Opinion on Bid Cost Recovery Mitigation Measures and Commitment Costs Refinement

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May 7, 2012

1. Introduction and Summary

The Market Surveillance Committee (MSC) of the California Independent System Operator has been asked to provide an opinion on the ISO's proposals on bid cost recovery (BCR) mitigation[1] and commitment costs.[2] Earlier versions of the BCR and commitment cost proposals have been discussed during MSC meetings in 2011 and, most recently, at the March 30, 2012 MSC meeting. In addition, MSC members have participated in stakeholder calls and have reviewed stakeholder comments submitted to the ISO.

These proposals are part of the ISO's initiative to provide incentives for increased flexibility in real-time markets to facilitate integration of variable renewable power sources into the ISO markets. As part of that initiative, the ISO Board approved two elements of Phase I of the Renewable Integration: Market and Product Review[3] at the December 2011 board meeting. These elements included lowering of the bid floor in two stages and revision of the bid cost recovery mechanism (BCR) to allow for separate calculation of BCR in the day-ahead and real-time markets. Among other features, the proposal included a feature to detect and disqualify persistent uninstructed energy deviations from BCR. This is because the current ISO BCR design can offer incentives for generators to offer very high bids for part of their capacity output range and then to deviate from real-time instructions in a way that would result in high energy as-bid costs and BCR.

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[1] *Bid Cost Recovery Mitigation Measures, Draft Final Proposal*, CAISO, April 6, 2012, www.caiso.com/Documents/DraftFinalProposal-BidCostRecoveryMitigationMeasures.pdf; *Addendum to Bid Cost Recovery Mitigation Measures Draft Final Proposal*, CAISO, April 27, 2012, www.caiso.com/Documents/Addendum_BidCostRecoveryMitigationMeasuresDraftFinalProposal.pdf

[2] *Commitment Costs Refinements 2012, Draft Final Proposal*, California ISO, April 11, 2012, www.caiso.com/Documents/DraftFinalProposal-CommitmentCostRefinements.pdf; *Addendum to Commitment Costs Refinements Draft Final Proposal*, CAISO, April 27, 2012, www.caiso.com/Documents/Addendum-CommitmentCostsRefinementsDraftFinalProposal.pdf

[3] www.caiso.com/Documents/DraftFinalProposal-RenewableIntegrationMarket-ProductReviewPhase1.pdf

The MSC submitted an opinion to the Board in December offering general support for those proposals.[4] In the opinion, the MSC cautioned that the performance of the revised BCR mechanism would depend on specific parameter choices, and that the system should be subjected to extensive testing before parameter values are selected and the system is implemented. In particular, we were unable at that time to conclude with confidence that the Performance Measure and Persistent Uninstructed Energy Check features of the proposal would function as intended. We stated that additional detail regarding the parameter values that would be used in applying these features along with additional testing data would be needed to allow us to reach a conclusion about their functioning. We also said that it would be important to ascertain that those features are (1) effective in discouraging strategic behavior aimed at increasing BCR payments, (2) while not inadvertently yielding large decreases in BCR payments for normal deviations from dispatch instructions. Such decreases would undermine the goal of encouraging more resources to participate in the real-time dispatch. We noted that testing might indicate that significant changes to the basic features as proposed would be necessary to accomplish these goals.

In the April 6 draft final BCR mitigation proposal, the ISO presents details of the mechanism, including parameters to be used in its implementation. In the present opinion, we comment on that implementation. In particular, we express our support for its major features, including the modified day-ahead metered energy adjustment factor; the real-time performance metric; and the persistent uninstructed energy (PUIE) check.

However, we believe that further examination is needed to determine the particular threshold values to be used to determine whether persistent uninstructed energy would be disqualified. In particular, although the analysis of historical data in the draft BCR proposal is very helpful in understanding the potential frequency of mitigation, it is not presently clear whether the instances in which generators would have had bid costs disqualified actually represent abuse or not. Nor is it clear whether or not significant cases of abuse might pass the proposed threshold and avoid mitigation. The MSC also recommends that the criteria used to determine whether mitigation will take place also include consideration of a total dollar or dollar/MW of capacity threshold.

Turning to the commitment cost proposal, as a general principle, we support the recovery of legitimate and verifiable start-up (SU) and minimum-load (ML) costs when they are incurred as part of the least-cost operation of the ISO market. We have addressed in past opinions the design of the limitations imposed by the ISO on how such fixed costs can be bid.[5] Our recommendations attempted to balance the need for responsiveness to changing fuel and other costs, while

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[4] Market Surveillance Committee of the CAISO, *Final Opinion on Renewable Integration: Market Product Review, Phase 1*, www.caiso.com/Documents/MSC_Final_Opinion_RenewableIntegrationMarket-ProductReviewPhase1.pdf

[5] Market Surveillance Committee of the California ISO, *Comments on Changes to Bidding Start-Up and Minimum Load*, July 16, 2009, www.caiso.com/Documents/FinalOpiniononStart-UpandMinimumLoadBiddingRules.pdf; Market Surveillance Committee of the California ISO, *Opinion on Changes to Bidding and Mitigation of Commitment Costs*, June 4, 2010, www.caiso.com/Documents/FinalOpiniononChanges-BiddingandMitigation-CommitmentCosts.pdf

limiting opportunities to take advantage of local market power to recover inflated as-bid levels of these costs. We expressed explicit support for accounting not only for fuel cost portion of SU and ML costs, but also the increased wear-and-tear costs to the generation unit due to the increased number of starts and the opportunity cost of a start due to maintenance contract and environmental restrictions on the total annual number of starts or run-hours. The ISO's present commitment cost proposal is certainly a step in the right direction on this issue. We noted previously that developing a reasonably accurate methodology for determining what these costs are for each generation unit is difficult to achieve, and that it is desirable to have a local market power mitigation methodology that focuses the application of mitigation on generators at locations where generators may have the ability to submit inflated SU and ML bids that will clear in the market.

The present proposal offers an improved methodology for estimating certain components of SU and ML costs that are not presently included in proxy bid and registered cost calculations, which we strongly support. In particular, the proposal would allow for inclusion of grid management charges, CO_2 costs, and maintenance costs in SU and ML proxy bids, which we support, as well as ex post recovery of operational flow order costs. This permits the lowering of the cap upon registered SU and ML costs to 150% of the proxy value, which we believe could be lowered further within a year to 125% if experience indicates that actual costs are generally below that value. Presently, we lack the information necessary to determine whether one or the other, or some different value, would be best.

We identify two further enhancements to the commitment costs proposal that we believe could improve the efficiency of system operations by allowing bids to more fully reflect costs. The complexity of these enhancements means that it is not practical to implement these enhancements in the commitment costs proposal at this time. Therefore we recommend that the ISO initiate, at an appropriate time, a stakeholder process that would move towards developing and implementing a follow-up proposal.

The first enhancement whose consideration we recommend concerns SU and ML opportunity costs due to limitations upon starts and run-hours. These can be significant for some units, but are not provided for in this proposal. At previous MSC meetings addressing the topic in 2009 and 2010, such costs were mentioned as important, and we have previously recommended consideration of their inclusion.[6] We repeat that recommendation here.

Second, we recommend that consideration be given in a future stakeholder process to including costs associated with operational flow orders (OFOs) in SU and ML bids used in the real-time market software if those costs can be reasonably anticipated with enough lead-time so that reasonably verifiable values can be included. If possible, this is much preferable to recovery based upon after-the-fact calculations because it is important for market efficiency that unit commitment decisions be based on all known costs. Otherwise, units might be committed which would not otherwise have been if their SU and ML costs had included OFO costs, thereby unnecessarily increasing costs. We recommend that a study be undertaken of the potential magnitude of OFO costs under alternative market conditions with the objective of determining whether they could

[6] Ibid.

be large enough to be relevant to commitment decisions, and if significant efficiency improvements could then result from including them in SU and ML bids.

Finally, we also make a long-term recommendation that the ISO consider possibilities for more tailored mitigation of market power in commitment costs. This would involve relaxing constraints on allowable bids where markets are likely to be highly contested (for example, by allowing them to change bids more often than monthly) and having tighter constraints where exceptional dispatch, load pocket conditions, or other constraints limit contestability. However, we were not able at this time to identify a transparent, readily implemented, and defensible basis for such a refined system, and so recommend that such tailored mitigation not be included in this proposal, but that it be studied for possible implementation in future BCR revisions.

2. BCR Mitigation

2.1 General Comments

As we explained in our December 2011 opinion on Phase 1, the BCR mitigation procedure would apply a performance metric that would scale certain components of the bid cost recovery calculation based upon deviations from ISO dispatch instructions. This prorating process is intended to remove the incentive, for instance, for a generating unit to receive a day-ahead BCR payment based on a day-ahead commitment, and then to declare an outage so that the unit would not actually run but would still received the payment, or for a unit to receive BCR for generation in excess of ISO dispatch instructions.

However, the performance metric only considers uninstructed deviations within a single real-time interval. Because of the way the ISO calculates dispatch instructions relative to a resource's actual metered output at the time the real-time dispatch software begins its calculations, uninstructed deviations that continue over time can impact ISO real-time dispatch instructions in future intervals. This means that uninstructed deviations calculated solely relative to the dispatch instructions for the current interval will not accurately reflect the *cumulative* deviations by the resource. In other words, a unit may only narrowly deviate from a dispatch order in a current interval, but that order might only be necessary because of additional non-compliance in previous intervals. In some cases a unit can force the dispatch, through previous non-compliance, to provide instructions it can profit from through bid-cost recovery and other mechanisms.

Therefore, the ISO proposed to augment the performance metric with a real-time calculation of a persistent uninstructed energy index (PUIE) that would disqualify real-time energy from the real-time BCR calculations in the case where generators choose to deviate consistently over several periods, yielding a greater deviation between actual operation and system cost-minimizing dispatch than can result from just one interval's deviation. The check would construct a "counterfactual" or hypothetical series of operating levels that would have occurred if the generator had adhered to the operators' instructions.

In our previous opinion, we expressed our support for the need for the proposed performance metric and persistent deviations check, and the general philosophy behind their calculation and application. They are likely to be more effective than the previous BCR procedures in avoiding potential BCR payment inflation from intentional deviations. We reiterate that general support here.

We support the proposed metered energy adjustment factor and performance metric. Although it has been suggested that more generally applicable uninstructed deviation penalties should be used instead, we prefer the more tightly focused proposal made by the ISO. We believe that in the vast majority cases, the appropriate "penalty" is just the real-time cost of energy, which represents the market's cost of making up for a market party's imbalance. We support this proposal's narrow applicability of adjustments to situations involving BCR payments. In the below comments, we focus on the persistent uninstructed energy check and its use for disqualifying certain as-bid energy cost shortfalls from eligibility for BCR, since this is the item that has attracted the most stakeholder attention.

2.2 Persistent Deviation Criteria for Disqualifying Energy Bid Cost Recovery

In our December 2011 opinion, we also noted that the revised BCR mechanism represents a significant departure from the previous BCR procedures at the ISO, and indeed at any other RTO or ISO. For this reason, we argued that it is important that the procedures, as well as the particular parameter values to be used to implement them, be subject to careful testing to ensure that they will work as intended. In particular, will they effectively guard against intentional inflation of BCR payments arising from unscheduled output, i.e., deviations from the ISO's dispatch instructions? And, at the same time, will they avoid penalizing innocent behavior by prorating BCR payments in response to normal scheduling inaccuracies or errors in a way that would undermine the goal of encouraging more resources to participate in the real-time dispatch? At the time that opinion was written, the specific triggers for mitigating persistent uninstructed deviations had not been defined.

In the ISO draft final proposal, specific triggers are provided, along with statistics based on historical data on how often they would have been violated in the past. There are two indices that are proposed for use in determining whether mitigation of persistent uninstructed deviations would occur (measures A and B, defined on p. 16 of the proposal). The final draft proposal has proposed that the following combinations of A and B would not trigger mitigation:

1. A less than 3%;
2. B less than 3 $/MWh; or
3. Combinations of A and B that satisfy both A less than 10% and B less than 10 $/MWh.

The first two criteria represent revisions to the previous proposal, and provide an additional safe harbor for generators whose deviations are small and quite possibly due to normal operational variations. In particular, if A is positive but B is small (or B is positive and A is zero), we do not believe it is necessary to adjust BCR, since BCR is close to zero anyway. Such points lie on or very near the A and B axes in Figures 3.3.4-1 (p. 17) and 3.3.2-5 (p. 23) of the proposal. The set of combinations in the third criterion was proposed in earlier versions of the BCR proposal.

On the other hand, there might be cases where A and B are both barely satisfy criterion 3 (e.g., A = 9% and B = $9/MWh), but the total dollar amount is large. Therefore, we recommend that the ISO examine these cases from the historical record to determine the magnitude of BCR associated with persistent uninstructed deviations. If the amounts are significant in some cases, we recommend that the above criteria be modified so that if the total dollar amount is above some total $/interval threshold that mitigation be triggered even if any of the above criteria are satisfied. Alternatively, to account for the fact that generators can be very different in size, this threshold could instead be phrased in terms of $/interval per MW of installed capacity, with some de minimus total $/interval amount below which mitigation would not be triggered.

In particular, we are concerned that the reasons for observed persistent deviations in the past are not understood, and as a result the thresholds might be set at levels that result in disqualification of BCR in cases where deviations are the result of normal operating variations. Several stakeholders share this concern. If the loss of BCR would then be significant and frequent, that could act to discourage real-time bidding by needed resources. We recommend that the data analysis conducted in Section 3.3.5 of the proposal be extended in order to inform possible adjustments to the proposed parameters. In particular, the possibilities of false positives and negatives should be examined by, first, determining, if possible, the reasons for a sample of historical instances that violate the proposed deviation criteria; second, doing the same for instances that come close, but do not violate the criteria; and, third, assessing the resulting impact on BCR for those units. We believe that such an analysis will provide useful information for fine-tuning the parameters to ensure that an appropriate balance is struck between reducing incentives for the inefficient bidding and generation output strategies that are the concern of the PUIE check, and the risk of discouraging participation in the real-time market by resources that would likely require BCR. We note that as output by variable renewable energy sources increases, instances of very low or negative real-time prices will happen more often, which could increase the frequency of BCR for thermal resources.

2.3 What Energy Bid Costs Should be Disqualified if Persistent Deviations Occur?

During the March 30, 2012 MSC meeting, we expressed support for revising the draft proposal so that the only energy bid costs that would be excluded from the BCR calculations would be those that were identified as persistent uninstructed deviations during intervals that the performance measures were violated. The draft proposal at that time would have resulted in disqualification of all energy bid costs from those intervals, which we believed would have been overly severe and perhaps would discourage resources from participating in the real-time dispatch. We support the change represented by the revised proposal of April 6, in which only the deviations identified as persistent uninstructed deviations would be excluded. This makes the penalty more proportionate to the impact of the potentially intentional over-generation, and will avoid the possible problem that might arise from incenting generators to skew somewhat towards undergenerating in order to avoid the risk of losing all energy bid BCR.

3. Commitment Costs

3.1 General Comments

Presently, market participants can choose between two methods for bidding their start-up and minimum load costs. Under the Proxy Cost option the market participant submits its start-up and minimum load costs on a daily basis, with the bids capped by the ISO's proxy cost calculation. Under the registered cost option, the start-up and minimum load cost bids submitted by the market participant must remain constant for 30 days and are required to be no more than twice a cost-based measure calculated by the ISO. This 100% head-room allows for volatility of spot fuel costs and for SU and ML costs that are excluded from the proxy. Regarding volatility, the ISO's analysis shows that spot fuel costs rarely exceed 110% of the monthly gas price used to calculate gas costs under the registered cost option. Although spot prices for individual days might be significantly higher than the monthly gas price, the single highest day is not the relevant measure under the registered price option for high capacity factor units that would operate many or most days (and be required to submit the same bids on all of those days under the registered cost option). For such units the amount of headroom needed for that reason is well below 100%. However, for low capacity factor units, their fuel costs can be significantly above average monthly levels, especially if periods of high electricity demand coincide with higher daily gas prices, so somewhat more head room can be justified in those cases. Intraday gas costs can also be higher than daily price indices. Finally, volatility may be higher in future months and years than it has been over the past few years during the recession. Thus, headroom of more than 10% could perhaps be justified on volatility grounds alone, especially for lower capacity factor units.

It would normally be more efficient for a gas-fueled generator in particular to vary its start-up and minimum load offer costs on a daily basis to reflect variations in gas prices as permitted under the ISO's Proxy Cost methodology. However, the ISO's Proxy cost measure has historically not included all costs. Hence, generators for whom those costs are substantial might prefer to submit bids based on the registered cost option, despite the inefficiency of being constrained to submit the same offers for 30 days. Hence, the present 100% headroom also allows for miscellaneous SU and ML costs that are not captured in the proxy; presently, these include maintenance costs, opportunity costs of start-ups, emissions costs, grid management charges, and possibly others. To the extent that those costs can be explicitly included in the proxy cost, the need for market participants to bid using the registered cost method is reduced. Further, to the extent that those costs can be explicitly included in the registered cost, the allowed percentage headroom over the ISO calculated costs can be decreased. Therefore, given the ISO's proposal to include many more categories of costs in the base registered costs, we agree with the ISO that the allowed head room above these estimated costs under the registered cost option can be decreased. If it was possible to allow inclusion of opportunity costs and operational flow order costs in bids (as we suggest below should be considered in future revisions of the commitment cost rules), then we would be comfortable with the percentage of headroom being lowered from 100% to 25%. However, the present proposal excludes opportunity costs from calculations of proxy costs, and provides no means for their recovery. For this reason, somewhat more headroom could be justified in the registered cost option.

However, we do not make a recommendation for a particular value for amount of head-room, since we do not have estimates of the likely magnitudes of opportunity costs. We do note that if maintenance costs typically amount to approximately one-third of the presently allowed proxy cost, then the ISO's proposal to allow 50% head-room would result in the same total allowable bid under the registered cost option as the previous 100% head-room. If maintenance costs are typically less than 33%, then a 50% head-room would generally result in lower total allowable bids than under the present head-room. However, we do not have information on typical maintenance costs and so cannot assess whether the ISO's proposed change would result in a significant decrease, on average, in the overall allowable SU and ML bids under the registered cost option.

As information is lacking that would definitively support one or another cap, we therefore suggest proceeding cautiously by lowering the cap, as proposed by the ISO, to 150% immediately. We recommend that then within a year it be lowered further to 125% if the ISO makes a finding that fuel cost variations, opportunity-costs, and other omitted costs are highly unlikely to exceed 25% of proxy costs for the great majority of generating units.

If all significant categories of costs are included in SU and ML proxy bids, then we would find merit in the suggestion that the head-room percentage be applied just to the fuel cost portion of the proxy. On the other hand, if potentially important categories are omitted, such as opportunity costs, then the purpose of the headroom is not just to insure against gas price volatility risks, but also to accommodate other categories of SU and ML costs that are not captured in the proxy. This is the case with the ISO's proposal. Therefore, we believe that the proposal's application of the percentage to the entire SU and ML cost, and not just the fuel cost portion, is appropriate.

3.2 Focusing Mitigation on Units with Local Market Power

The philosophy of mitigation in the energy market is to focus mitigation on units possessing local market power. In contrast, the mitigation system for SU and ML bids is system-wide. However, we expect that generating units that are not in locations that would confer local market power would have a strong market incentive to submit bids reflecting their actual SU and ML costs to the extent permitted by ISO rules. On the other hand, units located in load pockets or other areas in which they possess local market power might be able to inflate their SU and ML offers to levels well above their costs yet still clear in the market. We believe that it is desirable to focus mitigation on those resources having locational market power, including that due to the various minimum on-line rules. In the long run, therefore we recommend that mitigation efforts be focused upon areas with persistent local market power, while giving more flexibility to generators outside such areas. The MSC has previously recommended a dynamic local market power mitigation (LMPM) procedure similar to that used for energy bids.[7]

For instance, this proxy cost approach would be made more focused, and could eventually be turned into a cap on start-up and minimum load bids with the market participant allowed to vary its bids every day as long as they were under the cap. Also, areas with persistent market power

[7] Footnote 5, supra.

could have tighter head-room percentages for the registered cost option, and other areas could have looser percentages.

However, implementation of such a system would mean that the occurrence of persistent market power would have to be defined. The procedure would have to dynamic (responsive to changing market conditions), transparent, and a valid reflection of local market power. Unfortunately, the new local market power mitigation procedure (LMPM), based upon the contribution to locational marginal prices (LMPs) of shadow prices of uncompetitive transmission constraints, is not applicable to lumpy decisions to commit generating units. This is because commitment of units needed to resolve uncompetitive constraints will often result in those constraints becoming nonbinding and having a zero shadow price. Because of such conceptual challenges, as well as practical considerations, development of such a LMPM-like system for SU and ML bids is not possible within the context of this proposal, but should be considered in the future.

3.3 Negotiated Maintenance Costs

In general, procedures involving negotiation to determine which costs can be recovered have poor incentive properties. If (1) a generator faces relatively little competition in a locally constrained area, so that higher SU costs would not lower the frequency of commitment, and (2) the generator usually obtains BCR for its SU costs, then incentives to minimize costs are dampened. The expense and relative lack of transparency of negotiated costs are further disadvantages.

To the extent that (1) most start-ups are not subjected to BCR, and (2) maintenance costs are non-discretionary, involving standard contracts with vendors, then we are less concerned with the incentive effects of negotiations. It would be useful to have data on the percentage of incurred SU costs for various classes of units that are recovered through BCR. If the percentages are small, then our concern over the negotiated cost option is less. However, this percentage may increase in the future as more renewable capacity comes on line, and episodes of very low or negative prices become more frequent.

Nonetheless, we recognize the need for negotiation given the great variations in types of generators and maintenance contracts. Therefore, we urge the ISO to put into place procedures for identifying benchmarks for classes of units; for identifying cases in which maintenance costs are considerably above benchmark levels; and for providing incentives for lowering those costs, such as allowing recovery of only a portion of costs that are above identified benchmarks.

3.4 Opportunity Costs of Start Ups

Opportunity costs for start-ups arise as follows. A generating unit that has a limited number of starts per year due to maintenance contract requirements incurs an opportunity cost for starting up if there is a positive probability that the generator will run out of starts before the end of the summer high load season; that is, a start now results in foregoing net revenue later in the year. The amount of this opportunity cost depends on the probability of using up all the allowable starts, and the gross margin (price minus variable cost, including SU and ML costs) that would have been earned in the later start.

Opportunity costs can also arise for operating hours if a unit has a limited number of run-hours because of environmental or other limitations. In that case, a similar opportunity cost arises that should legitimately be reflected in ML bids.

Although such opportunity costs are difficult to estimate, they can be large for some units in some years. If disregarding those costs results in units burning through all their allowable starts or run-hours early in the summer, this can significantly hurt market efficiency by decreasing the availability of needed resources later in the summer. A possible approach to correcting this problem would be to allow generators to negotiate an opportunity cost component in their SU or ML costs, and if such a component is included, have it be updated throughout the high demand season to reflect changing expectations concerning probability of running out, fuel costs, and prices.

Clearly, this calculation would be complex, costly, and relatively difficult to monitor and verify. To calculate opportunity costs, a generator would have to make a showing of a binding constraint that can reasonably be expected to bind. Then it would be necessary to approximate the probability of lost opportunities and the gross margin (prices minus variable costs) associated with them based upon reasonable expectations of future energy prices. This calculation would consider the number of starts or run-hours available versus the rate at which the unit has been committed. The relevant gross margin would be for the 'marginal' start - the future start that would be precluded because a start was instead scheduled today.[8]

The ISO is not recommending such a procedure for estimating and including opportunity costs in SU and ML proxy bids at this time because of the practical challenges involved in its design and implementation in the timeframe available. Therefore, we recommend that consideration be given to inclusion of opportunity costs in proxy costs in a new stakeholder process in the near future.

If no provision is eventually made for including opportunity costs in SU and ML bids, this could result in significant inefficiencies. An obvious inefficiency would be if a unit runs out of available starts or run-hours early in the season. A less obvious, but also potentially important inefficiency, can arise if a generator tries to prevent that outcome by choosing designation as a “use limited resource” in order to be exempt from the all-hours must-offer requirement. This would prevent commitment during certain hours. However, as wind penetration increases, the times

[8] Such a calculation of opportunity costs could in theory take place through a negotiation process, based on some standardized procedure. This is not an easy calculation, but some standard and conservative values might be agreed upon that would be better than zero (the present value). Once quantified, then one approach to including opportunity costs in SU or ML bids could be to have a separate daily or weekly changing registered cost component to SU or ML costs.

Another alternative for calculating opportunity costs could rely more on historical data. The purpose would be to estimate the gross margin for the marginal start in the relevant time windows in past years. A rough approximation might be the margin that is exceeded some X% of the time in the, for instance, the last month of the time window. The procedure could then adjust this margin for differences in fuel costs between the historical period and the present season, and also account for how binding the constraint is (the number of starts or run-hours used relative to those available) if that affects the likelihood of running out of starts or run-hours.

when that generator would optimally be dispatched might occur more frequently during off-peak hours which cannot be anticipated by inflexible monthly use plans. Large inefficiencies are likely to arise if a significant amount of capacity withdraws itself from the market during many hours in this manner. It would be more efficient to instead allow high SU and ML bids that reflect opportunity costs of operation, which then gives flexibility to the market software to determine whether or not it is worthwhile to run the units. We recommend that a study be conducted to determine if inefficiencies of this type are resulting from monthly use plans, and if so, what their significance is. Development of a procedure to include opportunity costs in SU and ML proxies would help avoid this potential inefficiency.

3.5 Operational Flow Order Costs

We agree with the premise of the commitment cost proposal that it is important to enable generators to recover significant operational flow order (OFO) costs, since they have the potential to materially affect SU and ML costs. Although OFO costs have recently been very minor, there were much higher levels on occasion in previous years according to PG&E data.[9] Also, changes in pipeline pressure rules and the possibility of tight electricity supplies in the coming months might cause such charges to become larger and more frequent than in the recent past.

As a general principle, it is desirable that any costs that can materially contribute to SU and ML costs be reflected in SU and ML bids so that the costs can actually influence unit commitment decisions, and so improve market efficiency. After-the-fact recovery of such costs can help to make generators whole, and by lowering the risk of non-recovery of costs, can encourage participation in the real-time market, which is desirable. However, after-the-fact recovery could distort unit commitment choices. As a result, costs may be incurred that the market software would have chosen to avoid, if those costs had been fully reflected in SU and ML bids.

In the particular case of OFO costs, their inclusion in SU and ML bids are also desirable from a gas and electric system reliability standpoint. This is because OFO's can be pipeline specific and if it would be much better to meet load with a gas-fired generator served by a pipeline that has not imposed an OFO than one that has.

Application of this general principle in the case of OFO costs would require an ability to adjust reference bids for real-time SU and ML bids daily in response to OFO costs, or the creation of a registered cost component to those SU and ML bids. A requirement would be that it would be practical to anticipate OFO costs in time for such a procedure; because OFO costs are usually known at the time the bid is submitted, in which case this inclusion seems reasonable. It would also be necessary to reasonably expect that OFO costs are fully marginal for the unit (i.e., are part of the incremental cost of starting up and running a unit). Although there are ambiguities in allocating OFO costs among multiple units coming under a single gas contract, it appears likely that OFO costs are fully felt for marginal decisions.

[9] www.pge.com/pipeline/operations/ofo/ofoarch.shtml. For instance, as recently as July 10, 2010, there were days with charges amounting to $5/mmBTU, and during the crisis, charges as high as $25/mmBTU occurred.

If these conditions are met, and if the costs of implementation are reasonable relative to anticipated market efficiency benefits, we would recommend that consideration be given to instituting a procedure to include reasonably anticipatable OFO costs in the proxy, rather than after the fact. On the other hand, reasons for not including OFO costs in SU and ML can include the complexity of implementing such a procedure; uncertain or minor efficiency improvements in commitment; and ambiguities in assigning costs to particular units and possible opportunities for strategic behavior that these ambiguities might present.[10]

We do not have data that would allow us to compare the efficiency benefits of including OFO costs in SU and ML bids to the expense of implementing such a procedure. Because of the uncertain possibilities for strategic bidding that inclusion of OFO costs in bids might open up, we support for now the ISO's proposal for after-the-fact recovery.

However, if there is a potential for OFO costs to become more important in the future, so that disregarding them in real-time unit commitment decisions would result in significant inefficiencies, then this issue should be addressed in a stakeholder process and further consideration given to including OFO costs in allowable real-time SU and ML bids.

4. Conclusion

In summary, we support the goals and most of the specific elements of the commitment cost and BCR mitigation proposals. In the case of the commitment cost proposal, it is an important step towards inclusion of all relevant costs in start-up and minimum-load bids, which is desirable for both cost-recovery and market efficiency reasons. For this reason, we support the proposed lowering of the cap upon registered SU and ML costs to 150% of proxy costs, and further recommend that it be lowered to 125% a year later if the ISO finds that total SU and ML costs are very likely to fall under that tighter cap. We recommend that consideration be given in a future stakeholder process to address inclusion of an additional category in proxy costs (opportunity costs of start-ups and run-hours). We also recommend that consideration be given in the future to including operational flow order costs in real-time SU and ML bids, rather than recovering such costs after the fact if such costs have the potential to be large enough to significantly affect commitment decisions and market efficiency.

For the BCR mitigation proposal, there remains uncertainty over whether the criteria for identifying persistent uninstructed deviations will indeed catch most circumstances in which such deviations are deliberate actions intended to inflate BCR payments, will avoiding penalizing inadvertent and unintentional deviations. Further analysis is desirable of historical patterns of deviation.

[10] We note that opportunities for strategic behavior can also arise if OFO costs are recovered after-the-fact as proposed. If OFO costs cannot be included in the SU and ML bids and have to be recovered in an ad hoc reimbursement later, then allocation among units can become an issue. This is because there are revenues and costs for a group of units, and some will have had profits and others will not in a particular day before the OFO costs are accounted for. As a result, how OFO costs are allocated could impact the total BCR. Allocation rules could also affect efficiency; for instance, if the ISO allocates all the OFO costs to the profitable units, this will lead to undesirable incentive problems. Therefore, strategic behavior considerations do not necessarily favor after-the-fact recovery of OFO costs.

In the long run, we would prefer a BCR mitigation system that, like the local market power mitigation procedure for energy, focuses on locations where competition cannot be relied upon to incent efficient bidding for start-up and minimum load costs.