Opinion on Changes to Bidding and Mitigation of Commitment Costs

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Summary

This opinion comments on the California ISO's May 5, 2010 proposal for changing procedures for bidding and mitigation of commitment costs, which include start-up, minimum load, and transition costs for multistage generators (MSGs). We support many of these changes, as well as the ISO's recommendation not to consider opportunity cost bidding at this time, because we believe that the complexity of procedures required are not justified by the potential of market efficiency benefits from its implementation. We also support the ISO's recommendation to retain a 30 day minimum time period between changes in registered costs for SU, ML and transition costs for MSGs because of concerns about the possibility that market participants could use this flexibility to raise short-term market prices in response to temporary market conditions that increase their ability to exercise unilateral market. Finally, we suggest a change to the MSG transition costs mitigation procedure in order to allow bid-in transition costs to be decreased by the same percentage relative to the proxy transition costs. This would make the treatment of multistage generator transition costs consistent with the proxy cost option for simple generators' start-up costs, which under the ISO's proposal could be adjusted daily to any level between 0% and 100% of proxy costs.

1. Background

On May 5, 2010, the ISO released its final proposal for the second phase of its revisions of its procedures for bidding and mitigation of generating unit commitment costs,[1] which this opinion comments on. This proposal was the product of a process that, among other stakeholder consultation activities, included ISO staff presentations and public discussions at the MSC meetings of July 16, 2009 and March 19, 2010. We thank the ISO staff and stakeholders that participated in those meetings for their comments and insights.

The commitment costs covered include start-up (SU), which are expressed on a $ per start basis, and minimum load (ML) costs, which are expressed on a $/megawatt-hour (MWh) basis for each period that a unit is committed and operating at its registered minimum output level (P_{min}) or above. Under the new market design, generation units are committed on a least-as-bid-cost basis, considering both commitment costs, as bid by the unit owners, and the unit's energy offer curve. If day-ahead energy market revenues provide insufficient revenues above the

[1]The ISO proposal can be found at www.caiso.com/278e/278e8a8a3c8b0.pdf, while other materials, including stakeholder comments, are at www.caiso.com/23d9/23d9c75e22ab0.html.

generation unit owner's as-bid costs to cover these commitment costs, then a separate uplift or "make-whole" payment is made to make up the difference.

When the new market began, generation unit owners had two options for setting their SU and ML offers. The first, the proxy cost option, allowed suppliers to bid at any level below a unit-specific offer cap set by the ISO, subject to the restriction that these offers must remain fixed for six months. The second, the registered cost option, permitted a generation unit owner to submit cost-based offers that adjust on a daily basis to reflect natural gas prices, based upon a formula set by the ISO.

Several generation unit owners that elected the registered cost-based option at the start of the new market experienced more frequent commitment of their quick-start units than they had experienced historically. These units would often be run at minimum load for short periods, and then were quickly de-committed. Generator owners expressed concern that the increased wear and tear on these units were inadequately accounted for in the current cost-based option for SU and ML offers. Also, some of these quick-start units are subject to environmental or maintenance restrictions on the total number of starts during a pre-specified time period, and concerns were expressed that the opportunity cost of a start for these generation units is not accounted for in the current cost-based SU and ML offer option.

In response to these concerns, the ISO adopted a two-phase approach to revising restrictions on commitment cost bidding. After a stakeholder process that included a MSC meeting on July 16, 2009, the first phase was implemented that allowed generator owners to modify their SU and ML offers and to switch between the registered and proxy cost options as frequently as every 30 days. The second phase was to involve ISO and stakeholder consideration of further revisions of the SU and ML rules. Since the early summer of 2009, the problem with a high frequency of starts has largely abated, in part due to these rule changes.

At the July 16, 2009 meeting, the MSC adopted an opinion entitled "Comments on Changes to Bidding Start-Up and Minimum Load."[2] In that opinion, we supported of the removal of barriers to reflecting verifiable commitment costs in SU and ML offers. These costs could include opportunity costs, if a defensible method for estimating those costs can be devised. We expressed concern that an increasing frequency of adjustment of SU and ML offers could enhance the ability of generator owners to withhold capacity in order to raise wholesale power prices, for example in response to a short-lived system contingency. This was a particular concern for units outside of locally constrained regions whose registered cost offers were allowed to reach values up to 400% of the proxy cost-based option. We recommended that the ISO proceed with more frequent bidding only if improved mitigation procedures were put in place. One option we suggested was to have the registered cost-based offers for all units limited to 200% of the proxy-cost based option. Another suggestion was a hybrid approach that would divide offers into fuel- and nonfuel-based portions, in which the former would be indexed and the latter fixed for six months. Finally, we supported the ISO's long-term goal of subjecting SU and ML offers to local market power mitigation if commitment cost offers were allowed to be changed more frequently than every six months.

[2] www.caiso.com/23ee/23eeb5842a330.pdf .

The first-phase proposal that was adopted by the ISO in July 2009 was in part consistent with some of these recommendations, in particular the 200% cap for the registered cost option for all units and the adoption of a hybrid offer for the proxy cost option. Under the latter, proxy SU costs include a component indexed on natural gas prices as well as a fixed natural gas transport adder. Proxy ML costs also include an indexed component, as well as an operating and maintenance (O&M) cost adder that is either a default value (either \$2 or \$4/MWh, depending on the generation technology or a per MWh value negotiated with the Independent Entity).

2. Summary of the ISO Proposal

The phase two proposal in the document, "Changes to Bidding and Mitigation of Commitment Costs (May 5, 2010)," addresses issues of the frequency that SU and ML offers can be changed, whether SU and ML offers for a generation unit could be made under different options (proxy and registered cost bidding), and treatment of opportunity costs in SU and ML offers. In addition, because the costs and offers associated with transition costs between alternative configurations of a MSG are conceptually similar to start-up costs for single stage units, the proposal also addresses the bidding and mitigation of these transition costs as well. The May 5, 2010 proposal includes a number of changes relative to the previous phase two straw proposals as a result of consultations with stakeholders.

The first part of the proposal allows generators to choose the proxy or registered cost options for SU and ML independently, so that SU bids can be based on one option and the ML bids can be based on the other. For either SU or ML, if the proxy option is chosen, daily bids are to be allowed, as long as they are nonnegative and no more than the calculated proxy. However, registered costs would be revisable no more often than once every 30 days, which is the present system adopted under phase one. The ISO also does not propose to allow submission of a fixed component offer in the SU proxy cost option, nor does it propose calculation and inclusion of opportunity costs in either SU or ML proxy costs. The second part of the proposal modifies the proxy cost option by refining the calculation of gas prices by replacing the Southern California Border gas delivery point price with the Southern California City Gate price for generators in the SP15 zone.

The third part of the proposal expands the SU and ML mitigation procedures to include mitigation of MSG transition costs. This is proposed because it is possible to use transition cost offers to economically withhold generation from the market in the same manner that unmitigated SU and ML offers could. The ISO proposal involves two rules. Both rules allow only upward transition costs, with downward transition costs excluded. The first rule says that the sum of transition costs for each feasible path from offline to a feasible configuration must be between 100% and 125% of a proxy start-up cost for that configuration (where the proxy includes a 10% adder on estimated costs). The second rule says that the transition cost for any series of upward transitions starting at one configuration and ending at another must sum to between 100% and 125% of the cost of direct transition between the two configurations. Transition cost offers will be indexed by natural gas prices in the same manner as SU and ML costs.

We now discuss three selected features of the proposal relative to the following principles, which were outlined in our previous opinion on SU and MR costs: (a) offers should be allowed to reflect costs, including opportunity costs, if practical; (b) the added complexity and administrative burdens introduced by procedures for calculating and verifying costs need to be balanced against market efficiency benefits of verifying these costs; and (c) mitigation procedures should safeguard against non-cost reflective offers that would exploit temporary system conditions at the expense of consumers and other market participants. The features we discuss include the minimum frequency of revision of registered cost-based offers; the treatment of opportunity costs; and downward flexibility in bidding transition costs in MSGs. Aspects of the proposal that we do not discuss include independent selection of proxy and registered cost options for SU and MR; the allowance of daily SU and MR bids below proxy costs under the proxy cost option; and the refined gas price calculation procedures. In these cases, we agree with the ISO that these changes could increase market efficiency.

3. Frequency of Revision of Registered Cost-Based Offers

We understand the desire of stakeholders for more frequent revision of registered costs or more frequent switching among the proxy and registered options than the 30-day rule now allows. It is certainly possible that these costs can vary significantly over a month, and an offer that amply covered costs when made may result in significant under-recovery as market conditions, including fuel prices and opportunity costs, change. Some stakeholders have proposed daily bidding to deal with this problem.

However, in our July opinion, we expressed the concern that an increased frequency could significantly enhance the ability of generation unit owners to withhold capacity in order to raise wholesale prices during periods when transmission or generation outages would make such behavior profitable. The imposition by the phase one revision of a 200% rather than 400% cap upon registered cost-based offers from all generators alleviates that concern to a large extent. However, 200% still provides a large amount of headroom, and seems likely to provide insufficient protection if daily or other very frequent bid revision intervals were to be adopted. We can only recommend daily bidding if the cap on offers was very close to the proxy-based bid. Of course, that is in effect what the phase two revision of the proxy-bid option would provide, in which the cap is the proxy cost itself. Generators can change bids daily, as long as they are nonnegative and no more than the proxy cost. Thus, we believe that the phase two proposal embodies an option of daily bidding that includes sufficient market safeguards, in the form of the ability to bid under the proxy cost.

Some generators have argued that higher than proxy cost bids are needed to cover other costs not included in the proxy costs, including opportunity costs and certain nonfuel O&M expenses. We discuss the opportunity cost bidding issue in the next section. This concern can be a valid one. However, we note that for certain verifiable O&M costs, a generator always has recourse to negotiate with the Independent Entity a unit-specific O&M per MWh component of ML. Generators have not availed themselves of this in the past, however, and furthermore have not been very responsive to the July 2009 ISO request for information on nonfuel O&M expenses. It is possible that the effort required to negotiate with the Independent Entity is very high, and this has dissuaded generators from trying to collect justifiable and significant costs by this method. Assuming that this is not the case, we conclude that the lack of exercise of the negotiated cost option and the lack of response to the ISO's request for information about these costs indicates that these costs are not substantially high. They do not appear to justify either allowing more frequent registered cost-based bidding with a high cap, or a special new category of offer in the form of a fixed component to the SU proxy cost option. The ISO's proposal retains the negotiated cost option, and we believe that this provides a potentially useful recourse for generators who find themselves in a position in which other options result in significant under-recovery of commitment costs.

4. Opportunity Cost Bidding

As we stated in our July opinion, economically efficient regulation implies that suppliers should be allowed to express all verifiable SU and ML costs in their cost-based offers. The opportunity cost of a start due to environmental or other restrictions on the total annual number of starts is, in general, a legitimate reason for setting higher cost-based SU offers. An extra start early in the summer when prices are low could mean that a unit is unavailable during the peak summer weeks when prices are much higher, if it has used up all its starts by that point.

The principle of allowing opportunity cost bidding has already been accepted by the ISO and stakeholders for limited use resources (although the particular procedures for quantifying those costs are more controversial, as indicated by stakeholder comments on the phase two proposals). The main question is: Can a transparent, verifiable, and theoretically justified procedure based on reliable data sources be devised whose development and administration costs are reasonable relative to the market efficiency benefits produced by this change? For hydroelectric plants, for example, we believe that the benefits are reasonable relative to administrative costs because of the crucial role of hydropower in the California market and the central role that opportunity costs play in hydro operations. However, in the case of opportunity costs associated with starts of thermal units, the balance appears to tilt the other way, with the cost of system development exceeding the market efficiency benefits, as the total capacity likely to avail itself of any procedure for quantifying such benefits is likely to be small. Once again, we note that negotiating commitment costs with the Independent Entity remains an option for those cases where opportunity costs are significantly higher that the fuel and other O&M costs associated with starts.

However, if in the future a significant amount of capacity pursues the negotiated cost option in order to recover these opportunity costs, this would signal the need for a more systematic procedure to quantify such costs. The ISO can pursue the option of developing such a procedure at that time.

5. MSG Transition Costs

We agree that multistage generator costs should be treated by the ISO in a manner broadly consistent with the SU and ML offer and mitigation procedures, because SU costs are essentially a special case of MSG costs for a generator that has only two configurations: off and on. The same issues of potential capacity withholding by very high offers, or extraction of a higher fixed cost by taking advantage of temporary system conditions apply to MSG costs for many of the same reasons they apply to SU and ML costs.

The upper bound of 125% of the proxy direct cost of transition upon the sum of upward transition costs along a path between two configurations is a reasonable way to limit the ability of suppliers to exercise unilateral market power through setting these transition costs. However, the lower bound of 100% raises an issue of inconsistency between treatment of MSG units and simple units that just have SU costs. Under the proxy cost option, simple units can change SU bids daily between zero and the proxy, a degree of flexibility that we believe could improve market competitiveness. However, under the ISO proposal for MSG costs, analogous changes in transition cost offers are not possible, due to the tightness of the proposed [100%,125%] band and its being tied to the proxy cost. The reason for the lower bound is to prevent transition costs from being disproportionally loaded onto a particular transition that conceivably might be done in order to restrict output by making it more difficult to transition to the highest output configurations. However, that lower bound prevents MSG costs from being bid in daily in a manner analogous to SU costs under the proxy option. Thus, MSGs have less bidding flexibility than simple units with only SU costs, and this flexibility may harm their ability to compete to supply energy as well as overall market efficiency.

We recommend a change in the phase two proposal to make the MSG and SU offer limitations more consistent. Generators could be allowed to reduce their transition cost bids all the way down to zero, but in a manner that preserves the ratios among the various transition costs. In other words, the ISO-calculated proxy costs would be multiplied by a single percentage (between 0% and 100%), and the other transition cost offers would then have to satisfy the [100%, 125%] bounds implied by those de-rated proxy costs. For instance, a generator could set its transition cost offer to 50% of the proxy cost for each the transitions considered by the ISO. Then its other transition costs would have to satisfy Rules 1 and 2, but based upon the 50% de-rated offer rather than the original proxy. A property of this rule is that if there is a set of transition offers that satisfies Rules 1 and 2 based upon the original proxy costs, then a set of transition offers and de-rated proxy costs that are *X*% of the originals will also satisfy a version of Rules 1 and 2 based instead on the de-rated proxy costs. That is, all offers are multiplied by the same percentage. We believe that this would give multi-stage generators some flexibility to respond to market conditions in a way that could benefit consumers, while treating SU and MSG proxy costs in a more consistent manner.

Under the present proposal, such an adjustment could occur no more frequently than once every 30 days, when costs are submitted to the master file. We propose, if there is sufficient stakeholder interest, that the type of downward adjustment just described be allowed on a daily basis, analogous to the SU daily bidding proposal.

6. Concluding Comments

Until the California ISO develops an automatic procedure for local market power mitigation for SU, ML and MSG transition cost offers, we believe that the ISO should maintain its balanced approach to granting generation unit owners flexibility in the level and frequency that these bid parameters can be changed. Under a variety of system conditions, adjusting the value of any of these parameters can be a very profitable way for a supplier with a portfolio of generation units to exercise unilateral market power. The flexibility offered under the ISO's current proposal is sufficient for generation unit owners to recover these costs through market mechanisms. For those rare instances when this may not be possible, the option to set a negotiated value for ML O&M costs provides market participants an opportunity to recover at least some of these costs. We would favor expanding the negotiated option to allow other components of commitment costs to also be negotiated as a safety valve in case commitment costs are significantly higher than allowed under the ISO proposal and the generator owner can document them.