Comments on Bidding Rules Enhancements Revised Straw Proposal

Department of Market Monitoring

December 18, 2015

The Department of Market Monitoring (DMM) appreciates the opportunity to review and comment on the ISO's Revised Straw Proposal for Bidding Rules Enhancements. We have included comments below related to the following topics: Consideration of additional costs as marginal, breakup of the weekend gas package, improvements to the gas price index, adjusting minimum load costs with Pmin rerates, and after-the-fact cost recovery.

Requests to consider additional costs as marginal (Section 3.2)

Stakeholders have requested that the ISO consider additional costs (such as pooling arrangement costs, imbalance penalties, or gas trade risk premiums) as marginal costs, and therefore include them in proxy cost calculations. The ISO views most of these costs as capacity related and hence inappropriate to include in proxy cost calculations. As the ISO explained in recent comments filed at FERC:

> 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.[1]

In the ISO's most recent whitepaper in this initiative, ISO staff has expressed a similar position, except with respect to risk associated with being exceptionally dispatched off after the procurement of natural gas. In this initiative, ISO staff has expressed the position that this "*cash out"* risk does constitute a short-run marginal cost. However, staff believes that the 25 percent "headroom" included in current commitment cost bid cap provides sufficient headroom to cover this risk.

DMM supports the ISO's position that these additional costs should not be explicitly incorporated into proxy cost calculations. In addition to the rationale explained by ISO staff, DMM notes that in practice it can be extremely difficult to determine – especially before the

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[1] Comments by 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, March 6, 2015, p. 6: http://www.caiso.com/Documents/Mar6_2015_CAISOComments_onTechnicalWorkshops_AD14-14.pdf.

fact – how much any of these costs may actually be incurred, or if any are incurred as hourly marginal costs associated with any specific unit commitment or energy dispatch. The extent to which a change in gas burn on a given day translates into a realized cost likely depends on a range of factors, such as the applicable balancing rules and penalties as well as the trading portfolio and any pooling arrangement of the participant. Therefore, the costs associated with gas price risk are specific to each resource and are not easily quantified, especially as an expected hourly marginal cost associated with any specific unit commitment or energy dispatch.

To the extent that market participants are exposed to this risk, it is important that risk not be confused with cost recovery. Risk is a function of expected cost rather than after the fact calculations of realized costs. As such, DMM believes that the 25 percent commitment cost headroom is sufficient for allowing resources to incorporate a reasonable risk premium into their commitment cost bids whenever they believe it necessary to do so.

Requests to consider improvements to GPI (Section 3.3)

Trading of natural gas for "next day" delivery on Saturdays, Sundays and Mondays is typically traded as a package on the preceding Friday. Since the natural gas price index currently used by the ISO is based on next day trading prices, this price is constant for these three consecutive days (Saturday, Sunday and Monday). Some stakeholders have suggested setting prices for these three individual days in order to better reflect the true marginal cost of procuring natural gas. The ISO does not disagree with this in concept, and also argues that (1) no adequate index price is available for the individual days, and (2) the 25 percent headroom incorporated in the commitment cost bid cap is sufficient to cover the risk created by this lack of granularity.

DMM believes that the lack of a good index price for next day trading for each individual day does not necessarily preclude the possibility for improvements of the current approach. For example, information about Monday same day trade prices can be used to assess the average price difference between same day prices and the corresponding next day package price. Based on this difference, a Monday adder can be constructed that would capture the systematic difference between same day and next day prices.

Using this approach, DMM has used historical data to estimate what an appropriate Monday adder would have been, and to what extent this would have been helpful to cover additional trades on Mondays.[2] Our analysis shows that the resulting adders would likely be small (less than 5 percent in most cases) and would very rarely cause the final index price to cover any additional reported trades compared to the 25 percent headroom currently available for commitment costs. Based on this, DMM believes that a breakup of the weekend packages is not needed for commitment cost proxy cost calculations. DMM therefore supports the ISO's finding that the 25 percent headroom for commitment costs allows for a sufficient amount of flexibility to cover the variation in price for weekend package days.

[2] Because of holidays, the first trading day of the week is not always a Monday. This was taken into account in our analysis.

Correct inefficient accounting for minimum load costs after a Pmin rerate (section 7.2.1)

The ISO originally proposed to prorate the minimum load costs of resources with a temporarily re-rated Pmin level in order to improve accounting for the adjusted costs of the resources experiencing such an outage. DMM worked with the ISO to develop the current proposal and use the default energy bid (DEB) and the marginal heat rate curve of each resource to assign a rerated minimum load cost. DMM supports this proposal to more accurately reflect the costs of resources that are experiencing these kinds of outages. However, in the next iteration of the paper, DMM asks that the ISO clarify the circumstances under which these kinds of Pmin re-rates are appropriate.

DMM understands that this proposal was developed to address relatively large changes in the minimum operating level of resources that can occur due to extreme weather conditions that can occur in the desert southwest. DMM's understanding is the ISO intends to explicitly limit the use of upward re-rates in a unit's Pmin to cases involving actual physical limitations such as these extreme ambient weather conditions. The ISO should also explicitly prohibit use of Pmin re-rates due to non-physical limitations, such as a unit owners desire to operate at a higher level. Without such explicit limitations, the proposed revisions would allow unit owners to essentially force the ISO dispatch units above their actual minimum operating level and receive compensation in excess of actual costs due to the 10 percent adder included in DEBs.

Improve gas commodity price (Section 8.1.1.1)

Currently, the ISO uses a gas index based on the average of multiple gas prices in order to increase the accuracy of gas prices used and prevent potential manipulation of a single price index. 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. For example, at 10 a.m. on a Tuesday, when the ISO's day-ahead market for Wednesday begins to run, default energy bids and commitment cost bids are based on an index of multiple gas prices published for gas that traded on Monday for delivery on Tuesday.

The ISO suggests three options to address this situation. Option 1 is to make use of both the lagged and non-lagged index for a given trade day. The theoretically correct way to do this, which would match the gas trade day, would be to apply the lagged index value for hours ending 1 through 7 and the non-lagged value for hours ending 8 through 24. However, the current ISO market design does not allow commitment cost bids to change within the trade day. Therefore the ISO suggests to use the maximum of the two prices for the entire trade day. Because of the publication time of natural gas index prices this option would likely require the day-ahead market to run later in the day.

Using the maximum of the lagged and non-lagged index price would result in a GPI that is higher than the actual marginal cost almost half the time.[3] Since it would never be lower than the theoretically correct value, it would on average overestimate the true fuel cost. Overestimating the gas price is problematic since it would allow resources with market power to exercise this market power to a greater extent, which in turn could result in higher market costs. This would impact both commitment cost and default energy bids.

Option 2 is to replace the current lagged gas price index with a non-lagged index for the entire trading day. As with Option 1, this would likely require the day-ahead market to run later in the day. DMM supports this option as it would improve the alignment between the ISO's gas price index and the relevant next day natural gas index price without causing the gas price index used by the ISO to systematically overestimate the relevant natural gas price. The misalignment that would still remain during hours ending 1 through 7 would likely be of lesser concern, given that these are typically low load hours. As noted in the ISO's Revised Straw Proposal, DMM's analysis shows that using a gas price index for the correct flow date greatly reduces the number of historical trades not covered by the available headroom.[4] Further, DMM emphasizes that this would be an improvement both for commitment costs and default energy bids.

Option 3 is to not make any changes to the GPI. The main advantage of this option is that it does not require any changes to the timing of the day-ahead market run.

As noted above, DMM prefers Option 2 as a significant improvement compared to the current situation, as long as most stakeholders find that the gains from an improved accuracy of commitment cost proxy costs and default energy bids outweigh the costs associated with adjusting the timing of the day-ahead market run.

As an alternative to Option 1 the ISO could consider using a weighted average of the lagged and non-lagged price indices instead of the maximum.[5] The average could be weighted by, for example, the number of hours for which the index price is applicable or by the total MWh of forecasted load during those hours. Using a weighted average instead of the maximum would result in a GPI that on average is closer to the marginal cost of natural gas. Further, a weighted average price of the two indices would likely be more representative of the fuel portion of a commitment cost bid placed by a market participant striving to reflect its commitment costs especially since participants cannot place different bids for different hours.

However, for purposes of calculating default energy bids, a weighted average might still be less desirable compared to Option 2 (which would use only the non-lagged index price) since energy

[3] In any given hour, it will be higher with 50 percent probability, except for on days when the lagged and non-lagged prices are the same.

[4] Report on natural gas price volatility, September 2015: http://www.caiso.com/Documents/DMMReport-gas_price_analysis_september2015.pdf.

[5] This was proposed on slide 22 in the ISO's December 3 Bidding Rules Revised Straw Proposal Presentation: http://www.caiso.com/Documents/AgendaandPresentationBiddingRulesRevisedStrawProposal-Dec32015.pdf.

bids change within the trading day and resources are less likely to get mitigated during hours ending 1 through 7 because of lower levels of mitigation in these hours.[6]

Provide opportunity for after-the-fact cost recovery (Section 8.1.1.2)

The ISO proposes to allow scheduling coordinators to dispute their bid cost recovery settlement if they can support that actual costs from procuring same day gas exceeded 125 percent of the GPI.[7] This would be subject to documentation and verification of actual costs in the form of an invoice between unconnected entities, and that these costs were in line with market conditions at the time.

DMM asks the ISO to clarify or modify its proposal to also include potential cost recovery through bid cost recovery settlements for any gas costs associated with any mitigated energy bids dispatched by the ISO. It is unclear why recovery would be limited to commitment cost bids and not any energy bids that were lowered due to mitigation.

As stated in previous comments, DMM supports the consideration and discussion of the general concept of after-the-fact cost recovery in instances when fuel is procured at market prices that exceed 125 percent of the GPI.[8] However, DMM believes this approach would need to be limited by strict and clear conditions that are spelled out in detail and in advance. We do not believe that the information provided in the revised straw proposal is sufficiently detailed to meet this criteria and, thus, do not support the ISO's proposal as currently constituted.

For example, the ISO needs to provide more precise and detailed calculations that would be employed. This includes, but is not limited to, specifications on how to convert units of electricity (MWh) from different schedules and dispatches into natural gas, how to assess the source of gas when only portion of the gas was procured in the same day market, how to determine during which time intervals the gas that was bought at a higher price is assumed to be burnt, how to account for cases where gas was procured for a portfolio of resources, and to what extent the ISO should consider balancing rules and associated penalties when determining the appropriate cost recovery.

In addition, a more precise definition of "in line with market conditions" is needed, especially given the very limited liquidity in same day trading on most days. DMM also believes that any after-the-fact recovery should appropriately account for any mitigated energy bids and commitment costs. The ISO would also need to commit to ensuring that the necessary resources and processes were in place to implement this change within the ISO. DMM notes

[6] See Figure 6.5 in the 2014 Annual Report on Market Issues and Performance: http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

[7] The ISO here assumes that the GPI has been updated to reflect the correct flow date.

[8] DMM Comments – Bidding Rules Enhancements Straw Proposal: http://www.caiso.com/Documents/DMMComments_BiddingRulesEnhancementsStrawProposal.pdf.

that this may require additional expertise in gas procurement and auditing that do not currently exist within the ISO.

In line with DMM's comments above, at the December 3 bidding rules stakeholder meeting the ISO expressed concern that its expertise may be insufficient to accurately validate gas procurement costs. As an alternative the ISO suggested giving market participants the right to file for cost recovery at FERC.[9] However, even if the ISO pursued this approach, the ISO would need to develop the details and guidelines for of how gas procurement costs would be calculated and what portion of these costs would be eligible for recovery.

The complexities and challenges of providing after-the-fact cost recovery – whether costs were validated by the ISO or FERC – were specifically noted by the ISO in comments filed at FERC in March 2014.

> If the Commission decides to examine an approach that provides for after-the-fact reimbursement of costs above an offer cap, the CAISO would have concerns with such an approach. The CAISO may not have access to information necessary to verify that a gas invoice represents gas costs associated with a particular CAISO dispatch. If the Commission does pursue such an approach, it will need to define how to assess whether cost recovery is appropriate. Cost recovery could be assessed hourly, daily, or over longer periods and any assessment of cost recovery should consider hedging arrangements entered into by the supplier. Given the complexity of hedging instruments and programs, this assessment would likely be challenging for the CAISO or the Commission to complete. [10]

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[9] This was proposed on slide 27 in the ISO's December 3 Bidding Rules Revised Straw Proposal Presentation: http://www.caiso.com/Documents/AgendaandPresentationBiddingRulesRevisedStrawProposal-Dec32015.pdf.

[10] Comments by 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, March 6, 2015, p. 5: http://www.caiso.com/Documents/Mar6_2015_CAISOComments_onTechnicalWorkshops_AD14-14.pdf.