California ISO

Bidding Rules Enhancements

Revised Straw Proposal.v2 (*replaces November 23, 2015 proposal*)

December 3, 2015

Table of Contents

1. Executive summary

This stakeholder process combines consideration of energy and commitment cost bidding rules to refine and improve alignment between these rules. This initiative will review the rules for energy and commitment cost bidding flexibility and resource characteristics definitions. This initiative will balance the benefits of allowing market participants to reflect actual costs through increased bid flexibility against the increased potential for inefficient market outcomes by inappropriately changed bid prices – for example, when the market cannot incorporate a changed bid because a resource cannot respond due to an inter-temporal constraint.

The initiative will explore commitment costs and their bidding rules. In the *Commitment Costs Enhancements* (CCE) initiative, the ISO implemented tariff changes that:

1. Allow the ISO, in the event of a significant price spike, to execute and settle the market using a gas price published on the morning of the day-ahead market run rather than the prior evening's calculated gas price index.

2. Increase the existing proxy cost bid cap from 100 percent of the resource's calculated proxy cost to 125 percent.

3. Eliminate the registered cost option for all resources except use-limited resources.

The Federal Energy Regulatory Commission's (FERC's) December 2014 decision approving the filing for *Commitment Cost Enhancements'* proposals provided guidance to the ISO on its efforts to improve cost recovery for gas-fired resources as expressed below:

> *"While we agree with CAISO that the current proposal represents an immediate improvement that can be implemented in time to provide generators a better opportunity to recover their costs during periods of natural gas price volatility that may occur during the 2014-2015 winter season, we expect CAISO to abide by its commitment to consider* ***longer-term market design changes*** *for commitment cost bids in conjunction with the bidding rules enhancements stakeholder initiative commenced earlier this month.[1]"*

This initiative is revisiting commitment costs for gas-fired resources to address through long-term market design changes the ability to allow for commitment cost caps, and thus commitment cost bids, to provide sufficient cost recovery.

[1] See FERC Order, CCE available at: http://www.caiso.com/Documents/Dec302014_OrderAcceptingCommitmentCostEnhancementsTariffRevision_ER15-15-001.pdf.

Table 1 contains a summary of the revised straw proposal discussed in the remainder of the paper.

Table 1: Summary of Proposals

Section	Issue	Proposal	Change type
5.1.1	FERC order 809	Not move the day-ahead market to be earlier	Section 206 filing
6.2	Differentiated bidding headroom	Retain 125% proxy cost cap	Tariff
6.3	Commitment cost mitigation	Retain 125% proxy cost cap	None
7.1.1	Changing bids after a commitment decision during an inter-temporal constraint	Monitor or limit bidding flexibility	Tariff
7.1.2	Changing bids after a commitment decision without inter-temporal constraints	Continue monitoring or limit bidding flexibility	Tariff
7.2.1	Inefficient accounting for minimum load costs after a Pmin rerate	Calculate actual commitment costs based on the resource's default energy bid (DEB).	Tariff
7.2.2	Resources without a day-ahead schedule cannot rebid commitment costs.	Allow resources without a day-ahead schedule to rebid commitment costs in the real-time market.	Tariff
7.2.3	The ISO market inserts day-ahead market bids into STUC for resources that are not resource adequacy resources that are not scheduled in the day-ahead market and do not resubmit bids into the real-time market.	No longer generate bids for STUC for non-resource adequacy resources that do not have a day-ahead market award and do not resubmit bids into the real-time market.	Tariff
8.1.1.1 & 8.1.1.2	Gas price index may not reflect real-time gas purchase costs	Routinely use earliest published index for the day-ahead market, move day-ahead market timing to 11 am to 2 pm, and allow for consideration of real-time gas purchases above the gas price index.	Tariff
8.1.1.3	Gas price index may not reflect gas transportation costs	Increase the flexibility of registering fuel regions and allow for cap-and-trade credits to the base gas transportation rates for resources with GHG compliance costs within these fuel regions.	Tariff

8.1.2	Electricity price index may not reflect start-up energy costs	Change the electricity price index calculation consistent with the registered cost option to represent a projected electricity price during unit start-up or cost of auxiliary power provided by the generator based on a unit with a heat rate of 10,000 Btu/KWh.	Tariff
9.1	Proposal for resource characteristics	Allow for “market” resource characteristics in addition to physical characteristics	Tariff

2. Changes from straw proposal

Section 1 provides a summary of the revised proposals and the type of change it represents, if any.

Section 3 addresses stakeholder requests and comments on the ISO’s proposals.

Section 4 updates the plan for the *Bidding Rules Enhancements* initiative’s stakeholder engagement, aiming for the March 2016 Board meeting, except for the proposal outlined in Section 7.2.1, which will go to the February 2016 Board Meeting.

Section 5 provides background information helpful in developing this proposal including the the ISO’s FERC filing requesting not to move its day-ahead market run time window earlier (Section 5.1.1), discussion about the ISO’s short-term unit commitment (Section 5.1.2), the ISO’s survey of other ISO’s bidding rules (Section 5.1.3), proxy cost calculations used by the ISO for its commitment cost caps (Section 5.1.4), and discussion of changes to southern California’s gas penalty structure (Section 5.1.5).

Section 6 explores the ISO’s market power mitigation of its commitment costs. This section revises the ISO’s proposal from differentiated bidding headroom for the various commitment cost components to retain the current 125 percent cap on all components. Under this initiative, the ISO found various reasons a scheduling coordinator would legitimately use the 125 percent headroom to manage various risks. The ISO proposes to retain its current commitment cost market power mitigation structure that uses a commitment cost cap.

Section 7 explores the ISO’s bidding flexibility rules for both energy and commitment cost bids. As to energy bidding flexibility, Section 7.1.1 and 7.1.2 have been revised to consider two potential options for energy bidding rules: (1) monitor for inefficient behavior and consider resources significantly changing bid prices after market commitments to be potentially engaging in market manipulation or (2) introduce restrictions on the price differences of energy bids. The ISO proposes three improvements to commitment cost flexibility: (1) Section 7.2.1 proposes resolving the inefficient accounting of minimum load costs after a Pmin rerate by calculating the actual commitment costs based on the Default Energy Bid (DEB) associated with the capacity range between the Master File (MF) Pmin and the re-rated Pmin where the incremental DEB costs are added to the bid-in minimum load costs at the re-rated Pmin level, (2) Section 7.2.2 proposes allowing resources that did not receive a day-ahead award to rebid their commitment costs for the real-time market, and (3) Section 7.2.3 proposes no longer generating bids in STUC for non-resource adequacy resources.

Section 8 explores and proposes three improvements to commitment cost calculations: (1) Section 8.1.1.1 proposes improving the alignment of gas commodity prices to the electric day to better reflect natural gas price volatility in the ISO's commitment costs, (2) Section 8.1.1.2 provides for after-the-fact recovery of actual costs, (3) Section 8.1.1.3 continues the greenhouse gas discussion and adopts a proposed change suggested by a stakeholder to adjust the gas transportation adders allowing for more flexibility in selecting gas fuel regions in the Master File to better reflect actual transportation costs, and (4) Section 8.1.2 improves the electricity price index calculation to be consistent with the methodology used under the registered cost option.

Section 9.1 presents a proposal for introducing "market" characteristics for a subset of resource characteristics that will be used in the ISO market for normal operations. At minimum, these characteristics must support any resource adequacy showings and therefore adjust with changes to the resource specific resource adequacy showings but be able to reflect economic judgement outside of design capabilities.

3. Stakeholder comments

The following three sections address specific stakeholder requests that influenced the development of this proposal. A detailed description of all stakeholder comments and ISO responses are included in Appendix C.

3.1. Requests for periodic review of commitment costs

A stakeholder requested the ISO conduct periodic review of commitment costs. In addition to this initiative, the ISO is currently conducting the third in a series of stakeholder initiatives to address commitment costs. Each initiative has been intended to be an incremental improvement and therefore provided an opportunity for stakeholders to review cumulative changes. For this reason the requested periodic review of commitment costs is outside the scope of the bidding rules initiative.

Another stakeholder requested the ISO should reflect cold, hot, and warm starts in proxy costs calculation. The ISO clarifies that this already occurs for the proxy start-up calculation. The ISO is open to considering any additional suggested modeling improvements.

3.2. Requests to consider additional costs as marginal

Other stakeholders have requested the ISO consider additional cost inputs as marginal costs such as natural gas pooling arrangement costs, imbalance penalties, or risk premiums to cover the cost of selling natural gas at a loss when a resource procures gas and then is not dispatched by the CAISO. The ISO does not agree all of these costs reflect short-run marginal costs therefore finds that it would be inappropriate to include them in its proxy cost calculations. The ISO reiterates that fuel costs included in the ISO markets should reflect marginal costs related to variable operation of the resource such as commodity fuel costs and electricity costs for auxiliary power. Instead, the ISO views these costs that are not short-run marginal costs as capacity-related costs that are not compensated through the ISO's energy markets as explained below in recent comments:

> *Resources critical to the reliability in the CAISO's system receive compensation for capacity obligations under resource adequacy provisions. These capacity obligations include fuel costs associated with the resources' obligations to ensure they have fuel and are available to the market as required by resource adequacy obligations. The CAISO believes, if it were to provide reimbursement for fuel costs above the bid cap, these costs should only include incremental fuel costs supporting the resource's offer as opposed to other costs related to a resource's capacity obligation such as natural gas pooling arrangement costs, imbalance penalties, or risk premiums to cover the cost of selling natural gas at a loss when a resource procures gas and then is not dispatched by the CAISO. The CAISO believes these costs are more appropriately recovered through compensation the resource receives for providing capacity as a resource adequacy resource as opposed to through the CAISO's energy markets.*[2]

Of these costs, stakeholders requested the ISO to consider reimbursement for gas procured to operate a resource in cases where the resource was exceptionally dispatched off. Additionally, the ISO sought feedback on how to account for the net cost of the gas purchase if any amount was sold. As discussed more below, the ISO has reconsidered its view that risk premium is not a short-run marginal cost but it does not believe this warrants changes to commitment cost bid caps. The CalPeak Affiliates (CalPeak) and Six Cities provided comments in response to this request. Both stakeholders support recovery of the "net cost of the gas purchase," i.e. the difference between what the generator paid for the natural gas it purchased to run and what the gas was worth immediately after it was exceptionally dispatched off.

The ISO has further explored how other ISOs and RTOs have treated this risk to develop a market design feature allowing for this type of cost recovery.

NYISO's reference level calculation, which is similar to the ISO's proxy cost calculations, allows for inclusion of risk premium costs. The reference cost subcategory called "Risk Premium" is not a measure of the cost to generators of volatility in incremental costs. Rather, it reflects the NYISO's expectation of the average level of an incremental net cost (other than variable operating and maintenance costs) that occurs infrequently, at irregular intervals, and whose extent may vary, on the occasions when the cost does occur. For many generators, no such

[2] Comments of the California Independent System Operator Corporation on Technical Workshops, Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. AD14-14, pp 5-6.

reference risk premium is applicable. However, a risk premium might be appropriate to reflect infrequent situations such as cash-out risk.

NYISO defines cash-out risk in a draft version of its reference level manual as the expected incremental loss from selling back unused gas at a price below its purchase cost when DAM commitments are reduced in real-time. As explained in its manual, “The risk premium would need to incorporate the frequency and typical size of NYISO reductions in RT schedules relative to DAM schedules.”[3]

After considering further, the ISO agrees this is a short-run marginal cost because the amount of risk increases as a resource has more energy scheduled in the market. However, in evaluating a need for a risk premium against the ISO’s market design, the ISO does not see a need to change the proxy cost cap to account for the premium. The ISO’s commitment cost cap at 125 percent of its proxy cost calculation allows for headroom above its cost estimates for SCs to manage price risks such as cash-out risk. An appropriate use of this headroom would be to facilitate this cost recovery. The ISO proposes to not include a risk premium adder to the commitment cost calculations as the cap allows for sufficient flexibility to manage such risks.

3.3. Requests to consider improvements to GPI

Another stakeholder requested a breakup of the current three-day weekend gas “package.” While the ISO does not disagree with this in concept, the ISO has also received feedback that such products for the weekend days or holidays are thinly traded and no indices are available for this trading. The ISO has concerns that calculating maximum proxy costs for commitment costs using a measure of spot price other than an index would undermine the integrity of the proxy due to its illiquidity and lack of oversight.

The ISO finds providing a 25 percent headroom on top of the natural gas day-ahead index provides sufficient opportunity for cost recovery by gas-fired resources. The ISO can continue to monitor this situation but does not propose any change to the treatment of weekend package indices at the moment.

4. Plan for stakeholder engagement

The proposed schedule for the policy stakeholder process is below.

Date	Event
December 3, 2014	Issue paper posted
December 10, 2014	Stakeholder call
December 30, 2014	Stakeholder comments due

[3] See NYISO’s Draft Reference Level Manual available at: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-06-09/agenda%206%20M-34_Reference%20Level_6_2_15%20redline%20against%20currently%20effective%20manual.pdf.

April 22, 2015	Straw proposal posted
April 29, 2015	Stakeholder meeting
May 13, 2015	Stakeholder comments due
November 23, 2015	Revised straw proposal posted
December 03, 2015	Stakeholder meeting
December 17, 2015	Stakeholder comments due
January 05, 2016	Draft final proposal posted on Section 7.2.1
January 12, 2016	Stakeholder call on Section 7.2.1
January 19, 2016	Comments due on Section 7.2.1
February 03, 2016	Board of Governors Meeting for Section 7.2.1
February 04, 2016	
February 15, 2016	Draft final proposal posted
February 22, 2016	Stakeholder call
March 02, 2016	Stakeholder comments due
March 24, 2016	Board of Governors Meeting
March 25, 2016	

5. Background

In its exploration of potential changes to its bidding flexibility rules, the ISO researched four areas either to be leveraged through these proposals or market rules and operations impacting the feasibility of the ISO's proposals.

As discussed in Section 5.1.1, the ISO's proposals assume its filing under EL14-22 requesting FERC approve the ISO's proposal to not change its day-ahead market window is approved.

In Section 5.1.2, the ISO provides important background on its Short-term Unit Commitment (STUC) process essential to understanding the ISO's proposals discussed in Section 7.1 and Section 7.2.

In Section 5.1.3, the ISO reviews its analysis of its survey of bidding flexibility rules across selected ISOs and RTOs. The tables found in the Straw Proposal have been moved to Appendix A and Appendix B.

Section 5.1.4 provides information on the ISO's proxy cost calculations and its inputs referenced in the ISO's proposals in Section 8.

Finally, the ISO assumes the California Public Utilities Commission (CPUC) accepts Southern California Gas Company's and San Diego Gas & Electric's (SDG&E's) proposal to implement low operational flow order and emergency flow order requirements, discussed in Section 5.1.5, and will continue to follow the potential impacts of these changing regulations.

5.1.1. FERC order 809

FERC released a final order on April 16, 2015 (Order 809, RM14-2) establishing new times for scheduling practices used by the interstate pipelines to schedule natural gas transportation.[4] Table 2 below compares the current (black font) and revised or additional (red bolded font) nomination timelines in Central Clock Time (CCT). These changes will take effect on April 1, 2016.

Table 2: Current and FERC Order 809 gas nomination deadlines (CCT)

Nomination Cycle	Nomination Deadline (CCT)	Notification of Schedule (CCT)	Nomination Effective (CCT)	Bumping of interruptible transportation
Timely	11:30 a.m. **1:00 p.m.**	4:30 p.m. **5:00 p.m.**	9:00 a.m. Next Day	N/A
Evening	6:00 p.m.	10:00 p.m. **9:00 p.m.**	9:00 a.m. Next Day	Yes **Yes**
Intra-day 1	10:00 a.m.	2:00 p.m. **1:00 p.m.**	5:00 p.m. Current Day **2:00 p.m. effective**	Yes **Yes**
Intra-day 2	5:00 p.m. **2:30 p.m.**	9:00 p.m. **5:30 p.m.**	9:00 p.m. Current Day **6 p.m. effective**	No **Yes**
Intra-day 3	**7:00 p.m.**	**10:00 p.m.**	**10:00 p.m. effective**	**No**

The ISO provided an update to stakeholders on the impacts of FERC No. 809 on June 19, 2015.[5] The ISO did not discover sufficient benefits to gas-fired generators to justify costs of moving the day-ahead market run time window to earlier in the day. In a stakeholder process the ISO considered three alternatives and found Alternative 2, to not move the day-ahead market window, to be the most effective design for the California ISO market.[6]

In addition to the order, FERC issued a companion section 206 proceeding requiring ISOs and RTOs to propose changes to their electric market scheduling timelines, or to demonstrate why changes are not necessary after adoption of the final rule in RM14-2. The filing was due 90 days from April 16, 2015. The ISO filed its response to FERC's 206 proceeding in EL14-22 asking the Commission to find the ISO did not need to move the timing of its current day-ahead close and publication of market results forward.[7] This was based on the grounds that obtaining gas scheduling on the pipelines serving California generators is not a problem and it is sufficient to

[4] Federal Energy Regulatory Commission, Docket No. RM14-2-000; Order No. 809, April 16, 2015.
[5] See Proposal – FERC Order No. 809 available at:
http://www.caiso.com/Documents/Proposal_FERCOrderNo809.pdf.
[6] See Straw Proposal at 15 available at:
http://www.caiso.com/Documents/StrawProposal_BiddingRulesEnhancements.pdf
[7] See EL14-22 Filing, July 23, 2015 at 15 available at:
http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13939292

know electric dispatch obligations at the time of the day-ahead evening nomination cycle. The ISO's proposal to not change the day-ahead market window is still pending before FERC. For this stakeholder initiative, the ISO assumes its proposal is approved by FERC and the DAM window remains 10 AM to 1 PM PST.

5.1.2. Short-term unit commitment

The ISO market's short-term unit commitment (STUC) process is a reliability function for committing short and medium start units to meet the CAISO real-time demand forecast. The STUC function is performed hourly and looks ahead three hours beyond the current trading hour, at 15-minute intervals beginning with the third fifteen-minute interval of the hour prior to the current trading hour. STUC uses day-ahead market commitment cost bids for all resources with day-ahead market bids and will use the most recently submitted incremental energy bid price submitted. As described in Section 7.2.3, the ISO proposes to no longer insert bids into STUC for non-resource adequacy resources that bid into the day-ahead market, did not receive a day-ahead market schedule, and do not resubmit bids into the real-time market.

STUC cannot accept minimum load or start-up costs that differ across its time intervals. Medium start units with start-up times between two and five hours can receive commitment instructions from the STUC function but not from the real-time unit commitment process (RTUC) as their start-up time extends beyond RTUC's horizon.[8]

5.1.3. ISOs Bidding Flexibility Survey

The ISO surveyed various ISOs' bidding rules for start-up, minimum load, and incremental energy offers. This section will discuss the ISO's findings from its survey found in Appendix A and Appendix B that compare real-time market energy bidding rules and commitment cost bidding rules respectively.

As seen in Appendix A, CAISO's energy bidding rules are very flexible and allow for changes to energy bids regardless of whether there are existing day-ahead schedules. Energy bids submitted to the real-time market can be different than day-ahead market bids and can vary between hours in both the day-ahead and real-time markets. This is in line with ISO New England and MISO. NYISO and PJM have rules that largely limit market participants' ability to change between day-ahead and real-time to account for higher bid costs and/or when there is no corresponding day-ahead schedule. PJM is proposing to allow for changes to each generator's fuel cost calculation methodology.

In CAISO, as seen in Appendix B, a resource that provides a commitment cost (minimum load or start-up) bid in the day-ahead must use the same commitment cost bids in the real-time market,

[8] A start-up instruction produced by STUC is considered binding if the resource could not achieve the target start-up time (as determined in the current STUC run) in a subsequent RTUC run as a result of the start-up time of the resource.

regardless of whether or not it receives a day-ahead commitment. If the resource is not bid into the day-ahead market, the scheduling coordinator can bid commitment costs in the real-time market. Under either scenario the commitment costs are capped at 125 percent of the calculated proxy cost under the proxy cost methodology for all resources.[9] For use-limited resources only, until the ISO can calculate opportunity costs, the cap is set to 150 percent of the calculated proxy cost under the registered cost methodology.[10]

NYISO and PJM are similar to the CAISO in that commitment costs are largely provided in the day-ahead timeframe. They differ from CAISO in allowing resources without a day-ahead schedule to rebid commitment costs in the real-time market. NYISO explains its rationale for not allowing full bidding flexibility for commitment costs as generally a reliability concern. NYISO notes that "for system reliability, the NYISO needs to be able to rely on the Day-Ahead commitment of Generators sufficient to serve expected real-time Load. Maintaining the Minimum Generation and Start-up Bids for Day-Ahead scheduled Generators allows the NYISO to rely on them for incremental Energy, should the need arise."[11] However, NYISO allows real-time updates to fuel prices used in the reference levels—the levels to which a resource is mitigated when it tests positive for market power. PJM is considering a similar allowance to account for intra-day gas volatility.

MISO and ISO-NE allow bidding flexibility up until 30 minutes before the operating hour. ISO-NE explains that it requires this level of flexibility because it has experienced significant reliability degradation from gas supply constraints causing generators to not respond to dispatch. For example, ISO-NE found that "an examination, conducted in early 2012, of dispatch response performance following the 36 largest system contingency events over the last three years indicates that, on average, the response rate for New England's non-hydro generating resources was less than 60 percent of the amount requested during the events."[12]

5.1.4. Proxy Cost Calculations

Current ISO process for calculating the maximum proxy cost for start-up and minimum load cost uses a combination of cost inputs from either (1) market price publications (index prices) or (2) resource-specific registered values in the Master File. Equation 1 and Equation 2 show the proxy cost formulas used and Table 3 defines and categorizes the inputs by source as either an index price or a Master File value.[13]

Equation 1: Proxy Start-Up Costs

[9] Assumes proposals under *Commitment Cost Enhancements Phase 1* are approved by FERC.
[10] *Ibid*.
[11] NYISO, FERC docket no. ER10-1977, July 26, 2010, p. 4.
[12] ISO-NE, FERC docket no. ER13-1877, transmittal letter, July 1, 2013, p. 3.
[13] Market Instruments BPM.

Start-up Cost

$$= \begin{cases} \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder}, & GHG_{COMPLIANCE} =' N' and\ MMA = 0 \\ \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost}, & GHG_{COMPLIANCE} =' Y' and\ MMA = 0 \\ \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost} + MMA, & GHG_{COMPLIANCE} =' Y' and\ MMA \neq 0 \end{cases}$$

Where:

Start-up Fuel Cost $= STRT\_STARTUP\_FUEL * GPI$
Start-up Energy Cost $= STRT\_STARTUP\_AUX * EPI$
GMC Adder = $Pmin$ * $(STARTUP\_RAMP\_TIME/60min) * \frac{GMC}{2}$
GHG Cost = $STRT\_STARTUP\_FUEL$* Emissions Rate * GHG Allowance Rate

Equation 2: Proxy Minimum Load Costs

Minimum Load Cost

$$= \begin{cases} \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder}, & GHG_{COMPLIANCE} =' N' and\ MMA = 0 \\ \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost}, & GHG_{COMPLIANCE} =' Y' and\ MMA = 0 \\ \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost} + MMA, & GHG_{COMPLIANCE} =' Y' and\ MMA \neq 0 \end{cases}$$

Where:

Minimum Load Fuel Cost $= Unit\ Conversion *$ Heat_Rate $* Pmin * GPI$
$\text{VOM} = \text{VOM} * \text{Pmin}$
GMC Adder = $Pmin$ * GMC
GHG Cost = $Unit\ Conversion *$ Heat_Rate $* Pmin$ * Emissions Rate * GHG Allowance Rate

Table 3: Proxy Cost Inputs

Value Source	Value	Description
Index Price	GPI_{DAILY}	The average of index prices for the prior day-ahead index representing the market price for gas flowing on the day prior to the ISO's operating day.
Index Price	$GHG\ Allowance\ Rate$	The average of index prices based on at least two index publications either expressed as a based on futures or forward prices corresponding to December delivery or if publication provides range of prices, the volume-weighted average price for GHG price associated with DAM and RTM.
Index Price	EPI	Resource-specific daily electricity price as the maximum of a retail rate aligned to the registered fuel region and an estimated wholesale rate measured in \$/MW.
Master File	$STRT\_STARTUP\_AUX$	The Master File value for the electrical power used by a Generating Unit during startup. The Generating Unit's startup auxiliary power (in MWh) from the down time (i) to down time (i + 1).

Master File	$STARTUP\_RAMP\_TIME$	The Master File value in minutes representing the time it takes to physically ramp from zero to pmin.
Master File	$STRT\_STARTUP\_FUEL$	The Master File value for the fuel use (in mmBTU per start) expected for the startup of a natural gas fired Generating Unit that has been off-line for a substantial period of time. The startup fuel of the Generating Unit (in mmBTU) from the down time (i) to down time (i + 1).
Master File	$Pmin$	The Master File value for the minimum sustained operating level (Pmin) at which a given configuration can operate at a continuous level.
Master File	$HEAT\_RATE$	The Master File value for the minimum load heat rate which is the emission rate of the configuration on point 1 of its heat rate MW output point at point 1, PMIN, expressed in Btu/KWh.
Master File	$GHG_{COMPLIANCE}$	The Master File value for an indicator of a resource that has a Green House Gas compliance obligation and is, therefore, eligible to recover Green House Gas allowance costs.
Master File	$Emissions\ Rate$	The Master File value for Green House Gas (GHG) emission in $mtCO_2e$/MMBtu.
Master File	MMA	The Master File value for a configuration-specific lump-sum adder value per start-up for major maintenance, if applicable.
Administrative Fee	GMC	Grid Management Charge (GMC) comprised of CAISO Operating Costs, CAISO Other Costs and Revenues, CAISO Financial Costs, CAISO Operating Reserve Credit, and CAISO Out-of-Pocket Capital and Project Costs as a lump-sum adder.
Administrative Fee	VOM	Variable Operations & Maintenance (VOM) charge expressed in \$/MW representing non-fuel costs of running a generating unit at or above its Pmin operating level.
Conversion Factor	$Unit\ Conversion$	0.001 factor converting heat rate expressed in Btu/KWh into MMBtu/MWh.

5.1.5. Southern California low operational flow order

Within California, Southern California Gas Company and SDG&E filed applications with the California Public Utilities Commission for a proposed treatment of low operational flow order and emergency flow order requirements.[14] These changes could greatly impact the gas pipeline system in Southern California and bring it more in line with the current penalty structure in the Pacific Gas & Electric (PG&E) territory. Any policy created here should leverage these improvements.

6. Commitment cost mitigation

The ISO currently mitigates commitment costs for market power through an established bid cap of 125 percent of calculated costs under the proxy cost option, and 150 percent under the registered cost option.[15] In response to stakeholder requests, and as committed to in the straw proposal, the ISO conducted a survey of ISO and RTO market power mitigation methodologies as an alternative to bid caps. The results of the survey are summarized in Table 4 below.

Table 4: Survey of ISOs/RTOs Mitigation Methodologies

ISO/RTO	Mitigation	Additional details
CAISO	Bid cap	125% of daily calculated proxy cost or 150% of a proxy cost held fixed for a minimum of 30 days.
ISO-NE	Conduct and impact test[16]	Restricted from fuel price adjustment for 2 (first offense) to 6 months (second offense)[17]. Energy, start-up, and minimum load bids set to reference level.
MISO	Conduct and impact test[18]	Pre-determined thresholds to trigger conduct and impact tests. Mitigation only applied in the presence of binding transmission constraints or reserve zone constraints.
NYISO	Conduct and impact test[19]	Pre-determined thresholds to trigger conduct and impact tests.
PJM	Structural test (three pivotal suppliers) for active constraints[20]	6 month hold on market based or cost based option for commitment costs.

[14] Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) for Low Operational Flow Order and Emergency Flow Order Requirements, June 27, 2014. Available at: http://www.socalgas.com/regulatory/documents/a-14-06-021/FINAL%20Low%20Flow%20App.pdf
[15] Upon implementation of an opportunity cost methodology, the registered cost option will no longer be available.
[16] ISO-NE, Market Rule 1, Section III.A.5: Mitigation.
[17] ISO-NE, FERC docket no. ER13-1877, July 1, 2013, proposed tariff section III.A.3.4: Fuel Price Adjustments. Tariff amendment to become effective December 3, 2014.
[18] MISO, Market Monitoring and Mitigation Business Practices Manual BPM-009-r7, Section 5 Conduct Warranting Mitigation.
[19] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.1: Purpose and Objectives.
[20] PJM, Manual 15: Cost Development Guidelines, Section 1.6.1 Reason for Cost Based Offers: Market Power Mitigation.

ISO/RTO	Mitigation	Additional details
SPP	Conduct and impact test[21]	Mitigation only applied in presence of a binding constraint or reserve zone, or resource committed to address Local Reliability Issue.

ISO New England, Midwest ISO, Southwest Power Pool, and New York ISO mitigate commitment costs using a conduct and impact test, while PJM uses a three pivotal supplier test to trigger mitigation. In all the ISOs, resources' bids are mitigated down to a reference level[22], analogous to the CAISO's default energy bids and proxy costs for commitment costs.

Conduct and impact test

A conduct and impact test is a two-step mitigation methodology. A resource fails the conduct test when the bid reaches a pre-determined threshold, e.g., 200 percent above the reference level bid, and is subject to the impact test. How the impact test is conducted in each market varies, but essentially determines the impact the higher bid has on market prices. For example, this can be done by replacing the bid with a reference level bid in the market and comparing the resulting energy prices. If the energy prices using reference level bids are lower than the energy prices using the market bids, by a pre-determined threshold, the bids are mitigated.

Structural test (three pivotal supplier)

The three pivotal supplier test evaluates if a given constraint is competitive or un-competitive. The determination is made by comparing the demand at that location (e.g., flow on a constraint to relieve congestion) to the supply, with the three largest suppliers removed. If there is sufficient supply to meet demand, after removing the largest suppliers, the constraint is competitive. Otherwise, it is un-competitive and provides opportunity for the exercise of market power. Resources that provide supply to uncompetitive constraints are mitigated.

The intent of the survey was to understand how the mitigation methodologies of other ISOs are similar or differ from each other, and whether these methods could effectively be applied to California markets. As noted by the Department of Market Monitoring (DMM), the ISO market faces several challenges when developing dynamic mitigation of commitment costs. The methodology will need to consider transmission and contingency constraints, exceptional dispatches, operator action to override market software, and outage re-rates among others, while effectively identifying opportunities for market power and appropriately applying mitigation.

6.1. Considerations for CAISO

There are varying degrees of flexibility for bidding commitment costs in organized electricity markets. Each market has a methodology used to detect market power and trigger bid mitigation.

[21] http://app.spp.org/eTariff/etfdocs/MasterTariffs/5TariffSections/1452.pdf
[22] In all of the other ISO/RTOs sampled, the market monitoring unit either calculates or works with the ISO/RTO to calculate reference level commitment costs in conjunction with performing a market power mitigation test.

There are two primary methodologies of commitment cost mitigation in the other ISOs: conduct and impact test and a three pivotal supplier test. Each mitigation methodology slightly differs from one organized market to another to accommodate variations in each energy market. Below is a discussion of how effective each mitigation methodology would be in the California ISO markets and identifies concerns and challenges that arise with each.

Conduct and impact test

If the ISO were to implement a conduct and impact test for commitment cost mitigation, there are three areas of concern that need to be considered. As described above, a resource is subject to the impact test only if the submitted bid is above a pre-determined threshold. The challenge would be in determining an appropriate threshold at which the resource would fail the conduct test and be subject to the impact test. Options would include a trigger as a percentage of the reference level bid (e.g., 200 percent above reference level bid), a flat mark-up in terms of dollars (e.g., $100 above reference level), or a combination thereof. Along with that, is acknowledging that, by design, the mitigation methodology allows some degree of mark-up before failing the conduct test. Profit maximizing market participants may bid just below the pre-determined threshold, and in the long run, increase overall costs to the market through increasing commitment cost bids that surpass being subject to mitigation.

Conduct and impact tests only consider resources that are committed by the market. Resources that bid out of the market by bidding high would bypass the conduct and impact test. Therefore the conduct and impact test in the California ISO markets would need to be modified to test resources that are not committed by the market. Mitigating market power in resource commitment is more important in the California ISO market than other ISOs because of the greater amount of load pockets with limited generation alternatives. Such a modification to test resources not committed may introduce significant computational burden.

Lastly, the impact step in the conduct and impact test methodology compares market prices between a market run with unmitigated bids and a market run with reference level bids for those resources that fail the conduct test. In the California ISO market, commitment costs are not directly reflected in the energy LMPs. Therefore the energy price with reference level bids may not be significantly lower than the energy price from a market run with unmitigated commitment costs bids.

For example, take a resource located in a load pocket that is necessary to serve the local load. The proxy minimum load cost for the resource is $5,000 and has a default energy bid of $50/MWh. Assume the resource bids $50,000 for minimum load and $50/MWh for energy. The market solution would be to commit the resource and have an LMP of $50/MWh at that location. Under a conduct and impact test regime, it would fail the conduct test and be subject to an impact test. The proxy cost minimum load of $5,000 would be inserted as well as the $50/MWh DEB. The result would be the same, commit the resource and have a $50/MWh LMP at the location. Since the two resulting LMPs are the same, the resource would *not* have its minimum load bid of $50,000 mitigated.

Pivotal supplier test

The California ISO's current market power mitigation uses a three pivotal supplier test for energy bids. A similar construct could be applied to test commitments. These tests are triggered by a binding constraint or other defined need for supply in a clearly defined area. Commitment costs would be mitigated if, without the largest suppliers, the demand cannot be met.

However, there can be some instances where market power in commitments would not result in a binding constraint, and therefore not detected. Take for example the simple radial system in Figure 1 below. A transmission line rated at 50MW serves a load pocket of 60MWs at peak; there is a resource in the load pocket with a minimum load of 40MW. The only way to serve the load when it exceeds 50MWs is with the local resource at minimum load. If the transmission line is binding, it would trigger mitigation of the local resource. However, once the resource is committed to minimum load, the transmission line is no longer binding. Therefore the resource could exercise market power through high commitment cost bids and surpass being subject to mitigation because the commitment decision will relieve any congestion on the transmission line.

Figure 1: Example of difficulties applying dynamic mitigation to commitment costs

A potential solution to the aforementioned scenario would be to conduct a pivotal supplier test on all constraints in the critical constraint list. While this would alleviate the concern above, it would likely result in over-mitigation. Resources that are effective in relieving congestion on an uncompetitive constraint would be subject to mitigation, even if the constraint never binds and the resource would not have the ability to exercise market power. Furthermore, one of the main drivers in the ISO moving away from the static competitive path assessment to the dynamic path assessment was to reduce the instances of over-mitigation. Applying a pivotal supplier test to all critical constraints would be a step in the opposite direction.

6.2. Differentiated bidding headroom

In its Straw Proposal, the ISO proposed changing the commitment cost bid headroom from 125 percent of the proxy cost to calculating the maximum start-up or minimum load cost based on a sum of various percentage increases for each individual cost component of the proxy cost. The inputs to the proxy cost calculations are discussed in Section 5.1.4.

The ISO revises its proposal to retain the current process of establishing the commitment cost caps based on 125 percent of the proxy cost calculated. This is because the current headroom is in place in order to allow stakeholders to manage their risks, including but not limited to, price risk associated with the difference between actual gas costs and the use of a volume weighted average price index to estimate gas costs.

While that specific risk was emphasized in the *Commitment Cost Enhancements* initiative and its filings before FERC, the section on Commitment Cost Calculation in this paper discusses various reasons outside of those discussed in the *Commitment Cost Enhancements* initiative that a market participant would need to use the headroom to manage their risks. For example, another risk market participants requested to be allowed to reflect in their commitment cost bids is a cash-out risk, discussed in Section 3.2. The bidding headroom allows for commitment cost bids to reflect this premium.

6.3. Proposal for commitment cost mitigation

The ISO does not foresee how either a conduct and impact test or pivotal supplier test could be effectively implemented in the CAISO energy markets and effectively mitigate commitment costs. Each option has concerns that deter the ISO from further consideration.

The current commitment cost mitigation methodology in the CAISO markets is the 125 percent bid cap on start-up, minimum load, and transition cost bids. A bid cap allows for flexibility in commitment cost bids to reflect fluctuations in gas prices and other costs captured in the proxy cost calculation, while applying some degree of mitigation. As discussed in Section 6.2, the ISO is no longer considering determining the bid cap through differentiated headroom. Therefore the ISO is not proposing to change the current commitment cost mitigation methodology and instead proposes to retain the 125 percent bid cap on commitment costs.

7. Bidding flexibility rules

7.1. Proposal for energy bidding flexibility

The ISO believes the bid flexibility currently offered is useful to accommodate resources' responses to changing natural gas prices. However, there are two concerns that arise from this flexibility.

First, there are instances where resources can change their real-time market energy bid prices even when the market cannot utilize these bids because the resource cannot respond due to inter-temporal constraints. However, such changed bids can inappropriately inflate a resource's bid cost recovery (BCR) payments.

Second, there are instances when the real-time market will use bid prices that did not originally trigger commitment such as when STUC commits resources based on one bid price, then the resource later increases the bid price.

The ISO and its DMM monitors for inappropriate market behavior, including those described in this paper. To the extent the market participants engage in adverse market behavior, the ISO will take appropriate regulatory actions, which may include emergency tariff changes and referrals to the FERC Office of Enforcement.

The ISO has two proposals for addressing energy bidding flexibility as summarized in Table 5 below.

Table 5: Summary of energy bidding proposals

Issue	Proposal, Option 1	Proposal, Option 2
Changing bids after a commitment decision during an inter-temporal constraint	Continue monitoring	Limit bidding flexibility
Changing bids after a commitment decision without inter-temporal constraints	Continue monitoring	Limit bidding flexibility

7.1.1. Changing bids after a commitment decision during an inter-temporal constraint

The most effective market solution to prevent inappropriately inflating BCR would be to prevent resources from changing energy bids once they are dispatched by the market but the market cannot respond to a changed bid price because the dispatched bid moved the resource into an inter-temporal constraint. There would be a market benefit because the market cannot respond to the changed bid price but the changed bid price would inflate BCR.

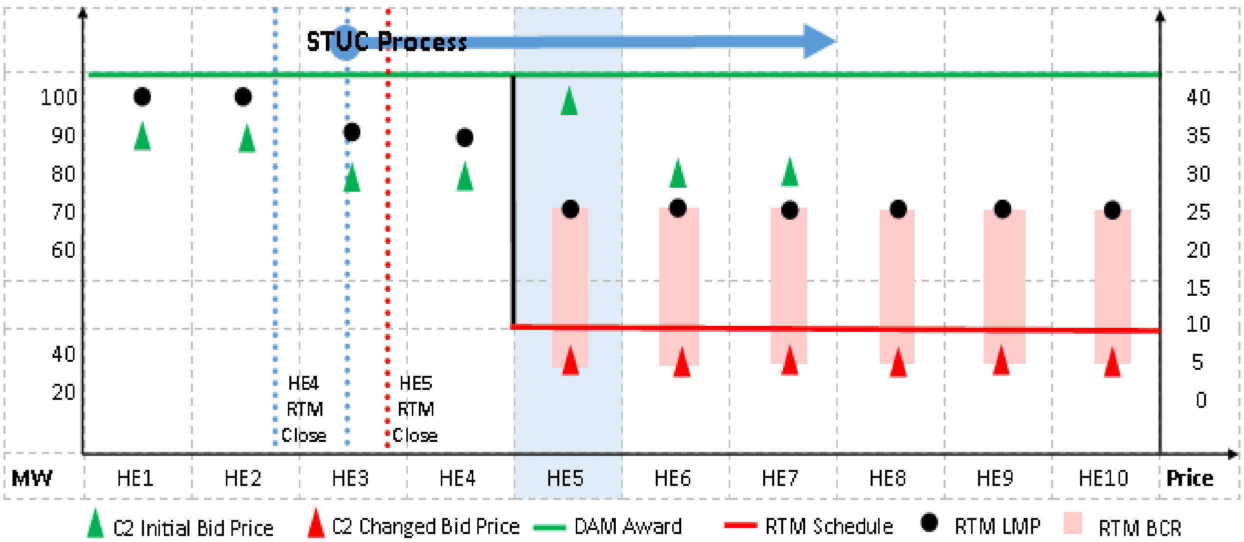
For example, Figure 2 illustrates the market inefficiency arising when a multi-stage generator (MSG) resource changes its real-time market energy bid price on a configuration that was originally scheduled in the day-ahead market and decomitted in the real-time market and subject to a minimum down time constraint. In this case the resource can potentially receive BCR on the decomitted configuration and could inflate its BCR by lowering its energy bid price for the decomitted configuration. The real-time market cannot respond to the lower energy bid price and dispatch energy from the decomitted configuration because of the minimum down time constraint.

The example in Figure 2 shows an MSG resource that received a day-ahead market schedule in its upper configuration, C2, for 100 MW due to bid prices ranging from $30/MWh to $40/MWh. The real-time market STUC process decommits it from C2 to a lower configuration, C1, based on these initial bid prices (green triangles) beginning in hour ending 5 and dispatches the resource to 40 MW. C2 has a minimum down time of 6 hours. This results in the resource buying back 60 MW and the resource will receive bid cost recovery to the extent the LMP exceeds the resources real-time market energy bid price for the energy between 100 MW and 40 MW. After the resource receives its transition instructions from the ISO to move to 40 MW, it can then use the ISO's bidding flexibility to update its real-time market energy bid prices for C2 to its changed bid prices (red triangles). The resource will not be able to move back into C2 for 6 hours regardless of the changed bid prices. Assuming the real-time market LMP for hour ending 5 is $25/MWh, the MSG resource has a revenue shortfall of $20/MWh as seen in Figure 2 as RTM BCR. The shortfall is the difference between RTM LMP at $25/MWh and the changed bid prices at $5/MWh.[23]

[23] Bid prices for decremental energy represent the highest price at which a resource is willing to pay for energy from the market. If the resource pays more than its willingness to pay due to the higher LMP, the ISO will make it whole for the difference (i.e. revenue shortfall=-1 decremental MW * ($5-$25)).

Figure 2: Illustration of bidding flexibility under inter-temporal constraint

Configuration	Min Gen	Max Gen	Min On Time	Min Down Time
C2	60	100	480	360
C1	10	40	360	360



While restricting bidding flexibility would prevent the opportunity to inflate BCR in this manner, the market changes needed to restrict bidding flexibility when intra-temporal constraints are binding would be complicated. Additionally, if STUC decommits the configuration, the ISO would need to "lock" the energy bids for the remainder of the intervals subject to the inter-temporal constraint at the bid prices that resulted in the commitment decision. However as Figure 2 shows, it is not clear what that bid price would be as there may not be bids for STUC's full horizon. For example, the green triangles in Figure 2 show the real-time market bid prices STUC used to decommit C2 beginning in HE 5. It used bids for HE5 – HE7 but there were not bids yet submitted for HE8 – HE10. It is unclear what bid price would be "locked" for HE8 – HE10.

Stakeholders requested the ISO perform an analysis to show the frequency and magnitude of impacts to BCR payments.[24] If a change to BCR settlement is found necessary, stakeholders also requested an indication be provided on settlement statements to show when a bid was "locked" or to show when there is an intertemporal constraint that triggered this new policy. The ISO has reviewed the impacts to BCR and has not found instances of market participants inflating BCR by changing bid prices in the situation described.

The ISO seeks stakeholder input on the two following options:

- Continue monitoring for this behavior and consider resources significantly lowering bid prices in this situation to be engaging in market manipulation.

[24] Northern California Power Agency and Calpine Comments on the ISO Issue Paper.

- Introduce bidding requirements to submit a daily profile of real-time market energy bids in which the price range of these bids will be limited. For example, all bids across the range could not increase or decrease by more than some percentage from the average bid price. Additionally, any changes to real-time market energy bids would be restricted to the range established by the initial daily bid profile. Another alternative, is to restrict real-time market energy bids from varying by more than an established percentage from day-ahead market energy bids. For example, real-time market bid prices could not be less than 50 percent of day-ahead market bids. This would limit the opportunity to inflate BCR.

The ISO seeks stakeholder comments on these two proposed solutions.

7.1.2. Changing bids after a commitment decision without an inter-temporal constraint

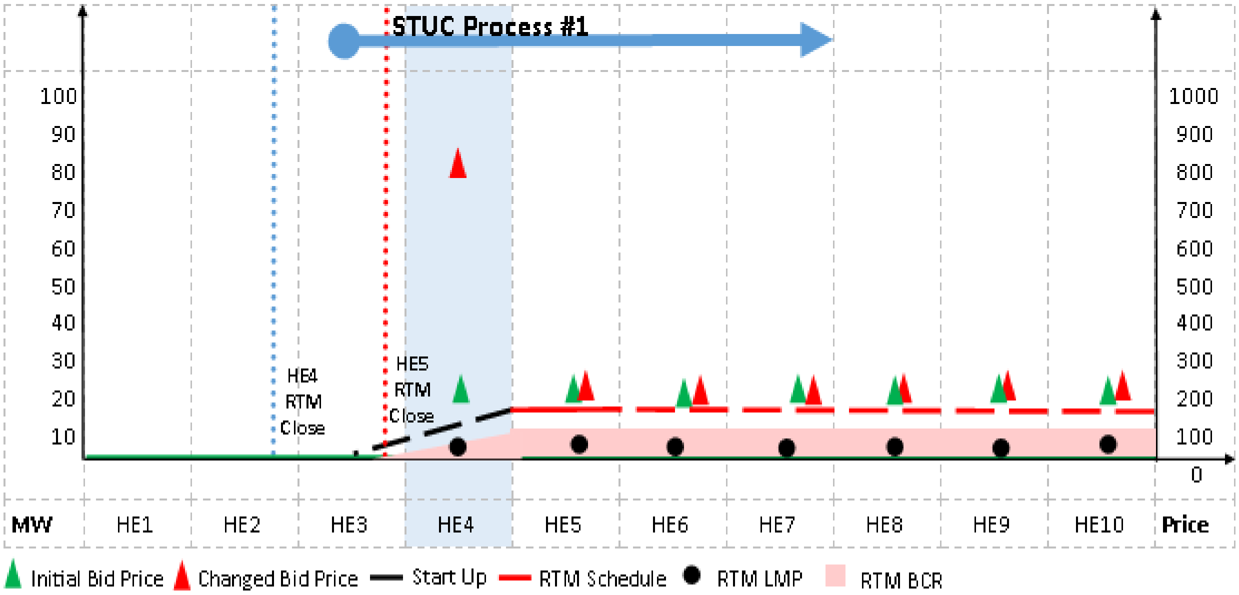
Figure 3 illustrates a scenario in which a resource increases its energy bid price for incremental energy to a price greater than the bid price STUC used to commit the resource. Unlike the previous example, it does not involve an inter-temporal constraint. In the scenario shown in Figure 3, the resource submits initial low-priced bids (the green triangles) that STUC uses for its run from hour ending 4 through hour ending 7. After receiving the STUC commitment for hour ending 4, the resource submits a higher priced bid for the first hour, hour ending 4. The higher changed bid (red triangle) for hour ending 4 is used in the RTUC and RTED runs.

This keeps the unit on because of the low bids after the first hour, but one of two things occurs in the first hour: (1) the market keeps the resource at min load and the resource can earn 125 percent of actual minimum load costs, or (2) the market dispatches the resource for energy at the higher bid price because an alternative resource that would not have bid as high as the increased bid was not started up.

As opposed to the ISO's concern with resources changing real-time market energy bids while subject to an inter-temporal constraint, there are economic reasons to update the energy offer in this scenario. For example, a resource may want to change its bids to account for gas price changes. Because the market optimization can respond to this new information, it is a positive market outcome for the real-time market to solve based on incremental energy offers factoring in changes in system conditions during the trade day. As such, the resource will be able to respond to dispatch instructions and increment or decrement based on the LMP.

Figure 3: Illustration of bidding flexibility without an inter-temporal constraint

Resource	Min Gen	Max Gen	Start Up Time	Min Run Time	Start-up Fuel	Start-up Cost	Min Load Cost
GEN A	20	100	180	60	1,000 MMBtu	$10,000	$2,500



The ISO revises its proposal to propose to the two following options:

1. Continue monitoring for this behavior and follow-up with SCs found engaging in this behavior. In this way, the ISO will be able to further explore what economic reasons, if any, exist for changing bids between the real-time market processes outside of triggering commitments of less economic resources.

2. Introduce bidding requirements to submit daily profile of real-time market energy bids where the range of these bids will be limited. For example, if the average bid price for the optimization horizon is $25 then all bids across the range could not increase or decrease more than 25 percent from the average bid price. Additionally, any changes to RTM energy bids will be restricted to the range established by the initial daily bid profile. The ISO is still exploring what criteria, if any, should apply to changes between DAM and RTM energy bids.

Option 1 could be a favorable option since changes in bid prices may be used to legitimately reflect changing economics. On the other hand, the ISO does not see a reason a resource's bid price would need to change outside a reasonable range once an initial bid profile has been submitted. For this reason, Option 2 would be a desirable alternative balancing tradeoff between bidding flexibility and resolving market inefficiencies.

The ISO seeks stakeholder comments on these two proposed solutions.

7.2. Proposal for commitment cost bidding flexibility

The ISO has two proposals to increase commitment cost bidding flexibility and correct for a current inefficiency as summarized in Table 6 below.

Table 6: Summary of energy bidding proposals

Issue	Proposal
Inefficient accounting for minimum load costs after a Pmin rerate	Calculate actual commitment costs based on the resource's default energy bid (DEB).
Resources without a day-ahead schedule cannot rebid commitment costs.	Allow resources without a day-ahead schedule to rebid commitment costs in the real-time market.
The ISO market inserts day-ahead market bids into STUC for resources that are not resource adequacy resources that are not scheduled in the day-ahead market and do not resubmit bids into the real-time market.	No longer generate bids for STUC for non-resource adequacy resources that do not resubmit bids into the real-time market.

7.2.1. Correct inefficient accounting for minimum load costs after a Pmin rerate

The ISO system treats the minimum load cost as a fixed dollar amount representing the bid cost under the minimum load (Pmin). An inefficiency arises if the minimum load (Pmin) of the resource or the minimum load (Pmin) of the MSG configuration is re-rated to a higher MW level than registered in the Master File. Currently the energy cost under the re-rated Pmin is using the fixed minimum load cost. This can lead to an unintended change in the economics of the resource. An example is provided below in Table 7. Resource A and B are exactly the same resource except that Resource B has higher bid costs of $50/MWh versus $30/MWh (shown in row [E]). Resource B increases its Pmin from 100 MW to 185 MW. Under the ISO's current process, the minimum load cost per MWh (shown in row [F]) decreases from $10/MWh to only $5/MWh for Resource B. There is a market inefficiency since the total cost of Resource B with a rerated Pmin seen by the market is now $6,750 which is below its actual total cost of $11,000 (shown in row [I]) and could displace Resource A since it falsely appears to be more economic.

To correct for this inefficiency, the ISO had two proposals for a market solution. The first was to scale the minimum load cost based on the original minimum load cost per original Pmin MW as calculated in Table 7. The second proposal was to calculate the actual commitment costs based on the default energy bid (DEB) associated with the capacity range between the Master File Pmin and the re-rated Pmin where the incremental DEB costs are added to the bid-in minimum load costs at the re-rated Pmin level.

Table 7 illustrates the impact on total cost for the resource with the Pmin rerate, Resource B, after applying the two proposed approaches. The approach scaling the minimum load cost (MLC) is shown in the column titled 'Scale MLC' where a $10/MWh minimum cost (row [F]) is applied to the new rerated Pmin of 185 MW (row [A]) to produce a new minimum load cost of $1,850 per hour (row [D]). The approach integrating the DEB cost is shown in the column titled 'Use DEB' where the DEB costs associated with the rerated energy is applied in the manner shown in Table 7 to produce a new minimum load cost of $5,250 per hour (row [D]).

Figure 4: DEB Integration Formula

$$MLC' = MLC + \int_{P_{min}}^{P_{min}'} DEB(p)dp$$

MLC'	Minimum load cost of the rerated Pmin level
MLC	Minimum load cost of the original bid-in minimum load cost
$DEB(p)$	Default energy bid cost
dp	Change in energy

Table 7: Illustration of Pmin rerate and minimum load cost

In the following example, we assume that the energy bid curve is the same as the default energy bid curve.

						Resource B w/ Pmin rerate		
	Data	***Units***	***Formula***	**Resource A**	**Resource B**	**Current**	**Scale MLC**	**Use DEB**
[A]	Pmin	MW		100	100	185	185	185
[B]	Pmax	MW		300	300	300	300	300
[C]	Capacity above Pmin	MW	*[B] - [A]*	200	200	115	115	115
[D]	Min load cost	per hour		$1,000	$1,000	$1,000	$1,850	$5,250
[E]	Bid cost	per MWh		$30	$50	$50	$50	$50
[F]	Min load cost / MWh	per MWh	*[D / [A]*	$10	$10	$5	$10	$28
[G]	Min load cost / hour			$1,000	$1,000	$1,000	$1,850	$5,250
[H]	Total bid cost / hour		*[C] x [E]*	$6,000	$10,000	$5,750	$5,750	$5,750
[I]	Total cost		*[G] + [H]*	$7,000	$11,000	$6,750	$7,600	$11,000

The ISO proposes implementing the market solution modifying the minimum load cost based on DEB costs because this approach will resolve the current market inefficiency as shown by the total cost of Resource B with Pmin rerate and without a Pmin rerate both being $11,000 (shown in row [I]). By adjusting the minimum load costs to reflect the cost of commitment under the rerated Pmin level, the market will be able to use the actual cost of commitment when solving for the most efficient commitment solution possible while ensuring market participants will recover those true costs through ISO market revenue and bid cost recovery settlement.

7.2.2. Allow rebidding of commitment costs for resources without a day-ahead schedule

The ISO currently does not allow resources that bid into the day-ahead market but that did not receive a day-ahead schedule to rebid commitment costs in the real-time market. This does not allow resources without day-ahead schedules to reflect changed natural gas prices in their real-time market commitment cost bids. Not allowing resources without day-ahead schedules to rebid commitment costs in the real-time market potentially results in resources not being able to recover their commitment costs. It also potentially results in inefficient resource commitment because the real-time market will miss-value minimum load costs.

The ISO proposes to allow resources without day-ahead market schedules to rebid their commitment costs in the real-time market. The ISO is proposing to keep the other commitment cost bidding rules the same: (1) the real-time market will use a single respective start-up and minimum load cost for each day, and (2) a resource cannot change its commitment costs once the resource has submitted a valid real-time commitment cost for any given trading hour in that trade day. This timing allows for the market participant to evaluate any changes to its commitment cost occurring after publication of the DAM results and will be compatible with the real-time markets current functionality.

For resources without a day-ahead schedule, real-time bids may be resubmitted at any time during the trade day. For example, if a resource chooses to begin participating in the ISO's market beginning hour ending 8 it can resubmit bids up to the real-time market close for hour ending 8 at 5:45 AM. If a resource adequacy resource without a day-ahead schedule wants to change their commitment cost offers, the resource must submit by the real-time market close for hour ending 1 since the ISO will continue to generate bids for resource adequacy resources and the generated bid will lock the commitment costs for the trade day unless a bid is present in SIBR.

The ISO is currently not proposing for additional commitment costs flexibility during the operating day because this functionality would require a significant market change to allow for minimum load or start-up costs to vary across hours in the markets. This would be a significant design and implementation effort and would have to address the potential for a resource to inflate bid cost recovery payments by changing minimum load costs across hours. For example, the ability of a resource to change minimum load bids when a resource is constrained to be running would have to be addressed.

7.2.3. Generating bids for non-resource adequacy resources that did not resubmit bids into the real-time market

The ISO market currently inserts day-ahead market bids into STUC for all resources, including those that are not resource adequacy resources, that are not scheduled in the day-ahead market and do not resubmit bids into the real-time market. This can result in STUC committing a non-resource adequacy resource that chose to not participate in the real-time market. This is not equitable because non-resource adequacy resources do not have an obligation to offer to the market. The ISO proposes to address this by no longer generating bids for STUC for non-resource adequacy resources that do not have a day-ahead schedule and do not resubmit bids into the real-time market.

8. Commitment Cost Calculation

The ISO is exploring the use of select index price inputs as well as the appropriate treatment of greenhouse gas (GHG) costs in the ISO's calculation of proxy commitment costs for start-up and minimum load energy. The select index price inputs explored are:

1. Daily gas price index (GPI) used in the calculation of the default energy bids, generated energy bids, and proxy commitment (startup and minimum load) and transition cost calculations[25]:
    a. Published Gas Price
    b. Intra-state gas transportation adder
2. Electricity Price Index (EPI)

The remainder of the section discusses the ISO's proposals for adjustments to the daily gas price index (GPI) and treatment of greenhouse gas (GHG) costs found in GPI_{DAILY} due to transportation rates in Section 8.1.1.3, and the electricity price index (EPI) in Section 8.1.2. The ISO's proposal assumes an opportunity cost methodology is in the market and therefore the registered cost option is no longer available except to those entities that do not have sufficient bidding history. The opportunity cost bid cap will be discussed in the *Commitment Cost Enhancements Phase 3* initiative.

8.1. Proposals for commitment cost parameters

The ISO has three proposals to refine the inputs to the proxy cost calculation which will improve commitment cost bidding as summarized in Table 8 below.

Table 8: Summary of commitment cost calculation proposals

Issue	Proposal
Gas price index may not reflect real-time gas purchase costs[26]	Routinely use earliest published index for the day-ahead market, move day-ahead market timing to 11 am to 2 pm, and allow for consideration of real-time gas purchases above the gas price index.

[25] Any proposals to the basis of the GPI such as changing the index price used or adding fuel regions to reflect GHG compliance status would affect both commitment and energy costs (i.e. DEBs and generated bids).
[26] Changes to the GPI will impact all reference prices calculated by the ISO including DEBs and generated bids.

Issue	Proposal
Gas price index may not reflect gas transportation costs	Increase the flexibility of registering fuel regions and allow for cap-and-trade credits to the base gas transportation rates for resources with GHG compliance costs within these fuel regions.
Electricity price index may not reflect start-up energy costs	Change the electricity price index calculation consistent with the registered cost option to represent a projected electricity price during unit start-up or cost of auxiliary power provided by the generator based on a unit with a heat rate of 10,000 Btu/KWh.

8.1.1. Improvements to the gas price index

As discussed in Section 6.3, the ISO does not provide unlimited bidding flexibility on its commitment costs therefore its necessary the "maximum" proxy cost caps are improved to better allow gas-fired resources to reflect their commitment costs.[27]

This section explores how the GPI can be improved to better reflect the commodity price and transportation costs of natural gas purchases for flow during the ISO's operating day.

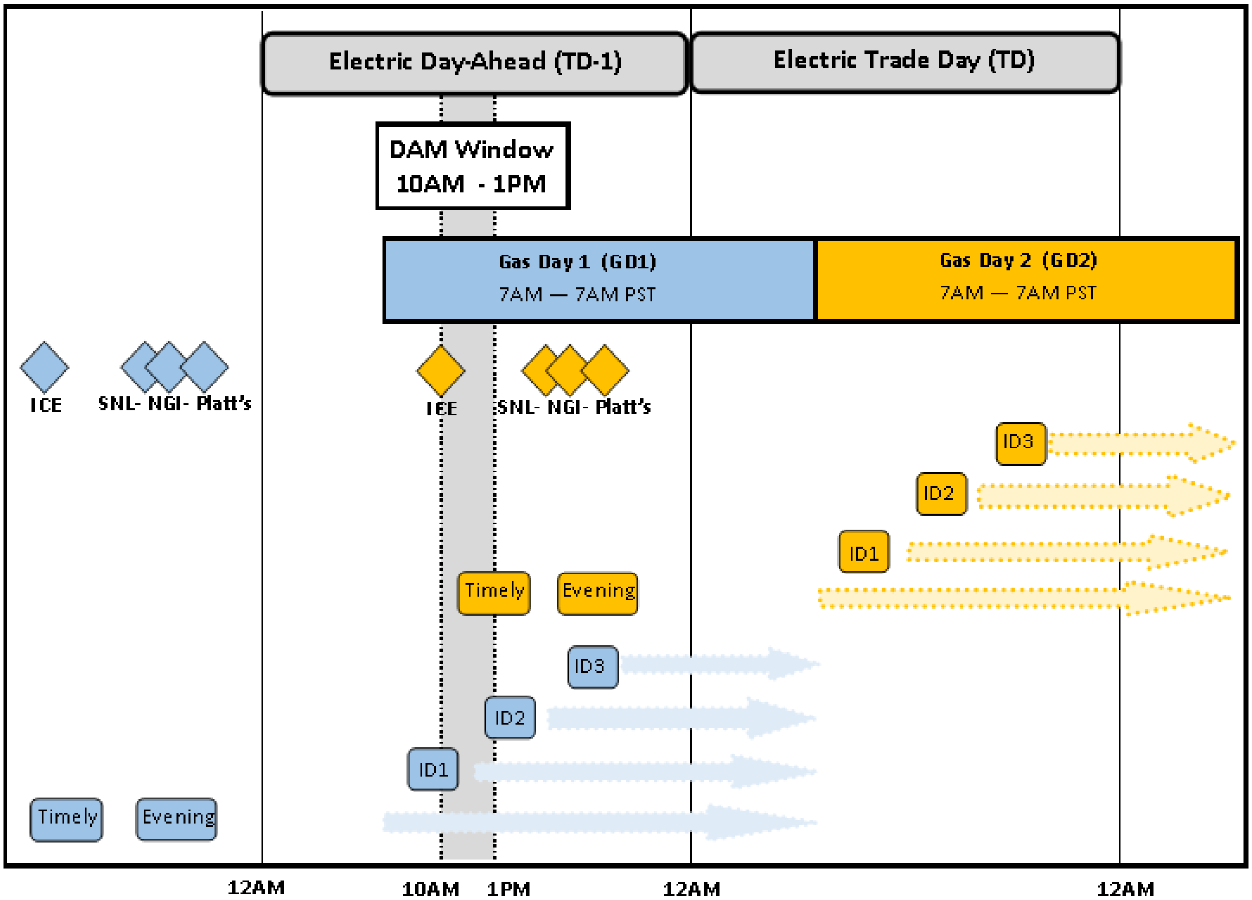
Alignment of natural gas and electric market commodity prices

A main driver behind the inaccuracy of the price information currently used by the ISO is the result of a misalignment between the gas day and the electric day. Due to this misalignment there are two gas prices associated with one electric day.

Figure 5 provides an illustration of the interaction of gas day and electric day timelines where the electric days, Gas Day 1 (GD1) and Gas Day 2 (GD2) flows are represented by the colors gray, blue and orange respectively. The discussion in this section uses GD1 and GD2 as defined in Figure 5.

Figure 5: Gas and Electric Day Timelines

[27] The maximum proxy cost cap is set at 125 percent of the calculated proxy cost under the proxy cost methodology.



The ISO market currently uses a daily gas price index (GPI) to calculate proxy commitment and transition costs, to generate energy bids, and to create default energy bids. The day-ahead market uses a GPI based on the gas price for GD1 traded on the day prior to the day on which the day-ahead market is run. GD1 consists of delivery beginning 7 AM in the day-ahead through 7 AM on the operating day. The gas price used is an average of natural gas day-ahead indices for gas flowing on GD1[28], shown in Figure 5 by blue diamonds.

There is an exception to this in the event of a natural gas price spike in which prevailing gas prices increase to at least 125 percent of the GD1 index. In this case, the ISO uses a manual process to update the market with the ICE GD2 index that ICE publishes at 10 AM on the day the day-ahead market is run.

The impact of using the GD1 price is that the gas price for purchases on the day the day-ahead market is run are not reflected in the ISO's commitment cost calculations. The gas price indices that do reflect these purchases are shown as orange diamonds in Figure 5. The corresponding gas day is also shown in orange.

The ISO averages natural gas day-ahead prices published in ICE, SNL Energy/BTU daily, NGI, or Platt's Gas Daily indices to determine its GPI. Table 9 shows the earliest and latest available

[28] ISO tariff section 30.4 and 39.7.1.1.1.3.

times for each publication. These publications and their earliest time available are the gas price indices shown as diamonds in Figure 5.

Table 9: Natural gas day-ahead indices publication times[29]

Source	Earliest Time Available (PST)	Latest Time Available (PST)
ICE	10:00 AM	12:00 PM
SNL Energy/BTU Daily	16:00 PM	19:00 PM
NGI	19:00 PM	2:00 AM (flow date)
Platt's	17:00 PM	19:00 PM

8.1.1.1. Improve gas commodity price[30]

The ISO explored three potential options for improving the natural gas commodity price used in the GPI and the markets. The ISO believes Option 1 appears to be the best option, but it seeks stakeholder input on which option is optimal. These options are:

Option 1: Use GD1 and GD2 prices to reflect natural gas price volatility differences between GD1 and GD2:

Hypothetically, the day-ahead gas index price could be aligned to the gas day for each trade hour. For example, hour ending 4's gas price could be the GD1 index price and hour ending 22's gas price could be the GD2 index price. However, the ISO's current market design does not allow commitment costs to vary across hours within the trade day so this option is likely not feasible. In addition, this approach may assume gas should be priced in the market at day-ahead price for GD1 rather than the current value of gas for GD1 as of the close of the electric day-ahead market.

Alternatively, the ISO could use the maximum of the two gas day indices so that the gas price volatility from either upward or downward movements between GD1 and GD2 prices is reflected in the ISO's calculations. In this way, the commodity price used in the GPI would better reflect gas price volatility.

In order to use GD2 index price under Option 1 and depending on the index chosen, the ISO may need to move its day-ahead market window later in the day, for example to 11 AM to 2 PM, i.e. one hour later then current practice. The ISO anticipates the benefits from improving the GPI cost input likely outweigh the drawbacks of moving the day-ahead market back an hour.

Option 2: Use day-ahead price for GD2:

This option would routinely use the day-ahead index for GD2 as a part of its normal operations and the ISO would no longer perform its manual price spike procedures. This index more

[29] Market Instruments BPM at 191.
[30] Changes to gas commodity price will impact all reference prices calculated by the ISO including DEBs and generated bids as well as proxy commitment costs discussed in this section.

accurately reflects gas price for purchases in the day-ahead timeframe for the majority of the electric trade day. This option would require the day-ahead market to be run one hour later[31].

The use of GD2 price without evaluating against the GD1 price does not completely alleviate the cost recovery concerns caused by inaccurate price information. However, historically the price risk concern was born out of price spikes associated with GD2's price and the GD2 price is the spot price for the majority of the trade hours across the operating day. This option would provide an incremental improvement however with a price risk remaining associated with downward price movements between GD1 and GD2. Generators would not be able to recover the high cost of gas for the hours of the operating day prior to 7 AM.

In order to use GD2 index price under Option 2 and depending on the index chosen, the ISO may need to move its day-ahead market window later in the day, for example to 11 AM to 2 PM, i.e. one hour later then current practice. The ISO anticipates the benefits from improving the GPI cost input likely outweigh the drawbacks of moving the day-ahead market back an hour.

In addition, Option 2 would likely not be practical if the day-ahead index does not always timely publish at 10 AM. However, DMM analyzed the ICE's publication times and found ICE publishes the index by 10:20 AM 99 percent of the time over the period analyzed. ICE has published the index by 10:13 AM the vast majority of the time in the recent year. For the 1 percent likelihood, the ICE day-ahead index is not timely published, the ISO will use the index price for GD1 for the entire operating day.

In addition, the DMM developed a May 2015 report on natural gas price volatility, described further below, which the ISO used to develop this proposal. Based on DMM's report, the ISO concluded:

- The ICE 10:00 AM GD2 index more accurately reflects day-ahead purchases of gas for a given electrical trading day.

- Using the ICE 10:00 AM GD2 index for the 125 percent proxy cost commitment cost bid cap allows the cap to reflect virtually all natural gas prices for purchases in the intraday market on a given electrical trade day.

Option 3: Use GD1 price currently used by the market:

The use of GD1 price, current ISO operations, has the same inherent inaccuracy present in using the GD2 price alone. However, the concern is greater because this price reflects a smaller portion of the operating day than GD2's price which reflects the price of gas purchases for power generated after 7AM. As mentioned above, since the concern comes from extreme price spikes occurring between GD1 and GD2, Option 3 is a less effective option since historical observations

[31] As of the date of publication, the ISO has not engaged in discussions with any publication or service regarding the feasibility or cost of this approach. If stakeholders are interested in this approach, the ISO will pursue discussions with potential vendors.

have observed more risk from failing to reflect high GD2 prices. However, Option 3 has the advantage of not requiring changes to the timing of the day-ahead market.

DMM's September 2015 report on natural gas price volatility

DMM's report shows Western natural gas trading hubs are significantly less volatile than the Eastern gas hubs impacting Eastern organized markets[32]. As seen in Table 10 and Table 11, only about 0.2 percent of trades at the PG&E Citygate and 0.5 percent of trades at the SoCal Citygate and Border in the ICE natural gas day-ahead market for GD2 were at prices that exceeded the ICE day-ahead index for GD1 by more than 25 percent.[33] DMM focused on Western trading hubs from 2010 to 2015[34] in its May report, and the September report expanded the analysis to span 2005 to 2015 and compare across regions.

Table 10: Next day prices compared to prior day average (PG&E Citygate)

PG&E Citygate				
Time Period	Range	Average higher than prior day average*	Trades higher than prior day average**	Maximum higher than prior day average*
2005-2009	> 25%	0.2%	0.2%	0.3%
	15% - 25%	0.5%	0.6%	0.9%
	10% - 15%	1.2%	1.2%	1.8%
	Total > 10%	**1.9%**	**2.0%**	**2.9%**
2010-2015	> 25%	0.2%	0.3%	0.5%
	15% - 25%	0.3%	0.2%	0.1%
	10% - 15%	0.0%	0.1%	0.4%
	Total > 10%	**0.4%**	**0.5%**	**1.0%**
2005-2015	> 25%	0.2%	0.2%	0.4%
	15% - 25%	0.4%	0.4%	0.5%
	10% - 15%	0.6%	0.6%	1.0%
	Total > 10%	**1.1%**	**1.2%**	**1.9%**

** Percent of days* *** Percent of next day trades*

[32] Report on Natural Gas Volatility, September 2015. Available at: http://www.caiso.com/Documents/Department-MarketMonitoringReport-NaturalGasPriceVolatility.htm.
[33] Report on Natural Gas Volatility, September 2015. Available at: http://www.caiso.com/Documents/Department-MarketMonitoringReport-NaturalGasPriceVolatility.htm.
[34] Report on Natural Gas Volatility at Western Trading Hubs, May 2015. Available at: http://www.caiso.com/Documents/Department_MarketMonitoringReport_NaturalGasPriceVolatility_WesternTradingHubs.htm.

Table 11: Next day prices compared to prior day average (SoCal Citygate & Border)

SoCal Citygate & Border				
Time Period	**Range**	**Average higher than prior day average***	**Trades higher than prior day average****	**Maximum higher than prior day average***
2005-2009	> 25%	0.7%	0.8%	0.9%
	15% - 25%	0.7%	0.8%	1.5%
	10% - 15%	1.9%	2.2%	3.6%
	Total > 10%	**3.3%**	**3.8%**	**6.0%**
2010-2015	> 25%	0.2%	0.2%	0.3%
	15% - 25%	0.2%	0.3%	0.2%
	10% - 15%	0.3%	0.4%	0.7%
	Total > 10%	**0.7%**	**0.9%**	**1.2%**
2005-2015	> 25%	0.5%	0.5%	0.6%
	15% - 25%	0.4%	0.6%	0.9%
	10% - 15%	1.1%	1.4%	2.1%
	Total > 10%	**2.0%**	**2.5%**	**3.5%**

** Percent of days* *** Percent of next day trades*

Further, while the gas price index for GD2 was only more than 10 percent higher than the gas price for GD1 between 1 and 2 percent of the days analyzed, the ISO believes the commitment cost caps should be based on a reasonable upper bound that allows market participants to recover their costs the vast majority of the time. By setting the maximum commitment costs at 25 percent above proxy costs based on a volume weighted average price, the ISO enables market participants to manage their natural gas price risks including (1) failing to beat the index price[35] or (2) delaying gas purchases beyond the more liquid next-day trading period into the electric trade day.

Shown below, Figure 6 and Figure 7 which are from the September report are histograms of the maximum trade on a given flow date as a percent of the ICE day-ahead index on that flow date. This analysis compares the range in which gas purchase costs exceed the volume-weighted average of the published index for day-ahead. These histograms provide support that if the day-ahead price for GD2 is used the 25 percent headroom is sufficient to allow resources to manage their price risk.

Figure 6: Distribution of daily maximum price (PG&E Citygate)

[35] Buyer beats the index by purchasing next-day natural gas at a price lower than the volume weighted average price (VWAP).

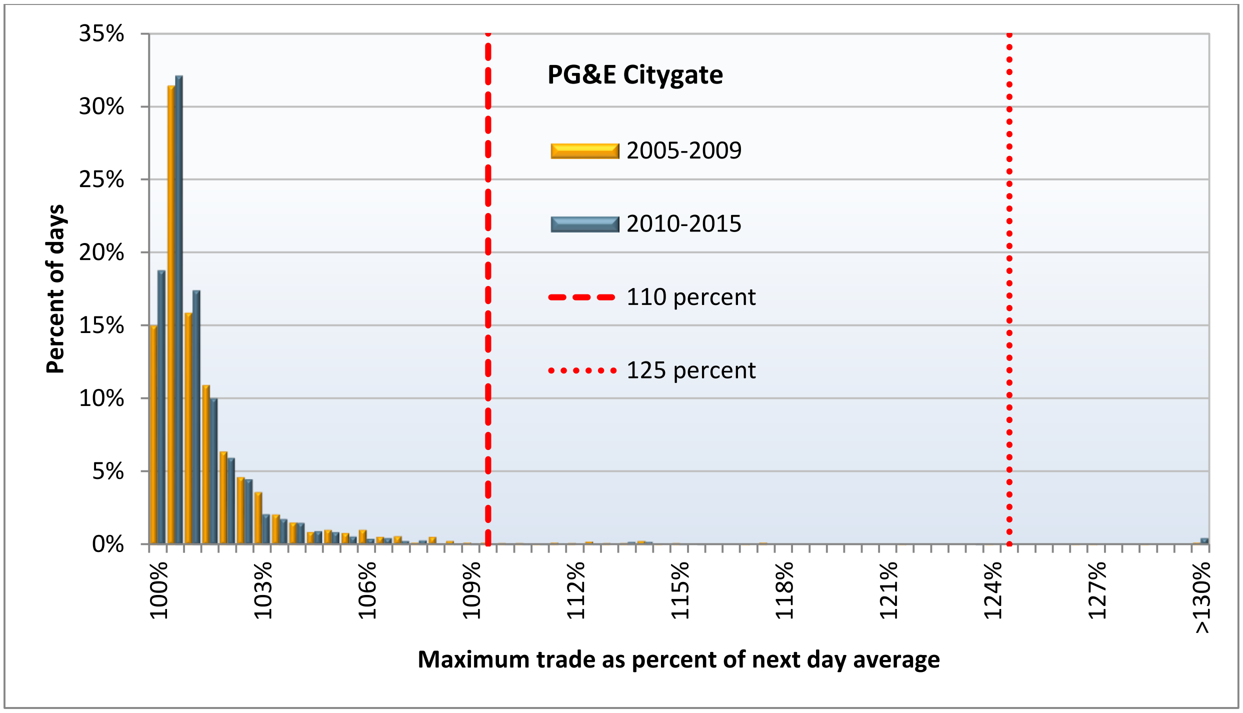
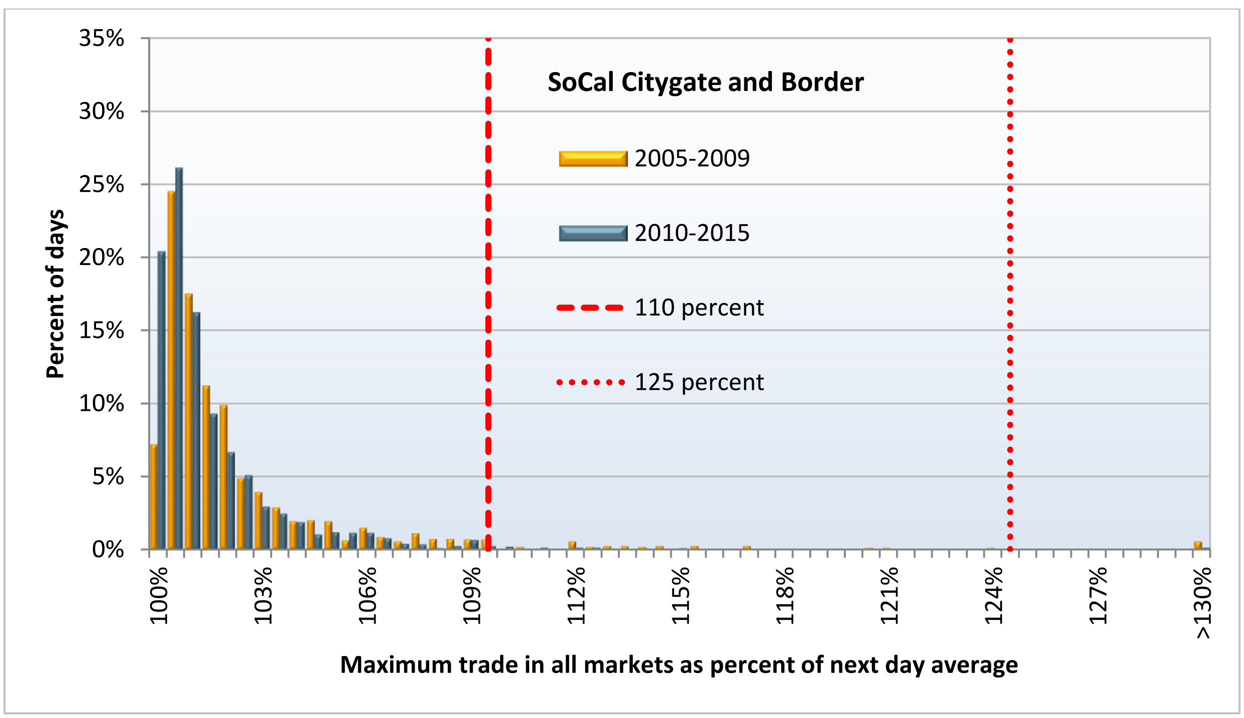


Figure 7: Distribution of daily maximum price (SoCal Citygate & Border)



8.1.1.2. Provide opportunity for after-the-fact cost recovery

As described above in Section 8.1.1, the ISO proposes to routinely use the earliest published index on the day of the day-ahead market run in the GPI. As described above in Section 7.2.2, the ISO also proposes that resources without a day-ahead schedule will be able to resubmit commitment cost bids to the real-time market. As described in Section 8.1.1, the day-ahead index price combined with the 125 percent proxy cost bid cap covers the vast majority of actual prices for gas purchased from the day-ahead, same day or intraday gas markets. However, to cover the instances when the proxy cost cap does not account for natural gas purchase costs, the ISO proposes to allow the opportunity for after-the-fact recovery.[36] This would consist of allowing scheduling coordinators to dispute their BCR settlement if they can support actual costs exceeding 25 percent of the GPI used.

The ISO worked with stakeholders to discuss how a process could be developed based on the following guidelines which have been updated to reflect the ISO's findings:

1. This process is to be used when a resource must procure incremental natural gas in real-time at a price above the gas price index plus the natural gas headroom when gas market price spikes above 25 percent. As shown in Figure 6 and Figure 7 the occurrence of such an event would be extremely rare.

2. The process will be an after-the-fact validation subject to documentation and verification of actual costs and verification that those costs were in line with market conditions at the time by no later than 77 business days from the relevant trading day (T + 77B).[37]

3. The ISO will verify the actual cost documentation which should be provided in the form of an invoice between unconnected entities.[38]

4. The ISO will include bid costs based on the actual gas purchase price in the resource's BCR calculations if the actual cost of the purchases can be verified.

The following example incorporates each guideline above. A short-start resource receives a real-time market award to run during the hours ending 22 to 24. This market award does not overlap with any day-ahead award and the resource needs to procure incremental natural gas in the Intra-day 3 market. The resource would be eligible for after-the-fact reimbursement of actual natural gas purchase cost if it procures gas at a price greater than 125 percent of the GPI used in the market.

The resource would provide the ISO with documentation to support its purchase. The ISO verifies the invoice documentation ensuring it reflects the actual cost to deliver gas at the resource and that the gas was procured from an unconnected entity.

---

[36] While this section focuses on commitment costs, the after-the-fact recovery applies to a dispute on gas prices which would impact DEBs and generated bids as well.

[37] BPM for settlement and billing at Page 21. Available at: http://bpmcm.caiso.com/BPM%20Document%20Library/Settlements%20and%20Billing/BPM%20for%20Settlements%20and%20Billing_v15.docx.

[38] "Connected entity" as used in Notice of Proposed Rulemaking RM15-23, Collection of Connected Entity Data. Available at: https://www.ferc.gov/whats-new/comm-meet/2015/091715/E-2.pdf.

The resource will have its additional costs incorporated into resettlement for the real-time award between 22:00 and 24:00 on April 22, 2016. The resettlement will be performed in the following 3 steps:

1. Recalculate proxy costs for start-up and minimum load as well as for any mitigated energy bids using the actual cost of the procured gas.

2. Recalculate the resource's BCR calculations using the updated costs in Step 1.

3. Resettle the adjusted BCR amount in the Recalculation Settlement Statement consistent with the dispute timelines used for all ISO settlement disputes[39].

As an alternative to this approach, the ISO is proposing that market participants have the right to file for cost recovery at FERC. This approach would require the market participant to demonstrate and have the burden of proof that it was not able to recover its costs from the ISO market or through hedging mechanism. For example to the extent the market participant establishes these costs, the ISO would include them as an input pursuant to FERC direction.

8.1.1.3. Improve gas transportation adders

In response to Assembly Bill 32, California's Air Resources Board established the state's market-based cap-and-trade program to reduce greenhouse gas emissions.[40] "Covered entities," such as thermal generators emitting more than 25,000 metric tons of carbon dioxide equivalents (MTCO2e) per year are required to comply. The program began on January 1, 2013 with phased compliance obligations for different parts of the economy. Thermal electric generating sources have already begun compliance.

The ISO currently allows covered entities to reflect in commitment costs, transition costs, and energy bids the costs of purchasing GHG allowances needed to cover their GHG emission associated with their energy output. Thermal resources that have not reached the 25,000 MTCO2e threshold cannot include a greenhouse gas cost unless they have voluntarily enrolled in the cap-and-trade program.

Starting January 1, 2015, natural gas suppliers will also be considered covered entities for the amount of gas delivered to California end-users, net of the amount delivered to existing covered entities.[41] The ISO followed the California Public Utilities Commission (CPUC) proceeding and

[39] BPM for settlement and billing at Page 21. Available at: http://bpmcm.caiso.com/BPM%20Document%20Library/Settlements%20and%20Billing/BPM%20for%20Settlements%20and%20Billing_v15.docx.

[40] Commitment Cost Enhancements Phase 2 initiative began a discussion of reviewing the ISO's procedures for considering GHG costs of its resources.

[41] California Public Utilities Commission, *Scoping Memo and Ruling of the Assigned Commissioner and Administrative Law Judge*, Rulemaking 14-03-003, July 7, 2014, p. 3.

reached out to stakeholders to understand how GHG costs of natural gas suppliers will impact the ISO's operation.

The CPUC released its final decision on the proceeding, 'Procedures Necessary for Natural Gas Corporations to Comply with the California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms,' on October 23, 2015.[42] The CPUC's decision allows for natural gas suppliers to recover the GHG compliance costs through introducing costs into rates effective April 1, 2016. Table 12 shows forecast rate impacts of incorporating these costs into their base rates submitted under this proceeding by SoCalGas and SDG&E.

Table 12: SoCalGas and SDG&E Forecast Rate Impacts[43]

	SoCalGas	SDG&E
End Users Forecast Compliance Cost	$78,995	$13,169
Adjusted Average Year Throughput, Mth	4,088,158	585,560
GHG Rate $/therm	$0.01932	$0.02249

For gas transportation rates for covered entities who have a direct compliance obligation with CARB, the CPUC decision creates a GHG compliance cost credit done in the form of a line-item credit to demonstrate exempt customers do not pay twice for natural gas GHG compliance costs. The line-item credit should be called "Cap-and-Trade Cost Exemption" according to the Decision at 42. This credit will be in addition and similarly done as the credit for AB 32 Cost of Implementation Fee (i.e. CARB fee credit).

The ISO found the decision will impact its operations by creating a need to differentiate between transportation rates paid by covered entities and non-covered entities that the ISO's GPI is based on. As a result, the ISO reviewed its current transportation adder process and accuracy of rates used for the GPI.

Currently, the GPI is based on the combination of a natural gas commodity price (SoCal Citygate, SoCal Border or PG&E Citygate) and a transportation rate specific to the resources' geographical location. Each fuel region (Col A) refers to a specific transportation rate found on the schedules for electrical generation (EG). The ISO's policy is to reflect the rates held on the EG schedules, even if there is more than one rate under the schedule. Which is why SCE and SDG&E have two fuel regions since their schedules differentiate rates based on usage.

Table 13 below shows the ISO's analysis of its current intra-state transportation rate schedules for electric generation. The ISO found the ISO's process for providing fuel regions requires more flexibility to appropriately reflect differences in rate payments by customer types.

Table 13: ISO's Fuel Region Rates

[42] See California Public Utilities Commission, Rulemaking 14-03-003, issued October 23, 2015.
[43] See California Public Utilities Commission, Rulemaking 14-03-003, issued October 23, 2015.

A	B	C	D	E	F
				Effective April 1, 2016	
ISO's Fuel Regions	Intra-state Transporation Rates ($/therm)	AB 32 CARB Fee Credit	Cap and Trade Exemption' Credit	Effective Rate for Covered Entities	Effective Rate for Non-covered Entities
PGE (Backbone level rate)	0.00915	0.00056		0.00859	0.00915
PGE2 (Other Customers Rate)	0.02921	0.00056		0.02865	0.02921
SCE1 (<3 million therms/year)	0.10554	0.0011	*0.01932*	0.08512	0.10554
SCE2 (> 3 million therms/year)	0.03688	0.0011	*0.01932*	0.01646	0.03688
SDG&E1 (<3 million therms/year)	0.105420	0.00041	*0.02249*	0.08252	0.105420
SDG&E2 (> 3 million therms/year)	0.036380	0.00041	*0.02249*	0.01348	0.036380

The table contains the following information for each fuel region:

- **Intra-state Transportation Rates ($/therm) (Col B):** Transportation rates found on the electric generation schedules
- **AB 32 CARB fee credit (Col C):** Line-item credit to base rate applicable to customers who are identified by CARB as being directly billed for CARB administrative fees.
- **'Cap and Trade Exemption' Credit (Col D):** PUC R.14-03-003 decision created line-item credit for recovery of GHG compliance costs through introducing costs into rates effective April 1, 2016[44].
- **Effective Rate for Covered Entities (Col E):** ISO's estimate of gas transportation rate for customers directly billed by CARB effective April 1, 2016.
- **Effective Rate for Non-covered Entities (Col F):** ISO's estimate of gas transportation rate for customers not directly billed by CARB effective April 1, 2016.

The ISO found a need for adjustments to the Master File Fuel Region values. PG&E brought to the ISO's concern that its schedule has more than one rate based on a network location criteria. The rate for resources connected directly to the backbone transmission network is shown Table 13 highlighted in yellow to emphasize this rate is currently not available to the ISO's resources for these customers.

The ISO also found a need to differentiate rates based on whether a resource is covered or non-covered. The changes to rate structures from cap-and-trade regulations, will have a substantial impact. For example in SDG&E's territory, the intra-state gas transportation rates will be different by 0.0229 $/therm or 0.23 $/MMBtu. If the ISO does not differentiate the rate it pays to covered

[44] SCE & SDG&E's estimated rate impacts from under the proceeding.

entities from non-covered, the ISO will be overcompensating for GHG costs since covered entities' proxy cost calculations already include compliance costs[45].

The ISO proposes two changes to its current process for fuel regions. First, the ISO proposes to create a more flexible process for scheduling coordinators to request adjustments to the fuel region values for registration in the Master File. Second, the ISO will create two values for each fuel region to differentiate rates paid by covered and non-covered entities, where applicable.

Under the new process, scheduling coordinators will be able to introduce a new fuel region by submitting a request to add a new pipeline schedule rate to Master File field. For example, if a scheduling coordinator schedules its gas on the Kinder Morgan pipeline, the stakeholder will be able to submit a request to the ISO to include Kinder Morgan's schedule for electrical generation to the selections in the fuel region field. In order to successfully add a new value for the Master File field, the ISO would need a scheduling coordinator to submit the transportation schedule at the time of its request. The ISO will program the new value into the Master File field and review the schedule rates semi-regularly to reflect any changes in rates.

8.1.2. Improve the electricity price index calculation

The calculation of the electricity price index (EPI) is described in the proposed update to the Market Instruments Business Practice Manual.[46] The ISO is also in the process of making the electricity price index available to market participants via the ISO's current data transparency efforts. In the meantime, resource-specific information is available on request by contacting: epi@caiso.com.

After reviewing stakeholder feedback on the ISO's questions from the Straw Proposal[47], the ISO proposes a process change to the commitment costs methodology for maximum proxy cost start-up costs that will continue to be consistent with existing tariff language found in Section 30.4.1.1.1(a). The ISO found the EPI to be unduly burdensome to stakeholders to project the prices used by the ISO.

The ISO found calculation of auxiliary proxy costs should have a consistent methodology as that used for registered cost and EIM resources. This will both improve ISO operations and alleviate stakeholder concerns as the methodology is transparent and provides a robust estimate of projected electricity price. The ISO proposes the calculation for the EPI be done by multiplying the start-up auxiliary energy by the monthly GPI by a factor of 10. This represents a projected electricity price during unit start-up or cost of auxiliary power provided by the generator based on a unit with a heat rate of 10,000 Btu/KWh.

[45] See Section 5.1.4 for the proxy cost calculations to see how GHG costs are incorporated.
[46] PRR 829: Electricity price index calculation. See http://bpmcm.caiso.com/Pages/default.aspx.
[47] Table 9, Straw Proposal at 23.

9. Resource characteristics review

Resource characteristics are submitted to the Master File based on the generator resource data template.[48] Valid inter-temporal constraints, such as minimum up and down times, and other resource characteristics are the foundation for effective bidding rules. The ISO currently requires scheduling coordinators to provide information reflecting physical characteristics. Specifically, the tariff requires:

> ***4.6.4 Identification Of Generating Units***
>
> *Each Participating Generator shall provide data identifying each of its Generating Units and such information regarding the capacity and the operating characteristics of the Generating Unit as may be reasonably requested from time to time by the CAISO. All information provided to the CAISO regarding the operational and technical constraints in the Master File shall be accurate and actually based on physical characteristics of the resources except for the Pump Ramping Conversion Factor, which is configurable.*

Many of the resource characteristics are difficult to verify as they may legitimately require some engineering and economic judgment to balance excessive wear and tear and the technical capabilities of the resource. At the same time, the ISO believes that the vast majority of resource characteristics should be static over a period of time and reflect resource vintage and use.

9.1. Proposal for resource characteristics

The ISO proposes two sets of Master File values. The first set consists of all the existing resource characteristics and these must be based on the maximum (or minimum) design capabilities of the resource. These characteristics will be kept as validation data and for exceptional dispatch under stressed system conditions and will be referred to in this paper as "design capability" characteristics.

The second set is a subset of resource characteristics that will be used in the ISO market for normal operations. At minimum, these characteristics must support any resource adequacy showings and therefore adjust with changes to the resource specific resource adequacy showings. These values may be different than the first design capability set and will be referred to in this paper as "market" characteristics.

The ISO seeks input on how to assign responsibility of submitting design versus market characteristics in the Master File between participating generators and scheduling coordinators.

Design capability characteristics

[48] See http://www.caiso.com/market/Pages/NetworkandResourceModeling/Default.aspx link to the excel file for the most recent Generator Resource Data Template.

This set of Master File values will consist of all the existing resource characteristics and must reflect the maximum, or minimum, design capability of the resource. For example, maximum daily starts must reflect the maximum starts the resource can endure under emergency conditions; minimum up time must reflect the shortest time period a resource necessarily has to be committed before shutting down.

For those characteristics which have both design capability and market values, the ISO will ordinarily respect the market characteristics. However, where the ISO may need to issue an exceptional dispatch in response to stressed system conditions, the ISO proposes to make the design capability values available to operators.

The ISO also proposes to revise Tariff Section 4.6.4 and the Tariff definition of “Maximum Daily Starts” to refer to “design capability” rather than “physical characteristics,” as a unit’s design capability can be more objectively determined than its physical characteristics. For example, determination of a unit’s physical characteristics arguably could include economic trade-offs involving wear and tear.

Market characteristics

As previously noted, the ISO believes the value each unit has registered for the vast majority of resource characteristics would remain static over time, but recognizes the need for some characteristics to reflect a balance between technical capabilities and economic trade-offs. At this time, the ISO proposes to allow generating resources to register market characteristic values for maximum daily starts and ramp rates. Subject to the proposed amendment to Tariff Section 4.6.4, the ISO does not propose other changes to the basic nature of how resource characteristics are registered. Outside of the maximum daily starts and ramp rate characteristics, all other registered values would reflect the unit’s design capability characteristics.

Maximum daily starts may warrant being more restrictive than the design capability values for a few reasons. It is the ISO’s understanding that a common trade-off is made between excessive wear and tear on a resource and the frequency of being started. While a resource may be able to start, for example, five times a day, starting it more than twice a day would drastically increase wear and tear on the resource and thus the probability of catastrophic failure. Tolling agreements or power purchasing agreements may impose restrictions on the use of the resource by limiting starts. While these restrictions would not qualify the resource for use-limited status and an opportunity cost adder, they can be reflected in the maximum daily starts field to ensure the resource does not exceed the restrictions.

Extensive discussion around contractual limitations, and how market participants can ensure those limitations are respected in the ISO markets, have occurred in the Commitment Cost Enhancement initiatives. The most recent initiative, Commitment Cost Enhancements Phase 3 (CCE3), is developing a methodology to determine opportunity costs for resource limitations. However, CCE3 reiterates that contractual limitations do not qualify for an opportunity cost but committed to addressing these types of limitations through this *Bidding Rules Enhancements* initiative. The market based values can be used by market participants to ensure the resources do not exceed contractual limitations without affecting the commitment costs used in the markets.

Ramp rates can currently be specified as a component of daily energy bids. The ISO has greatly enhanced the modeling capabilities of resources in the markets, such as multi-stage generating resources, reducing the need to accommodate daily bid-in ramp rates. Also, removing the daily bid-in ramp rate functionality minimizes potential adverse market impacts from resources changing ramp rates based on current system conditions while the ISO market is making awards based on ramping capability under planned new market products i.e. flexible ramping product and corrective capacity. Therefore, the ISO proposes to remove the capability to specify ramp rates in daily energy bids. However, the ISO also recognizes the need to reflect preferred ramp rate capabilities used under normal operating conditions in contrast to those used under emergency conditions. As an analogy, most can agree driving a car always at full throttle is not the most efficient or preferred way to operate the vehicle. The ISO is now proposing to allow resources to have a market based ramp rate to reflect the preferred operational ramp rate of the resource under normal system conditions.

At this time, the ISO believes daily starts and ramp rates are the two Master File values for which a reasonable argument could be made to allow registration of a market value and a design capability value. The ISO, however, is open to considering other characteristics and seeks stakeholder feedback if there are other Master File values that warrant having both a design capability and market value. The ISO requests that any stakeholder suggestion to consider additional characteristics for market values also include support for why it would be appropriate to create dual values for that specific parameter.

[Note that the market-based characteristics will track resource adequacy requirements which may change over time. Just as flexibility is a new concept based on operational needs, so may resource characteristics that support future operational needs.]

10. Next steps

The ISO will discuss this revised straw proposal with stakeholders at an in-person meeting on December 3, 2015. Stakeholders should submit written comments by December 17, 2015 to InitiativeComments@caiso.com.

Appendix A: Survey of Energy Bidding Rules

ISO/RTO	RTM close for energy bids	Rules for changing energy bids in real-time	Calculates reference levels?	Mitigation
CAISO	T-75[49]	No limit[50]	Yes	Dynamic structural test (three pivotal suppliers)
ISO-NE	T-30[51]	No limit[52]	Yes[53]	Conduct and impact test[54]; restricted from fuel price adjustment for 2 (first offense) to 6 months (second offense)[55]
MISO	T-30[56]	No limit[57]	Yes[58]	Conduct and impact test[59]
NYISO	T-75[60]	If day-ahead schedule exists, increase in bid only[61]; may revise fuel cost used to calculate reference levels[62]	Yes[63]	Conduct and impact test[64]
PJM	Day-ahead: 16:00 EST TD-1[65] If no day-ahead schedule: 18:00 EST TD-1[66]	Can only change bids if no day-ahead schedule[67]; proposing to allow fuel policy changes intra-day[68]	Yes[69]	Structural test (three pivotal suppliers)[70]

---

[49] CAISO, Tariff section 30.5.1 General Bidding Rules.
[50] CAISO, Tariff section 30.5.1 General Bidding Rules.
[51] ISO-NE, FERC docket no. ER13-1877, July 1, 2013, Ethier/Parent testimony, p. 7. Tariff amendment to become effective December 3, 2014.
[52] ISO-NE, FERC docket no. ER13-1877, July 1, 2013, Ethier/Parent testimony, p. 7. Tariff amendment to become effective December 3, 2014.
[53] ISO-NE, Market Rule 1, Section III.A.7: Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.
[54] ISO-NE, Market Rule 1, Section III.A.5: Mitigation.
[55] ISO-NE, FERC docket no. ER13-1877, July 1, 2013, proposed tariff section III.A.3.4: Fuel Price Adjustments. Tariff amendment to become effective December 3, 2014.
[56] MISO, Energy and Operating Reserve Markets, Business Practices Manual, BPM-002-r13, Section 8. Real-Time Energy and Operating Reserve Market Activities.
[57] MISO, Energy and Operating Reserve Markets, Business Practices Manual, BPM-002-r13, Section 8. Real-Time Energy and Operating Reserve Market Activities.
[58] ISO-NE, Market Rule 1, Section III.A.7: Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.
[59] MISO, Market Monitoring and Mitigation Business Practices Manual BPM-009-r7, Section 5 Conduct Warranting Mitigation.
[60] NYISO, Open Access Transmission Tariff (OATT) - 1 OATT Definitions - 1.18 OATT Definitions – R, "Real-Time Scheduling Window."
[63] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.3.1.4 Reference Levels.
[64] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.1: Purpose and Objectives.

[63] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.3.1.4 Reference Levels.
[64] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.1: Purpose and Objectives.
[65] PJM, Manual 11: Energy & Ancillary Services Market Operations, 2.3.1 Bidding & Operations Time Line.
[66] PJM, Manual 11: Energy & Ancillary Services Market Operations, 2.3.1 Bidding & Operations Time Line. Reflects the balancing market offer period close.
[67] PJM, Manual 11: Energy & Ancillary Services Market Operations, Section 2.3.3 Market Sellers.
[68] PJM, Gas Unit Commitment Coordination 2014/2015 Winter Scope Proposal Review, October 30, 2014, p. 5. Available at: http://www.pjm.com/~/media/committees-groups/committees/mrc/20141030/20141030-item-11-gas-unit-commitment-presentation.ashx.
[69] PJM, Manual 15: Cost Development Guidelines, Section 1.6.1 Reason for Cost Based Offers: Market Power Mitigation.
[70] PJM, Manual 15: Cost Development Guidelines, Section 1.6.1 Reason for Cost Based Offers: Market Power Mitigation.

Appendix B: Survey of Commitment Cost Bidding Rules

ISO/RTO	Last time to modify start-up / min load cost	Calculates reference levels?	Mitigation
CAISO	10:00 PST TD-1 / 10:00 PST TD-1	Yes	Bid caps[71]
ISO-NE	T-30 / T-30[72]	Yes[73]	Conduct and impact test[74]; restricted from fuel price adjustment for 2 (first offense) to 6 months (second offense)[75]
MISO	T-30 / T-30[76]	Yes[77]	Conduct and impact test[78]
NYISO	Day-ahead: 5:00 EST TD-1 / 5:00 EST TD-1[79] If no day-ahead schedule: T-75 /T-75[80] and may update fuel prices in reference levels[81]	Yes[82]	Conduct and impact test[83]
PJM	Day-ahead: 16:00 EST TD-1 / 16:00 EST TD-1[84] If no day-ahead schedule: 18:00 EST TD-1 / 18:00 EST TD-1[85] Daily bidding under cost-based option; 6 month hold for cost-based option.[86] Proposing to allow intra-day changes to fuel cost methodology[87]	Yes[88]	6 month hold on using cost- or price-based option.[89] Structural test (three pivotal suppliers)[90]

[71] Assumes proposals in Commitment Cost Enhancements Phases 1 and 2 are approved and all resources are on the proxy cost option.
[72] ISO-NE, FERC docket no. ER13-1877, July 1, 2013, proposed tariff section III.1.10.9: Hourly Scheduling. Tariff amendment to become effective December 3, 2014.
[73] ISO-NE, Market Rule 1, Section III.A.7: Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.
[74] ISO-NE, Market Rule 1, Section III.A.5: Mitigation.
[75] ISO-NE, FERC docket no. ER13-1877, July 1, 2013, proposed tariff section III.A.3.4: Fuel Price Adjustments. Tariff amendment to become effective December 3, 2014.
[76] MISO, Tariff Module C: Energy and Operating Reserve Markets, Section 40.2.5(b): Required Generation Offer and Demand Response Resource - Type II Offer Components.
[77] MISO, Market Monitoring and Mitigation Business Practices Manual BPM-009-r7, Section 6.9 Reference Levels.
[78] MISO, Market Monitoring and Mitigation Business Practices Manual BPM-009-r7, Section 5 Conduct Warranting Mitigation.
[79] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff (MST) – 4 MST Market Services: Rights and Obligations, 4.2.1 Day-Ahead Load Forecasts, Bids and Bilateral Schedules.
[82] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.3.1.4 Reference Levels.
[83] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.1: Purpose and Objectives.

Appendix C: Stakeholder Comments Summary

Topic	Market Participant	Stakeholder Comment	ISO's Response

[82] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.3.1.4 Reference Levels.
[83] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.1: Purpose and Objectives.
[84] PJM, Manual 11: Energy & Ancillary Services Market Operations, 2.3.1 Bidding & Operations Time Line.
[85] PJM, Manual 11: Energy & Ancillary Services Market Operations, 2.3.1 Bidding & Operations Time Line. Reflects the balancing market offer period close.
[86] PJM, Manual 11: Energy & Ancillary Services Market Operations, Section 2.3.3 Market Sellers.
[87] PJM, Gas Unit Commitment Coordination 2014/2015 Winter Scope Proposal Review, October 30, 2014, p. 5. Available at: http://www.pjm.com/~/media/committees-groups/committees/mrc/20141030/20141030-item-11-gas-unit-commitment-presentation.ashx.
[88] PJM, Manual 15: Cost Development Guidelines, Section 1.6.1 Reason for Cost Based Offers: Market Power Mitigation.
[89] PJM, Manual 11: Energy & Ancillary Services Market Operations, Section 2.3.3 Market Sellers.
[90] PJM, Manual 15: Cost Development Guidelines, Section 1.6.1 Reason for Cost Based Offers: Market Power Mitigation.

Capacity costs vs short-run marginal costs	CalPeak, LLC and Malaga Power, LLC	Although the CAISO is contemplating making changes needed to ensure that generators are compensated for natural gas costs, it does not intend to provide compensation for all natural gas costs. Thus, the CalPeak Affiliates point out that the CAISO's comment to FERC is erroneous and should not be used as the basis for determining compensation for natural gas costs. It misconstrues what is bought and sold in agreements to purchase resource adequacy benefits.	See discussion in Section 3.2, the ISO reviewed these cost types and ISO has reconsidered its view that cash-out risk is not a short-run marginal cost but it does not believe this warrants changes to commitment cost bid caps. The headroom provided on the proxy costs provides a mechanism for suppliers to incorporate those costs.
	Calpine	ISO characterizes several costs categories as related to "capacity obligations" and therefore concludes that these costs should be recovered through Resources Adequacy (bilateral) markets rather than through CAISO energy markets. The ISO's conclusion that these risks should be included in the dramatically over-supplied RA market leaves little opportunity for recovery and therefore is inappropriate.	
	NRG Energy, Inc.	NRG disagrees strongly with the premise that generators will be able to recover costs associated with achieving gas flexibility in their resource adequacy payments. Most of the costs of transacting gas to support operation in the CAISO's markets are fundamentally variable costs, incurred solely as a result of providing CAISO market products.	
	NRG Energy, Inc.	NRG also thinks that it is pollyanish to assume that the buyer counterparties to capacity contracts will be eager or willing to simply roll these difficult-to-quantify costs into their capacity contracts. If generators are forced to attempt to recover these variable costs through the RA market, they will be forced to guess as to their expected gas-related expenses and incorporate that risk premium into their RA bids. Such an outcome simply increases prices for everyone.	

	Six Cities	The Six Cities disagree with the ISO's overly restrictive definition of incremental fuel costs at page 13 of the Straw Proposal. Although some costs related to fuel procurement properly may be characterized as capacity-related, that is not the case with respect to costs that result directly from ISO dispatch instructions, such as balancing penalties. The ISO appears to simply assume, without support, that such costs can be recovered through payments for capacity.	
	Southern California Edison	SCE supports the CAISO's view that capacity-related costs should not be recovered through the CAISO energy markets.	
	Western Power Trading Forum	WPTF strongly supports recovery of all delivery-related fuel costs. WPTF does not agree with the ISO that it is acceptable to let some fuel costs go unrecovered because – as the ISO puts it – these are more capacity-related costs.	
	Western Power Trading Forum	RA contracts may well not recognize such incremental expenditures, and not all suppliers hold RA contracts.	
	Calpeak, LLC and Malaga Power, LLC	The CalPeak Affiliates believe that if the CAISO has scheduled a unit to run in the day-ahead or real-time market and then uses its exceptional dispatch authority to order the unit off line, it should compensate the generator for the "net cost of the gas purchase," i.e. the difference between what the generator paid for the natural gas it purchased to run and what the gas was worth immediately after it was exceptionally dispatched off.	See discussion in Section 3.2, in evaluating a need for a risk premium against the ISO's market design, the ISO does not see a need for a premium. The ISO's commitment cost cap at 125% of its proxy cost calculation allows for headroom above its cost estimates for SCs to manage price risks such as cash-out risk. An appropriate use of this headroom would be to facilitate this cost recovery. The ISO proposes to not include a risk premium adder to the commitment cost calculations as the cap allows for sufficient flexibility to manage such risks.
	Six Cities	Six Cities support recovery of the costs of gas procured to respond to an ISO dispatch that subsequently is exceptionally dispatched down or off.	
	Western Power Trading Forum	WPTF also strongly supports recovery of demonstrated losses on sales of gas when the CAISO reduces a supplier's schedule after the day-ahead market.	

	San Diego Gas & Electric	First, real time imbalance gas needs are not a large part of a scheduling coordinators (SC) gas portfolio. Natural gas pipelines also provide imbalance tolerances to SC's allowing fuel managers to have discretion on when they will allocate supplies to their units. This is typically where real-time awards (awards unknown to SCs in the day-ahead time frame) gas needs are managed. CAISO could take a survey of how much this actually affects SCs.	See discussion in Section 3.2, the ISO reviewed these cost types and ISO has not reconsidered its view that imbalance gas fees are a short-run marginal cost.
Changes to the commitment cost cap to differentiate headroom for each component	Calpine	Calpine believes that further scaling back the commitment cost adders with the apparent intention of reducing BCR payments adds complexity without clear benefit, and includes potential harm to suppliers when costs vary from the estimates included in the Masterfile.	See discussion in Section 6.2, the ISO revises its proposal to retain the current process of establishing the commitment cost caps based on 125% of the proxy cost calculated. This is because the current headroom is in place in order to allow stakeholders to manage their risks, including but not limited to, price risk associated with the difference between actual gas costs and the use of a volume weighted average price index to estimate gas costs.
	NRG Energy, Inc.	The CAISO has not adequately explained how it would implement or enforce the differentiated headroom concept when commitment cost bids are single dollar ($) values which are not broken into component pieces.	
	NRG Energy, Inc.	NRG objects to this proposal. The current 25% headroom provided was not the result of meticulous analysis, but rather a generalization offered to speed implementation of a badly-needed fix to the CAISO's bidding rules. Applying the 25% headroom to all of the components of the commitment cost was reasonable because (1) the headroom figure was a generalization and (2) commitment costs are single bid numbers, not presented to the CAISO as separate components.	
	NRG Energy, Inc.	The ISO's continued preoccupation with using dated gas indices as a proxy for the reasonableness of the cost of gas procured at different times (intra-day, next day etc.), makes it important to retain the current headroom for all commitment cost components.	

	San Diego Gas & Electric	SDG&E does not at all support the CAISO's proposal to disaggregate the bidding headroom for each of the items included in the proxy cost calculation. The 125% proxy cost headroom gives resources flexibility to account for cost fluctuations in each of the elements comprising the costs to commit a unit without discrimination. It is possible to exceed the 125% on one item but be afforded room because a different item is still below the 125% threshold. Pooling these items makes the 125% blanket acceptable. The proposed decreases on headroom percentages for certain elements make the cost recovery possibility too low for generators.	
	Six Cities	At this time, the Six Cities do not support the proposal for differentiated bid caps on the proxy cost components. Such fine tuning of the bid caps for different elements of commitment costs would increase the complexity of bidding on commitment costs, and no evidence has been presented that benefits of differentiated bid caps would be sufficient to justify the burden of such increased complexity for market participants or the ISO.	
	Southern California Edison	SCE does not support this CAISO proposal. With an already complex set of market rules, this would further complicate market functioning, increase costs for market participants and would not add value to the market. The end result of this differentiated bidding proposal is effectively a lower commitment cost cap. While SCE does not support lowering the commitment cost cap at this time, SCE prefers to maintain the simpler solution and is open to discussing a lower cap in the future.	
	Pacific Gas & Electric	PG&E supports the CAISO's proposal to differentiate the bidding headroom on the components of the commitment costs, and recommends a starting point of 100% for non-gas related components.	

	Pacific Gas & Electric	PG&E supports maintaining the 125% bid cap on the natural gas price component of commitment costs. PG&E proposes to use a100% bid cap initially on all other commitment cost components (GHG, GMC, MMA, Non-fuel related costs, default VOM, and auxiliary energy). The bid caps on these non-gas components could be adjusted up if CAISO has analysis to support that additional headroom is needed.	
	Viasyn, Inc.	Viasyn does not oppose the differentiated bid caps, assuming as the proposal does, that an opportunity cost mechanism is in production. Viasyn supports the use of percentages for bidding the cost components.	
	San Diego Gas & Electric	While we do not support differentiated bidding headroom, if this proposal is to be explored any further, SDG&E recommends employing a less arbitrary method of setting thresholds. We would recommend something along the lines of headroom of at least two standard deviations of the volatility of the item.	
Evaluate commitment cost mitigation facilitating bidding flexibility	Calpeak, LLC and Malaga Power, LLC	The CalPeak Affiliates, understand, of course, that the CAISO uses bid caps to limit possible market power, but bid caps are not the best way to limit possible market power.	See discussion in Section 6.3, the ISO is not proposing to change the current commitment cost mitigation methodology and instead proposes to retain the 125% bid cap on commitment costs. This is because it does not foresee how either a conduct and impact test or pivotal supplier test could be effectively implemented in the CAISO energy markets and effectively mitigate commitment costs. Each option has concerns that deter the ISO from further consideration. Given this, the ISO does not support additional bidding flexibility for commitment costs during operating day. However in the event the headroom currently provided is not sufficient, the ISO proposal contains a process for disputing the BCR settlement after-the-fact as long as actual costs can be verified.
	Calpeak, LLC and Malaga Power, LLC	The CalPeak Affiliates hope that in this stakeholder proceeding the CAISO will put substantial effort into making improvements to its market power mitigation rules.	
	Calpeak, LLC and Malaga Power, LLC	The CalPeak Affiliates are particularly concerned that the CAISO does not appear to be considering a key improvement to bidding flexibility - removal of bid caps for the commitment cost bidding process. The CAISO's own review of ISO-RTO commitment cost bidding rules shows that the CAISO is the only organized market that severely limits bidding flexibility by imposing bid caps.	
	Calpeak, LLC and Malaga Power, LLC	The CalPeak Affiliates agree that the CAISO should provide compensation for natural gas costs above the index costs. The CalPeak Affiliates believe, however, that the best way for the CAISO to insure that this happens is to allow a more flexible bidding policy which will make it easier for generators to change their bids to reflect natural	

		gas price increases above the gas price index.	
	Calpine	Calpine supports the ISO proposal to investigate and evaluate alternative forms of mitigation for commitment costs. As often stated, Calpine supports daily bidding and particularly seeks the ability to change commitment costs bids hourly so as to reflect the differences between gas and electric trade days.	
	NRG Energy, Inc.	NRG strongly supports this effort and looks forward both to the CAISO's results and to consideration of an alternative methodology. The current system of bid caps may work most of the time, but the times where it has not worked have cost NRG dearly.	
	San Diego Gas & Electric	Real-time gas purchase cost recovery is best solved by implementing the proposed opportunity to rebid commitment costs in the real-time market. This should allow resources to account for gas costs more accurately. And, the opportunity to rebid commitment costs multiple times throughout the day, as proposed above, would continue to increase gas cost accuracy eliminating the need for any cost recovery mechanism.	
	Southern California Edison	The CAISO believes that a limited scope, ex-post, approach is more appropriate given the lower gas price volatility experienced by California, relative to the East Coast. SCE's preference is for a more flexible bidding policy rather than reimbursement for incremental gas purchases.	
	Western Power Trading Forum	WPTF supports, first and foremost, a supplier's ability to bid their start up and min load costs; this would allow suppliers to manage the risks associated with intra-day dispatch. In the case that the ISO does not implement a means for suppliers to bid their start up and no load costs, WPTF supports recovery of costs in excess of the proxy gas price.	

Changing bids during inter-temporal constraints	Calpine	The first-best solution to this problem is simply to lock out RT rebidding during inter-temporal constraints. If technically feasible, Calpine could support this solution conceptually but would want assurances that refreshed RT bids would be accepted immediately after the temporal constraint expires.	See discussion in Section 7.1.1, the ISO seeks stakeholder input on revised options for addressing bid changes during inter-temporal constraint. The ISO found 'locking' in bid resulting in commitment decision complicated.
	Viasyn, Inc.	The ISO should consider bid and settlement restrictions during inter-temporal constraints based on each type of constraint individually, as opposed to flat restrictions for all bidding scenarios under all inter-temporal constraints, and should avoid suppressing market compensation to resources that accurately reflect marginal costs within established market timelines.	
	San Diego Gas & Electric	SDG&E agrees with this methodology. For transparency, we request this to be detailed explicitly on the settlement statement so we can validate the unit settlement. If there is no indication the bid was used to settle, we will assume it was the LMP and could find the settlement to be incorrect.	See discussion in Section 7.1.1, the ISO seeks stakeholder input on revised options for addressing bid changes during inter-temporal constraint. The ISO finds 'locking' in bid resulting in commitment decision complicated. This 'locking' of bid prices also renders the second option proposed by the ISO in the straw proposal, overly complex.
	Southern California Edison	Based on these complexities, SCE supports the CAISO's proposal to settle BCR on the bid that led to the binding commitment.	
	Viasyn, Inc.	The ISO should ensure that BCR compensation reflects timely energy bids when a resource is dispatched incrementally within the inter-temporal constraint.	
	Calpine	As a second-best alternative, the ISO proposes to make settlement adjustments during inter-temporal constraints to "neutralize" BCR impacts. The details of this adjustment are unclear, as they are described very differently: (1) The Straw Proposal states that the ISO will "settle on the bid that caused the commitment"; and, (2) The PowerPoint used in the Stakeholder call states that settlement will be "at the bid cost of the RT LMP."	
	Calpine	Calpine encourages the ISO to clarify the settlement changes that if proposes, provide bid-to-bill examples and ensure that the principle of preserving RT operational indifference is maintained.	

	NRG Energy, Inc.	The CAISO's proposal to settle on the original bid is a reasonable approach except for those situations in which the scheduling coordinator may desire to change the bid not because of the exercise of market power but because of legitimately changed circumstances. For example, a unit constrained to operate at a particular level due to an operational constraint may need to change its bid to reflect a sudden change in operating conditions – for example, the sudden declaration of an OFO. For situations in which the need to change the bid arises from external circumstances, the CAISO could still adopt its proposed rule as long it offered an opportunity for the market participant to recover unexpected costs through an after-the-fact administrative mechanism.	See discussion in Section 7.1.1, the ISO does not see a reason to change its incremental energy bids outside a range of reasonableness from its original bids. This is because the optimization cannot respond to this new information but BCR settlement will still be impacted.
	Southern California Edison	SCE recognizes the potential to increase BCR payments during inter-temporal constraints and supports the CAISO in its efforts to mitigate the harm caused by this bidding practice. Although the CAISO has stated it cannot identify a reason why a resource would need to change its bids during an inter-temporal constraint, SCE would like to clarify that at times, SCE may want to change its resource bids to account for gas price changes.	
	Southern California Edison	SCE also supports the ability to change bids after a commitment decision without an inter-temporal constraint.	See discussion in Section 7.1.2, the ISO seeks stakeholder input on revised options for addressing bid changes outside of an inter-temporal constraint. The ISO is still considering monitoring for behavior but additionally seeks input on restricting bidding flexibility between the market runs.
Inefficient account for minimum load costs after Pmin rerate	DMM	The ISO's initial proposal to scale minimum load costs is flawed, due to the fact that minimum load is generally an inefficient point for resources to operate, and so the resource is likely to be more efficient at its rerated PMIN. Additionally, minimum load costs can include other factors that are not related to operating level, such as costs for major maintenance. In addition to providing increased and unjustified bid cost recovery, the scaling option could	See discussion in Section 7.2.1, the ISO revises its proposal to correct for this inefficient accounting by calculating the actual commitment costs based on the default energy bid (DEB) associated with the capacity range between the Master File Pmin and the re-rated Pmin where the incremental DEB costs are added to the

		distort the merit order of resources more than if there were no change in costs for PMIN rerates.	bid-in minimum load costs at the re-rated Pmin level.
	DMM	Consequently, DMM has asked the ISO to consider an alternative option where the default energy bid is used to estimate the real costs to run at the level of the PMIN rerate. This estimate should be much closer to real costs that units face.	
	San Diego Gas & Electric	If the CAISO moves forward with this proposal, SDG&E believes the second CAISO proposal to be the more accurate option- calculating the actual minimum load costs based on the heat rate of the resource.	
	San Diego Gas & Electric	If resources were provided the flexibility to fully recover the cost of a rerated Pmin, intuition is this would incent rerating a Pmin over self-scheduling a unit. The resource would receive the benefits of the self-schedule behavior with the advantage of being eligible for BCR. SDG&E requests the CAISO illustrate scenarios in which a resource would need to rerate its Pmin and still be eligible to recover new Pmin costs.	
	Southern California Edison	SCE supports the heat rate approach to account for changes in the Pmin. SCE believes that using the heat rate approach would provide the most accurate calculation of the MLC at the new Pmin.	
	Calpine	Calpine supports a scaling of the Minimum Load costs to match the new, higher Pmin. We could support either a linear scaling, or a scaling based on filed heat rates.	
	DMM	The current approach serves as an important and effective means of limiting the incentive to try to game PMIN rerates for increased bid cost recovery. However, we understand that there are some objections to the current approach due to the possibility of inefficient commitments.	

	NRG Energy, Inc.	Option (1), scaling MLC, will yield an answer that is simple – but wrong. Option (2), basing new MLC on heat rate, forces a purely cost-based bid, and re-introduces the problems associated with using a daily gas price index to set costs.	
	NRG Energy, Inc.	NRG offers this alternative: calculate the new Pmin cost based on the minimum load bid and the energy curve in place for the unit. Using the minimum load and energy bid submitted for the unit to create a new Pmin value preserves the market participant's view of the economics of operating the unit at a particular operating level.	
Rebidding of commitment costs between day-ahead and real-time for resources without day-ahead awards	CalPeak, LLC and Malaga Power, LLC	The CalPeak Affiliates agree that the resources that do not have a day-ahead schedule should be allowed to re-bid commitment costs. The CAISO should give generators significantly greater bidding flexibility to make sure they can cover their costs. At a minimum, the CAISO should allow generators that do not have a day-ahead schedule to rebid commitment costs in the real-time market.	See discussion in Section 7.2.2, the ISO proposes to allow resources with day-ahead market schedules to rebid their commitment costs in the real-time market. The ISO is proposing to keep the other commitment cost bidding rules the same: (1) the real-time market will use a single respective start-up and minimum load cost for each day, and (2) a resource cannot change its commitment costs once the real-time market has started for a given day. Consequently, resources will be able to resubmit commitment cost bids consistent with the real-time market close for hour ending 1 (i.e. 75 minutes prior to midnight).
	Calpine	The ISO proposes to allow units with no DA or RUC schedule a single opportunity (at 00:00 – 75 minutes, or 22:45) to re-bid their commitment costs for the RT market of the trade day. Calpine supports this proposal, as it allows for a better representation of the cost and volatility of natural gas costs in the intra-day markets. As we understand, the total commitment cost rebid can include both gas price changes and inclusion of a different escalator (up to 125 % for proxy cost resources).	
	DMM	DMM supports the ISO's current proposal that minimum load and start-up costs for resources without day-ahead commitments should be allowed to submit new bids for these parameters, within the 125 % cap for most resources, into the real-time markets.	
	NRG Energy, Inc.	NRG supports this proposal, and encourages the CAISO to propose rules governing the timing of real-time re-bidding. Indeed, most ISOs already incorporate such a feature, with ISO New England recently changing their	

		rules to allow rebid of commitment costs.	
	San Diego Gas & Electric	SDG&E supports the proposal of being able to rebid commitment costs for the real-time market if a resource did not receive a day-ahead or RUC award.	
	Southern California Edison	SCE supports CAISO's proposal to rebid commitment costs prior to the RTM for unawarded resources.	
	DMM	In addition, DMM suggests that the ISO maintain the requirement that real-time commitment costs not differ across hours within a date. To implement real-time rebidding consistent with this requirement, the ISO would need to limit rebidding to the time period between calculation of commitment costs with updated natural gas prices and T-75 of the first interval of the trading date.	See discussion in Section 7.2.2, the ISO proposes to maintain this requirement. Resources will be able to resubmit commitment cost bids consistent with the real-time market close for hour ending 1 (i.e. 75 minutes prior to midnight and the real-time market will use a single respective start-up and minimum load cost for each day.
	San Diego Gas & Electric	We recommend every 5 hours. As an example, with the look ahead period for the short term unit commitment (STUC) process being 4.5 hours, resources could rebid commitment costs every 5 hours with a 5 hour delay.	
	Six Cities	The Six Cities support the proposal to allow resources to update bids for commitment costs in the real-time market, provided that commitment cost bids for resources that have market power are subject to effective mitigation. However, because gas prices can change significantly within a flow day, the Cities urge the ISO to allow updating of commitment cost bids on an hourly basis in the real-time market which will allow more accurate reflection of costs for gas purchased to respond to real-time commitments in the commitment cost bids.	
	Western Power Trading Forum	We strongly encourage the CAISO to support rebidding not just before the FMM starts but within the FMM as well. A rolling rebid deadline, or biddable windows for several blocks of time during the day, would be an improvement over the design expressed in the CAISO's straw proposal.	

	DMM	Currently, default energy bids are updated to reflect the appropriate next day index for the flow date, but commitment costs are not.	See discussion in Section 8.1 where the ISO proposes improvements to the GPI which will change the ISO processes so that both default energy bids and commitment costs reflect the next day index for flows on the operating day. The ISO still proposes to allow rebidding for resources without day-ahead market award to reflect changes in natural gas prices after the close of the day-ahead market and allow for resources to adjust their bids within the bid cap accordingly.
	DMM	We agree with the ISO proposal to only allow resources without day-ahead schedules to update commitment costs, but recommend that the ISO specify how this would apply to different configurations of multi-stage generating units.	The ISO will apply the proposal consistently between MSG configurations and other units. If a configuration does not receive a day-ahead market award, the MSG resource can rebid their costs for incremental configurations.
	CalPeak, LLC and Malaga Power, LLC	The CalPeak Affiliates believe, however, that the CAISO's proposed change does not go far enough. Other ISOs already allow significantly more bidding flexibility than the CAISO.	See discussion in Section 6.3, the ISO is not proposing to change the current commitment cost mitigation methodology and instead proposes to retain the 125% bid cap on commitment costs. Without a dynamic market power mitigation, the ISO is not proposing increased flexibility during the operating day. Assuming the proposal to allow resources without day-ahead market awards to rebid commitment costs is
	CalPeak, LLC and Malaga Power, LLC	In 2013 ISO New England submitted a number of changes to its tariff to improve bidding flexibility (See filing of ISO New England ISO in FERC Docket No. ER13-1877).	
	CalPeak, LLC and Malaga Power, LLC	The ISO New England also proposed an associated tariff change to allow generators to request fuel price adjustments to the reference levels used for market mitigation purposes.	

	CalPeak, LLC and Malaga Power, LLC	The Straw Proposal indicates that PJM has "considering" an allowance for intra-day gas volatility. Straw Proposal at 10. This information is out-of-date. See PJM, Manual 11: Energy & Ancillary Services Market Operations, dated April 5, 2015, Section 2.3.3 Market Sellers ("When a generation resource is not scheduled in the Day-Ahead Energy Market or the Reserve Adequacy Commitment (RAC) by PJM, the Market Seller may update the cost-based schedules availability hourly three hours prior to the operating hour. The cost-based schedule made available must follow the Generation Owner's fuel cost policy as defined in PJM Manual 15: Cost Development Guidelines. A generation resource may not change schedule availability once it has been committed by PJM for the hours in which it is committed.").	accepted, the ISO finds its flexibility sufficient.
	Calpine	Calpine does seeks a clarification of the limitation, which would state that any commitment that does not overlap, or extend a DA commitment would qualify for this re-bid commitment cost. For example, assume the ISO awards a single commitment from HE 7 to HE 14 for a unit. The unit re-bids its commitment costs and is committed in RT for HE18 to HE 22. That second commitment should be optimized using the RT re-bid costs.	See discussion in Section 7.2.2.
Commitment cost calculations, managing natural gas commodity price risks	DMM	The ISO normally uses prices based on the previous day's trading since all but one of the sources of published gas prices for next day gas trading do not become available until after the time that the ISO's day-ahead market begins to run. However, this creates a one day lag between the flow date of the next day gas prices used in this index and the flow date corresponding to the operating day for which the ISO's day-ahead market is being run.	See discussion in Section 8.1, the ISO has revised and expanded its discussion.
	Western Power Trading Forum	Although the DMM analysis that proxy costs are often sufficient to cover the index-based gas burn, we request that CAISO continue to characterize the limitations of the assumptions with such an analysis. The analysis presumes that the supplier will encounter no other operating costs outside those already built into the proxy price, and that the	See discussion in Section 8.1, the ISO has revised and expanded its discussion to include an acknowledgement of the price risks associated with variability of gas purchase costs around the index price. The ISO finds if the higher market price

		supplier does procure the gas at or below the index price.	associated with either GD1 or GD2 is reflected in the commitment cost cap, there would be a high probability of recovering cost.
	Western Power Trading Forum	Since other costs can be encountered, and since suppliers can pay more than index to buy gas to ISO deployments, the DMM's analysis should not be overgeneralized to suggest that with a high probability a supplier's gas costs are fully recovered.	
	Calpeak, LLC and Malaga Power, LLC	Because the CalPeak Affiliates only operate peakers, the natural gas used to run its power plants is generally purchased only after its peakers are selected by the CAISO to run. If units are selected to run in the day-ahead market, arrangements to ensure an adequate of natural gas are generally made the day before the unit is to run. If the units are not selected to run in the CAISO day-ahead market, but are committed in the fifteen-minute market or real-time market, natural gas is often purchased for same-day delivery. Due to the inherent variability of the schedule on which peakers run, it is not feasible to hedge natural gas price risks.	See discussion in Section 8.1, the ISO finds its commitment cost cap at 125% of its proxy cost calculation allows for headroom above its cost estimates for SCs to manage its various risks. An appropriate use of this headroom would be to facilitate this cost recovery. The commitment cost cap allows for sufficient flexibility to manage such risks.
	Calpeak, LLC and Malaga Power, LLC	As the CalPeak Affiliates have learned, between bid caps and the CAISO's market power mitigation rules it often is not possible to cover costs when operating in the CAISO, particularly for fuel.	
	NRG Energy, Inc.	The current state of the indices created by the package trading practices should not create a self-fulfilling prophecy that, because the daily indices are thinly traded, the weekend packages should be retained. NRG strongly encourages the CAISO to consider breaking up the weekend package; daily index liquidity may come if the multi-day packages are broken up and market demand is sufficient to attract buyers and sellers.	The ISO uses industry recognized publications of index prices. If other indices become available the ISO will evaluate them.

	DMM	DMM suggests that the ISO consider dropping the threshold for when the ISO invokes the update to its special price spike procedures.	The ISO's proposal provides a stronger benefit than adjusting the threshold for the price spike procedures and serves as a long term market solution. Assuming the ISO's proposal is accepted, the special price spike procedures will no longer be needed for market operations.
	Calpeak, LLC and Malaga Power, LLC	The CalPeak Affiliates believe that the mechanism that PJM recently implemented to provide compensation for gas natural gas costs above index costs is a good starting point for rules for the CAISO. These rules are available at PJM, Manual 11: Energy & Ancillary Services Market Operations, Appendix C: PJM Procedure for Cost Adjustment. See also PJM Manual 15: Cost Development Guidelines, Section 1.8: Cost Methodology and Approval Process.	See discussion in Section 8.1 and the survey of ISOs bidding flexibility in Section 5.1.3, the ISO reviewed other ISOs rules and finds there are sufficient reasons for ISO's operations to differ from those designed for the Eastern ISOs.
	Calpeak, LLC and Malaga Power, LLC	It is clear that in other RTOs and ISO, generators receive compensation for total fuel costs. For instance, PJM has extensive "Cost Development Guidelines" in which PJM makes it clear that generators are to provide the information needed to assess total fuel costs. See generally PJM Manual 15, Cost Development Guidelines at § 2.3. Similarly, the CAISO should provide compensation for total fuel costs.	
	San Diego Gas & Electric	The CAISO references the 'real-time gas price index' in the example scenario on page 18 of the Straw Proposal. Does the CAISO mean the day-ahead index price because that's what the commitment costs will still be based on without the approval of rebidding?	See discussion in Section 8.1, the ISO's examples have been revised to provide more clarity.
Commitment cost calculations, after-the-fact recovery	DMM	DMM supports further consideration and discussion of the ISO's general concept to allow for cost recovery for resources that don't cover their fuel costs due to gas price volatility. However, DMM believes this approach would need to be limited by strict and clear conditions that are spelled out in detail as part of this stakeholder initiative, rather than at a later point as part of the implementation process. Design details should include specific reporting and documentation requirements required from generators,	See discussion in Section 8.1.1.2, the ISO has provided additional details including documentation requirements and data verification.

		and data verification and calculation rules that would be employed by the ISO.	
	NRG Energy, Inc.	NRG submits that there is no reason why a market participant should have to lose an arbitrary amount of money, no matter how large or small, before it could seek reimbursement of legitimately incurred costs. NRG proposes that the threshold be zero.	See discussion in Section 8.1.1.2, the ISO's proposal for after-the-fact recovery applies a threshold where disputes will only be evaluated if the actual costs exceed 25 % of the index. The validation process will be an after-the-fact validation subject to documentation and verification of actual costs and verification those costs were in line with market conditions at the time.
	NRG Energy, Inc.	As NRG has experienced, while the bid cap system may work for the CAISO and for market participants most of the time, subjecting market participants to huge losses for those situations in which it does not work is not a viable alternative, and some system that would allow for reimbursement of gas costs above the index is necessary.	
	Six Cities	The Six Cities support the concept of allowing recovery of intra-day gas costs that exceed the gas index plus headroom allowance based on after-the-fact documentation.	
	San Diego Gas & Electric	CAISO states purchases will be reimbursed if they are within a threshold established on historical natural gas trades for the appropriate day and market. Does this mean, if the purchase is beyond the threshold, there is no reimbursement? For example, if a real time price spike in which a resource was bound to purchase gas was beyond the historical threshold, there would be no reimbursement? Or, would there partial reimbursement up to the threshold?	
	Six Cities	Six Cities request additional explanation for the proposed limiting threshold, as it is not clear why recovery of properly documented intra-day gas costs should be constrained by a pre-established threshold.	

	Western Power Trading Forum	We do not understand the relevance of a “threshold”, and rather believe the ISO should provide compensation for any incurred costs that can be demonstrated.	
	NRG Energy, Inc.	NRG proposes that a market participant seeking to recover above-index costs be allowed to submit its own invoice to the CAISO, with supporting documentation and explanation, as opposed to trying to create or require a template invoice that requires specific information. If the CAISO is not comfortable reviewing and approving such invoices, it could enlist the services of an independent entity to perform that review.	See discussion in Section 8.1.1.2, the ISO proposes the scheduling coordinator submits its own invoice and documentation following the ISO's required documentation.
	San Diego Gas & Electric	But, in practice, there are many issues concerning SDG&E in regards to the CAISO’s proposal of creating a method to figure out the additional gas cost above the gas index and accounting for this in BCR. SDG&E believes CAISO and stakeholders should qualify the need for this reimbursement mechanism before CAISO moves forward. SDG&E feels there is not a great need and the potential risks outweigh small benefits.	See discussion in Section 8.1.1.2, the ISO's proposal for after-the-fact recovery applies a threshold where disputes will only be evaluated if the actual costs exceed 25 % of the index. The ISO surveyed other ISOs and found several provide some version of the after-the-fact recovery. Since the ISO's proposal is to retain commitment cost mitigation caps, the ISO finds this process will provide cost recovery.
	San Diego Gas & Electric	If gas marketers know there is a compensation mechanism in the real-time CAISO market for gas purchases to satisfy real time generation commitments, what’s to stop them from taking advantage of this when generators call to purchase gas, especially in the later illiquid cycles? Marketers can add a mark-up and generators are indifferent because this then flows on to consumers. This cost would be passed on to Load.	
	Six Cities	The ISO’s review and validation process should limit after-the-fact adjustments to the volume of gas necessary to respond to real-time commitment, which the Cities believe can be estimated based on Master File data.	The ISO agrees with this point.

	San Diego Gas & Electric	If CAISO were to proceed with this reimbursement, SDG&E proposes CAISO use a separate platform than BCR for reimbursement. In most instances, this type of case assumes the generator will not make money over the day. And, SDG&E agrees. However, there may be instances when a peaker, or short term committed unit, might actually make money over the day and not qualify for BCR. This could present confusion in accounting and settlement validation.	The ISO does not think generators should receive cost recovery outside of the 25 % headroom if their market revenues resulted in revenue surplus overall.
Adjusting gas transportation rates to closer reflect transportation rates	San Diego Gas & Electric	We agree with the CAISO on waiting to propose policy changes on the greenhouse gas costs for natural gas suppliers until the CPUC has issued a proposed decision in June.	See discussion in paper at Section 8.1.1.3, where The ISO proposes to create two values for each fuel region to differentiate rates paid by covered and non-covered entities, where applicable, due to CPUC's decision to allow natural gas suppliers to recover GHG compliance costs through their rates.
	DMM	To the degree that resources with greenhouse gas compliance obligations are given a greenhouse gas obligation rebate on gas transport prices set by retail tariffs, the ISO's gas price indices should recognize that. DMM would support the addition of greenhouse gas adjusted fuel regions.	
	Pacific Gas & Electric	PG&E supports CAISO's proposal to develop a GHG cost methodology for natural gas suppliers once the CPUC rulemaking is completed.	
	San Diego Gas & Electric	SDG&E currently reflects different gas transport adders based on physical location for each resource's submitted bids to the CAISO. SDG&E would like more information on what the CAISO proposes in addition to adjust gas transportation adders.	See discussion in Section 8.1.1.3, where the ISO proposes to create a more flexible process for scheduling coordinators to request adjustments to the fuel region values for registration in the Master File. This change will support the inclusion of multiple gas transportation adders if reflected in gas suppliers' schedules. The ISO clarifies that the magnitude of differences in gas transportation costs is not a consideration in allowing for the fuel regions to reflect actual costs. The proposal is to create a fuel region if there is a rate the resource pays to transport its gas purchases represented in an inter-state transportation tariff schedule for EG not present currently in
	Six Cities	The Six Cities support the general concept of differentiated gas transportation adders if there are significant differences in gas transportation costs such that more granular allowances are necessary for resources to recover their costs.	
	Six Cities	The Cities request that the ISO provide further analysis, however, with respect to the magnitude and consistency of locational differences in gas transportation costs.	
	DMM	The proposed change would allow calculation of regional gas price indices that better reflect the true incremental cost of gas within the PG&E system. DMM is supportive of this change.	

	NRG Energy, Inc.	NRG supports this proposal.	the Master File to allow resources to request a new field.
	Pacific Gas & Electric	As PG&E outlined in the CCE2 initiative, we support the development of multiple gas transportation adders for the PG&E region (similar to currently practice in Southern California). This would create indices that better reflect the sometimes large difference in gas transportation costs faced by units on the gas pipeline backbone versus units on the local transmission system.	
	Southern California Edison	SCE supports the proposal to allow for more differentiation in gas transportation costs. In addition, SCE would like the CAISO to consider an additional gas region to more accurately represent Kern region prices.	
Improve transparency and accuracy of electricity price index	DMM	Resources incurring wholesale electricity costs for auxiliary power should be assigned an EPI based on an estimated wholesale electricity cost at their location and resources incurring retail electricity costs should be assigned an EPI based on the retail electricity costs they incur.	See discussion in Section 8.1.2, the ISO found the EPI to be unduly burdensome to stakeholders to project the prices used by the ISO. The ISO found calculation of auxiliary proxy costs should have a consistent methodology as that used for registered cost and EIM resources.
	DMM	The wholesale EPI should be based on analysis of prices from the resources specific appropriate commitment period rather than the 5-minute real-time market in all cases (i.e. DAM vs RTM commitments).	
	DMM	The current calculation of the off-peak wholesale EPI is based on the average off-peak wholesale price at the pricing node from the prior year. In some cases, the earliest interval included may be almost two years prior to the trade date. DMM recommends that a more recent time period would be more representative of congestion driven price differences between the pricing node and trading hub where future price conversion factors are calculated.	
	DMM	The wholesale price for days containing peak hours is estimated by averaging prices from the top 8 peak hours within each day of the relevant season in the prior year and multiplying the seasonal average by the future price conversion factor. DMM suggests that an average of all peak hours and from a more recent time period would be more representative.	

	DMM	Future price conversion factors are restricted to be between 100 and 150 %. The restriction appears arbitrary and only allows price increases. DMM recommends that the future price conversion factor be symmetrical and allow for downward price changes (e.g. 50 to 150 %).	
	DMM	DMM recommends that the EPI for EIM resources should instead be calculated in a manner consistent with ISO balancing area resources.	
	Pacific Gas & Electric	The logic of paying the higher of the retail or LMP is not clear. Why is the higher of these two appropriate, other than for possible ease of implementation?	
	Pacific Gas & Electric	Is it possible to have the resource pre-select the use of their preferred/applicable index (i.e. retail or LMP)?	
	Pacific Gas & Electric	CAISO will currently adjust the forward wholesale monthly price projections – only upwards – based on historical monthly prices. Why is an adjustment needed, and why only upwards?	
	Calpeak, LLC and Malaga Power, LLC	Although the Straw Proposal indicates that resource-specific information is available by contacting the CAISO, the Scheduling Coordinator was informed that such information is not currently available. The Scheduling Coordinator was also informed, however, that the Energy Price Index is provided to CAISO by a third party, Potomac Economics, on a daily basis and the CAISO plans to publish this data as part of the Fall 2015 Release. The CalPeak Affiliates request that the CAISO make historical information regarding how the Energy Price Index was calculated for its units available to the CalPeak Affiliates so that they can provide better informed responses to the questions that the CAISO has included in the Straw Proposal regarding how the Energy Price Index should be calculated.	See discussion in Section 8.1.2, the ISO is in the process of making the EPI accessible to market participants.
	NRG Energy, Inc.	NRG notes that the CAISO does not publish this component of the commitment cost, and so it remains opaque to market participants. Whatever modifications are made to this cost component, NRG urges the CAISO to publish this component to	

		provide some transparency as to its value.	
	DMM	The electricity price index (EPI) should be assigned based on the retail electricity provider of the resource, rather than the natural gas fuel region.	See discussion in Section 8.1.2, the ISO proposes to introduce a Master File field to reflect retail electric provider of a resource.
	DMM	Resources paying for auxiliary power under the SDG&E tariff should be assigned an EPI based on SDG&E's tariff rather than SCE's tariff.	
Changes to introduce 'market' characteristics in the Master File.	Calpine	We have long struggled with the implication of the tariff that there is a single, unquestionable value for many of the Masterfile characteristics. The physical capability of the machines can be different than the capability recognized through economic and operations judgment.	See discussion in Section 9.1, the ISO recognizes the need for some characteristics to be able to reflect a balance between technical capabilities and economic trade-offs. At this time, the ISO proposes to allow market characteristic for scheduling coordinators to reflect the economic judgement used to determine plant operations. Additionally, the market based values can be used by market participants to ensure the resources do not exceed contractual limitations without affecting the commitment costs used in the markets. The ISO clarifies this proposal is not limited to resource adequacy resources.
	NRG Energy, Inc.	NRG supports this proposal, which it perceives to be similar to PJM's "eco/emergency" values. This proposal reflects the reality that a market participant may not wish to operate its unit at its extreme capabilities under normal market operations, but would make the unit available at those extreme capabilities in an emergency.	
	San Diego Gas & Electric	SDG&E supports the CAISO proposal to add a 'Market Value' column to the Master File.	
	San Diego Gas & Electric	SDG&E agrees and believes the Market Value column will allow resources to better manage usage to keep the unit available to the market for the year as planned. Excessive wear and tear runs the risk of less time between maintenance cycles. Since this cost is not accounted for in an opportunity cost, SDG&E believes the properly designed Market Value column will help reduce this issue. Therefore, SDG&E believes the 'Market Value' column should allow for more than just RA commitments. This column is important to help manage a resource's usage based on maintenance constraints not implicit to the already existing physical value column or energy bids.	

	Six Cities	On a preliminary basis, the Six Cities support this aspect of the Straw Proposal and recommend that the opportunity to include market characteristics in the Master File be available to all resources, rather than being limited to Resource Adequacy resources.	
	Southern California Edison	SCE sees potential merit to the CAISO's proposal to allow SCs to provide information for two sets of operating characteristics.	
	Viasyn, Inc.	Viasyn does not oppose the separate reporting of physical and market characteristics of the resource fleet.	
	Western Power Trading Forum	WPTF sees merit in distinguishing between physical and market resource characteristics, and we look forward to more dialog on this issue.	
	Pacific Gas & Electric	PG&E does not support the CAISO proposal, as it creates an artificial distinction between "market" characteristics and "physical" characteristics which does not exist in reality. A small subset of resources are subject to environmental permits which result in true "physical" values in the Master File. The "physical" value of all remaining resources (the majority) are based on engineering and economic judgment. For most resources, the "physical" and "market" characteristics will be the same – e.g. the number of starts that are permitted under the contract. CAISO will not be able to access more starts than what PG&E is contractually able to offer. PG&E urges the continued discussion regarding contractual limitations and how they can best be planned for and factored into CAISO dispatch protocols.	
	Southern California Edison	Will allowing only Exceptional Dispatches (EDs) to use physical characteristics of the resource address the problem of contractual resource limitations?	
	Viasyn, Inc.	Any contractual or regulatory constraints such as emissions restrictions that the resource must abide by should be permitted to be reflected in the physical characteristics of the resource, as they should not be required to breach a contract or regulatory constraint for purposes of ISO exceptional dispatch.	

	Calpine	Calpine would recommend that reliance on physical characteristics should be limited to Significant Events, such as the declaration of an emergency and not always be available to ISO dispatch for exceptional dispatches.	See discussion in Section 9.1, the ISO's intent is that the ISO would only use design characteristics for reliability purposes which could fall short of a declared emergency. The ISO anticipates the use would be limited.
	NRG Energy, Inc.	NRG will make every effort to make its units available to the CAISO at the unit's full capabilities when needed, but sees value and reduced risk in being able to operate units "away from the edge" under normal, non-emergency conditions.	
	Viasyn, Inc.	The ISO proposes to mandate the availability of the full physical range of the resources for exceptional dispatches without providing for additional consideration of the potential financial or operational consequences of such increased flexibility.	
	Viasyn, Inc.	The ISO should consider a compensation mechanism through which the resource may recoup the costs of this capability to perform between the market and physical range, such as the bidding of the physical range of the resource without such bids being considered during non-exceptional dispatch conditions.	The ISO is not proposing market values for capacity based Masterfile values.
	Calpine	Calpine would anticipate that there is a larger set of characteristics that should be included in the list of potential candidates for "market characteristics". For example, if daily starts is included, why not daily transitions?	See discussion in Section 9.1, the ISO's review of characteristics is still ongoing and will consider additional characteristics if others are brought to our attention. The two selected to need market values are those found to require a subjective engineering and economic judgment and do not inject market vulnerability to manipulation. The initial characteristics identified are max daily starts and ramp rates.
	Southern California Edison	How will the CAISO determine what resource characteristics will be allowed to have market characteristics?	
	Southern California Edison	Using the physical characteristics of some resources, such as Demand Response (DR) and storage, may still not be feasible. Such resources may reject certain CAISO ED instructions, based on the potential for physical damage should the instructions be followed. How does the CAISO propose to address these technologies? Is the upcoming, new, storage initiative the	The ISO will address these issues under the storage stakeholder initiatives.

		appropriate venue to address physical characteristics of storage resources?	
	NRG Energy, Inc.	NRG also hopes that this concept would provide a reasonable fix for some issues it encounters with its combustion turbines with very small operating "ranges", for example, when an ambient de-rate effectively lowers the Pmin to a value outside of the Master File value, and the unit may be producing at the lower value but is not recognized as "on" because the value is below the Master File value.	The ISO anticipates the proposed solution for the inefficient accounting of MLC when a Pmin rerate occurs will simultaneously address this concern.
Validating Master File characteristics	DMM	DMM is supportive of this approach as an alternative to the status quo if the necessary design and implementation details are further developed as part of the stakeholder process. As a result, DMM believes it would be reasonable to set guidelines limiting the degree to which a unit's market characteristics could be more constrictive than their actual physical characteristics. Resource adequacy obligations are clearly required to provide the capacity and flexibility to the market for which resource adequacy compensation or credit is being provided.	See discussion in Section 9.1, market characteristics need to comply with any resource adequacy criteria of the resource.
	Southern California Edison	What level of differences between physical and market characteristics would the CAISO consider acceptable?	
	Southern California Edison	Are there any limitations on market characteristics relative to physical characteristics? Can the CAISO clarify that any market characteristics limited by physical characteristic parameters will be conveyed to SCs with a reasonable amount of lead time for such notification?	
	Southern California Edison	Will the CAISO require the resource owners or SCs to provide physical characteristics to the CAISO? Who will ultimately be held responsible in any disputes regarding accuracy of these physical characteristics? Will the CAISO detail these responsibilities in the tariff?	See discussion in Section 9.1, the ISO proposes changes to the Master File registration. The ISO seeks input on how to assign responsibility of submitting design versus market characteristics in the Master File.

	Calpine	Calpine conceptually supports the development of a range of reasonable resource characteristics.	See discussion in Section 9.1, the ISO explored establishing a range and is proposing to clarify the definition of "physical" in its tariff to refer to 'design capabilities' and therefore is not proposing default ranges.
	NRG Energy, Inc.	NRG encourages the CAISO to explore ways to shorten the lead time for making changes to these new – and to all – Master File values.	See discussion in Section 9.1.