Submitted by	Company	Date Submitted
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Commitment Costs and Default Energy Bid Enhancements
Comments on March 30 and April 20 Working Groups

On October 1, 2017, PGE will become the fifth entity to join the Western EIM. At that time, PGE will begin managing its diverse generation and transmission assets according to the rules of the EIM, while also continuing to participate in the ISO's forward markets. As such, PGE has a vested interest in the price-formation policies of the ISO and Western EIM.

PGE submits the following comments in response to the ISO's detailed questions distributed to the CCDEBE Working Group on April 26, 2017.[1]

PGE appreciates the ISO, DMM, MSC, and Stakeholders' engaged participation in the MSC Meeting held May 5, 2017.[2] The insights shared have informed PGE's comments here, and provided valuable data points for the next CCDEBE Working Group meeting. PGE looks forward to continued dialogue with the MSC on these issues.

In addition to answering the detailed questions below, PGE would like to express support for the comments submitted by NV Energy.[3] Specifically, PGE agrees that a commitment has been made to the FERC to remedy certain EIM-specific issues related to cost-recovery in the context of persistent mitigation of bids to an EIM participant's DEB. PGE supports the position that at a minimum this initiative should result in the near-term implementation of a stop-gap measure to allow EIM participants to communicate to DMM prior to the running of the real time market that their fuel costs will likely exceed the DEB reference level. PGE believes an interim process could be put in place to manage these narrow instances, even if manually, while a long-term solution is developed and implemented. Finally, PGE supports NV Energy's request that this initiative be listed as "EIM Governing Body – Hybrid" due to the impact it will have on EIM participants and price formation specific to their market.

ISO Questions:

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*

[1] PGE's submitted summary comments May 3, 2017: http://www.caiso.com/Documents/PortlandGeneralElectricComments_CommitmentCosts_DefaultEnergyBidEnhancementsWorkingGroupMar30_Apr202017.pdf

[2] http://www.caiso.com/Documents/Briefing-CommitmentCost-DefaultBidEnhancements.pdf

[3] http://www.caiso.com/Documents/NVEnergyComments_CommitmentCosts_DefaultEnergyBidEnhancementsWorkingGroupMar30_Apr202017.pdf

or maximum allowable commitment cost level determination concerns was inclusive of the issues held by stakeholders.

Yes, this has been a very well-run and inclusive initiative to date. PGE especially appreciates the working-group atmosphere, which allows for open dialogue and sharing of constructive ideas. Given the rapid pace of change in the ISO's markets and the need to evolve certain market design attributes, PGE believes it is critical that stakeholders be given an opportunity to "think outside the box" alongside ISO and DMM staff and bring potential best-practices from their experience in other markets. PGE encourages the ISO to continue this working-group process for the "Phase 2" aspects of the initiative while transitioning the "Phase 1" aspects to a formal implementation process.

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?*

The decision-tree graphic was helpful for framing the discussion and is appreciated. However, the perspective from which the qualitative judgements of "high" vs. "low" risk need to be articulated and explained in more depth. PGE believes the risks of over- and under-mitigation, and of inaccurate price representation, are not symmetric or linear, and have not been evaluated on a probabilistic basis that could accurately inform decision making.

Within the "possible" paths presented, PGE supports as Phase 1 (at a high level) the incremental improvements suggested by DMM and others of performing more frequent and appropriately-timed updates to the gas price index to arrive at an improved reference level as compared to the status quo.

That said, PGE believes a market-based solution would significantly improve market efficiency over the current design. PGE views this type of solution as an important change that should receive adequate time, attention, and resource commitment by the ISO to ensure it is implemented without undue delay. PGE believes a transition to a market-based solution will further market participant confidence in their ability to accurately price their bids and offers, and thereby encourage increased market participation.

c. *What items would you like to briefly discuss in the next workshop on May 23?*

It is important that stakeholders be given some line of sight to the implementation cost and timeline expectations the ISO has at this point for the various options, even if it's only at a very high level.

It would also be good to discuss any current or planned initiatives that would link to this work, and how updates or changes in one area could fit with updates or changes being considered in this initiative.

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

   Yes. PGE believes there is no harm in allowing suppliers maximum flexibility in pricing their bids. PGE sees the introduction of additional bidding flexibility as an overall benefit to market efficiency and competition, and thereby to end-use customers. PGE encourages a "circuit breaker" offer cap that tracks with the energy market.

   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?*

   PGE would like to see the ISO continue to work on re-designing its cost based framework if the preferred market based path isn't chosen.

   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	

The ability to submit cost based offers should be left in place, either using the same methodology as today, or preferably with the improvements considered in the next question. Submitting market based offers will likely require more work by the market participant in multiple areas, and some participants may prefer to take the less complex option if they have a unit with very straightforward commitment and dispatch costs, or do not have the resources to support the additional regulatory work cost-effectively. It is important, however, that this remain a voluntary choice to be made by the entity, and that one is not perceived in practice as more preferred or appropriate from a regulatory standpoint than the other.

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

Yes, the improvements do not need to be mutually exclusive unless it is cost- and/or time-prohibitive. The market based offer solution should still be prioritized though as it offers the greatest potential to benefit end-use customers.

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?

Yes. Suppliers need the flexibility to shape their dispatch to their load and ramping needs. The bilateral market for flexible capacity is not sufficiently liquid at this time to be able to assume that capacity can always be replaced in a future intra-day interval if it is use-limited and dispatched in a prior intra-day interval. EIM entities retain their NERC requirements and must plan to operate their BA on a stand-alone basis. EIM entities cannot rely on the EIM on a forward basis to reduce their reserve requirements or to provide replacement ramping capacity should their resources be dispatched in a previous interval and no longer be available due to fuel or other constraints.

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.*

   Providing for the flexibility to submit hourly values for all components would be an incremental improvement. If Option 3 is infeasible for any number of reasons, we would support Option 2.

   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)?*

   Yes. This would ultimately be the preferred path. However, this has to be weighed against timing, cost, and regulatory complexity. Stakeholders need more data there before being able to say it is worth the effort to go to 100% of the cost components being hourly, vs. a subset.

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

Each of these would be an improvement on the current design, and we would again express our support for the design that lends maximum flexibility, which appears to be "4a", subject to previous comments about time, cost, and complexity considerations.

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.*

         It is somewhat difficult to state definitively that this is happening. However, it should be noted that the existing market rules do influence bidding behavior. It is therefore not sufficient to look back at past behavior and conclude if the cap was increased that offers would stay at the current level simply because they previously had not been pushing against the cap. As was stated at the working group meetings, entities have other reasons for running their units and may be resigning themselves to taking the losses that operating within the existing rules brings, simply for a lack of other options. Improving the framework may or may not ultimately result in prices significantly different than seen in the market today, at least if certain market conditions persist (such as historically low natural gas prices); however, it is still important for the efficiency and long-term sustainability of the market to make these changes and prepare for the market dynamics facing our region over the known resource-planning horizon.

      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?*

         Yes.

      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.*

         Only if other options are truly infeasible should a static competitive path assessment be used. If it is, the implementation of dynamic market power mitigation should be set as a future-phase goal and worked toward as resources allow. PGE notes that if this option is chosen it will be important to work closely with EIM participants on how the test is applied in their specific instance given the unique nature of the market relative to their BA reliability obligations and the lack of historical path data specific to EIM dispatch under various conditions.

As a foundational matter, PGE agrees with EDF's assertion that "structural market power mitigation approaches such as the pivotal supplier test are too restrictive in that they assume that a supplier with the ability to exercise market power has the incentive to do so, regardless of whether there has been any market power abuse."[4]

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).*

PGE would like to see this issue discussed in more detail at the next working group meeting.

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?*

Cost and implementation trade-offs would be helpful. Stakeholders have little line of sight to the complexity facing the ISO and DMM in this area, or how market changes would impact existing processes.

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.*

Yes. We are operating in a highly volatile energy market where ramping capability and on-system flexibility are at a premium and a supplier's ability to recover their costs are constricted into narrower dispatch horizons. This trend is only going to increase in intensity over the known resource-planning horizon. It is critical that market participants have the ability to accurately reflect their costs to prevent cross-

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[4] http://www.caiso.com/Documents/EDFComments_CommitmentCosts_DefaultEnergyBidEnhancementsWorkingGroupMar30_Apr202017.pdf, p. 5.

subsidization and/or under-recovery, both of which are unsustainable and long-term uneconomic, as well as to ensure they can manage their fuel-supply risk, and run-time or other constraint-based risk, to be able to meet their NERC mandated reliability requirements and customer load service expectations.

As has been shown in more open markets, it is highly preferable from an economic efficiency standpoint to have market dispatch be controlled by economic bids and offers, and to allow the forces of supply and demand to produce rational economic outcomes. Relying on a complex system of outage cards, use limitation markers, and other workarounds to protect an asset's value is inefficient and counterproductive to the goals of an organized market. Entities should not be forced to manage their portfolio this way due to a lack of in-market mechanisms.

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?*

   Yes. If the ISO is seeking a "cleaner, greener grid", it must ensure that its market rules support the efficient participation of carbon-free resources, such as hydroelectric generation or emerging technologies.

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.*

   Yes. Bid-in cost based offers would be preferable, but fuel price adjustments would still be helpful, so long as there is sufficient flexibility for the unique fuel-storage scenarios faced by many market participants.

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?*

   Those are all reasonable to include.

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?*

   Those are all reasonable to include.

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.?*

   Those are all reasonable to include.

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?*

   Those are all reasonable to include.

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)?*

   Both; all of those considerations are important to allow adequate flexibility on the supplier side.

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?*

      The ex ante process for the bid-in cost based offer should be formulaic and should put as much compliance/verification on the supplier's internal controls as possible. Put another way, the goal should be "trust the process, but have a way to verify if/when desired to check the process is working across its input-to-output lifecycle."

      The feasibility of reference level adjustments for short-term updates needs to be further tested and needs to be assessed at gas trading hubs beyond those identified in the DMM study. For example, the Sumas and Rockies trading hubs are most relevant for Pacific Northwest EIM participants, and their price formation and liquidity fundamentals may vary significantly from those observed at SoCal City Gate.

   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?*

      For the bid-in cost based offer, periodic spot checks should suffice, and a process should be in place to test under certain extreme market conditions or "tail events".

      For the reference level option, much depends on how the prices will be captured, and until those options are settled on its difficult to tell what approach is warranted. That said, the more straightforward the rules, the easier it will be for entities to develop internal reporting controls that would obviate the need for regular ex post checks and would make any periodic ex post checks more expedient.

   iii. *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)*

All options seem valid to some extent; however, (1) is probably the least likely to result in adequate flexibility for suppliers as an opportunity cost consideration is informed by what could happen, not necessarily by what did happen, and the timing relative to bid submittal is very important in that instance.

It should also be noted that price is inextricably linked to quantity, which may require the reporting of multiple points of information – for example, replacing 25MW of power (via the underlying fuel purchase) for tomorrow's peak may be priced significantly differently than replacing 250MW, and a supplier would need the ability to reflect those differences when considering what to input in their bid curve. This is especially true when regional supply is constrained and there is a high level of price volatility, the presence of which is one of the key drivers of this initiative.

PGE looks forward to sharing more of its experience in this area at the next working-group meeting.