Memorandum

To: Energy Imbalance Market Governing Body

From: Keith Casey, Vice President, Market & Infrastructure Development

Date: August 30, 2017

Re: **Decision on extending the option to EIM entities to use generator contingency and remedial action scheme modeling**

This memorandum requires EIM Governing Body action.

EXECUTIVE SUMMARY

Management proposes to enhance the real-time market's security constrained economic dispatch models, used for the western energy imbalance market, to include the potential loss of individual generators and to model remedial action schemes. Remedial action schemes are designed to automatically disconnect generators or load in the event of an unexpected loss of service of a transmission line to prevent system overloads. Currently, the real-time market models the potential unexpected loss of transmission lines to ensure that electrical flows do not exceed transmission system limits, but does not model the potential unexpected loss of a generator. The real-time market currently only has limited means to account for remedial action schemes and does not explicitly model them. As a result, grid operators must manage the potential for generator contingencies and remedial action schemes mostly through manual actions.

Management's proposal to include the unexpected loss of a generator and remedial action schemes in the ISO market models will improve the market dispatch, decrease out-of-market actions, and appropriately price each generator's contribution to congestion in the market. The proposed enhancements will also allow the market to more fully utilize generation that is part of a remedial action scheme.

Management proposes to apply this functionality to the ISO balancing area and to provide EIM Entities the option to use this functionality in their respective balancing areas. Therefore, Management is seeking approval from the EIM Governing Body under its primary authority to allow EIM entities the option of using the new functionality. The EIM Governing Body also has the option to provide advisory input to the ISO Board of Governors regarding the general design of the proposed real-time market modeling enhancements.

Management proposes the following motion:

> ***Moved, that the EIM Governing Body approves the proposal to allow EIM Entities to have the option to have the ISO model generator contingencies and remedial action schemes in their respective balancing areas; and***
>
> ***Moved, subject to Board of Governors' consent, that Management is authorized to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.***

BACKGROUND

ISO and EIM balancing area operators must plan in order to meet unscheduled changes in system configuration and generation dispatch in accordance with North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) requirements. Generators must be operated at output levels that ensure that transmission lines are not overloaded if generation or transmission is unexpectedly lost. The ISO and EIM balancing area operators accomplish this by establishing and operating within system operating limits to ensure system security.

A secure transmission system is able to withstand the unexpected loss of transmission or generation, including generation loss resulting from remedial action scheme operation. Remedial action schemes are network upgrades that detect and automatically disconnect generation or load on the system in the event of a transmission contingency.

Currently, the potential for generator contingencies are not considered by the real-time market's security-constrained economic dispatch. This requires ISO and EIM balancing area grid operators to constantly monitor the potential for generator contingencies that could result in electrical flows exceeding operating limits. Grid operators take manual actions to prepare the system so that electrical flows do not exceed limits in the event of a generator contingency. These manual actions consist of out-of-market interventions based on offline studies and manual review and analysis. Similarly, the current market does not model remedial action scheme operation.

Remedial action schemes are becoming more common in the ISO and energy imbalance market balancing areas because they enable the transmission system to relatively inexpensively accommodate new renewable generation. Remedial action schemes enable new generation without having to increase transmission capacity because they typically are designed to trip-off the generator if a transmission line it is connected to is unexpectedly lost. Consequently, no additional redundant transmission capacity is needed to ensure electrical flows are not exceeded if there is a transmission contingency. Remedial action schemes involve approximately 19,800 MW of generation within the ISO balancing area alone.

Because the real-time market currently has only limited means to account for remedial action schemes, it tends to overly constrain the output of the generators connected to them.

This requires grid operators to manually dispatch these generators above the market dispatch to take full advantage of the remedial action schemes.

PROPOSAL

Management proposes enhancements to include potential generator contingencies and remedial action scheme operation into the real-time market model.

The ISO will select the specific generator contingencies and remedial action schemes to model as required to reliably manage its balancing area as based on engineering analyses and outage studies. EIM Entities would have the option to select the potential generator contingencies or remedial action schemes that the real-time market will model in their balancing area, but would not be required to do so. This is consistent with their existing authority to determine specific transmission constraints that the market models in their respective balancing areas.

These enhancements will enable the market models to calculate how electrical flows will change if one of these events occurs. This modeling will ensure electrical flows will not exceed transmission limits by reflecting the potential change in flows in locational marginal prices, which will ensure generators are dispatched to appropriate output levels. Other independent system operators and regional transmission operators employ similar methods to account for the loss of generation in their markets.

If a generator unexpectedly trips off, frequency responsive devices on the other generators throughout a balancing area automatically increase the output of these other generators to replace the lost generation. Management's proposed enhancements will calculate the change in electrical flows on the transmission system, given this automatic response, and determine the appropriate amounts of transmission capacity to reserve to account for this potential change in flows. This modeling uses the same methodology that grid operators currently use as part of manual studies.

The proposed enhancements incorporate the impact of these potential changes in electrical flows into the congestion component of locational marginal prices. For example, if additional transmission capacity needs to be reserved to account for the potential changes in electrical flows when a generator is lost, the congestion component of the generator's locational marginal price will increase, decreasing the generator's locational marginal price. This will result in the market dispatching the generator to a lower output than it otherwise would have, which frees up additional transmission capacity to prepare for the potential unexpected loss of the generator.

As described above, the proposed enhancements will also account for generators that are connected to remedial action schemes that automatically trip the generator off when transmission is lost. Transmission generally has multiple lines so transmission capacity remains if an individual line is lost. Secure grid operation typically requires generators to be operated at output levels that will not instantaneously overload transmission if an individual line is lost. Since a generator that is part of a remedial action scheme will automatically trip-off if transmission is lost, the enhanced modeling will not reserve capacity on transmission connected to the remedial action scheme to account for this generator's output. This will decrease the congestion component of the generator's locational marginal price, increasing the generator's locational marginal price. This will result in the market dispatching the generator to a higher output than it otherwise would have, more fully accounting for the remedial action scheme in the market.

The enhanced modeling will also account for any load that is also connected to the remedial action scheme.

POSITION OF THE PARTIES

Stakeholders generally support Management's proposal because it will reduce out-of-market actions by modeling generation contingencies and remedial action schemes in the market. The only comments received from EIM participants involved requests to clarify implementation details.

The Market Surveillance Committee provided a formal opinion on Management's proposals, which is included as Attachment A.

CONCLUSION

Management requests the EIM Governing Body approve allowing EIM Entities the option to use the generator contingency and remedial action scheme modeling proposal described above in their respective balancing areas. This new modeling functionality will improve the energy imbalance market dispatch, decrease out-of-market actions, and appropriately price each generator's contribution to congestion in the market.

Opinion on
Modeling of Generator Contingencies and Remedial Action Schemes
in the California ISO Markets

by

James Bushnell, Member
Scott M. Harvey, Member
Benjamin F. Hobbs, Chair

Members of the Market Surveillance Committee of the California ISO

Draft
August 24, 2017

1. Introduction

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.[1] The first, the Generator Contingency and Remedial Action Scheme Modeling (GCARM) initiative,[2] 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 discon-

[1]The two initiatives are contrasted on p. 29 of California ISO, *Generator Contingency & RAS Modeling*, Draft Final Proposal, July 25, 2017 (henceforth referred to as the "Proposal"), www.caiso.com/informed/Pages/StakeholderProcesses/GeneratorContingency_RemedialActionSchemeModeling.aspx

[2]Ibid.

nection 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. RASs are increasingly and widely deployed in the CAISO 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. Costs are not considered in the CME redispatch optimization.

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.[4]

We have been asked by the CAISO to provide comments on the CAISO's GCARM proposal. The Market Surveillance Committee (MSC) has previously considered the modeling of generator contingencies and remedial action schemes in the CAISO market software during several public meetings, including Nov. 18, 2016 and Feb. 3, May 5, and July 10, 2017. In this Opinion, we first provide some background on remedial action schemes before summarizing the need to include them and generator contingencies in market software in Section 2. In Section 3, we summarize the CAISO's GCARM proposal, which is designed to address this need. Then in Section 4, we address several issues associated with design of the GCARM proposal, including 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.

Finally, our recommendations are summarized in Section 5. In short, we conclude that modeling of generator contingencies and remedial action schemes in the CAISO market models will contribute to increasing the security and efficiency of the CAISO's day-ahead and real-time markets. The replacement of ad hoc operator actions and constraints with explicit modeling of the sys-

---

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

[4]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*, 93(5), 2005, 965-979. There is also a large academic literature arguing for the explicity 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). However, there are many conceptual and practical hurdles to using such fully-stochastic models to run ISO markets.

tem's response to transmission and generation contingencies, including approximations 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.

2. Remedial Action Schemes and Generator Contingencies and Their Effects on Markets

2.1 Definition

The Federal Energy Regulatory Commission-approved definition of a Remedial Action Scheme (RAS) is "*(a) scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a system(s).*"[5] The CAISO's proposal would include modeling of all three of those types of corrective responses, although we understand that tripping generation is the most common type of RAS in California. As explained by the Western Electricity Coordinating Council (WECC),[6] RASs "*accomplish objectives such as:*

> "• *Meet requirements identified in the NERC Reliability Standards;*
> "• *Maintain Bulk Electric System (BES) stability;*
> "• *Maintain acceptable BES voltages;*
> "• *Maintain acceptable BES power flows; (and)*
> "• *Limit the impact of Cascading or extreme events.*"

As explained by WECC, RASs include predetermined ("open loop") rules that trigger corrective actions based on direct or indirect detection of predefined critical events. More sophisticated RASs can also involve monitoring of system response and adjustment of corrective actions ("closed loop"). The CAISO's GCARM proposal would only model open-loop rules, although it can accommodate adjustment of those rules throughout the day prior to executing the market software in response to anticipated system conditions and stresses.

As explained in the CAISO proposal, RASs have become more widely used in the California power system. This is because they can be a relatively inexpensive way for the transmission grid to accommodate the output of new generation, especially renewables, while deferring the need to add transmission facilities, under the assumption that generation tripped by the RAS to avoid a

---

[5]*Glossary of Terms Used in NERC Reliability Standards*, Updated August 1, 2017, p. 24, www.nerc.com/files/glossary_of_terms.pdf. Note that synonyms for RASs include system protection schemes and, more generally, wide-area protection. For an in-depth discussion of issues associated with design and operations of RASs, see Y. Zhang, M.E. Raoufat, and K. Tomsovic, "Remedial Action Schemes and Defense Systems," in C.-C. Liu, S. McArthur, and S.-J. Lee (eds.), *Smart Grid Handbook*, 3 Volumes, J. Wiley (On-line), Aug. 2016, http://onlinelibrary.wiley.com/doi/10.1002/9781118755471.sgd032/abstract.

[6] WECC, *Remedial Action Scheme Design Guide, November 28, 2006*, p. 2 (updated after April 1, 2017), www.wecc.biz/Reliability/RWG%20RAS%20Design%20Guide%20_%20Final.pdf.

post-contingency transmission overload can be almost immediately made up at the system level by frequency-responsive generation in the system.

The purpose of the CAISO's proposal is to include constraints that account for RASs in their market models of contingency-constrained scheduling of resources. This would expand their present system of modeling contingencies from so-called "N-1" contingencies (loss of one circuit in the network) to include "N-1+RAS" contingencies (in which the loss is accompanied by actions predefined in the RAS for a given contingency). In particular, like N-1 contingency modeling, the purpose of the new constraints is to ensure that the post-contingency flows satisfy all network constraints (some of which may be adjusted to reflect emergency ratings). In modeling N-1+RAS constraints, the market software is to model post-contingency network flows not only to reflect changes in distribution factors[7] due to the transmission contingency, but also changes in distribution factors and network injections reflecting the RAS corrective actions and assumed system response. In particular, if corrective actions include network reconfigurations, then those reconfigurations will also need to be reflected in changes in distribution factors; meanwhile injections will change to reflect both RAS rules regarding dropping of generation/load as well as the assumed distribution of changes throughout the network in frequency response-enabled generators that make up for dropped generation/load.

The CAISO's proposal also would add so-called "G-1" generator contingencies to the contingency constraints included in the market software. By adding the capability to model dropped generation/load as well as the distribution of make-up generation in the manner explained above, the market software will now also be able to model and constrain post-contingency flows for G-1 contingencies, representing the sudden forced outage of a generator that is replaced by frequency responsive generation elsewhere.

2.2 The Need to Consider RASs and Generator Contingencies

Disregarding RASs and G-1 contingencies can have two types of impacts on system operations: system security and market efficiency. The CAISO has not performed simulations of these potential impacts for the CAISO system, so we cannot comment on the magnitude of these impacts, nor on how large they are relative to the costs of implementing GCRAM and potential increased execution times.[8] Therefore, our comments are limited to general statements about benefits.

System security is likely to be harmed if generator contingencies are disregarded by the market software because large generator trips are a major risk. Although the CAISO's specification of operating reserve requirements considers that risk at a system-wide or zonal level, those requirements do not consider risks of overloading individual circuits, which depend on the real-

[7]Here we use the term "distribution factors" to describe power transfer distribution factors (PTDFs), which describe how flows on particular elements change when injections change. These elements are also sometimes called swing factors or shift factors. These are used to calculate the generation distribution factors referred to in the proposal.

[8]We understand that these modeling enhancements can be accommodated by the day-ahead and real-time models, allowing them to be solved within the desired timeframes. However, we note that if execution times are approaching those time limits, then modeling RASs and G-1 contingencies might be at the expense of other possible modeling enhancements.

time distribution of system loads and generation. Modeling specific generating contingencies and how the system is likely to respond to those contingencies will provide a more precise estimate of impacts on flows, allowing generation to be pre-positioned such that post-contingency flows do not violate emergency limits. In the absence of G-1 constraints in the market software, operators can manage the risks by defining nomograms or manual out-of-market dispatches.[9] But such operator actions are likely to be an inefficient way of ensuring feasible post-contingency flows, relative to an optimization that automatically predicts those flows as a function of system conditions. Further, operator actions may distort market prices. In this way, modeling G-1 contingencies can also contribute to market efficiency.

System security can also be harmed if market models omit the effect of RASs on post-contingency flows. Although RAS corrective actions (generator tripping, load shedding, or transmission reconfiguration) are designed to reduce the risk of certain flows exceeding emergency limits, there may be unanticipated interactions with other constraints or unusual system operating conditions such that triggering a RAS might prevent one overflow problem but create others. Systematic post-contingency flow modeling accounting for corrective actions can be expected to decrease the likelihood of this happening.

Market efficiency is likely to be harmed as well if RASs are not modeled. One reason is that operators might use ad hoc out-of-market actions or approximate nomograms to avoid the risks that may result from unanticipated interactions or unusual operating conditions.[10] These actions will likely yield less efficient generation schedules and nodal prices than an optimization that systematically accounts for network, load, and generator conditions and the precise RAS rules when calculating post-contingency fuels. Another reason, as pointed out in the examples in the CAISO's proposal,[11] is that a likely outcome of modelling RASs is that larger pre-contingency power flows can be accommodated, because RAS corrective actions are usually designed to reduce flows on certain critical circuits. Operators currently take account of the impact of remedial action schemes (RASs) through a variety of ad hoc actions which may not always be completely accurate and also require continuing operator attention to manage as transmission system flows change.[12] A change in constraints in the market optimization that results in a larger feasible region can result in a better market solution (that is, an improved objective function), and cannot worsen it. The current design in which RASs are only accounted for in real-time through ad hoc operator adjustments can distort prices in the day-ahead market, discouraging some physical resources from participating in the day-ahead market and instead incenting the submission of virtual bids.

---

[9] Proposal, Section 5.2.

[10] It is our understanding that in the day-ahead market, a limited-use RAS nomogram has been implemented. Such nomograms do not explicitly model post-contingency conditions, and are therefore at best a rough approximation of the system effects of a RAS. It is also our understanding operators take out-of-market actions to account for RASs in the real-time markets.

[11] Proposal, Section 5.1.5.

[12] Proposal, pp. 27,30.

In summary, disregarding generator contingencies and remedial action schemes will likely decrease system security and/or market efficiency relative to a market model that accounts for them. Besides increased resource costs, market inefficiencies can also include nodal energy prices that fail to reflect the actual value to the system of additional supply, and may in some cases result in pricing congestion where it actually won't exist. However, we are not able to assess the magnitude of these inefficiencies, the elimination of which is the goal of the CAISO's proposal.

3. The GCARM Proposal

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 (involving generators, loads, and/or transmission switching) in order to ensure that the following post-contingency requirements are met:[13]

> "*(1) Given a generator loss, all transmission facilities must be below emergency ratings.*
> "*(2) Given a transmission line loss, plus a generation loss due to remedial action scheme operation, all transmission facilities must be below emergency ratings.*"

In both cases, the proposal assumes that any net load change due to a generation contingency or triggering of a RAS is immediately made up by other frequency response-capable generation, according to a predetermined set of generation distribution factors (GDFs). The proposal describes the rationale for the proposal and the proposed reformulation of the feasible region of the day-ahead and real-time market models, and addresses several issues raised by stakeholders.

Section 6.3 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 approximate post-contingency changes in dispatch and the resulting flows on transmission elements, which are constrained by emergency ratings. The changes in dispatch include changes due to the contingency itself (if either a generation contingency is involved, or a RAS that adjusts generation or load) and the shifts in supply from frequency-responsive resources.

If transmission constraints under any G-1 or N-1+RAS contingency are binding, then in general they will change resource schedules. Although the proposal refers to such changes as reserving transmission capacity, with the exception of transmission switching actions such reservation can only be accomplished by altering resource schedules. The proposal states that it does not reserve generation capacity, and although this may be true per se, in fact some capacity may be unloaded as a preventive measure to avoid violating post-contingency flow limits. However, the incentive for unloading this capacity is not a capacity payment, but rather a lower locational marginal price (LMP) for the energy it produces. This is consistent with the philosophy of LMP, in which re-

[13] Proposal, p. 27.

sources that contribute to congestion are paid a lower price than resources that help relieve it; in this case, it is post-contingency congestion that causes prices to be differentiated.

Because the energy provided by different resources at a particular bus will in general have different coefficients in the model constraints, the marginal value of their outputs will in general be different—i.e., they will have different LMPs. (For instance, one resource's scheduled output will be removed from the flow constraints for a contingency that involves that resource, while the supply from other resources may be omitted for a particular transmission contingency because the RAS in that case curtails those resources.) A differentiation of LMPs at a given bus can only occur if the flow constraints for some contingency are binding, and the energy from different resources at the same bus enter post-contingency constraints differently. The proposal gives several simple numerical examples where such differentiation occurs.

The CAISO proposes to enforce the constraints in the day-ahead energy and RUC markets, and the real-time fifteen- and five-minute markets.[14] This would avoid gaming opportunities that could arise if the constraints are enforced in some markets but not others. In order to encourage convergence of day-ahead and real-time LMPs, virtual bids would be treated like physical bids. In particular, virtual bidders could be treated as generators or loads that are subject to contingencies or arming under RASs.

An important feature of the proposal is modification of the Congestion Revenue Rights (CRR) allocation and auction processes. In particular, constraints will be added to the CRR allocation models to represent G-1 and N-1+RAS constraints, and CRRs can be acquired between buses that are either subject to or not subject to the contingency constraints. In a sense, a bidder for a CRR can make the corresponding injection/withdrawal pair subject to a selected outage contingency and/or RAS at those nodes, if the purchaser of the right desires to do so. If the bidder does not want the injection/withdrawal to be affected by a contingency or RAS, then the that CRR will be modelled as affecting flows in all contingencies consistent with MW injected/withdrawn.

4. Issues

In this section, we address some particular concerns raised by stakeholders about the CAISO's proposal. These include questions about the efficiency of LMPs that may differ among resources located at the same bus, and resulting incentives to participate in RASs (Section 4.1); the treatment of virtual supply and demand by the constraints (Section 4.2); and potential effects of inconsistencies in GDFs on real-time congestion rent shortfalls and CRR revenue inadequacies (Sections 4.3 and 4.4, respectively).

4.1 Distributional and Incentive Implications of RAS Pricing

Some stakeholders, such as SCE, have raised concerns that these changes would "lead to unjustified revenues" because RAS-equipped resources could, under some conditions, earn higher pric-

[14]The CAISO will also model generator contingencies and RASs in non-CASO balancing areas participating in EIM if requested by the balancing area.

es than non-RAS resources at geographically identical locations that do not participate in the RAS. The CAISO's position is that, from an efficiency standpoint resources participating in RASs should be paid this premium. If the RASs are accounted for only in the ad hoc fashion that they are today,[15] then participating resources could be under (or even over) utilized in the real-time economic dispatch, potentially raising real-time prices and unnecessarily curtailing renewable output.

If the value of a RAS is incorporated into scheduling but somehow not reflected in pricing, this could incent resources to set offer prices in a way that also distorts the use of RASs away from their most efficient usage. Therefore, we agree with CAISO staff that, given the existence of RASs, it is more efficient to consistently model and price the capabilities of those RAS resources when running the day-ahead and real-time markets. Furthermore, it is appropriate for such resources to receive a different price than non-RAS resources when the contingent flows are binding.[16]

However, the SCE comments do highlight a more complicated question regarding RAS policy that relates to the selection of the resources that install RASs, and the allocation of the costs of those schemes. Our understanding is that almost all of the current RASs were installed as a requirement of interconnection at the time that the resource connected to the CAISO system. Similar to other transmission related interconnection costs, the costs of the RASs are recovered by the resource over time through the CAISO's transmission access charge (TAC).

We therefore interpret the SCE comments as objecting to the notion that a resource would be rewarded, through potentially higher LMPs, for the presence of a RAS whose costs were eventually borne by all network users. SCE views this as unfair, both because of the cost recovery, and also because SCE views the RAS, unlike a transmission network upgrade, as providing no additional benefit to other network users. "*A decision to now reward late coming generators who can only be interconnected with the use of a RAS would absolutely change the economics which could have resulted in requiring physical upgrades to the transmission system instead of the use of a RAS*."[17]

It is worth noting that the same asymmetric rewards to network investments can also arise from investments in traditional transmission infrastructure whose costs are either recovered from TAC or associated Congestion Revenue Rights. However, we also acknowledge that these objections do raise some legitimate issues about the CAISO interconnection policy.

[15] RASs are currently only informally accounted for in the market operations, sometimes through nomograms that may approximate the effect of RASs or through other operator adjustments that reflect some impacts of the RAS.

[16] This is predicated on the assumption that the modeling and pricing is implemented correctly, without adding further unintended distortions. Our understanding is that the CAISO has not yet performed any detailed testing or parallel operations of the proposed methodology.

[17] SCE Stakeholder Comments on the CAISO Generator Contingency & RAS Modeling Revised Straw Proposal. April 5, 2017.

One issue is whether the full costs of RASs should be recovered through TAC. This is not the case in other ISOs, where resources at times choose to invest in such schemes based upon the benefits they receive from the market dispatch. Another issue that speaks more directly to efficiency, rather than equity, concerns is the process through which RASs are selected. The concern is that RASs are considered only sequentially, at the time of a resources' interconnection with the grid. It is not a question of transmission upgrades instead of RASs – the interconnection studies select RAS because it is the least-cost option to support all the units – but rather a question of which resource should install the RAS.

For example, consider a case where two units connect at a location over time, and only one RAS is required to support the two units at that location. No RAS is required if only one unit is connected. Only the second unit to interconnect would be required to install RAS, but would also be compensated for this cost *and* be eligible to receive market benefits from recognizing the RAS in market operations. However, one could imagine a case where the first unit was actually a better candidate for a RAS, either because of the cost of the scheme or because of other operational characteristics. Ideally, an interconnection process would take a more holistic (rather than sequential) approach to installing RASs, and allow existing resources to "compete" with the newly interconnecting resource for the eligibility to install a RAS.

We conclude that, conditional on a RAS being in place, it is more efficient for the CAISO to incorporate the capabilities explicitly into the optimal market solution. However, the questions of how RASs are selected and how the costs of RASs are recovered are legitimate areas for further analysis. It is important to recognize that many of these questions relating to the efficiency and equity of interconnection policies pre-date this current GCRAM proposal, and should not be viewed as justification for weakening that proposal.

4.2 Virtual Supply and Demand Treatment

The CAISO's general approach with regards to convergence bidding has been to model virtual supply offers and demand bids at specific locations identically to physical supply and demand bids. The CAISO intends to apply that policy also in the case of this proposal.[18] In other words, virtual supply offers will be subject to contingency constraints at a node equipped with RAS, and 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.

This last point is particularly important in this context because we understand RASs are often used to accommodate renewable energy output, and load serving entities at times used virtual supply bids to reflect the output of renewable resources whose output they have contracted for, but for which they are not the scheduling coordinator. Moreover, the current failure to account

[18] Proposal, p. 57.

for the impact of RASs in the day-ahead market may be incenting the submission of virtual bids that create counterflows on constraints that would be relieved by RASs in real-time operation.

Further, a policy where virtual offers create a differential impact on pricing from physical supply offers can create incentives for strategic bidding of virtual (or physical) resources in order to further exacerbate the price differences that can result from modeling these resources differently. Therefore, we conclude that the CAISOs proposed treatment of virtual bids in this proposal is appropriately consistent with its treatment of virtual bids with regards to other network constraints.

4.3 Real-time Congestion Rent Shortfalls

There is a potential for the explicit modeling and pricing of RASs in the day-ahead market to impact the level of real-time congestion rent shortfalls (real-time congestion imbalance offset). This can occur if the real-time unit commitment is different from that modeled in the day-ahead market and furthermore these commitment differences cause the generation pick-up factors used to model post-contingency RAS transmission impacts (called GDFs in the proposal) to differ between the day-ahead market and real-time.

The CAISO calculated the magnitude of these differences for each hour over the period January 2016 through January 2017 for a representative large RAS. That study found that the differences lead to a calculated net imbalance of +$148,341 (i.e., a surplus) and a calculated gross imbalance of -$44,609.[19] It is possible that under other conditions, the change in imbalances could be in the other direction, but neither the CAISO nor we have examined the factors contributing to the direction of the imbalance. Changes on the order of $\$10^5$/year are approximately three orders of magnitude smaller that recently experienced CAISO CRR revenue inadequacies due to other factors. This analysis indicates that explicit modeling of RASs in the day-ahead and real-time market as proposed by the CAISO would likely lead to small or negligible changes in real-time congestion rent shortfalls due to differences in GDFs between the day-ahead market and real-time.

The CAISO pricing design would, however, likely collect less congestion rent than today in the day-ahead market for two reasons. The first is that RASs are currently not modeled in the day-ahead market, which tends to depress the day-ahead market price for resources participating in RASs in real-time below the real-time price, and may lead to real-time congestion rent surpluses when transfer capability is greater in real-time than day-ahead. This difference may also discourage the participation of resources participating in or impacted by RASs in the day-ahead market but this has not been examined. Second, the proposed changes in RAS modeling would also potentially reduce real-time congestion rent collections because the real-time prices used to settle real-time output would reflect the RAS more accurately that the current ad hoc adjustments, and could also lower congestion charges on the real-time output both of the resources par-

[19]The net imbalance is the difference between (1) the surplus collected during the hours in which the differences between day-ahead and real-time GDFs contributed to a congestion rent surplus and (2) the deficit during the hours in which differences between the day-ahead and real-time GDFs contributed to a real-time congestion rent shortfall (Proposal, p. 59).

ticipating in the RAS and other resources.[20] Neither effect is a source of current congestion rent shortfalls, but they would potentially reduce a source of congestion rent surpluses that currently offset shortfalls due to other factors. The CAISO analysis did not attempt to estimate the size of this impact.

There are a few caveats relating to the CAISO congestion rent shortfall analysis. First, the CAISO calculated these net and gross imbalances for a single large RAS, not simultaneously over all RASs in use by the CAISO. It is expected that the GDFs would generally be very similar over all RASs as they are based on the generator pick-up in response to a transmission/generation outage and would differ only with respect to the generation pickup on the generators impacted by the RAS.

Second, the $44,609 shortfall figure was calculated for all constraints binding in the day-ahead market, as any increase in real-time flows on these would result in a shortfall. This is not quite the worst-case scenario, as there could be constraints that were almost binding in the day-ahead market that would have been overloaded in real-time, leading to congestion rent shortfalls as a result of differences between day ahead and real-time GDFs. However, the tiny size of the gross shortfall figures suggests that the gross changes in flows are very small; as a result, it is unlikely that there would be a material impact upon the differences in GDFs and transmission flows on these other constraints.

Third, the CAISO shortfall calculation assumes that the RAS scheme studied would have been active in every hour in real-time, which is a worst-case assumption for the gross impact calculation.

Fourth, the CAISO shortfall is not a worst-case assumption in two other respects that are somewhat difficult to evaluate. One is that if there are constraints that will predictably bind with a higher shadow price in real-time than in the day-ahead market, virtual bids would be submitted in the day-ahead market that would increase day-ahead market flows on these constraints, leading to somewhat larger real-time congestion rent shortfalls. The other is that the CAISO shortfall analysis only considers one RAS. While the GDFs of the generator pick-up would not vary a lot across RASs, the impact of the reduction in flows due to the RAS dropping generation or load upon other binding constraints could vary across RASs and be larger for some specific RASs than for the particular RAS studied in detail by the CAISO. Without analysis, we do not know whether this could lead to larger congestion rent shortfalls associated with some RASs than indicated by the CAISO analysis.

Hence, the CAISO's analysis does not exclude the possibility that there might be constraints that would bind much more tightly in real-time than indicated by the analysis of this one RAS because of the differences in the generation being dropped in the contingency, leading to larger real-time congestion rent shortfalls than indicated by the CAISO analysis.

[20]Proposal, pp. 27, 30.

Therefore, we think the CAISO's analysis of real-time congestion rent shortfalls provides a sound basis for expecting little if any impact from the modeling of RASs. However, we also agree with the proposal that it is desirable to track the impact going forward to enable assessment of whether some of these more complex impacts would lead to shortfalls that need to be addressed.

4.4 Effects on Congestion Revenue Rights Revenue Adequacy

There is also a potential for differences between the GDFs 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. PG&E has proposed a methodology for computing the GDFs that would be used in the CRR allocation process that the CAISO proposes to implement. The CAISO has assessed the potential for material congestion rent shortfalls by comparing monthly GDFs calculated using the PG&E methodology for the CRR allocation/auction to those in the day-ahead market for a representative RAS over the period January 2016-January 2017. The CAISO concluded that most day-ahead market GDFs are very similar to the auction GDFs calculated in this way over the vast majority of hours.[21]

However, the CAISO did not report the magnitude of the GDFs, so the small absolute changes reported could involve substantial increases in percentage terms and possibly material differences in post-contingency flows overall. In addition, the CAISO reported that 99% of the GDFs in the day were within 0.02 of the proposed CRR GFDs, but did not report the size of the largest differences. If there are large differences for some particular resources or on some days, the shortfalls might be larger than expected.

The CAISO also calculated that the net impact of these imbalances would have been a $199,352 net shortfall in the CRR market under the assumption that all of the constraints in the day-ahead market were fully loaded in the CRR auction.[22] This calculation suggests that the PG&E modeling approach would ensure that modeling the RASs in the day-ahead market would have very small impacts on congestion rent shortfalls.

However, there are a few caveats to this conclusion. One is that the CAISO estimate for the net shortfall figure offsets positives and negatives. Hence, it is not quite a worst-case assessment, as some day-ahead market constraints might not be fully awarded in the CRR allocation and auction. This could result in either larger or smaller shortfalls than estimated. Second, the analysis was based on GDFs calculated monthly, rather than seasonally, for the FTR allocation and auction. The use of seasonal GDFs would likely lead to at least some increases in day-ahead market congestion rent shortfalls but we do not have a basis for assessing how large or small this impact might be. Third, the analysis has not been carried out for all RASs simultaneously but for a single large illustrative RAS. We understand that the CAISO repeated this analysis, including both the above RAS and a second RAS for a few simulated months and found that the increase in the congestion rent shortfall was less than 5%. This supplemental analysis provides additional rea-

[21]Proposal, p. 65.

[22]Proposal, p. 66.

son to expect small impacts on congestion rent shortfalls in the CRR market but the analysis was limited to a single additional RAS for a short period of time.

We do not recommend any further analysis of historical data to address these caveats, however, as CRR holdings could change in any case with implementation of the RAS design. We think the CAISO's analysis provides a reasonable basis for expecting minimal impacts on congestion rent shortfalls in the day-ahead market. We furthermore suggest that the CAISO calculate day-ahead market congestion rent shortfalls associated with RAS modeling following implementation to identify any material impacts on revenue adequacy so their source can be identified and addressed at that time.

5. Conclusions

In this Opinion, we have reviewed the CAISO's GCARM proposal, and some of the issues raised by stakeholders concerning the details of its implementation.

The MSC concludes that modeling of generator contingencies and remedial action schemes in the CAISO market models will contribute to increasing the security and efficiency of the CAISO's day-ahead and real-time markets. The replacement of ad hoc operator actions with constraints that explicitly model the system's response to transmission and generation contingencies, including approximations 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.

In this Opinion, we have also considered several concerns articulated by stakeholders. These include questions about (1) the efficiency of LMPs that may differ among resources located at the same bus, and resulting incentives to participate in remedial action schemes; (2) the treatment of virtual supply and demand by the constraints; and potential effects of inconsistencies in GDFs on (3) real-time congestion rent shortfalls and (4) congestion revenue rights inadequacies.

Regarding 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. However, the question of how RASs are selected, and how the costs of RASs are recovered are a legitimate area for further analysis. It is important to recognize that many of these questions relating to the efficiency and equity of interconnection policies pre-date this GCRAM proposal, and should not be used to justify weakening that proposal.

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 CAISO'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. However, we furthermore agree with the proposal that it is desirable to track the impact going forward to enable assessment of whether some of these more complex impacts would lead to shortfalls that need to be addressed.

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 CAISO has assessed the potential for material congestion rent shortfalls by comparing monthly GDFs calculated using a methodology proposed by PG&E methodology for the CRR allocation/auction to GDFs in the day-ahead market for a representative RAS. The CAISO 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 this study, we do not recommend any further analysis of historical data to address these caveats. We think the CAISO's analysis provides a reasonable basis for expecting minimal impacts on congestion rent shortfalls. We in addition suggest that the CAISO calculate the shortfalls associated with RAS modeling following implementation to identify any material impacts on CRR revenue adequacy so that their source can be identified and addressed at that time, if necessary.

EIM Governing Body **September 6, 2017** **Generator Contingency and Remedial Action Scheme Modeling Proposal: Decision on Extending the Option to EIM Entities to Use Generator Contingency and Remedial Action Scheme Modeling**

General Session

<u>Motion</u>

Moved, that the EIM Governing Body approves the proposal to allow EIM Entities to have the option to have the ISO model generator contingencies and remedial action schemes in their respective balancing areas.

Moved: Schmidt **Second: Howe**

EIM Governing Body Action: **Passed**	Vote Count: **5-0**
Fong	Y
Howe	Y
Linvill	Y
Prescott	Y
Schmidt	Y

Motion Number: 2017-09-G7.2