Opinion on
Contingency Modeling Enhancements

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Draft
November 28, 2017

1. Introduction[1]

Secure operation of electric power systems requires that generation scheduling and market pricing recognize the need to pre-position generators so that in the case of disturbances, or "contingencies", the system remains stable and meets load without violating crucial network constraints. Contingencies can include sudden disconnection of generators, loss of circuits, and unexpected net load variations. Secure operation for some contingencies require that network flows remain feasible immediately after the event, while other contingencies require that the system be returned to a secure operating point within a specified time.

Consideration of preventive (pre-event) and corrective (post-event) actions to maintain feasibility and security of the network imposes important constraints on market solutions, significantly impacting generation schedules and nodal prices. Disregarding these actions in the market software can result in resource schedules that endanger system security or, if operators take out-of-market actions to address security problems, can result in unnecessary market inefficiencies relative to efficient preventive-corrective actions. Furthermore, because corrective actions may allow more power flow to be accommodated, disregarding those actions may result in overly conservative and costly resource schedules, relative to an optimized schedule that satisfies all security criteria.

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) proposal, was the subject of a separate

[1] This is the second of two Market Surveillance Committee (MSC) opinions that address the inclusion of contingencies and associated corrective actions in the California ISO markets. The first opinion addressed the Generator Contingency and Remedial Action Scheme Modeling proposal of the CAISO (J. Bushnell, S. Harvey, and B.F. Hobbs, *Opinion on Modeling of Generator Contingencies and Remedial Action Schemes in the California ISO Markets*, Draft posted on August 25, 2017, www.caiso.com/Documents/MSCOpinionGeneratorContingencies_RemedialActionSchemes-Aug28_2017.pdf).

[2] The two initiatives are briefly 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

Opinion.[3] 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 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.[4]

The second initiative is the Contingency Modeling Enhancements (CME) proposal,[5] and is the subject of this Opinion. The CME proposal differs from the GCARM proposal 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 a required length of time. This operating point is defined as satisfying system operating limits (SOLs), and are more general than the emergency limits on transmission flows considered in the GCARM proposal. SOLs can include equipment ratings, bus voltage limits, transient stability limits, and voltage stability limits. These system operating conditions are addressed by NERC standards and the Peak Reliability SOL methodology, and must be met within a specified time after the contingency.[6] Costs are not considered in the CME redispatch optimization.

Presently, the CAISO addresses these requirements to meet SOLs after transmission contingencies through a combination of ad hoc manual commitments and dispatches (exceptional dispatches) and through minimum on-line constraints (MOCs) that specify the amount of capacity

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[3] Bushnell et al., op. cit.

[4] At its November 2017 meeting, the CAISO Board of Governors authorized CAISO management to submit tariff changes to the Federal Energy Regulatory Commission to implement these modeling changes.

[5] California ISO, *Contingency Modeling Enhancements*, Draft Final Proposal, August 11, 2017, www.caiso.com/Documents/DraftFinalProposal-ContingencyModelingEnhancements.pdf (referred to henceforth as "Proposal").

[6] Although 30 minute requirements are often mentioned, the time requirement depends on the choice of emergency rating for facilities (for instance, four hour ratings might be considered rather than higher 30 minute ratings). We are told that the entire 500 kV system along with 230 kV/500 kV transformers are operated by the CAISO using 30 minute ratings.

During the August 22, 2017 stakeholder call, CAISO staff stated that although the application of the proposal will target constraints with 30 minute recovery time limits, the CAISO also intends to implement the CME design on constraints with recovery times up to 4 hour limits. In the proposal Addendum (Aug. 29, 2017, Section 5.3, www.caiso.com/Documents/AddendumDraftFinalProposal-ContingencyModelingEnhancements.pdf), it is indicated that this will occur only after an additional study and comment period through existing stakeholder forums.

that is committed within certain specified zones.[7] The CME proposal points out that a large fraction of CAISO exceptional dispatches and associated costs result from the need to meet SOLs.[8] The CME initiative was developed in response to concerns about the economic efficiency of the current approaches to managing the impacts of transmission contingencies, the potentially distorting effects of these approaches on energy prices, and concerns that these approaches may inadequately address the security criteria. The CME initiative proposes to implement more explicit statements of the system conditions that are to be satisfied within the specified post-contingency time requirement (in many cases 30 minutes), and the corrective actions (including resource re-dispatch, short-term commitment decisions, and release of contingent operating reserves) needed to reach those conditions, given the pre-dispatch operating point. The CME initiative proposes to do this only for those contingencies that are the subject of MOCs, including interconnection reliability operating limits and major transfer paths, particularly those involving Paths 15 and 26, the Pacific AC Intertie, SCIT, and SDGE.

The inclusion of corrective actions, whether predefined and immediate (as in the GCARM initiative), or optimized to occur within 30 minutes (as in the CME proposal), are an important innovation in US ISO markets.[9] Previously, only preventive actions have been modeled in CAISO scheduling software, and the inclusion of corrective actions has the potential to improve both the economic efficiency and security of generation schedules.[10] If the implementation of the explicit modeling of corrective actions under the CME initiative is judged to be successful, this may encourage the CAISO to consider using similar approaches to represent corrective actions for a wider set of contingencies. In general, explicit corrective modeling can be a more efficient way to define operating reserve and flexible ramping requirements in the face of contingencies and uncertain net load scenarios, and are the subject of active research. The CME proposal can be viewed as a first step towards what can be viewed as a new paradigm for operating electricity markets under risk.[11]

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[7] The MOCs are intended to ensure that capacity needed to meet SOLs is committed, and such capacity is often exceptionally dispatched down to ensure that there is unloaded capacity that can then be moved upwards in case of a contingency. That exceptional dispatch is needed if the energy price exceeds the bid cost for the portion of capacity above the unit's minimum output level.

[8] Proposal, p. 21.

[9]As explained in the proposal, most ISOs in the US consider impose constraints in their market models with a goal of achieving SOLs within 30 minutes, but do not explicitly model corrective actions and resulting transmission flows post-contingency. The CAISO would be the first to do so.

[10]K. Tomsovic, D.E. Bakken, V. Venkatasubramanian, and A. Bose, Designing the Next Generation of Real-Time Control, Communication, and Computations for Large Power Systems, *Proceedings of the IEEE*, Vol. 93(5), 2005, 965-979.

[11] There is a large academic literature that proposes the explicit modeling of preventive-corrective actions in scheduling models in order to define the optimal location and amount of reserves and to maximize probability-weighted benefits (e.g., A. Papavasiliou, S.S. Oren, R.P. O'Neill, "Reserve Requirements for Wind Power Integration: A Scenario-Based Stochastic Programming Framework," *IEEE Transactions on Power Systems*, 26(4), 2011, 2197-2206). Much of this literature shows significant improvements in market efficiencies. However, there are many conceptual and practical hurdles to be overcome before using such fully-stochastic models to run ISO markets, including ambiguities concerning the definition of prices and settlements (F.Bouffard, F.D. Galiana, and A.J. Conejo. "Market-clearing with stochastic security-part, I: formulation," *IEEE Transactions on Power Systems*, 20(4): 1818–1826, 2005).

We have been asked by the CAISO to provide comments on the CAISO's CME proposal. The Market Surveillance Committee (MSC) has previously considered the contingency modeling enhancements during several public meetings, including Jan. 17, Mar. 19, and July 2, 2013, Dec. 11, 2015, Feb. 11, 2016, and Feb. 3 and July 10, 2017. In this Opinion, we first summarize the CAISO's CME proposal, and provide comments on individual features of the proposal. In Section 3, we consider the issue of bidding to provide corrective capacity. Then in Section 4, we briefly review the CAISO's technical analysis of the effect of CME on market operations and costs. Our recommendations are summarized in Section 5.

In brief, we support implementation of contingency modeling enhancements as being a more transparent and efficient means of representing the effect of corrective actions in order to achieve post-contingency system operating limits than current methods. The immediate as-bid cost savings may not be large, but increased savings are likely to be realized in the future from extending the preventive-corrective modeling approach to consider a greater range of contingencies and system disturbances. This extension will allow reserve requirements to be increasingly endogenized and tailored to system conditions in the market software, so that reserves can be scheduled where and in the amounts needed. This will likely lower the as-bid cost of meeting the SOL relative to the approximate methods now used (exceptional dispatches/commitments and MOCs). In addition to the possible cost savings and/or possible increase in the effectiveness in meeting post-contingency SOLs, we also note that the CME market design has the advantage of more transparently compensating the resources that are providing corrective capacity, calculating and compensating the opportunity costs they incur in doing so. We hope that a more efficient price signal will provide investment incentives that reduce costs in the long run, as well as production cost savings in the short-run.

We do not believe that it is necessary that resources be allowed to submit non-zero offers for corrective capacity (CC) in the day-ahead market in the initial implementation of CME because we believe this element of the long-run design needs to be developed as part of a comprehensive review of ancillary services optimization in real-time and a consideration of the bidding rules for all ancillary services, CC, and flexi-ramp in the real-time market enhancements and day ahead integrated market reform stakeholder processes planned for the future.[12] There are several elements of the interactions between the proposed CME design and current AS and energy markets that could potentially result in inefficiencies, including the lack of capacity bids for corrective capacity in the day-ahead market, differences in the bidding rules for spinning and non-spinning reserves compared to corrective capacity, and incomplete re-optimization of ancillary service schedules in FMM and RTD.

We believe that these issues, which can affect efficiency in the day-ahead, FMM and five-minute real-time markets, are best addressed in a comprehensive manner as part of the real-time market enhancements and integrated day-ahead market stakeholder processes. However, there is a risk of distortion of incentives, which may range from minor to significant, to provide flexible supply and demand response resources to the market. This risk can arise if day-ahead schedules for CC

[12]CAISO Market and Infrastructure Policy, *2017 Policy Initiatives Roadmap*, Dec. 15, 2016, www.caiso.com/Documents/DraftFinal_2017PolicyInitiativesRoadmap.pdf, G. Angelidis, *Integrated Day - Ahead Market, Draft Technical Description*, CAISO, Sept. 28, 2012, [www.caiso.com/Documents/IntegratedDay-AheadMarketDraftTechnicalDescription-FlexibleRampingProduct.pdf.](www.caiso.com/Documents/IntegratedDay-AheadMarketDraftTechnicalDescription-FlexibleRampingProduct.pdf)

chronically clear at a zero price or otherwise well below real-time prices for CC, or below day-ahead spin and non-spin reserve prices. As a result, flexible capacity will see their energy and ancillary service revenues materially reduced relative to what they could earn if not scheduled day-ahead for CC.

We are not able to assess how significant these impacts could be because we lack complete information on several factors affecting the magnitude of these impacts. These factors include the amount of CC that will typically be cleared in the day-ahead market, the likelihood that CC will typically clear at a price of zero in the day-ahead market on days with high real-time energy and flexiramp prices, and the value that will be selected for the CC penalty price in real-time. The CAISO indicates that this will be a value between the flexible ramping product penalty price ($247/MWh) and the contingency reserves penalty price ($250/MWh). If the CC penalty price were set at $250 and the load bias limiter was eliminated, there should be an opportunity for resources that are scheduled to provide CC at a low or zero price in the day-ahead market to earn some real-time market revenues when there is a power balance violation and the dispatch converts CC into energy. However, because there is a potential for material unintended adverse market impacts, we recommend that the CAISO be prepared to rapidly implement modifications to the CME design if significant distortions arise.

Finally, we agree with the CAISO's proposal to not alter the allocation and auction of congestion rights to reflect the implementation of contingency modeling enhancements. This conclusion is based upon the CAISO's simulation results that indicate that accurately modeled CME constraints are unlikely to bind often in the day-ahead market and the more accurate modeling will reduce costs by avoiding unnecessary commitments to meet system operating limits after transmission contingencies occur.

2. Summary of the CME Proposal

General Features. With a goal of improving the efficiency and security of CAISO schedules, the CAISO's proposal would involve adding variables and constraints to the market model that represent corrective actions in response to certain enumerated transmission contingencies order to ensure that system operating limits are satisfied within the required timeframe, often thirty minutes. The proposal describes the rationale for the method and the proposed reformulation of the feasible region of the day-ahead and real-time market models, and addresses several issues raised by stakeholders.

In this section, we summarize the proposal and offer some brief observations on some aspects, namely, awards in the RUC market and virtual bidding. We make longer comments in later sections of this Opinion on the economic benefits of the CME constraint and congestion revenue rights impacts.

Section 5.2 of the proposal describes the mathematical formulation of the optimal market dispatch model that implements the above requirements. The formulation includes constraints and variables that define the feasible region for post-contingency changes in dispatch that can occur within the desired time horizon,[13] and the resulting changes in flows on impacted transmission elements.[14] The corrective actions involve shifts in supply among dispatchable resources and/or commitment of short-start resources.

The proposal presents several examples as part of its explanation of how payments for post-contingency effects on binding transmission constraints affect the settlements. The per megawatt corrective capacity payment to a particular resource is defined as the sum over all post-contingency constraints of the resource's post-contingency shift factor (power transmission distribution factor) of that resource on that constraint times the constraint's shadow price. This is properly viewed as a payment for corrective capacity, and can be negative or positive depending on whether a resource's injection exacerbates congestion on a transmission constraint after the contingency, or provides counterflow.[15]

The CAISO proposes to enforce the constraints in the day-ahead energy market, the RUC commitment, and the EIM real-time fifteen- and five-minute markets.[16] A consistent enforcement of these constraints across the various market timelines would help avoid inefficiencies that could arise if the constraints are enforced in some markets but not others.

Bidding. The proposal does not allow for bidding for corrective capacity. This issue is discussed in depth in Section 3, below.

Residual Unit Commitment. Although Section 7 of the proposal says that the CAISO will not award corrective capacity in RUC, enforcement of the CME constraints in RUC implies that the CME constraints may cause changes in commitments and flows in the RUC model. It is our understanding that although the resources providing corrective energy could be different in the IFM

[13] Such as 20 minutes, if a 30 minute requirement is specified for a particular contingency.

[14]This constraint is readily generalized to other time limits, although if the time limit is beyond the horizon of the real-time markets, there may be some formulation and data issues that need to be addressed.

[15]It is of interest to note that, as in the GCARM proposal, because different resources at the same bus may have different capabilities to respond to contribute to corrective actions, they will in general receive different payments for energy and corrective capacity together, when measured on a per MWh of pre-contingency energy. For instance, consider two 100 MW resources: one is able to reduce its output to 50 MW post-contingency within the required 20 minutes, but the other must maintain its output at 100 MW. If the pre-contingency LMP is $70/MWh, and the post-contingency LMP is -$30/MWh based on the shadow prices of the constraints in the corrective load flow (negative prices can result if a bus injection would contribute to post-contingency congestion), then the first resource will be paid 100 MW*$70 + 50 MW*(-$30) or $5500, or $5500/100 MW = $55/MWh per unit of pre-contingency supply. The second resource will instead be paid 100 MW*$70 + 190 MW*(-$30) or $4000, or $4000/100 MW = $40/MWh per unit of pre-contingency supply. The ability of the first resource to back off post-contingency makes its output more valuable on net to the system than the output of the second, less flexible resource. This difference can be viewed as analogous to the different LMPs that resources can receive under the generator contingency and remedial action scheme proposal as a result of their varying roles in post-contingency load flows. However, in the CME proposal, the settlements will be made not in the form of possibly different LMPs for resources at the same bus, but rather as separate payments for pre-contingency energy and post-contingency capacity. The net effect (as measured per unit of pre-settlement energy) is the same. Note however that every resource at a given bus will receive the same pre-contingency energy price (i.e., LMP) per unit of pre-contingency supply, and the same price per MWh of corrective capacity.

[16]Proposal, Section 6.1.3. In the case of the fifteen minute market case, the constraint is enforced in the short-term unit commitment and settled in the fifteen minute market.

and RUC, the binding financial schedules that will be used for settlements will be those determined in the IFM, and they will not depend on how a resource might be dispatched in RUC.

Virtual Bids. Virtual bids in the IFM will be modeled as having the same impact in terms of creating power flows on the preventive-corrective constraints as on other network constraints. They will not receive corrective capacity awards, and will be assumed to not be adjusted in the post-contingency corrected load flows. Stakeholders are supportive of this design in which virtual bids cannot provide corrective capacity but can create the needs for corrective capacity to be scheduled. We also support this design, since virtual bidders are not allowed to provide other ancillary services capacity, and corrective capacity can be viewed as being similar to capacity devoted to operating reserves and regulation.

Congestion Revenue Rights. Regarding congestion revenue rights (CRRs), the presence of the CME constraints in the CAISO's energy markets will affect congestion in the IFM when the constraints bind, which would affect CRR settlements if those settlements reflect shadow prices of both preventive and corrective network constraints. If that is the case, then CRRs should be allocated and auctioned in a way consistent with the CME constraints enforced in the energy market. If the CRR allocation does not take account of the CME constraints but CRRs were nonetheless settled as a hedge against congestion on the CME constraint, then revenue inadequacy problems could be exacerbated (in circumstances where the CME constraints restrict flow such that awarded CRRs are no longer feasible when the CME constraint binds).

On the other hand, enforcing the CME constraints in the current allocation/allocation model could greatly reduce the amount of hedges available to hedge congestion charges. One reason for the magnitude of the potential reduction in feasible CRRs is that the current CRR allocation and auction model only models the transmission system and does not model the additional transfer capability that would be available if supported by generation providing corrective capacity. A more complete CRR allocation model could be developed that included offers from generators to provide corrective capacity, but the development of which a more complex model would not be cost effective if these CME constraints bind as rarely as the CAISO's analysis indicates.

This alternative for handling the impact of contingency modeling enhancements upon CRRs was considered in the development of the CME proposal. However, the CAISO is instead proposing to allocate and auction CRRs that only hedge preventive flow congestion (which does not involve the supply of corrective capacity), and settle those congestion revenue rights only on the difference in the preventive constraint congestion components of LMPs, which are based on the shadow prices of the preventive flow constraints. In particular, in light of the finding from the simulations and parallel operations (discussed further in the next section) that enforcement of CME requirements very rarely leads to binding constraints in the day-ahead energy dispatch, the CAISO concluded that it would not model the correct constraints in the CRR allocation and would symmetrically define CRRs so that they do not hedge congestion charges on the corrective constraints. If these constraints bind very rarely day-ahead, as suggested by the CAISO simulation, this exclusion would have very limited impact on the ability of load serving entities to hedge congestion charges. The exclusion would also avoid large congestion rent shortfalls if these constraints bind more often than currently anticipated.[17]

3. Bidding for Corrective Capacity

As mentioned above, the CME proposal would not allow potential suppliers of CC to submit offer prices to provide CC. The CAISO's rationale for this design include the following: (1) resources offering to supply energy in the real-time market incur no costs in providing corrective capacity other than possibly energy market opportunity costs, (2) the costs incurred in the day-ahead time frame in order to be able to provide corrective capacity in real-time are generally small, and (3) allowing generation suppliers to submit capacity bids to provide corrective capacity in the day-ahead market would necessitate implementing a likely complex local market power mitigation mechanism for generator CC bids. Consequently, the CAISO concluded that not allowing positive offer prices is a reasonable balance between the benefits of implementing CME against the complexity of designing a bidding mechanism and accompanying local market power mitigation measures. As we explain below, we agree with the first and third rationales, but are not convinced that day-ahead costs, for instance for reserving gas, are necessarily negligible.

In the real-time market, as with the flexible ramping product, the primary cost to a resource owner of providing corrective capacity is the opportunity cost of not being able to use the capacity to provide other products (energy, regulation, flexible ramping product, and non-contingent spinning reserves) in the market. Any costs arising from changes in commitment would be recovered through bid cost recovery mechanisms. Although the market software does not consider redispatch costs associated with corrective actions when assigning CC, the output associated with the corrective dispatch would be treated as instructed deviations in the CAISO markets and would be eligible to receive real-time energy prices and bid cost recovery. There is no need for suppliers offering energy in the real-time energy market to reflect CC costs in a separate CC bid in the fifteen-minute and real-time dispatch markets because their energy supply offers reflect the cost of real-time supply.

However, there may be costs that must be incurred by resources in the day-ahead time frame in order to be able to provide reserves or CC in real-time. In particular, while day-ahead energy offers cover the cost of output scheduled in the day-ahead market, there is no payment for the cost of making any gas supply arrangements for contingent output that is *not* scheduled day-ahead, as would be the case with corrective capacity. Day-ahead gas scheduling costs are partly the reason that suppliers are allowed to submit non-zero price offers to supply operating reserves in the CAISO. This is also a reason why the New York ISO allows bidding for day-ahead reserves but not real-time reserves.[18,19]

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[17] Proposal, pp. 79-81

[18] See New York ISO, Market Services Tariff, Sections 15.4.2.1 (day-ahead market) and 15.4.3.1 (real-time).

[19] One of the MSC members suggests that if the probability that a transmission contingency leads to a corrective adjustment is very low, then it might be argued that a corrective capacity offer price should also be very low. There would then be little distortion in not allowing non-zero price offers. But if the CME approach is extended to a greater number of constraints, the probability of corrective capacity being needed will increase, and such a rationale

Few comments were submitted by suppliers through the stakeholder process and those comments did not argue that they would incur material day-ahead gas scheduling costs in order to provide CC. Moreover, the need to incur gas scheduling costs day-ahead in order to be able to provide CC in real-time would be limited to constrained portions of California's gas system. On unconstrained portions of the gas system, generators would not incur scheduling costs in order to be assured of being able to respond in the relatively rare event that a contingency occurs and the CC is dispatched to correct for the contingency.

A related issue raised by stakeholders is the effect on market efficiency of a design that allows the submission of offer prices to provide operating reserves but, in effect, requires the equivalent of zero price offers to provide corrective capacity. Since the two products can tradeoff in the day-ahead market and FMM, the contrast in pricing could lead to a misallocation of responsibilities. The difference in designs could, for example, result in the market acquiring corrective capacity from a resource that submits a high offer to provide reserves and does not clear in the reserve market, and then acquiring the reserves instead from a resource with a lower offer for operating reserves. If operating reserve bids accurately represent costs other than opportunity costs, this might not be an efficient outcome if the offers set the reserve price, since it would reasonably be expected that providers of CC would incur the same costs incurred to provide spinning reserves.[20]

In addition, there is a potential for a difference in bidding rules between spinning and non-spinning reserves and corrective capacity to lead to inefficiencies in real-time dispatch in situations where the system is ramp constrained, and the dispatch is attempting to meet the corrective capacity requirement. This is because the existing real-time market does not re-optimize spinning and non-spinning reserves schedules, while corrective capacity schedules can be adjusted.

It is our understanding that this design would also apply to demand-side resources that offer to supply reserves and could, under the proposed design, be scheduled to provide corrective capacity at price of zero while not clearing in the reserve market. Demand response will be eligible to

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for not allowing bidding might no longer apply. Whether this is the case might depend in part on whether a generator pays day-ahead for a real-time option to acquire real-time gas, or whether instead the generator chooses to pay higher gas prices and imbalance penalties in real-time in case the contingency occurs.

[20]If: (1) similar gas reservation costs need to be incurred for operating reserves and upward corrective capacity; (2) those costs do not depend on whether a given MW of a resource capacity is used to meet just one or several contingencies; and (3) a given MW of capacity can be used both for reserves and upward corrective capacity, then one possible approach to bidding and pricing these products that would be consistent with these assumptions is the following. Resources would bid to provide generic post-contingency capacity (call it "X") in the day-ahead market. Then in the market operation, the amount of corrective capacity for each individual CME contingency would be constrained to be no more than X, and the amount of spinning reserve provided would similarly be upper bounded by X. This would ensure that the cost of reserving gas is not incurred more than once. This would also result in more uniform treatment of spinning reserve (which bundles many types of contingencies in one product) and corrective capacity (which has a separate capacity reservation for each contingency considered). This or similar approaches could be considered in the planned real-time and day-ahead market enhancement initiatives.

provide CC if it bids to provide energy or spinning reserves.[21] However, if commitment cost offers submitted by demand response indeed represent the cost to the consumer of making the option available to respond to a contingency in real-time, then it appears that the CME market design could result in demand response providing this option at a loss when the CC clearing price is zero. An unintended consequence could be to discourage demand response from bidding to provide ancillary services.[22]

This consequence could materialize if demand response resources are not able to represent their minimum load costs because the market would identify the resource as committed and therefore consider its upward capacity as available for CC. The CAISO has explained to the Market Surveillance Committee that this risk will be largely mitigated once demand response resources are able to represent their minimum load costs in the market as proposed in the CAISO's CCDEBE initiative.[23] This is because demand response resources will be able to use this minimum load bid, in effect, as a capacity bid for providing CC, leaving only "fast-start" demand response resources potentially at risk of being discouraged from bidding to provide ancillary services.

In our opinion, opportunity costs are the only significant cost for generating resources providing operating reserves, corrective capacity, or flexiramp in real-time, and capacity bids are therefore unnecessary for generating resources able to provide these services in the CAISO's co-optimized markets in real-time. However, as just noted, for day-ahead bids, the supplier might need to incur gas scheduling, or other costs in order to be able to provide corrective capacity if called upon in real-time, but, absent the ability to submit offer prices in the day-ahead market, these costs would not enter into the determination of the price of CC in the day-ahead market. These gas scheduling costs might often be zero, but might be nonzero at particular times of year or at particular locations, providing a rationale for allowing day-ahead bids that would reflect these scheduling costs during at least some days of the year.

Similarly, while the spinning and non-spinning reserve offer prices of demand-side resources will reflect their marginal opportunity costs, the cost of being prepared to interrupt operations and reduce load within 10 or 20 minutes are not necessarily zero for those resources. As a result, these demand side resources would not want to provide either reserves or CC at a price of zero. The CAISO's CC design should not make it uneconomic for demand-side resources to participate in the CC market. This is because reliance on demand-side resources might be an efficient way for the CAISO to meet its need for corrective capacity in the long-run because it would not

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[21] According to CAISO staff, of the 200 DR resources that bid into the ISO markets in October 2017, 13 would have been eligible to provide corrective capacity, based on their start-up times and ramp rates. Their potential contribution to corrective capacity would amount to between 21 and 53 MW.

[22] CAISO staff analysis shows that in October 2017 none of the 200 DR resources participating in the day-ahead and real-time markets made ancillary services offers; however, we hope they will be encouraged to do so in the future, because there is evidence that some DR resources can respond reliably at very short notice (Eto, J.H., Nelson-Hoffman, J., Torres, C., Hirth, S., Yinger, B., Kueck, J., Kirby, B., Bernier, C., Wright, R., Barat, A. and Watson, D.S., 2007, Demand response spinning reserve demonstration, Lawrence Berkeley National Laboratory, https://escholarship.org/content/qt5m75b2gc/qt5m75b2gc.pdf).

[23] CAISO, "Commitment Costs and Default Energy Bids Enhancement, Draft Final Proposal," August 23, 2017, p. 64, www.caiso.com/Documents/DraftFinalProposal_CommitmentCosts_DefaultEnergyBidEnhancements.pdf

require keeping gas-fired capacity on line. The CAISO believes this risk will be largely mitigated once demand response resources are able to represent their minimum load costs in the market as proposed in the CAISO's CCDEBE initiative, as these resources will thereby be able to submit offers that would in effect represent the cost of providing stand-by capacity that can that can be used for corrective capacity.

There are several reasons to not plan on implementing capacity bids in the day-ahead market for generating resources able to provide corrective capacity at this time. Unlike bidding for operating reserves or flexiramp which are acquired system-wide or zonally, the submission of offer prices to provide CC would require implementation of local market power mitigation mechanisms. This is because corrective capacity will model local constraints and may result in a predictable need to acquire corrective capacity from a more narrow set of resources than would compete to provide spin or non-spinning reserves and could possibly require the purchase of corrective capacity from a small set of sellers. The application of local market power mitigation to the procurement of CC would require changes in the current mitigation designs, such as perhaps allowing non-zero capacity offers up to a cap when the gas pipeline system is constrained and gas must be scheduled day-ahead. The issues arising in the CAISO market design relating to the submission of capacity bids for supplying CC are not unique to that product. Similar questions arise about whether there should be capacity bids for spinning and non-spinning reserves in real-time, for RUC capacity in the day-ahead market, and whether there might be reason to treat demand-side resources differently.

Another complication occurs if financially binding schedules for corrective capacity are assigned to flexible resources in the day-ahead market at a zero price (reflecting a lack of opportunity costs in the day-ahead market). Then capacity able to meet the CAISO's need for flexible capacity (flexiramp and operating reserves as well as corrective capacity) would earn no return on corrective capacity cleared in the day ahead market. Such capacity might as a result earn even less profit relative to the inflexible capacity that is not capable of providing corrective capacity. The magnitude of this reduction will be lower if the CC penalty price is set at lower levels and if the load bias limiter were eliminated. The CAISO indicates that the penalty price for CC will be a value between the flexible ramping product penalty price ($247/MWh) and the contingency reserves penalty price ($250/MWh). If the load bias limiter were eliminated, penalty prices set at the levels envisioned by the California ISO would ensure that under tight real-time supply conditions, resources scheduled to provide CC at a lower or zero price would be able to earn some additional margin in real-time during intervals in which real-time prices rose to the power balance penalty price.

To avoid possible delays in implementing the CME constraint due to a need to develop a new market power mitigation design and a holistic capacity bidding approach, we support deferring bidding on day-ahead corrective capacity until the CAISO's comprehensive reforms of the real-time and day-ahead markets, which we understand are scheduled for consideration in the near future.[24] However, we recommend that the CAISO immediately begin development of a back-stop solution that can be implemented quickly if either of two problems develop as a result of consistently low or zero CC prices:

[24] *2017 Policy Initiatives Roadmap*, op. cit.

1. We understand that there are currently relatively few demand side resources providing ancillary services but the proposed CME design could deter additional participation. If, as we anticipate, demand-side resources are scheduled to provide CC needs, but then receive zero or very low compensation compared to their spinning or non-spinning reserves offer prices, this could discourage demand side resources from offering to provide ancillary services.
2. If material amounts of flexible capacity are scheduled to provide CC at low or zero prices in the day-ahead market, this would possibly result in that flexible capacity receiving a significantly lower return than if it were scheduled to provide CC, flexiramp or energy in real-time.

A long-term design for the bidding and pricing of ancillary services, corrective capacity and flexi-ramp in both the day-ahead market and real-time should be considered as part of the CAISO's planned real-time and day-ahead market enhancements to design a bidding, scheduling, and settlements system for energy and ancillary services that:

1. Recognizes that day-ahead reservations of capacity, either supply or demand-response, can involve significant costs in addition to opportunity costs, which provides a justification for allowing non-zero bids for operating reserves and CC.
2. Recognizes that reserving capacity for a single contingency or multiple contingencies will likely involve similar costs, so that settlements should avoid multiple payments to the same capacity for meeting multiple CC constraints if the cost to the resource of reserving capacity is incurred only once.
3. Recognizes that spinning and non-spinning reserves can provide CC for many contingencies, but that spinning and non-spinning reserves (being a 10 minute product) are likely of higher quality than CC (which usually has 20 minutes or more to react).

While the CAISO has conducted some retrospective simulations of the application of the corrective capacity constraints in the day-ahead market, we have not been able to assess how often these constraints would be enforced in the day-ahead market and how much flexible capacity would generally be scheduled to provide corrective capacity at low or zero prices in the day-ahead market. The CAISO has also not conducted simulations of RT operations with the CC constraints that would aid in assessing how frequently corrective capacity requirements would bind in real-time and how high real-time prices might be. DMM data show positive FMM prices for flexiramp in 40% or more of the morning ramp hours and over 60% of time in hours ending 21 to 24.[25] Therefore we expect that CC prices will be positive at approximately this frequency when CC is scheduled, and that CC and FMM flexiramp prices will be of the same order of magnitude.

Finally, we do not believe it is possible to assess how often the different bidding rules for spinning reserves and corrective capacity in the day-ahead market will in practice lead to inflated capacity reserves for spin and corrective capacity without undertaking extensive simulations of day-ahead market solutions, so we cannot offer any insight into how material the impact of the

[25]See California ISO, Department of Market Monitoring, Q2 2017 Report on Market Issues and Performance, September 25, 2017, Figure 1.20.

excess reservations resulting from the different bidding rules for corrective capacity and reserves might be, or how often they would flow through into RTD and result in price spikes that do not reflect an actual shortage of capacity but are a result of inefficient capacity reservations.

We are therefore unable to assess the frequency and magnitude of the various unintended consequences from the implementation of the proposed corrective capacity design. While we are not persuaded that the impacts will necessarily be material, we are also not persuaded that we can be confident that they will be immaterial. We therefore recommend that the CAISO have plans for adjustments that could be implemented quickly without a long delay for a stakeholder process and software changes.

4. Benefits of Using Preventive-Corrective Constraints rather than Minimum On-Line Constraints

In this section, we address the general question of estimating the market efficiency benefits of switching from the MOC to the CME formulation in order to satisfy SOL requirements. In theory, the ideal way to calculate the cost savings would be run the market software three times:

1. a base case with neither MOCs nor CME constraints;
2. a case with a set of MOCs that reasonably simulate how operators would actually define those constraints in practice in response to the contingencies and SOLs under consideration; and
3. a case with CME constraints defined using those same contingencies and SOLs.

In theory, the CME approach (case 3) cannot be more expensive than MOCs (case 2) for meeting the SOL requirements, if those requirements are correctly modeled when defining the corrective constraints and MOCs, [26] respectively, and assuming that the software optimally solved the unit commitment while enforcing the CME constraints. This is because the CME method explicitly represents what transmission flows will result in satisfaction of the SOLs, and by definition optimizes the market solution subject to those constraints.[27] The difference in the system's objective function (equal to the value of accepted demand bids minus the cost of supply offers) between (case 2) and (case 3) represents the market efficiency benefits (if any), in dollar terms from adopting the CME approach rather than the MOC method to manage SOL requirements, assuming that both meet the SOLs after the considered contingencies.

[26] It would be important to check, with appropriate off-line analyses, that the minimum on-line constraints would indeed result in the SOLs being satisfied under those contingencies. Because of constantly changing and imperfectly predictable system conditions, we understand that MOCs are defined conservatively to ensure that the SOLs are met for a range of system operating conditions.

[27] Note that some system operating limits might involve bus voltage or dynamic stability requirements that cannot be explicitly represented in the linearized load flow models used in the market software. Therefore, offline studies are needed to define flow constraints that would conservatively result in satisfaction of those SOLs. However, the CAISO's proposal implicitly assumes these are likely to be less conservative than MOCs that would also result in satisfaction of those SOLs, because the effect of on-line capacity on voltages and stability is through its effect on flows.

For perspective, this measure of market benefits could be compared to the difference between (case 2) and (case 1), which would represent the cost (in terms of reduction in the value of accepted demand bids and the increase in supply costs) of meeting the SOL requirements under the present system. Although market efficiency, as measured by the optimizations' objective function, is the paramount economic consideration, other indices of interest, such as congestion costs and payments to CRRs, settlements for various market parties, and payments to resources that are providing corrective capacity, could also be calculated. A wide range of cases, emphasizing stressed system cases when meeting the SOL requirements would most likely change commitments and dispatch, should be examined, and ideally both day-ahead and real-time markets would be simulated.

The CAISO has undertaken some simulations of the performance of the CME constraint, and the results allow the CAISO to portray some possible impacts on system costs. These are summarized in the proposal, and described in more detail in a separate document.[28] In summary, it appears that the CME constraints rarely bind in the dispatch across 12 "stress" cases considered as well in a set of parallel operations analyses. If indeed those cases are representative of the situations in which those constraints are most likely to bind, this provides some indication that the cost of imposing the CME constraints will rarely impact market operations and net benefits (as gauged by the market software objective function)

For the one case examined in detail (December 4, 2014), the minimum on-line constraints commit more capacity than CME. The CAISO compared the MOC and CME commitments for one day (runs type (case 2) and (case 3), respectively), and found that the CME committed less capacity than the MOC commitment during 14 of the 24 hours of the day studied.[29] This suggests that CME would lower commitment costs relative to the current market.[30]

However, the difference in cost was apparently relatively small for that run, amounting to $11,185 over the day between the MOC Commitment and the CME commitment.[31] This amount may understate the total cost savings because it does not include any exceptional dispatch costs that CAISO might have incurred in real-time to provide CC with the MOC commitment to ensure that the required CC capacity was unloaded in real-time. This is a difference in cost, given a hypothesized fixed load; but it is quite possible that the difference in market net benefits (value of demand bids minus supply offers) was much less or much more in the runs in which demand bids were allowed to vary.

Unfortunately, we also do not know if CME (case 3) raised costs vs. a non-CME/non-MOC run (case (1), above), or if CME had any effect on commitment or dispatch in any of the runs. This information would be useful because the CME cases examined (other than Dec. 4, 2014) were

[28] L. Xu, Contingency Modeling Enhancements Prototype Analysis with Production Cases, CAISO, August 17, 2017, www.caiso.com/Documents/TechnicalAnalysis-ContingencyModelingEnhancements.pdf.

[29] Ibid., Table 6.

[30] Ibid., p. 19.

[31] Ibid., p. 21.

generally non-binding because they had many hundreds of MWs more corrective capacity available than was needed (i.e. far more than could be possibly due simply to lumpiness in commitment decisions).[32] If CME was committing any additional resources in the simulations for which there was far more corrective capacity than needed to meet reliability needs (case 3), it would apparently have been doing so inefficiently.[33]

In conclusion, the CAISO analyses indicate that there would be cost savings by using the CME approach, but there is only one case comparing the CME commitment to the MOC-based commitment. If the cost savings calculated for this case are typical and there are 100 to 200 days a year in which the CME constraint would replace MOCs in the commitment, this would translate into savings of on the order of one to two million dollars per year. However, the CAISO has not provided an estimate of how often such a daily savings would happen. It is also possible that there will be times when the CME constraints enable the system to meet the SOLs under the considered contingencies when the MOCs fail to ensure that enough unloaded capacity is available to achieve the SOLs. However, the simulations do not provide information as to whether or how often this has been happening with current processes.

5. Conclusions

We believe that implementation of preventive-corrective modeling approach to represent system actions to satisfy system operating limits within the time required has the potential both to lower the cost and to improve system security. Such an explicit representation of system response to contingencies is, in in theory, the most efficient approach to managing those constraints, subject to possible limitations in representing the relationship between voltage and stability operating limits and transmission flows in the market software. However, the simulations conducted by the CAISO do not provide unambiguous evidence of large cost savings, since the costs of meeting operating limits with minimum on-line constraints versus the CME approach were calculated only for a single day and we do not have an estimate of the number of days per year such differences would exist. Nevertheless, there will be a desirable increase in price transparency for the unloaded capacity that resolves these constraints in the market, which is now missing in the current mechanisms employed by the CAISO.

There may also be additional long-run benefits through an improved price signal what would incent investments in resources able to meet CC needs at a lower cost. However, these benefits may be small or even provide a disincentive to invest in flexible capacity if the procurement of CC at low or zero prices in the day-ahead market reduces the returns to flexible capacity.

In the future, there is a potential for increased savings from extending the preventive-corrective modeling approach to consider a greater range of contingencies and system disturbances, which

[32]The lowest excess commitment was between 360 and 410 MW and ranged upwards into thousands of megawatts. We think that even 360 excess MW are unlikely to be a result of lumpiness if the software is solving for the optimal commitment, so the simulation results are only consistent with CME operating as intended if CME was not committing any additional generation in any of these cases.

[33]Ibid., p. 12.

could improve the definition of, for instance, reserve and flexible ramping requirements by allowing them to more accurately reflect system conditions. We also note that that the CAISO has agreed to implement these constraints under the settlement agreement related to the Sept. 8, 2011 Pacific southwest outage.[34]

Because of costs of securing gas day-ahead for upward corrective capacity, there is a rationale for allowing non-zero offers in the day-ahead market for corrective capacity. Similarly, for demand response, there are likely to be real costs in addition to opportunity costs that consumers incur if response capability is designed as CC day-ahead. Such offers would need to be subject to local market power mitigation tests and the CAISO would ideally develop a holistic capacity bidding approach across all operating reserve products. The policy implications and implementation of such a system might be so complex as to delay implementation of the enhancements. We believe that, even absent the ability of resources to make capacity offers, the current proposal represents a useful incremental improvement over current practices. It is therefore acceptable to proceed with the current proposal and defer further consideration of non-zero offers to a later initiative. This could take place in the context of the comprehensive real-time and day-ahead market enhancements reforms.[35]

However, if problematic signs emerge that the current practice is distorting ancillary service procurement or creating other compensation issues, measures to adjust the compensation of CC capacity would need to be expedited. The CAISO should immediately prepare a backstop modified settlement procedure, such as the possibility of paying spinning or non-spinning reserve prices to day-ahead corrective capacity, that can be implemented rapidly if problems arise with CC day-ahead prices being much lower than real-time CC prices or being too low to compensate demand-response resources.

We understand that the penalty prices that would be applied to corrective capacity in FMM and RTD have not yet been determined. Moreover, some of the CAISO's current policies concerning the scheduling and settlement of corrective capacity in the current market are also not clear, so we have not been able to assess the extent to which the implementation of CME (and the differing rules regarding capacity bids for reserves and corrective capacity in the day-ahead market, combined with limited reoptimization of reserves in FMM) will reduce the supply of flexible capacity available to balance load and generation in RTD if these corrective constraints bind in the real-time dispatch. However, it appears to us that there is a potential for unintended consequences from these effects if the corrective constraints bind more than very occasionally in RTD. The CAISO needs to assess the potential for such unintended consequences and be prepared to adjust elements of the CME implementation on an expedited basis if these problems arise in actual operations.

We agree with the CAISO's proposal to not alter the allocation and auction of congestion rights to reflect the implementation of contingency modeling enhancements, based upon the simulation results that indicate that the CME constraints are unlikely to bind often. However, the CAISO

[34]Proposal, p. 13.

[35]*2017 Policy Initiatives Roadmap*, op. cit..

should monitor the constraints after implementation to confirm that this is indeed the case, and if not, then consider implementation of a system to allocate CRRs for corrective congestion.