Potential Methodology to Account for OFO Penalties Incurred due to Real-time Energy Dispatches

Department of Market Monitoring

White Paper

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Introduction

In early February 2012, the ISO posted an issue paper on commitment cost refinements.[1] One of the items the ISO is seeking stakeholder feedback on is when and how the ISO should account for potential penalties associated with natural gas operational flow orders (OFOs). Specifically, the ISO requested feedback on three items:

- The circumstances under which OFO penalties are assessed vary. In concert with stakeholders, the ISO will develop a proposal as to the circumstances under which OFO penalties would be appropriately recovered through the ISO.
- Since any OFO penalties are incurred based on daily gas imbalances, these are not hourly marginal costs (i.e., a per-MWh cost). Thus, the structure of OFO penalties is not congruent with commitment cost bids, default energy bids (DEBs) or generated bids (used to enforce the must-offer requirement for resource adequacy units if bids are not submitted for the unit's full RA available capacity). The ISO therefore seeks input on what mechanism would best be used for compensating generators for OFO penalties that would be appropriately recovered through the ISO.
- There are situations in which purchases of natural gas by multiple generating units are pooled such that they appear to the gas supplier as one customer. As a result, the deviation of some subset of generators within that bundled group may not trigger an OFO penalty to be assessed to the whole group. The ISO seeks input into the manner and extent to which these bundling arrangements should be considered in cost recovery through the ISO.

This whitepaper provides comments and suggestions by the Department of Market Monitoring (DMM) relating to these issues.

Background

In 2011, as a result of the National Transportation Safety Board investigation into the San Bruno pipeline rupture and fire[2] and a subsequent rulemaking from the California Public Utilities Commission (CPUC),[3] PG&E was required to test the integrity of its natural gas pipeline system.[4] As a precaution, PG&E was required to reduce gas pressure on their system until testing revealed that the pressure could be increased.

Reducing pressure required pipeline customers to more closely match scheduled natural gas deliveries with actual system off-takes. At higher pressure levels, the natural gas system can more easily handle situations when a customer takes or leaves more gas than they scheduled. To enforce customer performance, PG&E instituted regular OFOs, which penalized daily over- and under-usage of gas within a

[1] See http://www.caiso.com/Documents/IssuePaper-CommitmentCostsRefinement2012.pdf.

[2] For further details of the incident, please see the following report: http://www.ntsb.gov/doclib/reports/2011/PAR1101.pdf.

[3] Further details of the CPUC rulemaking can be found under Rulemaking 11-02-019: http://docs.cpuc.ca.gov/WORD_PDF/AGENDA_DECISION/136874.pdf.

[4] Throughout this whitepaper, all references to PG&E refer to the subsidiary responsible for PG&E's natural gas pipeline.

tolerance band.[5] These OFOs began for the gas-operating day, July 8 and continued through November 30, 2011

The ISO issues operating instructions to generators that are customers of the PG&E natural gas pipeline – as well as other pipelines in California. These instructions can cause generators to deviate – above or below – scheduled natural gas levels. Recognizing this issue, PG&E and the ISO operators developed procedures that successfully coordinated the reliability of both systems during the pressure reduction period.

However, a key unresolved issue was if and how the ISO would provide the economic incentives for resources to follow ISO instructions in light of potential penalties under low gas pressure situations. DMM and the entity contracted by the ISO to calculate default energy bids (Potomac Economics) reviewed the possibility of allowing an OFO bid adder to the incremental energy bids. Upon reviewing this option and further understanding natural gas market dynamics, DMM believed that adding an OFO penalty adder was not an appropriate option. For instance, the OFO penalty is not a true hourly marginal cost since it is dependent on a resource's total daily natural gas deviation relative to its nominated gas deliveries[6] and the participation of a resource in a natural gas pooling/customer bundling agreement.[7]

Initial DMM recommendation

DMM suggests that the ISO consider an approach under which certain OFO penalty costs would be recovered *ex post* to the extent that gas deviations are directly attributable to pre-specified types of ISO dispatch instructions. These criteria should give generators reasonable assurance that they will recover costs incurred in response to ISO dispatch instructions beyond their control which impact electric system reliability and market stability. At the same time, the criteria for recovering OFO penalties should be sufficiently targeted and narrow to avoid reducing the incentives for scheduling coordinators to take actions to avoid the penalties.

In 2011, DMM developed a general approach we believe may meet these goals, while being reasonably easy to implement. DMM developed this approach to help the ISO be prepared in the event that PG&E raised the OFO penalties and tightened the tolerance levels. This approach would make OFO penalties actually incurred due to certain categories of ISO dispatch instructions eligible for inclusion in daily bid cost recovery calculations. The approach would be similar to how the ISO deals with emissions costs and would require tariff modifications. More specifics of this general methodology are outlined in the following section of this paper.

DMM also considered various methodologies to incorporate OFO risk into DEBs used in local market power mitigation and potentially into minimum load costs. However, upon further review, DMM believes that these methodologies would be problematic and much less accurate than an approach based on recovery of actual OFO penalties through bid cost recovery payments. The final section of this

5 For further discussion, see the following PG&E press release: http://www.pge.com/pipeline/news/20110706_1539_news.shtml.

6 Natural gas pipeline customers have two nomination cycles in the intra-day market where they can nominate gas schedules in real-time. Even though the second nomination cycle is complete by 3pm, the nomination periods allow opportunities for generators to schedule gas based on real-time conditions.

7 Natural gas pipeline customers can manage their deviation risk by bundling natural gas deliveries as part of a set of resources. For instance, an electricity supplier may bundle natural gas deliveries to combined cycle plants with combustion turbines, reducing the volatility of the deviation risk of the combustion turbines.

paper discusses an approach to incorporate OFO risk into negotiated DEBs developed based on discussions between DMM and the entity contracted by the ISO to calculate default energy bids (Potomac Economics).

General methodology

DMM believes that generation unit owners can typically avoid OFO penalties associated with their day-ahead market schedules in a variety of ways. Day-ahead unit commitments and energy schedules can be managed through the bid and schedules they submit in the day-ahead market. If day-ahead schedules are unexpectedly high or low, this may often be offset by adjustments in real-time schedules and dispatches that can be managed by the unit owner through the bids and schedules they submit in the real-time market. Adjustments may be made to gas nominations after the day-ahead market, and, if necessary, adjustments can be made to their nominations in real-time.[8]

However, DMM believes that the ISO should have a backstop approach developed that would make any resource whole as part of the bid cost recovery process for OFO penalties realized for real-time exceptional dispatches, real-time bid mitigation and real-time commitment. Therefore, the approach is designed to allow resources to recover OFO penalties for additional unit commitments and incremental energy in the real-time market that may be difficult to avoid using ISO market mechanisms. These three categories include:

- **Exceptional dispatch.** Participants can bid their incremental capacity in the real-time market as they feel appropriate within the bounds of the bid cap and floor. However, resources may not be able to avoid commitment or dispatch for additional out-of-market energy through an exceptional dispatch issued by the ISO. Therefore, gas deviations related to real-time exceptional dispatch would qualify for recovery to the extent that the exceptional dispatch causes a deviation. Exceptional dispatches that limit output above the day-ahead schedule would not be considered recoverable.

- **Hours with mitigation.** If participants believe that potential OFO costs should be included in their marginal energy cost, they can include this into their energy bids. However, when real-time mitigation occurs, their bids are modified to their DEBs — which will not include any adder for potential OFO penalties. Thus, any additional real-time incremental energy dispatched due to resources having their bid mitigated to a lower level would be eligible for recovery of any OFO penalties assessed.

- **Real-time commitments.** Bids for minimum load costs are limited by the proxy cost or registered cost option. For participants with fast-start units that can be started and committed at minimum load in the real-time market, the minimum load bids under the proxy cost option does not incorporate potential OFO penalties. Participants with units under the registered cost option can incorporate potential OFO penalties (along with other costs they do not feel are covered by the proxy cost option) into these bids to avoid commitment of fast-start units in the real-time market at minimum load. Recent analysis by DMM shows that most gas units under the registered cost option submit start-up and minimum load bids well in excess of the proxy cost – with most participants

[8] For instance, if a unit was scheduled in the day-ahead market one hour more than expected, the unit could seek to decrease its generation in the real-time market during another hour to compensate for this over the 24-hour period that daily OFO penalties are assessed (hour ending 1 through hour ending 24).

bidding at or near the cap for registered cost bids (200 percent of actual projected gas costs).[9] Under low OFO penalty levels, the registered cost option should cover these costs. Under high OFO penalties, however, the registered cost may not cover deviations related to real-time commitment costs. Therefore, short-start units committed in the real-time market by ISO dispatches would be eligible to receive recovery of any OFO penalties associated with gas needed to operate at minimum load.

Any OFO penalties actually incurred due to these categories of ISO dispatch instructions would be eligible for inclusion in daily bid cost recovery calculations. The approach would be similar to how the ISO deals with emissions costs. DMM envisions that this process would work as follows:

- **Scheduling coordinators apply with the ISO for recovery of the penalty.** The ISO would not automatically include any OFO penalties in its bid cost recovery calculation. Scheduling coordinators would need to submit a request to the ISO with supporting information necessary for the ISO to determine what recovery is eligible. The methodology for calculating eligible OFO penalties would be clearly specified and participants would have the data necessary to do these calculations based on their own bids and dispatch instructions received from the ISO.[10]

- **Scheduling coordinators would provide the information necessary to the ISO to determine the portion of a unit's gas deviation relative to any natural gas pooling relationship the units may be a part of.** This would allow the ISO to verify what recovery amount the resource would be eligible for. For instance, if additional gas usage associated with the categories of real-time ISO dispatches eligible for recovery of OFO penalties accounted for 50 percent of the total gas usage of a pool of units for which an OFO penalty was actually incurred, then only 50 percent of the penalty charges would be eligible for recovery.

- **Scheduling coordinators will only be able to recover OFO penalties through bid cost recovery payments.** If a resource's market revenues over the day are sufficient to offset the OFO penalties, they would receive no penalty compensation. If the resource's revenues are insufficient to cover costs – after inclusion of eligible OFO penalties – then the unit will receive a make-whole payment. In keeping with the ISO's planned market rule changes to decouple bid cost recovery for the day-ahead and real-time markets, any OFO penalties associated with for real-time dispatches would only be included in real-time bid cost recovery calculations.

DMM developed a computer program to test this approach using actual market data in 2011 as part of its efforts to help the ISO be prepared in the event that OFO charges increased to levels that had a much more significant impact on the market. The program appeared to yield reasonable results and could be used by the ISO for further assessment of this approach.

Other methodological issues and details associated with this approach include the following:

- **Converting electric dispatches into gas usage.** Ideally, the additional gas usage associated with real-time commitments and dispatches made by the ISO in its real-time market would be calculated based on each unit's heat rate curve. This would add some additional complexity to this calculation

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[9] See *Quarterly Report on Market Issues and Performance,* Department of Market Monitoring*,* November 8, 2011, pp.41-44, http://www.caiso.com/Documents/QuarterlyReport-MarketIssues_Performance-November2011.pdf.

[10] DMM believes that participants currently receive all data necessary to do these calculations. This issue could be examined further as additional details of this approach were reviewed by participants.

but would improve the accuracy of this approach compared to a simplified approach based only on the portion of a unit's overall generation associated with ISO dispatches.

- **Alignment of gas and electric market days.** DMM is aware that there are differences in the timelines for gas nominations and trading and the OFO penalty period. These differences could make it appropriate to perform the calculations of electric market dispatches over a different 24-hour period than the period used to define each 24-hour day in the electric market.[11] Further discussion of this would be warranted.

Including OFO adder to default energy bids

In 2011, DMM and the entity contracted by the ISO to calculate default energy bids (Potomac Economics) also considered a methodology to incorporate OFO risk into negotiated DEBs. However, upon further review, DMM believes that this methodology would be problematic and much less accurate than an approach based on recovery of actual OFO penalties through bid cost recovery payments.

The methodology considered for incorporating OFO risk into negotiated DEBs is as follows:

1. Calculate the unit run-hours and daily MWh output from the real-time dispatch results for all resources in the pipeline's gas territory for the previous N similar days.
    - For instance, if N is set to 3 then the calculations are based on the unit's dispatches over the last 3 similar days.
    - If the market day of the DEB is a workday, then the most recent N workdays are used.
    - If the target day is a weekend or holiday, then the most recent N off-peak days (weekends/holidays) will be used in the formulation.

2. Next, for each resource, calculate the starting MW point for the OFO adder.
    - If the minimum daily MWh over N similar days is 0 (meaning the unit was offline for at least one entire day in the period), then the adder will apply to the entire dispatchable range from its minimum load to it maximum load.
    - Otherwise, the starting MW point is equal to:

    $$(1 + \text{OFO tolerance band}) \times \frac{\text{Minimum Daily MWh during N}}{\text{Maximum Online Daily Hours during N}}$$

    This result is bound by the unit's minimum and maximum operating levels so it conforms to the DEB specifications.

3. The OFO adder is equal to the imbalance penalty (in $/Dth of gas) and is additive to the GPI value or custom gas price as defined in the negotiated DEB summary for the resource.

[11] The natural gas trading and operations day is from 7 a.m. to 7 a.m. PT, whereas the OFO penalty period is consistent with the electric day, midnight to midnight PT.

DMM's review of this methodology indicates that in practice it will typically result in the potential OFO charges being added to most or all of a resource's DEBs, even in cases when a unit's output is relatively constant and predictable from day-to-day.

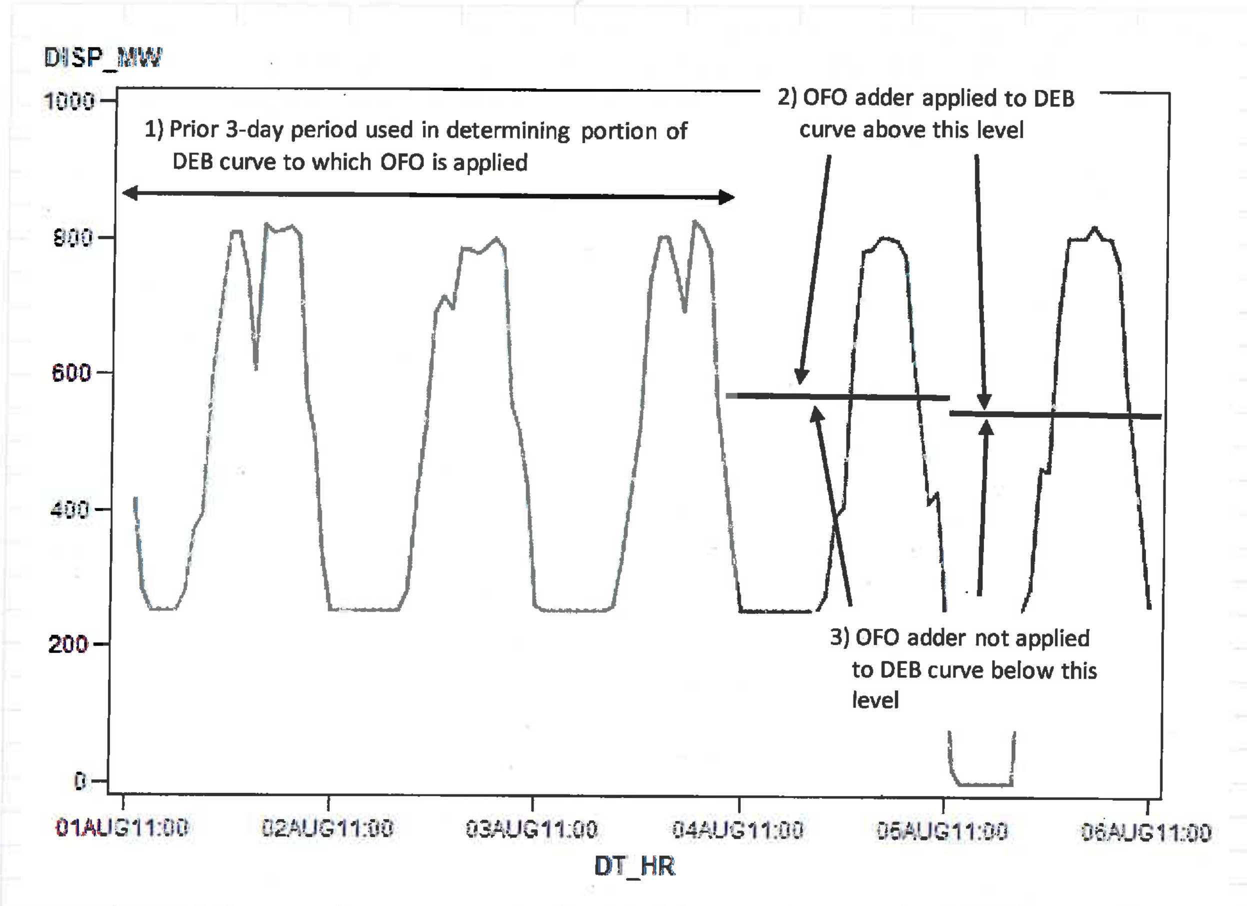
Figure 1 provides an illustration of this for a typical combined cycle unit with a total maximum capacity of 880 MW. As shown in Figure 1, the unit operates at its minimum load of 253 MW during off-peak hours and ramps up to just over 800 MW during peak hours. Given the unit's operating profile over the first 3 days in Figure 1, the methodology would apply the OFO adder to the unit's DEB above 522 MW on the fourth day and 505 MW on the sixth day.[12] However, as shown in Figure 1, the unit's DEB in the range at which it was dispatched during peak hours – when it is most likely to be needed to mitigate congestion and could set price – would always include the OFO adder. Thus, even under a very predictable situation such as that illustrated in Figure 1, the new approach would result in the OFO being incorporated in the unit's DEBs for the portion of its capacity most likely to be dispatched and potentially set market prices, despite the fact that output from the unit was highly predictable and consistent from day-to-day.

Under other scenarios DMM believes this methodology would tend to result in the OFO adder being incorporated in the DEB for an even larger portion to the unit's output than as depicted in Figure 1. For example, assume that during one of three prior days the unit operated less than 24 hours per day or had a lower level output. This would decrease the numerator in the equation shown in Step 3 above (Minimum Daily MWh during N). There would be no change in the denominator (Maximum Online Daily Hours during N). The net result of this would be to lower the "starting MW point" above which the OFO adder is applied.

For quick start peaking units that were dispatched more sporadically, it appears that under this approach the potential OFO penalty will frequently be incorporated into the unit's DEB. For example, under this approach, if the minimum daily MWh over N similar days is 0 (meaning the unit was offline for at least one entire day in the period), then the adder will apply to the entire dispatchable range from minimum load to maximum load.

[12] The minimum daily output of the unit (11,388 MWh) occurred on day 3, while the maximum on-line hours were 24. Therefore, assuming a tolerance band of 10 percent, the starting MW point on day 4 would be 522 MW (1.1 x (11,388 / 24) = 522).

Figure 1. Illustration of OFO default energy bid adder methodology



Other issues

Unpredictability in gas usage can also be avoided by either self-scheduling at a units' maximum available capacity and/or by submitting an ambient de-rate. Although both of these options were mentioned as part of prior ISO discussions of this issue, DMM does not consider these alternatives desirable from the perspective of system reliability, market stability or efficiency, as described below:

- **Self-scheduling at maximum output.** If a scheduling coordinator self-schedules a resource to its maximum output, the ISO loses is ramping capability. The ISO may then be forced to exceptionally dispatch the unit to maneuver it to different output levels. Under this scenario, the unit can buy its gas day-ahead and generate in real-time to its schedule. If it deviates, it will only be as a result of an ISO instructed exceptional dispatch.

- **Ambient de-rates.** One option that has been discussed within the ISO for enabling units to avoid OFO penalties would be to allow units to report an ambient de-rate to avoid getting dispatched above a level that might create risk of an OFO penalty. DMM believes this would be an inappropriate use of the capability to report ambient de-rates for a unit in the ISO outage management system (SLIC). Under this scenario, the de-rate would be done for economic purposes rather than for actual lack of fuel. In many cases, the fuel is available, and the key is to nominate and coordinate the gas delivery. DMM is aware that there is a same-day gas market and multiple intra-day nomination cycles where a unit could potentially nominate its gas. Allowing ambient de-rates to be used under such circumstances would decrease the ISO's real-time supply and could create adverse reliability and market issues should actual loads come in higher than forecast.

