Pricing Enhancements

Final Proposal

October 30, 2014

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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?

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[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

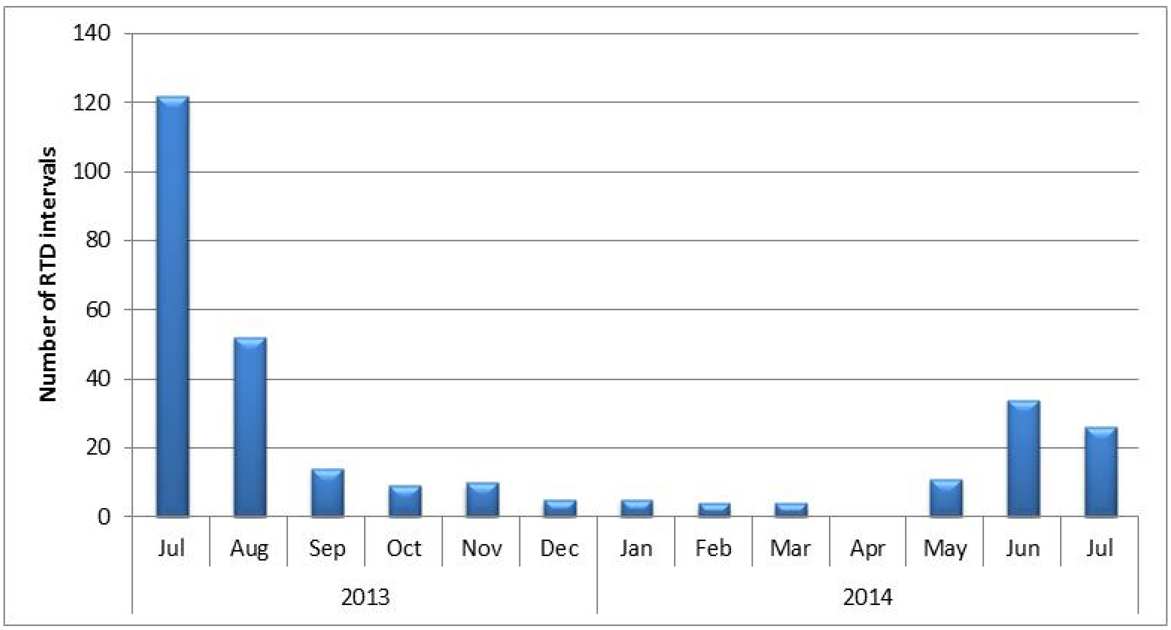
The ISO market systems contain a number of transmission constraints that are enforced in the through the formulation of its security constraint dispatch for both the base and contingency cases. The market system makes use of a series of pricing parameters that when they are binding indicate the cost 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:

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

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

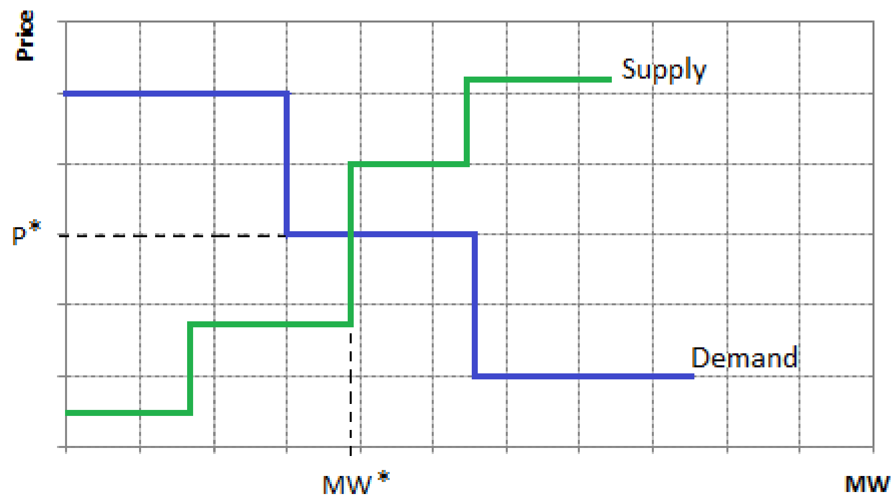
6.1 Issue

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.

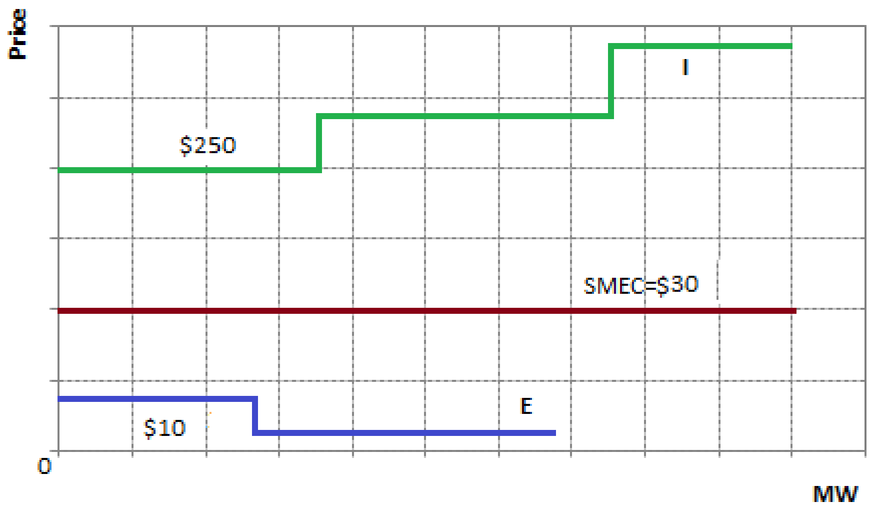
The security constrained economic dispatch is an optimization problem of maximizing the benefits defined by sum of demand bids costs minus the cost of supply offers subject to a number of operational, system and transmission constraints. Mathematically the optimization takes the form of a linear programming 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.

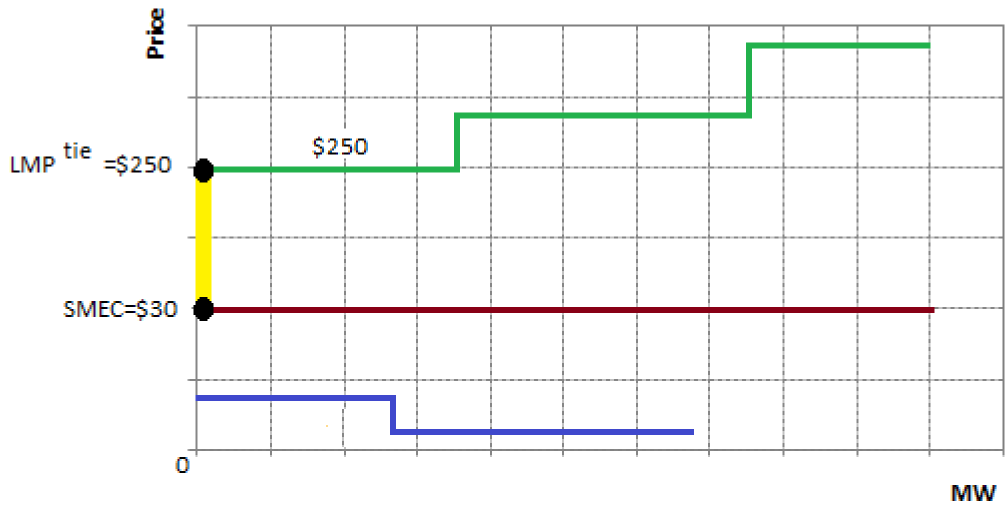
Figure 3: **Bid stack for imports and export for an intertie with to 0 MW in the export direction**



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:

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

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:

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

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.

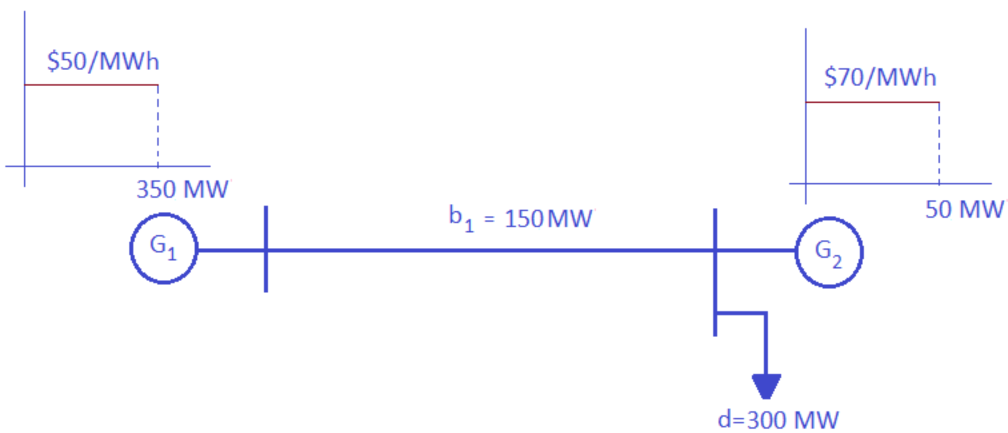
$$
\begin{aligned}
\min \quad & \sum_j c_i(x_i) + \sum_k \left(\delta_k^p s_k^s + \delta_k^p s_k^p \right) \\
s.t. \quad & \sum_i x_i = d & & (\lambda) \\
& \sum_j a_{kj} x_j - s_k^s - s_k^p \le b_k, \quad \forall k & & (\mu_k) \\
& 0 \le x_i \le \overline{x}_i, \qquad \forall i & & (\overline{\pi}_i)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

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

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

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

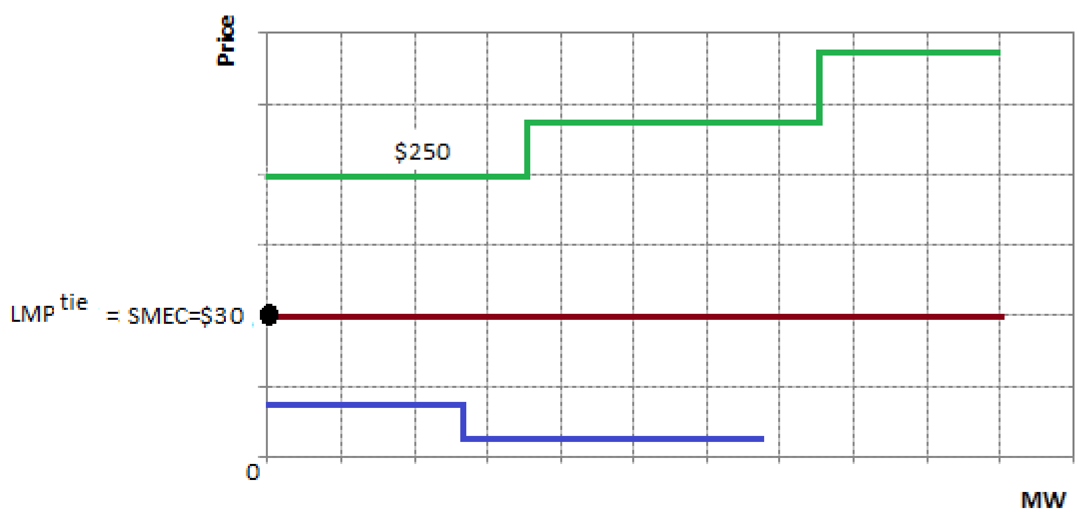
In the first two cases where the weight is set to a large value, the relaxation relies on the slack variable of the quadratic term and also defines prices that do not reflect the relaxation condition. Only in the cases with the weight set to a value of 0.1 or lower the shadow price and LMPs reflect the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

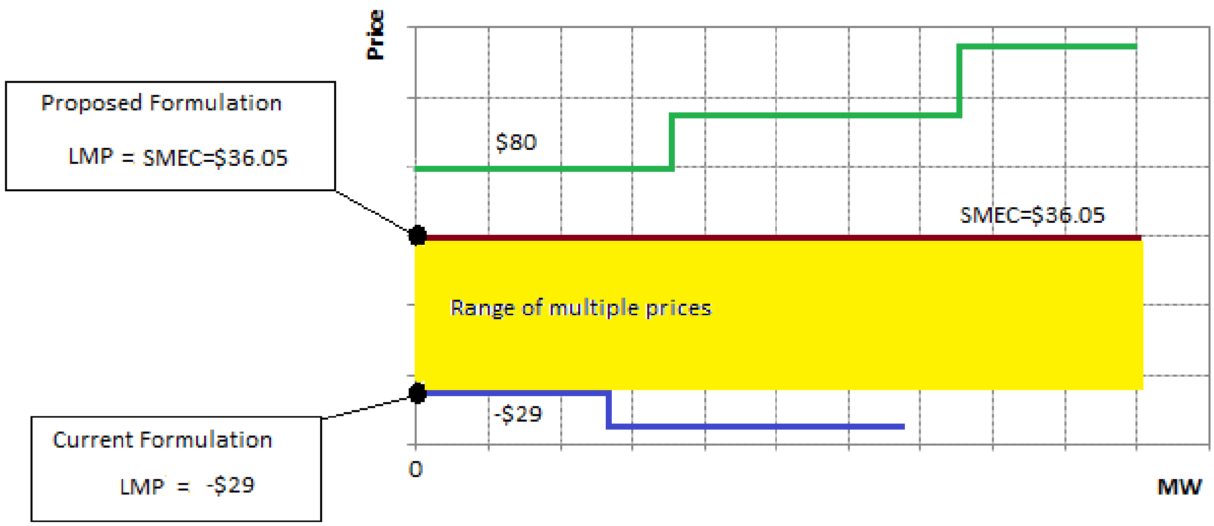
Figure 5: Market solution at the intertie with alternate pricing



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