Memorandum

To: ISO Board of Governors

From: Benjamin F. Hobbs, Chair, ISO Market Surveillance Committee

Date: September 12, 2017

Re: Briefing on MSC activities from July 11, 2017 to September 8, 2017

This memorandum does not require Board action.

During the period covered by this memorandum, the Market Surveillance Committee (MSC) adopted an Opinion on the generator contingency and remedial action scheme modeling initiative on August 28, 2017, which is summarized below. The MSC also held a general session meeting in Folsom, on September 8, 2017, which is also summarized later in this memo. During that meeting, two of the ISO's initiatives were discussed, including dynamic mitigation of commitment costs (under the ISO's general initiative concerning commitment costs and default energy bids) and greenhouse gas attribution in the energy imbalance market. Also reviewed in that meeting was the recent performance of the flexible ramping product.

The MSC also consulted with ISO staff on several initiatives. In addition, MSC members worked on drafting an Opinion on the contingency modeling enhancements initiative, which the MSC anticipates will be adopted and submitted to the ISO Board of Governors when that initiative is considered by the Board.

Opinion on Generator Contingency and Remedial Action Scheme Modeling[1]

Two initiatives by the California ISO address the efficient inclusion in market schedules of preventive and corrective approaches to managing contingencies.[2] The first, the generator contingency and remedial action scheme modeling (GCARM) initiative, is the subject of this Opinion. That initiative is designed to include preventive constraints in market models to account for the need to maintain feasible flows immediately after two types of contingencies: (1) generator outage events and (2) transmission outage events that are directly followed by deliberate disconnection of generation, other transmission, or load as a result of triggering of

[1] J. Bushnell, S.M. Harvey, and B.F. Hobbs, *Opinion on Modeling of Generator Contingencies and Remedial Action Schemes in the California ISO Markets*, Market Surveillance Committee of the California Independent System Operator, August 28, 2017, www.caiso.com/Documents/MSCOpinionGeneratorContingencies_RemedialActionSchemes-Aug28_2017.pdf

[2] The two initiatives are contrasted on p. 29 of California ISO, *Generator Contingency & RAS Modeling*, Draft Final Proposal, July 25, 2017, www.caiso.com/informed/Pages/StakeholderProcesses/GeneratorContingency_RemedialActionSchemeModeling.aspx

so-called remedial action schemes (RASs). The proposed market changes would impose constraints that ensure that post-event flows are feasible, accounting for emergency limits on transmission components and assuming a pre-defined pattern of corrective actions in the form of make-up generation from sources that immediately respond to frequency declines. RASs are increasingly and widely deployed in the ISO system to manage the transmission congestion impacts of grid-scale renewables. Meanwhile, the second initiative, the contingency modeling enhancements (CME),[3] differs in that it explicitly optimizes both preventive and corrective actions in response to certain transmission contingencies. The corrective actions involve the search for a feasible system redispatch that satisfies generator ramp and network constraints in order to return the system to a secure operating point within 30 minutes or other time period.

The inclusion of corrective actions, whether predefined and immediate (as in the GCARM initiative) or optimized to occur within 30 minutes or another finite interval (as in the CME initiative), are an important innovation in US ISO markets. Previously, only preventive actions have been modeled in ISO scheduling software, and the inclusion of corrective actions has the potential to improve both the economic efficiency and security of generation schedules. For instance, as noted later in this memo, such an approach could be used to improve the effectiveness of the flexible ramping product in meeting real-time energy needs when there is transmission congestion.

The MSC has previously considered the modeling of generator contingencies and remedial action schemes in the ISO's market software during several public meetings, including Nov. 18, 2016 and Feb. 3, May 5, and July 10, 2017. Our Opinion on the GCARM initiative was adopted during the August 28, 2017 general session teleconference meeting.

In that Opinion, we first provided background on remedial action schemes before summarizing the need to include those schemes and generator contingencies in market software. The Opinion then summarized the ISO's GCARM proposal, which is designed to address this need. We then addressed several issues associated with design of the GCARM proposal. These included the potential for different resources at the same bus to be paid different prices for their output when particular transmission constraints are binding; the treatment of convergence (virtual) bids; possible effects on the real-time congestion offset; and consistent treatment of generator contingencies and remedial actions schemes in the energy and congestion revenue rights markets. Our recommendations concluded the Opinion.

Those recommendations can be summarized as follows. We concluded that modeling of generator contingencies and remedial action schemes in the ISO's market models will contribute to increasing the security and efficiency of the ISO's day-ahead and real-time markets. The replacement of *ad hoc* operator actions and constraints with explicit modeling of the system's response to transmission and generation contingencies, including approxima-

[3]California ISO, *Contingency Modeling Enhancements*, Draft Final Proposal, August 11, 2017, www.caiso.com/Documents/DraftFinalProposal-ContingencyModelingEnhancements.pdf

tions of corrective actions, will likely lead to lower cost schedules that meet security requirements and pricing that more accurately reflects the value of resources to the system. Although the magnitude of these benefits is uncertain because of the lack of system-wide simulations of their effects, we believe that the modeling changes are highly likely to be worthwhile.

Regarding particular issues raised by stakeholders, we concluded the following. First, concerning locational prices, we believe that it is appropriate to reward a resource based on its marginal value to the system, reflecting how that resource impacts post-contingency congestion, and the resulting preventive actions that the market scheduling software takes to manage that congestion. This can mean that different resources at the same bus receive different prices, but we believe that this is appropriate and is unlikely to provide distorting incentives to participate in remedial action schemes.

Second, we support the proposal's treatment of convergence bidding. Virtual supply offers are to be subject to contingency constraints, and virtual bids at a node equipped with RAS will be assumed to also be RAS capable (and therefore eligible to earn the same prices as physical RAS-equipped resources). To not do so (e.g., to assume that virtual bids have a differential impact on constraints than physical ones) would undermine the purpose of virtual bidding: to better reconcile day-ahead and real-time prices and to remove incentives for submitting intentionally unrealistic physical supply and demand offers.

We have reviewed the ISO's analysis of real-time congestion rent shortfalls, and conclude that it provides a sound basis for expecting little if any impact from the modeling of RASs. Finally, there is a potential for differences between the generation distribution factors used in the CRR allocation and auction process and those used in the day-ahead market to result in congestion rent short-falls in the day-ahead market. The ISO has analyzed the potential for material congestion rent shortfalls, and concluded that most day-ahead market GDFs are very similar to auction GDFs calculated in this way over the vast majority of hours. Although we note several possible caveats to the conclusion of that analysis, we conclude that the ISO's analysis provides a reasonable basis for expecting minimal impacts on congestion rent shortfalls.

General Session Meeting of September 8, 2017

The issues addressed at this meeting included (1) the ISO staff proposal for dynamic mitigation of commitment cost offers, under the commitment costs and default energy bid enhancements initiative; (2) the recent performance of the flexible ramping product market in the ISO's real-time markets; and (3) the ISO's proposal for accounting for greenhouse gas emissions by imports to California from other balancing authorities in the energy imbalance market.

***1. Commitment Costs and Default Bid Enhancements*.** Cathleen Colbert, Senior Market Design Policy Developer, briefed the Market Surveillance Committee on commitment costs and default bid enhancements, in particular the proposed dynamic market power mitigation test for commitment cost bids. Two particular market design issues were discussed:

(a) What is a robust approach to testing whether a resource may have been committed to relieve a constraint that does not bind in the final dispatch?
(b) Should local market power mitigation tests be performed and applied separately for energy and commitment cost components?

The first issue arises because commitment of a generator in order to relieve congestion on a particular transmission constraint in general results in a “lumpy” addition of energy representing a significant fraction of that generator’s capacity. This can result in that constraint becoming nonbinding with a significant amount of slack, even though it forced commitment of the unit. Thus, any local market power mitigation procedure has to consider not only transmission constraints that are binding in the market solution, but also nonbinding constraints that may have triggered commitments. Unfortunately, this means that the philosophy of the energy bid mitigation procedure, which considers shadow prices of binding transmission constraints in deciding whether a generator possesses local market power, cannot be used. This is because nonbinding constraints by definition have zero shadow prices.

After Ms. Colbert’s presentation, Dr. Michael Castelhano of the ISO’s Department of Market Monitoring made a presentation outlining DMM’s current position on the commitment cost and default energy bid initiative, and in particular DMM’s position on four issues:

(a) The use of static tests of local market power mitigation on a seasonal basis to identify noncompetitive transmission constraints. They believe that such tests are insufficiently reflective of actual market conditions. In contrast, Dr. Harvey’s proposed approach would consider just the constraints that actually could have forced commitment in the particular market intervals being considered.
(b) The burden of proof: in the ISO’s procedure, a constraint is considered competitive unless shown to be potentially non-competitive, while DMM prefers that constraints should be assumed to be non-competitive unless demonstrated otherwise.
(c) Inter-temporal issues in bidding commitment costs, especially minimum operating costs. A concern they and stakeholders have raised is that once a generator has been committed, there is a need to mitigate the generator’s ability to inflate those bids in later intervals in which the generator will need to continue producing due to limited ramp rates or long minimum run times.
(d) The final issue concerned the treatment of constraints (especially nonbinding constraints) in the test for local market power for commitment costs. DMM argues that a fundamentally different approach than one based on aggregating across constraints is needed. At least some of the MSC members expressed agreement with that position.

The ISO's proposal for handling nonbinding constraints was then discussed by Ms. Colbert as well as by MSC members, DMM and attending stakeholders. Dr. Scott Harvey, member of the MSC, summarized the merits of an approach to identifying constraints that had been discussed by MSC members and ISO staff, which would consider only constraints that are generated in the iterative transmission feasibility checks used in the market software. Since constraints that are not generated in these checks and then enforced in the unit commitment could not have forced the commitment of a generating unit, it was observed that it would not be necessary to consider other constraints, such as those that would have been identified in the ISO's proposed seasonal identification of noncompetitive constraints.

Dr. Harvey also explained the rationale for the proposal that a generator's commitment cost bids be mitigated if the generator has significant market power on any single transmission constraint, as opposed to a procedure that would aggregate across all system constraints. Although this proposal would be conservative, it was pointed out by MSC members that it would still provide generators more bid flexibility than the present procedure, which in essence mitigates all commitment cost bids in all circumstances.

The second issue was discussed by the Ms. Colbert, the MSC members, DMM, and attending stakeholders. Dr. Hobbs pointed out that, in theory, commitment cost bids and energy offers could interact in complicated ways to confer market power, but that unless a full market price and bid cost recovery impact test was conducted (similar to the eastern ISOs), these interactions would not be practical to evaluate. The MSC members tentatively agreed that the present LMPM procedures for energy bids appear to be widely accepted as sufficient to identify local market power in energy, in which case commitment cost bids should also be mitigated. But there also needs to be an additional test to account for how non-binding constraints might have triggered commitment and provide opportunities to increase bid cost recovery payments.

2. Performance of the Flexible Ramping Product. In a number of real-time intervals in the past few months, there have been energy price spikes while, at the same time, either upward flexible ramping prices have been zero and/or flexible ramp was not acquired in the previous period, or capacity that had been designated as upward flexible ramp was not available to generate energy as intended. As a result, the intention of the flexible ramping product to help meet energy needs and prevent power balance violations has not been fully realized.

Dr. Lin Xu, Senior Advisor Engineering Specialist, Market Analysis, made a presentation that showed the results of the ISO's analysis of the possible reasons why this occurred. One reason was the implementation of an unnecessary constraint upon the ability of generators to provide flexiramp. Correction of this oversight should make more flexible ramping product available when it is economic and needed. Another reason is the disregarding of energy limits in assigning flexible capacity, which can result in generators not being able to provide energy when called upon. MSC members suggested that this should be readily corrected, and ISO staff agreed.

A third reason is apparently the fact that capacity designated to provide flexible ramping capability in one interval was prevented from generating energy in the next interval because of transmission congestion. The MSC members and staff discussed whether this was due to constraints between balancing areas in the energy imbalance market, or constraints within those areas. Dr. Harvey of the MSC suggested further analyses to better understand the role of transmission constraints and the reasons for the problem. Dr. Hobbs of the MSC suggested that an approach similar to the contingency modeling enhancements initiative could address this problem, in which corrective dispatches in response to contingencies are modelled. Such an approach could be used at some point in the future to make zonal flexible ramping capacity designations that would be able to provide needed flexibility during unexpectedly high or low net load episodes despite transmission congestion.

3. Greenhouse Gas Attribution for California Imports in the Energy Imbalance Markets. Mr. Don Tretheway, Senior Advisor for Market Design Policy at the ISO, provided an update on the ISO's proposal for attributing greenhouse gases to power imports to California under the AB32 emissions trading process. The two-pass solution is intended to first calculate a counterfactual in which California does not, on net, import power, and, second, perform the market optimization, identifying generators whose output increased and can be identified as being associated with imports.

The two pass approach presents some conceptual difficulties concerning the pricing of power, in that unlike a single pass market dispatch, the resulting energy prices might be inconsistent with the energy dispatch. Such an inconsistency might mean that, given the energy and greenhouse gas prices, a generator would find it more profitable to have a different energy production schedule, or different allocation of its output between non-California and California sales. Such a situation of "non-supporting prices" can encourage generators to make energy and commitment cost offers that deviate from their true costs, possibly leading to market inefficiencies. ISO staff, MSC members, and attending stakeholders then discussed several issues, including the strength of this possible incentive, the impacts on market efficiency, and the extent to which contract shuffling and emissions leakage would be avoided by this proposal.

Mr. Tretheway pointed out that the first pass calculations are also useful for documenting the carbon impacts of EIM. Dr. Hobbs of the MSC asked if it would be possible to do an additional set of runs in which there would be zero imports or exports from California in real-time, so that an aggregate assessment of the net carbon effects of the energy imbalance market over a longer period of time (e.g., yearly) could be assessed. Although such a study might not meet the present requirements of the California Air Resources Board, it could contribute to building understanding of and support for the energy imbalance market within and outside of California.