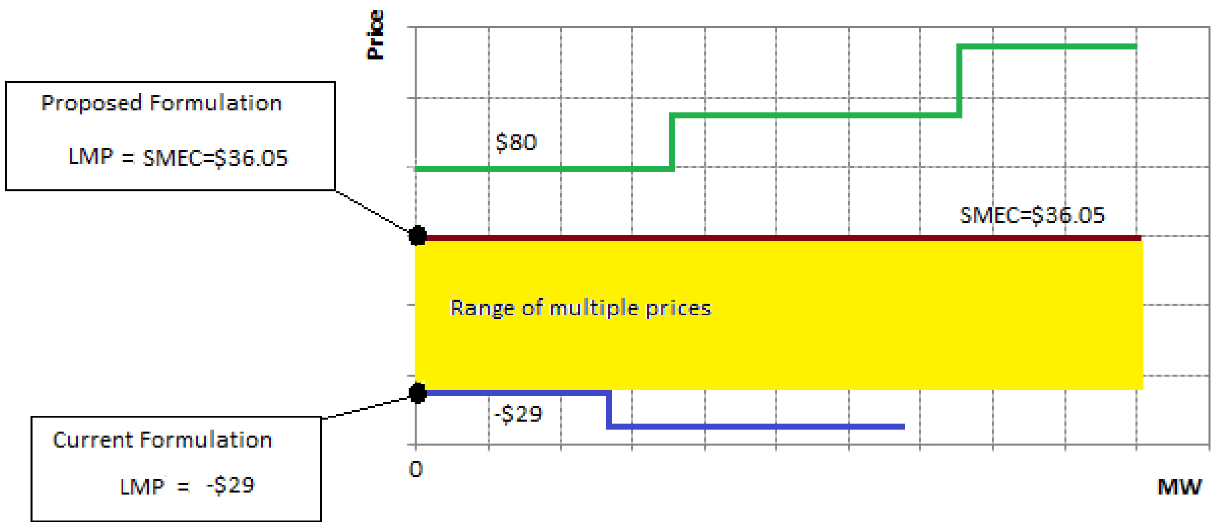
Figure 5: Market solution at the intertie with alternate pricing



Note that this solution is the result of the alternate formulation of the optimization problem, and is not based on any new logic instructing the solver to pick any particular solution of the set of multiple optimal solutions. The enhanced formulation actually solves to a single market outcome, thereby eliminating degeneracy. This no-congestion outcome still results in the same optimal dispatch as the old formulation but avoids the multiplicity of prices. This solution is also consistent with system operations in these scenarios.

In contrast, consider an alternative scenario where an intertie is derated to 0 MW in the import direction and the export limit is non zero. The bid setup is presented in Figure 6 with the import stack represented in green and the export stack represented in blue. In this case there are no awards in either the import or export direction. In the current formulation the price at the intertie location is set by the export at -$29. With the system price at $36.05, the price differential between the system price and the tie price is defined by the congestion on the intertie at a shadow price of -$65.05. Like in the previous example, this case also leads to degeneracy and multiplicity of prices. The current formulation provides a market solution at the lower bound of the set of degenerate prices, which is the maximum level of congestion the intertie in the export can observe. The proposed formulation would clear the price at the intertie location equal to the system price of $36.05, leading to no congestion on the intertie. The optimal dispatches in either case are still 0 MW for both imports and exports.

Figure 6: Illustration of an intertie derated to 0 MW in the import direction



7 Stakeholder feedback

The ISO's responses to stakeholders' written comments can be found at the Pricing Enhancements initiative webpage. In several instances, the ISO referred to this revised paper for a reference of how the ISO has incorporated the comments and responses.

8 Next Steps

The ISO will discuss the issue paper with stakeholders during a teleconference to be held on November 6, 2014. Stakeholders should submit written comments by November 13, 2014 to PEnhancements@caiso.com

Attachment D – Board Memorandum (Including Matrix of Stakeholder Comments)

Tariff Amendment to Implement Pricing Enhancements

California Independent System Operator Corporation

June 6, 2016

Memorandum

To: ISO Board of Governors

From: Mark Rothleder, Vice President, Market Quality & Renewable Integration

Date: December 10, 2014

Re: **Decision on pricing enhancements proposal**

This memorandum requires Board action.

EXECUTIVE SUMMARY

Management proposes market rule changes to improve pricing efficiency in four areas: administrative pricing rules that apply when market clearing prices are not available; validation of self-schedules supported with transmission contract or ownership rights; formulation of contingency-related constraints; and formulation of market constraints to ensure unique market clearing prices.

Administrative pricing is used during market disruptions or suspensions for when prices cannot be generated through its normal market clearing mechanism. After the September 8, 2011 southwest outage, the ISO committed to revise its administrative pricing rules that would apply for similar system emergencies or market disruptions. The ISO launched this effort in August 2012, and resumed it in June 2014 as part of a broader stakeholder process that led to the proposed changes. The current rule is to use the last available price produced in the market, referred to as the "last best price." Management now proposes a tiered approach for administrative pricing that will provide simple and practical rules and price certainty, and have minimum impact on the market as a whole. The proposal also addresses settlements implications for both physical and financial resources and will clarify market participants' financial obligations for force majeure events.

In June 2014, the ISO launched an effort to consider refinements to its market rules aimed at increasing price certainty and efficiency of prices cleared through its market. As a result, Management proposes the following three modifications to its market rules. First, a modification of the validation of self-schedules supported by transmission contract or ownership rights to avoid creating artificial congestion and to ensure efficient use of the ISO-controlled transmission grid. Second, a modification of the mathematical formulation for pricing constraint relaxation to eliminate the compounded pricing effect of penalty parameters for relaxation of contingency-related constraints. Third, a modification of the mathematical formulation of market clearing logic to ensure that the market application produces a unique price in cases where constraints would otherwise create an array of possible prices. These three enhancements will strengthen market outcomes and provide more accurate and appropriate price signals.

Management proposes the following motion:

> ***Moved, that the ISO Board of Governors approves the pricing enhancements proposal as described in the memorandum dated December 10, 2014; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.***

DISCUSSION AND ANALYSIS

Administrative pricing rules

On June 13, 2012, FERC granted the ISO's petition to waive tariff provisions related to setting administrative prices and settling real-time market transactions in response to the September 8, 2011 southwest power outage. FERC found that the administrative prices established by the ISO to set price signals in order to manage the emergency were not authorized by the tariff, but granted the ISO's waiver request. FERC also granted a tariff waiver to permit the ISO to hold tripped load and resources harmless by reversing out the day-ahead awards for both load and resources. FERC declined to decide whether the September 8 southwest power outage constituted a force majeure event or whether the ISO had tariff authority to hold resources harmless in the event of a force majeure event. FERC acknowledged the ISO's commitment to consider tariff changes to avoid confusion regarding pricing in the event of a similar emergency or market disruption in the future through a stakeholder process.

Management recognized that the existing administrative pricing tariff rule of using the last best price, while useful in filling brief gaps caused by intermittent market disruptions, may not provide appropriate price signals for more serious and lengthy market disruptions such as the 2011 southwest power outage, where the ISO had to suspend the market for several hours. Management also recognized the need to clarify the settlement implications in the event of a force majeure event. The following three part proposal for administrative pricing rules addresses these elements:

(1) Day-ahead administrative pricing

While such occurrences are very rare, it is possible that the day-ahead market outcome is either not available or is unreliable. For such cases, Management proposes that the ISO have the authority to use either day-ahead results – for both awards and prices – from the previous day, or rely fully on the results of the real-time market to operate and price the energy transactions. The ISO will notify the market of its intended election by 6:00 PM the day before the operational day and will use it unless the ISO is ultimately able to clear the day-ahead market with a reliable solution in time to issue schedules and prices for the next day. This approach provides notice to the market of the ISO's anticipated use of the administrative pricing option while it continues to address the issues preventing a market clearing solution. Management believes that this approach will allow the ISO to pursue a day-ahead market solution that is superior to an administrative price option if one can be achieved.

The selection of the administrative option will be based on system conditions. If system conditions are not reasonably similar to the previous day, the ISO will rely on the real-time market. Although the ISO proposed to seek authority to use either the previous day's results or the real-time market, the ISO's preferred option will be to use the previous day's results if at all possible, for the following reasons. First, use of the previous day's day-ahead market results mitigates against the worst case scenario in which the real-time market might also be suspended. Second, using the previous day's solution provides the ISO with a starting point for dispatch and settlement, while the real-time market can provide the incremental or decremental differences between the day-ahead and real-time, thereby minimizing the need for manual instructions. Third, market participants will know in advance their awards and prices for the applicable trading date, minimizing uncertainty and allowing them to secure fuel and prepare their resources for commitment.

These rules are accompanied with corresponding settlements provisions. If the ISO decides to use the previous day's results of the day-ahead market, congestion revenue rights will be settled also with the prices of the previous day's results. Convergence bids will be suspended for the day when the day-ahead market is suspended. If the ISO determines it must rely on the real-time results, resources will be fully settled with real-time prices, and there will also be no convergence bids to settle. Based on feedback from stakeholders and the Market Surveillance Committee, Management proposes to settle congestion revenue rights with the hourly average of the fifteen-minute real-time market prices if there is the need to rely fully on the real-time market. This is necessary because, in such cases, resources will settle fully on real-time prices and will still be subject to congestion charges; this provision will provide the hedge for the real-time congestion.

(2) Real-time market administrative pricing

For the real-time market, the current requirement of using the last best price is well suited for minor market disruptions involving a limited number of missing fifteen-minute market or real-time dispatch intervals. This approach does not work as well for other circumstances in which, for example, the ISO experiences prolonged disruptions over multiple intervals. Therefore, Management proposes a three-tier approach that addresses the broader array of circumstances more effectively.

a) Tier 1- Brief non-emergency market disruptions

If the fifteen-minute market prices are missing for fewer than four consecutive intervals, or if the five-minute real-time dispatch interval prices are missing for fewer than twelve consecutive five-minute intervals, Management proposes to preserve the current administrative pricing of using the last best price for each market accordingly.

b) Tier 2 - Longer non-emergency market disruptions

If either the fifteen-minute market prices are missing for more than three consecutive intervals or the five-minute real-time dispatch interval prices are missing for more than eleven consecutive intervals under non-emergency system conditions, then the ISO will fill in missing prices as follows:

i. Where the real-time dispatch interval dispatch prices are not available but the fifteen-minute market prices are available, then the fifteen-minute market prices will be used to fill in missing real-time dispatch prices. Conversely, if the fifteen-minute market prices are missing but the five-minute real-time dispatch interval prices are available, then the simple average of the three applicable five-minute real-time dispatch interval prices will be used to fill for the missing fifteen-minute market intervals. This approach utilizes prices for the same corresponding hour, thus reflecting as closely as possible the same market conditions and would minimize the participants' exposure to imbalance charges between the fifteen-minute market and the five-minute market.

ii. Where both the fifteen-minute market and five-minute real-time dispatch interval prices are not available, the ISO would use prices from the day-ahead market cleared for the same trading hours. This provides greater price certainty and transparency and also minimizes imbalance charges across markets.

c) Tier 3 - Market suspension

The ISO already has tariff-based authority to suspend its market under specific conditions, and Management does not propose changes to that authority. Generally, suspension of the market, or elements of the market, occur under two scenarios: (1) the market could fail as a result of catastrophic software failure; or (2) the market results are of such poor quality that system operations cannot use them for reliable operation of the grid. The September 8, 2011 event involved such a large scale system emergency where generation and load tripped. Although the ISO's market software continued to function, the market results did not reflect the major system changes and did not align with actual conditions. For such instances in which the ISO suspends the real-time market, Management proposes to use prices from the day-ahead market cleared for the same trade hours. This approach provides the following benefits: First, it provides certainty to the marketplace as the prices are already known. Second, use of the day-ahead prices minimizes the settlements implications since any deviation of resources between the day-ahead and the real-time markets will be settled at zero price difference. Third, using day-ahead prices also addresses the settlements for convergence bids since they will be liquidated at zero cost/profit. In case the day-ahead prices do not fully compensate resources, the bid cost recovery mechanism will use bids from the previous day-ahead market, while resources instructed manually will settle with the standard mechanism of exceptional dispatches. In the extreme case where both the day-ahead and real-time markets are not functioning and the ISO relies on using the previous day's results, the same applicable settlements provisions apply for the scenario of using the previous day's results for the real-time market suspension.

(3) Force majeure

Management proposes to preserve the current imbalance energy settlement rules that apply under force majeure events, but proposes to add language to the tariff that explicitly states that force majeure events do not alter the rules for settling deviations from day-ahead schedules and awards. As part of its tariff waiver filing in connection with the September 8, 2011 outage, the ISO argued that both tripped load and resources should be held harmless during the term of the massive outage and requested a tariff waiver to allow this result. FERC granted the ISO the relief through a tariff waiver, but its waiver was not based on a finding of whether the force majeure provision in section 14 of the tariff authorizes this result.

Management does not propose to extend force majeure to excuse imbalance energy charges as such. The ISO market design at its core relies on a two-step settlement between the financially binding day-ahead and real time markets. It imposes financial obligations on parties to pay or be paid based on the day-ahead award; if deviations from such awards take place in the real time, uninstructed deviations are settled accordingly. Such mechanism provides a framework for allocating price risk between the day-ahead and real-time markets. If a participant does not deliver its day-ahead award, it has the financial obligation to pay for the uninstructed deviation. When a market participant submits bids into the day-ahead market based on its location, economic strategy and risk premium, among other factors, participants are taking on the risk and consequences of participating in the market under such settlement terms. This rationale is important to consider for the efficient economical operation of a market.

Bid validation for bids supported with transmission rights

Currently, all market self-schedules submitted pursuant to the terms of existing transmission contract or ownership rights are exempt from any congestion charges accruing out of the congestion component of the locational marginal price. Scheduling coordinators must submit specific types of self-schedules in order to exercise this right. These special self-schedules are also afforded a higher scheduling priority than ordinary self-schedules that are not supported by transmission contract or ownership rights.

The self-schedules supported by transmission contract or ownership rights are validated during the bid submission process to ensure that only authorized holders of such rights receive the perfect hedge by validating that the special self-schedules are associated with registered contract reference numbers. Under the current rules, if a scheduling coordinator submits a self-schedule supported by a transmission contract or ownership right that is not consistent with the contractual terms, the self-schedule is not always rejected entirely. Instead, in some cases the ISO accepts the self-schedule as an ordinary self-schedule and designates it with the same lower priority afforded to ordinary self-schedules. The ISO still provides the self-schedule the perfect hedge for the capacity scheduled within the terms of the agreement. This may result in artificial congestion in the system and may impact others participating in the market through either higher congestion charges for their energy or congestion revenue rights charges caused by the artificial congestion.

Management proposes to modify the bid validation rules so that if the validation detects an erroneous self-schedule, it is rejected entirely rather than allowing it to flow into the market as an ordinary self-schedule. Participants have the mechanism to identify bids in error during the bid submission process and will have the ability to resubmit a corrected self-schedule if it is submitted in time.

Enhanced formulation of contingency-related constraints

The ISO market system enforces transmission constraints that protect the system in case of a contingency of an outage of another transmission element. In some cases a transmission constraint may be affected by multiple contingencies that may occur. The market application uses a set of pricing parameters to indicate the cost associated with relaxing any of these constraints. There are instances when the market application produces a solution in which a transmission constraint cannot be resolved and must be relaxed due to multiple contingencies. Since each base and contingency case is treated as a separate constraint, each contingency case will have a congestion cost that will in turn be compounded in the marginal congestion component of the various locations impacted based on the shift factors. The cost of relaxing a constraint is based on a set of penalty prices, which are currently administratively pegged to the maximum bid caps. Therefore, in these cases where multiple constraints are relaxed, the market solution reflects a compounded price based on the totality of the penalty prices. This pricing is not the optimal way to price energy, because the compounding of penalty prices does not provide any further congestion relief than the congestion cost based on the pricing of the most relaxed contingency.

Management proposes to modify the current market application formulation so that the price will reflect the cost of congestion associated with the most limiting contingency under constraint relaxation conditions. With this proposal, all credible contingencies determined by operations studies will continue to be enforced in the market, as usual, but only the most limiting contingency will bind and be priced.

Modified market application formulation to attain unique prices

In an ideal market clearing process, prices are optimally set at the point where the downward sloping demand curve and upward sloping supply curves intersect. In cases where the curves intersect at a single point, this price is unique. This simplistic characterization of supply and demand curves does not hold for markets with a step-wise bidding structure. Multi-step-wise bids can create the so-called “degenerate” pricing conditions that can result in multiple market-clearing prices under economic dispatch.

Although degenerate cases can lead to multiplicity of possible pricing solutions for the same dispatch, any of these solutions is optimal from a market clearing perspective. Degeneracy is rooted in the mathematical formulation and (pricing) optimization of a physical problem and is a well-known and understood condition. Linear programming commercial software products, like the one used in the ISO market application, often produce only one of the optimal solutions even though many others may also exist. This does not pose a problem for the physical market itself, but it does for when such prices are used outside of the physical energy market, as is the case for the day-ahead market whose prices are used for settlement of congestion revenue rights.

The ISO enforces multiple constraints in its market application to reflect the physical and scheduling, limitations of the system under various possible conditions. One type of constraint is the intertie constraint to limit import/export schedules between the ISO and neighboring balancing authority areas based on system conditions. Certain conditions, such as where an intertie is derated to zero limit in one direction but not in the other, can produce degenerate pricing solutions, and it is possible under such circumstances that a scheduling coordinator can set the price through a bid that creates artificial congestion even though no megawatts actually clear.

Management proposes an alternative solution formulation that will eliminate the condition leading to multiple prices and enable the market optimization to select the optimal price. That is, if the market clearing problem is limited by any constraint, the market clearing process would create a price for the constraint only when the relaxation of the constraint would result in a reduction in the total cost to operate the system. To do so, the existing linear programming model would be modified into a quadratic programming model using a new slack variable in both the objective cost function and in the constraint definition, which guarantees the uniqueness of prices associated with the various constraints in the system, including intertie constraints. The new formulation will ensure the price attained is consistent with existing least-cost dispatch principles already embodied in the ISO tariff. The new formulation will also ensure that for those cases in which the intertie is derated to a zero limit in only one direction, the resulting price does not create artificial congestion that creates complications for other products settled on the basis of the cost of congestion at the applicable locations.

POSITIONS OF THE PARTIES

There was general support for the proposals associated with: 1) the validation of self-schedules supported by transmission contract or ownership rights to avoid creating artificial congestion and to ensure efficient use of the ISO-controlled transmission grid, 2) the modification of the mathematical formulation for pricing constraint relaxation to eliminate the compounded pricing effect of penalty parameters for relaxation of contingency-related constraints, and 3) the modification of the mathematical formulation of market clearing logic to ensure that the market application produces a unique price in cases where constraints would otherwise create an array of possible prices.

For the administrative pricing rules, there is one opposing view of the policy for settlements provisions for force majeure events, where a participant believes that intertie resources need to be financially excused of imbalance charges under force majeure events. Management believes that the current policy adheres to the market principle where participants bear the risk and cost of participating in a market. The market surveillance committee also expressed their opinion about having an alternate approach instead of using the day-ahead market prices for real-time market suspension. Management believes that using day-ahead prices provides a certain price signal and most importantly minimizes the settlement implications for resources dispatched under a market suspension.

The attached matrix of stakeholder comments discusses the positions of the parties related to each of Management's proposals.

MANAGEMENT RECOMMENDATION

Management recommends that the Board approve the various elements of the pricing policy enhancements proposed in this memorandum.

Attachment A

Stakeholder Process: Pricing Enhancements

Summary of Submitted Comments

Stakeholders submitted three rounds of written comments to the ISO on the following dates:

- Round One, 7/22/14
- Round Two, 10/10/14
- Round Three, 11/13/14

Stakeholder comments were received from: Brookfield Energy Marketing LP, California Department of Water Resources, Calpine Corporation, Morgan Stanley Capital Group, Pacific Gas & Electric Company, Powerex Corp., Six Cities, San Diego Gas and Electric, Shell Energy North America, Southern California Edison, Western Area Power Authority and Western Power Trading Forum.

Stakeholder comments are posted at: http://www.caiso.com/informed/Pages/StakeholderProcesses/PricingEnhancements.aspx

Other stakeholder efforts include:

- Stakeholder call, 7/10/14
- Stakeholder call, 10/03/14
- Stakeholder call, 11/06/14

Stakeholder	Management proposal: Administrative Pricing Rules. Use two tiers for setting administrative pricing in the real time market for non-market suspension conditions	Management response
Pacific Gas & Electric Company	Final proposal strikes an acceptable balance between price certainty and assurance of cost recovery, and flexibility for the ISO to manage the grid under adverse conditions.	During this stakeholder process, staff and stakeholders discussed and explored the advantages and disadvantages of the various alternatives to determine the administrative pricing rules. The conclusion was to pursue the tiered approach. The proposal strikes a balance between preserving price signals, providing price certainty, and practicality. The tiered approach accounts for the length of the disruption. The ISO provided further clarifications and numerical examples through the process as needed. The option of calculating an administrative price based on last available information may not work in instances where the software fails to find a solution; also, if the failure is for a long enough period of time, recreating the conditions for each market interval that failed would require multiple assumptions of conditions. The last available information may also not be representative of what the market solution and system conditions, like outages, should have been if a long period of time has passed.
Six Cities	Supports	
San Diego Gas and Electric	Supports - would like to see monitoring of methods employed to ensure best practices are implemented.	
Southern California Edison	No position - requested scenarios for the proposed tiers.	
Powerex Corp	No comments	
Morgan Stanley Capital Group	Prefers to use current logic of last available price instead of day-ahead prices.	
Western Power Trading Forum	Appreciates the firm rules specified by the ISO with respect to which prices to use during brief periods when the ISO's systems fail to produce prices.	
Brookfield Energy Marketing LP	Support a tier approach to account for length of the disruption. Suggests to calculate price on last available information; if not possible, then resorting to day-ahead prices.	
Calpine Corporation	Prefers re-calculation of prices using the best information available in absence of prices for longer than one hour.	
California Department of Water Resources	The last price is appropriate for a short period of missing prices. For longer periods suggests to have an adjustment factor based on conditions.	
Shell Energy North America	Certainty is very helpful to market participants; it may be an improvement to have a tariff based administrative price rather than the last valid price set in the market prior to intervention.	
Western Area Power Authority	No position	

Stakeholder	Management proposal: Administrative Pricing Rules. Use the day-ahead market prices for a real-time market suspension	Management response
Pacific Gas & Electric Company	Final proposal strikes an acceptable balance between price certainty and assurance of cost recovery, and flexibility for the ISO to manage the grid under adverse conditions.	Management proposes to use prices from the day-ahead market cleared for the same trade hours. This option provides various benefits. First, it is a knowable and defined price that provides certainty to the market place. Second and most importantly, use of the day-ahead prices minimizes the settlements implications since any deviation of resources between the day-ahead and the real-time markets will be neutralized, including the settlements for convergence bids. This with the use of the standard bid cost recovery mechanism to compensate for uncovered cost will provide the certainty for settling resources affected during a market suspension. The option of calculating an administrative price manually and then accounting for a premium was originally explored. Based on the nature of the event, a higher price will not always be the right price and resources may be required under some scenarios to decrease generation or shutdown. These factors will result in unintended imbalance charges that would require another mechanism to correct. Similar problems may result in using a set price.
Six Cities	Supports	
San Diego Gas and Electric	Supports - would like to see monitoring of methods employed to ensure best practices are implemented	
Southern California Edison	Requested to provide scenarios for the proposed tiers.	
Powerex Corp	No position	
Morgan Stanley Capital Group	Prefers to calculate an administrative price manually and then adding a risk and uncertainty price	
Western Power Trading Forum	Prefers to calculate an administrative price based on prevailing conditions, but if not then request to describe how resources will be compensated	
Brookfield Energy Marketing LP	Supports a tier approach to account for length of the disruption. Suggests to calculate price on last available information; if not possible, then resorting to day-ahead prices.	
Calpine Corporation	Supports administrative pricing rules with known or knowable prices as opposed to the last "good" price for "major collapses".	
California Department of Water Resources	The last price is appropriate for a short period of missing prices. For longer periods suggests to have an adjustment factor based on conditions.	
Shell Energy North America	Suggests establishing a set price	
Western Area Power Authority	No position	

Stakeholder	Management proposal: Administrative Pricing Rules. For a day-ahead market suspension use either the previous day of the day-ahead market or rely fully on the real-time market results.	Management response
Pacific Gas & Electric Company	Final proposal strikes an acceptable balance between price certainty and assurance of cost recovery, and flexibility for the ISO to manage the grid under adverse conditions.	Management proposes to use either day-ahead results for both awards and prices from the previous day, or rely fully on the results of the real-time market to operate and price the energy transactions. The ISO will make its decision to use one of these two options by 6:00 PM based on the evaluation of the actual and expected system conditions. If system conditions are not reasonably similar to the previous day, the ISO will rely on the real-time market. Management believes that having the option to choose either the previous day-ahead solution or the real-time market results does not deteriorate the certainty aimed for this process because the decision and option will be made by the time the ISO has to declare a day-ahead market suspension, in advance of the trading date. This decision will be made once all the conditions are known for this event. In the final proposal, it was clarified that the bids from the day-ahead market will also be used for the bid recovery settlement.
Six Cities	Opposes to use either/or approach; prefers the option of always using previous day of the day-ahead market.	
San Diego Gas and Electric	Supports - would like to see monitoring of methods employed to ensure best practices are implemented.	
Southern California Edison	Requested clarification of what bids would be used for bid cost recovery.	
Powerex Corp	No position	
Morgan Stanley Capital Group	No position	
Western Power Trading Forum	No position	
Brookfield Energy Marketing LP	No position	
Calpine Corporation	No position	
California Department of Water Resources	No position	
Shell Energy North America	No position	
Western Area Power Authority	No position	

Stakeholder	Management proposal: Preserve the current policy for settlements provisions related to events outside the control of market participants.	Management response
Pacific Gas & Electric Company	Supports	The settlements implications for force majeure events was considered in this stakeholder process as part of the revision for the administrative pricing rules in light of the discussion associated with the September 2011 outage. Management considered it necessary to take this opportunity to explore and clarify the settlements implications. Management proposal is to preserve the current imbalance energy settlement rules that apply under Force Majeure events but proposes to add statements in the ISO tariff that explicitly mention that force majeure does not alter the rules for settling deviations from day-ahead schedules and awards. By market principle, this existing provision provides a framework for allocating price risk between the day-ahead and real-time markets. If a participant does not deliver its day-ahead award, it has the financial obligation to pay for the uninstructed deviation. When a market participant submits bids into the day-ahead market based on its location, economic strategy and risk premium, among other factors, participants are taking on the risk and consequences of participating in the market under such settlement terms. This rationale is important to consider for the efficient economical operation of a market.
Six Cities	No comments	
San Diego Gas and Electric	No comments	
Southern California Edison	Force Majeure as defined in the ISO tariff is not for this discussion	
Powerex Corp	Opposes - proposes that intertie resources should have settlements provisions for conditions beyond the intertie resources	
Morgan Stanley Capital Group	No comments	
Western Power Trading Forum	Has no particular objection to holding all parties to day-ahead positions.	
Brookfield Energy Marketing LP	Supports to further clarify the implications as part of this stakeholder process	
Calpine Corporation	Believes that risks of delivering energy to load centers should not be eliminated by ISO market rules, and that benefits of locational marginal pricing will only be captured if ISO market rules preserve locational delivery risk	
California Department of Water Resources	Believes that there is a need for more clarity regarding the settlements associated with force majeure	
Shell Energy North America	Supports an approach in which market participants are settled out at their day-ahead schedules at day-ahead prices.	
Western Area Power Authority	No comments	

Stakeholder	Management proposal: Modify bid validation rules for bids associated with contract transmission rights	Management response
Pacific Gas & Electric Company	Supports	Clarifications were added to the revised proposal
Six Cities	Supports	
San Diego Gas and Electric	Supports	
Southern California Edison	Supports	
Powerex Corp	No comments	
Morgan Stanley Capital Group	No comments	
Western Power Trading Forum	Supports	
Brookfield Energy Marketing LP	Supports	
Calpine Corporation	No comments	
California Department of Water Resources	Supports	
Shell Energy North America	No comments	
Western Area Power Authority	No position - asked for clarifications to the description in the straw proposal round	

Stakeholder	Management proposal: Enhance the modelling of contingencies to handle compounding pricing of relaxed contingencies	Management response
Pacific Gas & Electric Company	Supports	Data related to the frequency of historical instances was provided in the revised proposal.
Six Cities	Supports	
San Diego Gas and Electric	Supports	
Southern California Edison	Supports	
Powerex Corp	No comments	
Morgan Stanley Capital Group	No comments	
Western Power Trading Forum	Is open to the ISO's exploration of modifying the pricing effects when multiple contingencies affect a single constraint.	
Brookfield Energy Marketing LP	The proposal seems to be the best solution as it will only be utilized in the event that there are insufficient economic bids to settle the contingencies. Requires to provide data of historical instances.	
Calpine Corporation	No comments	
California Department of Water Resources	Requested more information about historical instances, details of the proposal and examples	
Shell Energy North America	No comments	
Western Area Power Authority	No comments	

Stakeholder	Management proposal: Enhance the market modelling of constraints to ensure uniqueness of prices related constraints	Management response
Pacific Gas & Electric Company	Supports	The revised proposal included more details of the proposal as well as examples.
Six Cities	No position	
San Diego Gas and Electric	Supports	
Southern California Edison	Does not oppose	
Powerex Corp	No position	
Morgan Stanley Capital Group	No position	
Western Power Trading Forum	Strongly supports - encourages the ISO to publish further information about its proposed methods.	
Brookfield Energy Marketing LP	Supports the ISO's further evaluation of solutions to address multiplicity of prices. Requires examples to better understand.	
Calpine Corporation	No position	
California Department of Water Resources	Supports	
Shell Energy North America	No position	
Western Area Power Authority	No position - asked for more details and examples.	

Attachment E – Mathematical Description of Existing Pricing Formulation

and Enhanced Pricing Formulation

Tariff Amendment to Implement Pricing Enhancements

California Independent System Operator Corporation

June 6, 2016

Attachment E

The CAISO and its vendor developed an alternative for effectively addressing such degenerate cases that relies on modifications to the mathematical structure of the linear programming security constrained economic dispatch currently used in the CAISO markets to ensure convexity of the objective function and uniqueness of prices. This existing structure can be described in detailed mathematical terms as follows:

$$\begin{aligned} &\min \quad \sum_{j} c_i(x_i) \\ &s.t. \quad \sum_{i} x_i = d && (\lambda) \\ &\qquad \sum_{j} a_{kj} x_j \le b_k, \quad \forall k && (\mu_k) \\ &\qquad 0 \le x_i \le \bar{x}_i, \quad \forall i && (\bar{\pi}_i) \end{aligned} \tag{4}$$

This linear programming problem stands for the minimization of bid-in cost for supply subject to a power balance constraint, transmission limits, and supply limits, respectively. Supply is defined with variables x_i and upper limits $\bar{x}_i$; parameter *d* stands for demand, parameter a_{kj} stands for the shift factor associated with transmission constraint *k* and location *j*; transmission limit for constraint *k* is defined with parameter b_k ; the variables in brackets on the right-hand side of each constraint are their associated dual variables. In the current CAISO market software formulation, this standard problem is expanded for the scheduling run to account for potential relaxation of transmission constraints by introducing a slack variable s_k^s to each transmission constraint and then appending these slack variables into the objective function which yields the following linear programming problem:

$$\begin{aligned} &\min \quad \sum_{j} c_i(x_i) + \sum_{k} \delta_k^s s_k^s \\ &s.t. \quad \sum_{i} x_i = d && (\lambda) \\ &\qquad \sum_{j} a_{kj} x_j - s_k^s \le b_k, \quad \forall k && (\mu_k) \\ &\qquad 0 \le x_i \le \bar{x}_i, \quad \forall i && (\bar{\pi}_i) \\ &\qquad s_k^s \ge 0, \quad \forall k \end{aligned} \tag{5}$$

The slack variables are penalized in the objective cost function with the corresponding constraint parameter prices as defined in the business practice manual for market operations.

Similarly, in the pricing run the problem is expanded to account for any potential relaxation that took place in the scheduling run:

$$
\begin{aligned}
\min \quad & \sum_j c_i(x_i) + \sum_k \left(\delta_k^p s_k^s + \delta_k^p s_k^p \right) \\
s.t. \quad & \sum_i x_i = d & & (\lambda) \\
& \sum_j a_{kj} x_j - s_k^s - s_k^p \le b_k, & \forall k \quad & (\mu_k) \\
& 0 \le x_i \le \overline{x}_i, & \forall i \quad & (\overline{\pi}_i) \\
& 0 \le s_k^s \le \hat{s}_k^s, & \forall k & \\
& 0 \le s_k^p \le \varepsilon^l, & \forall k &
\end{aligned} \tag{6}
$$

In this formulation, $\hat{s}_k^s$ is the amount of relaxation determined in the scheduling run for transmission constraint *k* that now serves as an upper bound to the first-segment slack variable in the pricing run. The pricing run uses a second-segment slack variable s_k^p, which is limited by an epsilon amount ε^l. The cost of moving these slack variables to regain feasibility in the system by relaxing the transmission constraint is defined by the corresponding penalty prices currently used in the CAISO markets system.

The CAISO's proposed formulation expands the current formulation with another slack variable with an associated weight ω^q. The linear transmission constraints are expanded with a penalized slack variable while a quadratic penalized term is added to the objective cost. With these modifications, the traditional security constraint economic dispatch is transformed from a linear programming problem into a quadratic (convex) programming problem. The problem is strictly convex and separable with respect to the slack variable and, therefore, it can guarantee the uniqueness of prices. In addition, the resulting prices are continuous functions of the problem parameters. Thus, small changes in the problem parameters, such as the constraint limits, will only result in smooth changes in prices. This alternate formulation addresses the multiplicity of shadow prices and eliminates the potential steep changes in prices when there are small changes in the requirements or conditions.

The additional slack variable introduced in the formulation will compete with the existing slacks s_k^s, s_k^p to fulfill the relaxation required. The slack variables s_k^s, s_k^p contribute linearly to the relaxation of the constraint limit, but their impact on the objective cost function also grows at a constant rate as defined by the penalty price for transmission relaxation. Additionally, with a weight ω^q associated with the slack variable, the growth of new slack variable's contribution to the objective cost function is also limited even if its increase is quadratic. If the weight is relatively large, the slack variable effect will be cheaper to use than the slack variables for the linear terms priced at the high penalty price, and the optimization will lean more on that slack for small relaxations. This outcome, however, will result in the slack variable for the quadratic term setting the price potentially at prices that will not reflect the conditions of constraint relaxation. In order to preserve the price signal of constraint relaxations, the weight needs to be sufficiently small. This interplay was identified and discussed during the stakeholder process. The CAISO has done preliminary testing of this proposal pricing mechanism and has found that a weight small enough in the order of 1.E-5 preserves the pricing that reflects the conditions of constraint relaxations.[1]

[1] The CAISO intends to set this weight to this amount when this change goes into effect and will include this parameter in the business practice manual for market operations. This parameter may need to be adjusted over time as conditions change and the CAISO observes its performance in the market. While this parameter setting is necessary to ensure the pricing order is maintained, its value does not set the price specifically. Therefore, it is appropriate to maintain this parameter in the business practice manual. Amendments to the business practice manual normally require sixty days' notice and vetting with stakeholders. This amendment process will provide the necessary notice to market participants should the CAISO determine it is necessary to amend the parameter.

Attachment F – List of Key Dates in the Stakeholder Process

Tariff Amendment to Implement Pricing Enhancements

California Independent System Operator Corporation

June 6, 2016

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

Date	Event/Due Date
July 1, 2014	CAISO issues paper entitled “Pricing Enhancements – Issue Paper and Straw Proposal”
July 10, 2014	CAISO hosts stakeholder conference call that includes discussion of paper issued on July 1 and presentation entitled “Pricing Enhancements – Issue Paper and Straw Proposal”
July 22, 2014	Due date for written stakeholder comments on paper issued on July 1
September 26, 2014	CAISO issues paper entitled “Pricing Enhancements – Revised Straw Proposal”
October 3, 2014	CAISO hosts stakeholder conference call that includes discussion of paper issued on September 26, stakeholder comment matrix, and presentation entitled “Pricing Enhancements – Revised Straw Proposal”
October 10, 2014	Due date for written stakeholder comments on paper issued on September 26
October 30, 2014	CAISO issues paper entitled “Pricing Enhancements – Final Proposal”
November 6, 2014	CAISO hosts stakeholder conference call that includes discussion of paper issued on October 30, stakeholder comment matrix, and presentation entitled “Pricing Enhancements – Final Proposal”
November 13, 2014	Due date for written stakeholder comments on paper issued on October 30
July 6, 2015	CAISO issues draft tariff revisions to implement pricing enhancements
July 20, 2015	Due date for written stakeholder comments on draft tariff revisions issued on July 6
July 24, 2015	CAISO hosts stakeholder conference call that includes discussion of draft tariff revisions issued on July 6