Stakeholder Comments Template

Commitment Costs and Default Energy Bid Enhancements

Submitted by	Company	Date Submitted
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March 30 and April 20 Working Groups

This template has been created for submission of stakeholder comments from the March 30 and April 20, 2017 working groups for the Commitment Costs and Default Energy Bid Enhancements initiative. Information related to this initiative may be found at: http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCosts_DefaultEnergyBidEnhancements.aspx

Upon completion of this template, please submit it to initiativecomments@caiso.com. Submissions are requested by close of business on **May 1, 2017**.

Questions:

As explained during the March and April workshops, CAISO's current bid structure design includes up to four components where the commitment cost components are considered cost based offers subject to validation and the energy component is a market based offer that is mitigated if potential to exercise market power is detected. The minimum load component combines both the variable and short-term fixed costs of operating at minimum operating level (See March Market Working Group Slides 11, 21-43; April Market Working Group Slides 12-18).

Figure 1: Illustration of CAISO bid structure components

Type	Sub-type	Market Based Offer	Cost Based Offer
Energy	Variable Cost	X	
MLC	Variable Cost		X
	Fixed Cost		
TC	Fixed Cost		X
SUC	Fixed Cost		X

CAISO seeks Stakeholder feedback on the following questions in light of the market working group discussions. For each of these questions please expand on a yes/no answer with inputs on advantages or disadvantages to the potential design choices.

1. General Questions:
    a. We are seeking feedback on whether the Issue Paper and working group discussions regarding the bidding flexibility, market power mitigation methods, and mitigated price or maximum allowable commitment cost level determination concerns was inclusive of the issues held by stakeholders.
    b. The High-Level Design Paths Handout contains a decision tree with four design paths. What are stakeholder views of the preferred path on the decisions trees? Are there more than four design paths that should be considered to evaluate for a preferred path?
    c. What items would you like to briefly discuss in the next workshop on May 23?

Six Cities' Response: In their December 12, 2016 Comments in response to the ISO's November 18, 2016 Issue Paper on this initiative, the Six Cities urged the ISO to phase this initiative to prioritize potential enhancements that support recovery of supplier costs and to defer to a second phase of the initiative potential enhancements that will allow suppliers increased bidding flexibility under competitive conditions to express their willingness to supply energy. The Six Cities continue to recommend that the ISO phase this initiative to facilitate more expeditious consideration and implementation of enhancements that will improve the ability of suppliers to recover their costs when gas prices are volatile. There are several such potential enhancements that are straightforward and relatively easy to implement.

The discussion in the April 20, 2017 workshop indicated a general consensus among the participating stakeholders that market-based bids for commitment costs would be appropriate provided that the ISO has the ability to identify and effectively mitigate market power that may affect commitment costs. As demonstrated by the length and complexity of this comments template, a broader expansion of bidding flexibility for commitment costs will require resolution of a number of complex and challenging issues, including the appropriate structure of tests for market power.

The ISO should not permit the quest for the perfect to remain the enemy of the good. The ISO should focus first on the more straightforward measures for enhancing supplier opportunities to recover costs and then deal with the more complex issues thereafter, as suggested previously by the Six Cities and in the comments on the Issue Paper submitted by the ISO's Department of Market Monitoring on November 29, 2016 (the "DMM Comments").

2. Supply Offer Structure with Market Based and Cost Based Offers
    a. Should the California ISO enhance its bid structure to support suppliers' submitting market based offers for the commitment cost components? If done, the California ISO would need to determine an appropriate "circuit breaker" offer cap and mitigation test to identify conditions where mitigation is needed. (E.G. Bid Structure and Bidding

Rule Design Option Handout 3b)

Type	Sub-type	Market Based Offer	Cost Based Offer
Energy	Variable Cost	X	
MLC	Variable Cost / Fixed Cost	X	X
TC	Fixed Cost	X	X
SUC	Fixed Cost	X	X

b. If the ISO does not propose to introduce market based offers subject to mitigation, would stakeholders prefer the ISO to evaluate increasing the level of the commitment cost bid cap used to ex ante validate these cost based offers fall within a reasonable range of expected costs or to continue to focus in re-designing the cost based framework? To illustrate, what are the preferences based on trade-offs between either (1) making no changes to the gas and non-gas unit processes for estimating costs but increasing the scalar used in both the maximum allowable commitment cost levels and default energy bid calculations to e.g. 150% versus bid-in cost based offers or reference level adjustments?

c. If the ISO proposes to introduce market based offers for the commitment cost components, would that necessitate removing the functionality today of submitting cost based offers even for those components? For example, today ISO allows suppliers to submit its cost expectations in the bid submission subject to the bid cap as a validation method. If market based offers are supported, the ISO could remove the cost based offer from the bid stack, reduce the scalar to 110% consistent with default energy bids, and insert the calculated cost based offers when mitigation applies. On the other hand, if the cost based offers subject to 125% bid cap was retained there would be greater flexibility to submit representative costs. (E.G. Bid Structure and Bidding Rule Design Option Handout 2b)

Type	Sub-type	Market Based Offer	Cost Based Offer
Energy	Variable Cost	X	
MLC	Variable Cost / Fixed Cost	X	
TC	Fixed Cost	X	
SUC	Fixed Cost	X	

d. If introducing market based offers does not necessitate removing the cost based offers for commitment costs from the bids, should the California ISO enhance its bid structure to support suppliers' submitting a cost based offer for the incremental energy

component? (E.G. Bid Structure and Bidding Rule Design Option Handout 4b)

Type	Sub-type	Market Based Offer	Cost Based Offer
Energy	Variable Cost	X	X
MLC	Variable Cost Fixed Cost	X	X
TC	Fixed Cost	X	X
SUC	Fixed Cost	X	X

Six Cities' Response: The Six Cities take no position at this time on the questions raised in the sub-parts of Item 2. These questions should be deferred to a second phase of this initiative, as recommended in the Six Cities' response to Item 1 above.

3. Hourly Commitment Costs or No Load Structure
    a. Do minimum load, start up, or transition costs have hourly variation and should market participants be able to select which hours to offer that component or if start up and transition should be allowed to have hourly values as well? Do stakeholders have a preference for how to move to hourly values? Please explain the reasons that suppliers need to have minimum load, start up, or transition costs that vary hourly beyond what can be accomplished through re-bidding minimum load subject to its minimum run time in the real-time market?
    b. At the March Market Working Group meeting, the California ISO put forward two options for moving to hourly treatment of minimum load, they included:
        i. Would stakeholders support Option 2, "Hourly Minimum Load Cost Component", which would change the commitment cost components (minimum load including variable and short-term fixed costs, start up, and transition costs) to hourly components (March Market Working Group slides 35, 38-40; April Market Working Group slides 12 and 13)? ISO seeks input on all commitment cost components as it understood from the April Market Working Group meeting that there may be some stakeholders voicing a need for hourly values for all.
        ii. Would stakeholders support Option 3, "Hourly and Daily Minimum Load Energy Bid Components", which would move to a "no load" structure in lieu of its "minimum load structure"? Put differently, should the California ISO move to a bid structure where there is a bid value for both the hourly variable cost portion and the daily short-term fixed cost portion (see March Market Working Group slides 25, 35, 41-43)?
    c. Depending on whether the ISO proposes to introduce market based offers for the components for short-term fixed costs or introducing a bid-in cost based offer for variable energy components, the bid structures could include either:
        i. No changes to short-term fixed cost components – only supporting flexibility for the hourly variable component of minimum load energy as shown in Bid

Structure and Bidding Rule Design Option Handout 5a.

Type	Sub-type	Market Based Offer	Cost Based Offer
Energy	Variable Cost	X	
MLC	Variable Cost	X	
	Fixed Cost		X
TC	Fixed Cost		X
SUC	Fixed Cost		X

ii. Introducing market based offers and retaining cost based offer functionality for short-term fixed commitment cost components while adding the flexibility for the hourly variable component of minimum load energy as shown in Bid Structure and Bidding Rule Design Option Handout 3a.

Type	Sub-type	Market Based Offer	Cost Based Offer
Energy	Variable Cost	X	
MLC	Variable Cost	X	X
	Fixed Cost	X	X
TC	Fixed Cost	X	X
SUC	Fixed Cost	X	X

iii. Introducing market based offers and removing cost based offer functionality for all components while adding the flexibility for the hourly variable component of minimum load energy as shown in Bid Structure and Bidding Rule Design Option Handout 2a.

Type	Sub-type	Market Based Offer	Cost Based Offer
Energy	Variable Cost	X	
MLC	Variable Cost	X	
	Fixed Cost	X	
TC	Fixed Cost	X	
SUC	Fixed Cost	X	

iv. Introducing market based offers and retaining cost based offer functionality for all components while adding the flexibility for the hourly variable component of minimum load energy as shown in Bid Structure and Bidding Rule Design Option Handout 4a.

Type	Sub-type	Market Based Offer	Cost Based Offer
Energy	Variable Cost	X	X
MLC	Variable Cost	X	X
	Fixed Cost	X	X
TC	Fixed Cost	X	X
SUC	Fixed Cost	X	X

<u>Six Cities' Response:</u> The Six Cities support immediate modification of the bidding rules to allow hourly updating of Commitment Costs until a unit has been committed. In addition, the Six Cities support immediate implementation of the following enhancements

to recognize more current information on gas prices in the determination of Commitment Cost bid caps and Default Energy bids:

i) Using on a permanent basis the weighted average of trade prices on the InterContinental Exchange ("ICE") available prior to the Day-Ahead market run for establishment of the gas price component of the Commitment Cost bid cap and Default Energy Bids;

ii) Using trading information from ICE for the first trade day of a week for the gas price component of the Commitment Cost bid cap and Default Energy Bids; and

iii) Updating real-time gas indices between 8:00 a.m. and 9:00 a.m. using prices for gas trades observed during earlier hours of the same day.

In addition, the ISO should proceed to develop a detailed process and guidelines to allow for after-the-fact recovery of commitment costs and incremental energy costs not recovered through market revenues.

For the reasons described in response to Item 1 above, the other questions raised in Item 3 regarding bid structures should be deferred to a second phase of this initiative.

4. Market Based Commitment Cost Offers Subject to Market Power Mitigation
    a. Assuming the California ISO proposes to support market based offers for commitment cost components, please respond to the following:
        i. Is the current method used to cap commitment costs resulting in over-mitigation of units and/or regularly limiting suppliers' ability to submit prices based on their willingness to sell when there is unlikely to be market power concerns? If so, please explain.
        ii. Would a dynamic assessment performed in tandem with the energy mitigation be preferable to stakeholders similar to that described in the March Market Working Group slides 50?
        iii. Would stakeholders support considering a static competitive path assessment for commitment cost mitigation if a dynamic one is not feasible? A static competitive path assessment might take the form of a structural test (pivotal supplier test) that identifies paths likely to be uncompetitive based on assumed or representative historical conditions.
        iv. Provide feedback on the California ISO's conceptual proposal to introduce a dynamic market power mitigation test for commitment cost offers (March Market Working Group slides 45-50).
    b. What analysis or additional information, if any, would stakeholders request to be in a better position to support or oppose a California ISO proposal for a commitment cost mitigation test?

<u>Six Cities' Response:</u> The Six Cities take no position at this time on the questions raised in the sub-parts of Item 4. These questions should be deferred to a second phase of this initiative, as recommended in the Six Cities' response to Item 1 above.

5. Cost Based Framework and Validation Deterring False or Misleading Submissions
    a. Is the current method of determining the mitigated energy price (default energy bid) or the maximum allowable levels for commitment costs imposing too large of a price risk on suppliers to potentially incur losses? If so, please explain. Please discuss what, if any, implications there are to suppliers' business of price risk imposed based on California ISO limiting bids, cost based through maximum allowable levels or market based through mitigation, to different levels than suppliers' cost expectations.
    b. Regardless of whether market based offers are introduced for the commitment cost components or not, the ISO seeks stakeholder feedback on whether it should introduce bid-in cost based offers to resolve concerns raised. We previously asked if the California ISO should re-examine its policy that gas-fired units' costs can be estimated with other technology types cannot as well as should we consider moving to a bid-in cost based offer. As shown from the content in the March Market Working Group slides 18-19 and the April Market Working Group slides 16-18, the California ISO currently believes to transition to a technology neutral bidding design a bid-in cost based offer would likely be necessary. We are seeking feedback on whether technology agnostic treatment should be a key design principle as the California ISO evaluates a straw proposal for these issues?
    c. In lieu of bid-in cost based offers should the California ISO consider introducing fuel price adjustments to its reference level calculations to reduce the risks that suppliers' will not have mitigated prices that reasonable reflect their cost expectations? Such a process would closely resemble those performed by the Eastern RTO/ISOs such as NYISO's examined at the April Market Working Group meeting.
    d. In its Issue Paper, the California ISO asked, "What is a reasonable approach to valuing expected production costs that results in an efficient market solution and cost recovery?" To develop the dialogue around this question, stakeholders brainstormed cost components during the April Market Working Group meeting. Provide feedback on whether the California ISO rules should support cost based offers that contain the following cost items (from April Market Working Group discussion) or not? Specifically respond to the following:
        i. What components are associated with variable energy costs ($/MWH) those brainstormed included fuel costs at a delivered fuel price (as refined in BRE), variable operations & maintenance, grid management charges, greenhouse gas compliance costs, and opportunity costs for eligible energy output limitations?
        ii. What components are associated with variable costs for minimum load energy ($/MWH) those brainstormed included fuel costs at a delivered fuel price (as refined in BRE), variable operations & maintenance, grid management charges, greenhouse gas compliance costs?

iii. What components are associated with run hours ($/run hours) those brainstormed included minimum load major maintenance adders, opportunity costs for eligible run hour limitations, service agreements, etc.?
iv. What components are associated with a startup($/start) or MSG transition ($/transition) those brainstormed included start-up fuel costs at a delivered fuel price (as refined in BRE), start-up auxiliary costs, grid management charges, greenhouse gas compliance costs, start-up major maintenance adders, and opportunity costs for eligible start limitations?
v. For each portion with a fuel cost component (incremental energy, minimum load energy, and start up/transition), please provide feedback on whether the fuel cost policy should be clarified to include either or both fuel replacement costs (e.g. foregone revenues as result of reducing consumption of demand response resources) and risk margin for risk of non-compliance with gas transport rules (e.g. risk of non-compliance with an OFO, SOC, or COC)?

e. What validation method would Stakeholders prefer for bid-in cost based offers ($/MWH, $/run hour, $/start, $/transition open to any technology type) or reference level adjustments ($/MMBtu applicable only to gas based reference levels)?
   i. What should ex ante verification include and should the approach differ between the two options given one is a cost based supply offer where the other is a natural gas market price value?
   ii. What should ex post verification include and should the approach differ between the two options given one is an energy offer where the other is a natural gas market price value?
   i. Seeking feedback on the types of supporting documentation used today in other RTO/ISO for both approaches discussed at the April Market Working Group meeting, which includes in order of relevance as a function of liquidity (earlier items more relevant during highly liquid conditions, lower items more relevant during highly illiquid or strained conditions):
      1. Invoices
      2. Index publisher information (consummated low-mid-high values)
      3. Electronic platforms (consummated/unconsummated bid-ask spreads)
      4. Broker quotes (text, emails, squawk box)
      5. Current line pack levels
      6. Notice of Fuel Transport Flow Orders (e.g. SOC/COC/OFO/EFO)
      7. Fuel scarcity conditions (e.g. "can't find counterparty", Feb 2014)

<u>Six Cities' Response:</u> See the Six Cities' response to Item 3 above for a summary of modifications that should be implemented immediately to recognize more current information on gas prices in the determination of Commitment Cost bid caps and Default Energy bids.

In addition, the Six Cities recommend immediate implementation of a targeted mechanism, described below, to provide an opportunity for recovery of unavoidable gas penalties or charges triggered by ISO dispatch instructions. Commitment cost bid caps

and (for mitigated resources) Default Energy Bids ("DEBs") should be adjusted to reflect gas penalties or imbalance charges that will (or are likely to) be triggered by compliance with ISO dispatch instructions and cannot be avoided.

As the Six Cities previously described in their December 12, 2016 comments on the Issue Paper, generators at times are faced with the Catch-22 choice of failing to follow ISO dispatch instructions or incurring unavoidable penalties if they do follow the ISO's instructions. For example, the SoCal Gas balancing requirements are tied to stages of Operational Flow Orders ("OFOs") and include escalating penalties and narrowing tolerance bands for balancing gas burn with scheduled deliveries as the OFO Stage increases. On days when OFOs are in effect, ISO Real-Time Dispatch can cause a resource to incur a financial penalty due to use of natural gas outside the applicable tolerance band.

The ISO's current commitment cost recovery provisions are not sufficient to allow reasonable recovery of costs incurred to comply with ISO dispatch instructions when penalties are triggered. The risk of unavoidable penalties is a consequence of ISO Real-Time dispatch directives (as opposed to Self-Schedules or Day-Ahead economic awards), especially Real-Time dispatches occurring after 3:00 p.m. The last regular trading cycle for natural gas (known as the "Intraday 3 Cycle") closes for the flow day at 5:00 p.m. The time required to locate trading counter-parties and complete trades becomes longer and more difficult as the flow day advances, and a two-hour transaction time (*i.e.*, between 3:00 and 5:00 p.m.) is necessary as a practical matter for last minute trades. If, but only if, a resource has the ability to withdraw gas under firm storage contracts, additional gas may be available until 9:00 p.m. on the flow date. Thus, arranging for delivery of additional gas to cover an ISO Real-Time dispatch order is significantly hampered after 3:00 p.m. and impossible after 9:00 p.m. daily. As a result, late-day dispatches by the ISO create a substantial risk of non-avoidable penalties when OFOs are in effect, and even the 150% commitment cost allowance currently applicable to use-limited resources may not be adequate to cover the balancing penalties plus other commitment costs.

Gas-fired resources cannot address this risk by over-procuring gas supplies, because there also may be penalties that apply to over-deliveries of gas. If a resource owner assumes a unit will run and buys additional gas to meet the daily balancing requirement, and the unit does not run, the resource owner is exposed to the potential of penalties for exceeding the high side of the daily balancing tolerance range that prohibits a resource owner from delivering too much gas. For Day-Ahead schedules, arranging for gas supplies within the allowed minimum and maximum amounts is possible. The ISO's Real-Time dispatches and the resulting gas burns are the unknown.

The Six Cities recommend that gas-fired resources be permitted to include amounts to reflect the risks of imbalance penalties in their commitment cost bids and (for mitigated resources) Default Energy Bids ("DEBs") for hours beginning with HE 16:00 on days when OFOs are in effect. The incremental bid amounts would be modest for the lower OFO stages but would increase for higher OFO stages. For example, based on a

hypothetical heat rate of 10,000 mmBTU/kwh, the potential bid adders would range from $2.50/MWh at OFO Stage 1 to $500/MWh for an Emergency Flow Order violation.

The Six Cities understand that some entities have expressed concern that allowing direct recovery of natural gas penalties may undermine the deterrent effect of the penalties and thereby reduce reliability of the gas system. However, restricting the inclusion of potential imbalance penalties to commitment cost bids and DEBs for hours after 3:00 p.m. on days when OFOs are in effect will allow suppliers the opportunity to recover penalties only for hours when they have no practical ability to avoid the penalties and, therefore, should have little or no adverse impact on the deterrent effect of the penalties. Allowing adjustment of commitment cost bids and DEBs under the narrow circumstances proposed also will reduce the likelihood of dispatches that would result in gas overburns, which would enhance gas system reliability. To deter abuse of the opportunity to include potential penalty costs in commitment cost bids and DEBs, the ISO should have the authority to require resources that increase their commitment cost bids by a penalty adder to document their exposure to potential penalties and should make clear that including a penalty cost bid adder when a resource is not at risk of incurring penalties will constitute a violation of the market conduct rules.

If the ISO does not allow adjustment of commitment cost bids and DEBs for mitigated resources after 3:00 p.m. on OFO days, gas imbalance penalties that could not be avoided should be recoverable as part of an after-the-fact cost recovery filing with the FERC. Exposing generators to non-avoidable and non-recoverable costs incurred to comply with ISO dispatch instructions is not only confiscatory but also has the potential to adversely affect electric system reliability. Unless suppliers have the opportunity to include the risk of non-avoidable penalties in their commitment cost bids and DEBs, the opportunity to request after-the-fact recovery of costs should include the ability to request recovery of gas penalties that were incurred to respond to ISO Real-Time dispatch instructions and could not be avoided.

For the reasons described in response to Item 1 above, the other questions raised in Item 5 regarding structure, components, and validation of cost-based commitment cost bids should be deferred to a second phase of this initiative.