Opinion on
Local Market Power Mitigation Enhancements

by

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I. Introduction and Summary

The Market Surveillance Committee (MSC) of the California Independent System Operator (CAISO) has been asked to comment on the ISO's proposed Local Market Power Mitigation (LMPM) Enhancements.[1] The initiative leading to this proposal has been addressed during MSC meetings on Aug. 3, 2018, Sept. 28, 2018, Dec. 7, 2018, and Jan. 25, 2019.

This Opinion is structured as follows. Background material (Section I.A) and a summary of our recommendations (Section I.B) are provided in this introduction. Then three major features of the proposal are addressed in subsequent sections. First, in Section II, we consider the proposed addition of constraints in the Energy Imbalance Market (EIM) real-time markets to limit changes in between-balancing authority (BA) flows that would result from mitigation of supply offers. We identify several possible unintended consequences of those limits that should be monitored. Then, in Section III, the proposed definition of default energy bids (DEBs) for hydropower resources is considered. We comment on several issues, including how far in the future that forward hub prices should be considered in defining the DEB, and the use of distant hubs in the DEB calculation and how opportunity costs of transmission are treated.
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I.A Background

The CAISO's LMPM design is structured to identify the potential for the exercise of locational market power in meeting load within constrained regions within the ISO footprint, and within BAs in the EIM fifteen-minute and five-minute energy markets. The Appendix to the ISO's draft final proposal[2] summarizes the mechanics of the present LMPM procedures. Its basic features are a test to detect market power on uncompetitive transmission constraints within the ISO and between BAs in the EIM. The tools used for that detection include dynamic competitive

[1] Local Market Power Mitigation Enhancements, Draft Final Proposal, Updated Jan. 31, 2019, www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements-UpdatedJan31_2019.pdf

[2] Ibid., Appendix.

path assessment based upon a three pivotal supplier test for supply to relieve congestion into individual BAs within the constrained area. If removal of the three largest suppliers means that it is not feasible to meet load in an area, then those suppliers are collectively pivotal, and the LMPM procedure designates them noncompetitive. Then, for each resource, the components of the LMP that are associated with noncompetitive transmission constraints.

The present LMPM system is the cumulative result of a number of expansions and revisions of the original LMPM system under the Market Redesign and Technology Upgrade system implemented in 2008. The MSC prepared several opinions since then that discussed the various reforms proposed by the ISO:

- In our 2014 Opinion on LMPM Implementation in the EIM,[3] the MSC supported modification of the LMPM framework to deal with market structures that are quite different than inside the CAISO balancing authority. Among other differences are the degree concentration and the lack of a must-offer obligation in these other markets. The ISO subsequently made changes in how the test was applied as more BAs joined, as the original methodology was not applicable to multiple BAs.
- In 2011, we reviewed the ISO's proposed Dynamic Competitive Path Assessment procedures.[4] The MSC endorsed the proposal because it would allow the LMPM process to consider all demand and supply bid into the day-ahead market (including virtual bids); eliminate the potential for anomalous outcomes arising from the two-pass approach; and speed up the process, potentially allowing on-line (dynamic) competitive path analysis.
- The MSC has prepared several Opinions addressing ISO proposal to modify procedures for mitigating commitment costs offers in the ISO's LMPM procedures.[5,6,7,8,9,10,11,12] Is-

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[3] J. Bushnell, S. Harvey, B. Hobbs, and S. Oren, "Opinion on LMPM Implementation in the Energy Imbalance Market," July 7, 2014, www.caiso.com/Documents/FinalOpinion-LocalMarketPowerMitigationImplemenation-EnergyImbalanceMarket-July7_2014.pdf

[4] J. Bushnell, S. Harvey, and B. Hobbs, "Opinion on Local Market Power Mitigation and Dynamic Competitive Path Assessment," July 1, 2011, www.caiso.com/Documents/110713Decision_LocalMarketPowerMitigationEnhancements-MSC%20Opinion.pdf

[5] J. Bushnell, S. Harvey, and B. Hobbs, "Opinion on Commitment Costs and Default Energy Bid Enhancements (CCDEBE)," March 5, 2018, www.caiso.com/Documents/MSCOpinionCommitmentCost-DefaultEnergyBidEnhancements-Mar5_2018.pdf

[6] F. Wolak, J. Bushnell, B. Hobbs, "Opinion on Start-Up and Minimum Load Bid Caps Under MRTU," Aug. 2007, www.caiso.com/Documents/FinalOpiniononStart-upandMinimumLoadBidCapsUnderMRTU.pdf

[7] F. Wolak, J. Bushnell, B. Hobbs, "Comments on Changes to Bidding Start-Up and Minimum Load," July 9, 2009, www.caiso.com/Documents/DraftOpiniononStart-UpandMinimumLoadBiddingRules.pdf

[8] F. Wolak, J. Bushnell, B. Hobbs, "Opinion on Changes to Bidding and Mitigation of Commitment Costs," June 4, 2010, www.caiso.com/Documents/FinalOpiniononChanges-BiddingandMitigation-CommitmentCosts.pdf

[9] J. Bushnell, S. Harvey, B.F. Hobbs, and S. Oren, "Opinion on Bid Cost Recovery Mitigation Measures and Commitment Costs Refinement," May 7, 2012, www.caiso.com/Documents/MSCFinalOpinion-BidCostRecoveryMitigationMeasures_CommitmentCostsRefinement.pdf

[10] J. Bushnell, S. Harvey, B. Hobbs, and S. Oren, "Opinion on Commitment Cost Enhancements," Sept. 8, 2014, www.caiso.com/Documents/MSC_FinalOpinionCommittmentCostEnhancements-Sept2014.pdf

sues addressed in those opinions include the need to extend LMPM procedures to encompass commitment costs as well as energy offers; the detection of local market power in commitment cost offers, estimation of opportunity costs, adjustment of natural gas price indices, and revision of bid cost recovery rules.

In addition to the above opinions, in response to a FERC request, the MSC in 2013 prepared a report on the appropriateness of the 3-pivotal supplier test and other competitive screens in LMPM procedures.[13] In that report, we analyzed CAISO data, and concluded that there is no compelling justification for changing the three pivotal supplier screen in the LMPM competitive path assessment at that time. Potential ways were identified for improving the definition of path competitiveness and the determination of DEBs in order to decrease the likelihood of false negatives and false positives. This report was compiled prior to the operation of the EIM and did not address the issues involved in applying the 3-pivotal supplier test within the EIM.

The present proposal to enhance the LMPM system addresses several issues that have arisen since LMPM was expanded to encompass the EIM. The primary issue is greater uncertainty in estimates of variable costs of generation, which makes the setting of DEBs more difficult, increasing the risk of both over- and under-mitigation. Over-mitigation can result in overuse of limited energy resources and disincentives for participation in the voluntary EIM markets. Under-mitigation poses a risk of market power exercise. This greater uncertainty is the result of lower quality of information on natural gas supply costs in many EIM BAs, and the inherent nature of long-term hydropower storage, which makes opportunity costs dependent on uncertain future inflows and market conditions. Market power mitigation cannot function without estimates of variable costs, and so the ISO must estimate them; in choosing their values, the degree of uncertainty, as well as the consequences of possible over- vs. under-mitigation need to be weighed. In addition, there are issues in defining competitive supply that can potentially flow into a BA, which can affect whether supply in BA is declared noncompetitive and subject to mitigation.

The ISO's LMPM enhancements proposal has a number of features designed to address the need for DEBs in the EIM and the uncertainty involved in their estimation. These features can be classified as either DEB- or quantity-oriented.

The features that address DEBs focus on improving estimates of natural gas costs and long-term energy market prices that determine opportunity costs for the large amount of hydropower facilities that exist in many EIM BAs. We comment in detail on several of the offer/DEB-oriented

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[11] J. Bushnell, S. Harvey, B. Hobbs, and S. Oren, Opinion on Reliability Services Phase 1 and Commitment Costs Enhancements Phase 2, March 23, 2015, www.caiso.com/Documents/Decision_ReliabilityServicesPhase1-MSC_Opinion-Mar2015.pdf

[12] J. Bushnell, S. Harvey and B. Hobbs, Opinion on Commitment Cost Bidding Improvements," March 10, 2016, www.caiso.com/Documents/MSC_Opinion_CommitmentCostBiddingImprovements-Mar10_2016.pdf

[13] J. Bushnell, S. Harvey, B.F. Hobbs, and S. Oren, Report on the Appropriateness of the Three Pivotal Supplier Test and Alternative Competitive Screens, June 27, 2013, www.caiso.com/Documents/Report-Appropriateness-ThreePivotalSupplierTest-AlternativeCompetitiveScreens.pdf

aspects of the LMPM enhancements proposal in Sections III and IV, with our conclusions and recommendations summarized in the next subsection (Section I.B).

Meanwhile, the quantity-oriented features in essence attempt to limit the risk of overuse from too low DEBs by attempting to indirectly restrict the upward dispatch of mitigated resources in a BA if that supply expansion would either (a) change that BA from an importing to an exporting region, or (b) increase net exports from that region, if it is an exporting region. The export limit seeks to ensure that to the extent that a BA needs supply from another BA to balance load and generation (as determined in the market power mitigation run), that supply will be sold at a price that reflects the application of market power mitigation. But the export limit will constrain the extent that a BA can rely on purchases of power at mitigated prices to replace additional output of its own generation in the market run. Our assessment of these quantity-focused features of the LMPM enhancements is in Section II, with our conclusions summarized in Section I.B, next.

I.B. Summary of Recommendations

Limits on Transfers among BAs When Offers are Mitigated. Our recommendation on imposing limits on changes in inter-BA transmission flows as a measure to avoid the risk of overuse of mitigated resources whose DEBs have been underestimated is as follows. As long as these export restrictions are not applied as a matter of course but are available as a last resort to a BA in which application of mitigation is resulting in power being exported for less than its cost, we accept the availability of these restrictions as being an acceptable price to pay for encouraging EIM entities to participate in the EIM with a broader set of resources. They are a blunt but potentially necessary instrument to lower the risk of adverse efficiency and reliability consequences of understated DEBs.

However, we do not agree with the blanket statement of the proposal that "it is not appropriate to export greater quantities at the mitigated price than what was originally scheduled in the market power mitigation run."[14] We believe that *if* DEBs are a reasonable approximation of variable cost (including opportunity costs) then the application of market power based on those DEBs would be appropriate, whether or not it resulted in exports or an increase in exports.

We note that limiting exports in the market run based on levels calculated by the mitigation run could have unintended consequences. These could include:

- limiting the effectiveness of market power mitigation in some circumstances;
- overly restricting the use of flexible ramp resources to meet unexpected changes in net load in other BAs between the advisory and binding RTD that could reduce EIM benefits in general and the EIM flexible capacity diversity benefit in particular, and potentially lead to wealth transfers between the owners of resources located within the BA implementing the export limit and the BA operator; and

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[14] Draft Final Proposal, op. cit., p. 5. This statement in the proposal should be understood as excepting increases in exports due to upward dispatch of resources scheduled as flexible ramping product.

- the use of advisory interval flows in the mitigation run for an advisory interval to define limits in the binding interval of the next market run of the real-time (5 minute) dispatch market.

Since an EIM BA can choose to impose or not impose these limits, we hope that EIM entities will not have a need to do so often. If they are imposed frequently, this will have the consequences noted above, and make EIM prices more difficult to predict by increasing the complexity of the network constraints and thus congestion cost calculations. Frequent use should be viewed as a signal that there may be a continuing issue with DEB accuracy that the ISO needs to address. Alternatively, if it is concluded that the DEBs involved are accurate or even somewhat high, it might be an indication that a BA is either attempting either to exercise market within a constrained EIM subregion, or to benefit a subset of market parties in its area by decreasing energy prices but also earning congestion rents on the limits. This implies that the use and impacts of these limits needs to be carefully monitored and action taken if this option is utilized on more than a sporadic basis and by more than one EIM entity at a time.

Default Energy Bids for Hydropower Offers. Regarding the calculation of hydropower DEBs, we support the general procedure, but recognize its imperfections and limitations. One limitation is the potential use of future energy prices to set opportunity costs at times of year beyond the time when reservoirs are expected to refill and spill in the case of larger storage reservoirs. This may not be not the situation in all years, but during wet years, a reservoir that is likely to spill in the spring should not be able to use late summer power prices to determine DEBs early in the previous winter. Conversely, in dry years, some reservoirs may have higher opportunity costs in the summer then estimated by the proposed methodologies. However, due to the complexity and lack of transparency of hydro operations and constraints, the large uncertainties surrounding inflows and future energy prices, and the changes in generation use that will come with the expansion of the EIM, we are not confident that a more accurate and practical design can be developed at this point in time. Therefore, we support implementation of the proposed procedure, while recognizing its imperfections, and we further recommend that the ISO should monitor its performance over time, and make improvements based on what is learned. If offers are often at the DEBs, this might be either an indication that DEBs are too low, or alternatively indicate that there is a potential for the exercise of market power if close examination of the DEBs indicates that they are well above a particular resource's opportunity cost.

One element of the California ISO's proposed opportunity cost calculation for hydro resources with storage is the use of forward power prices. It is necessary for the ISO to use forward prices at trading hubs to determine forward prices for use in the DEB procedure. This is because forward prices with acceptable liquidity are available only at a limited number of regional hubs. In many cases, the hydro resources are not located at a trading hub so the ISO's proposed designs includes rules for determining which trading hub should be relied on to provide forward prices for calculating opportunity costs for each resource. The actual relationship between resource locations and their trading opportunities is complex; there is no simple rule that can be used to accurately measure these relationships, and some resources may have opportunity costs that reflect forward prices at multiple trading hubs.

The CAISO proposes to address these complexities involving trading opportunities in estimating opportunity costs by defining a default trading hub for each balancing area.[15] In addition, the California ISO will allow a market participant to select additional trading hubs for use in this calculation if the market participant can "show the CAISO firm transmission from the resource to one of these hubs or an electrically similar location."[16] However, we do not support the use of distant hub prices in the calculation of the DEB merely if firm transmission rights are held.

In an efficient and liquid wholesale market, the opportunity costs presented by future export opportunities, or sales at "distant hubs", would be fully captured in local futures prices. The difference between the local and distant futures price would reflect the costs of transmitting the power to the distant hub. Therefore, in a fully integrated transmission market, such as the CAISO's internal market, the futures price at the local hub would be the appropriate price upon which to base opportunity costs. If, however, the transmission market is *not* efficient or liquid, the above logic can break down. First, there may be no hub near to the resource. Second, a distant hub price could represent a legitimate opportunity cost *if* transmission rights from the resource to the hub have a use-it-or-lose-it character, are likely to be in surplus, and are not easily marketed to other participants. Some stakeholders have pointed to exactly these kinds of inefficiencies in arguing for the use of a distant hub.

Therefore, the CAISO's proposed use of a distant hub is appropriate if a participant can be plausibly shown to possess export opportunities, through the ownership of transmission rights, that are not readily transferable to others and would otherwise have no value to the owner, or if there is no hub located near to the resource. The question then becomes, how can stakeholders demonstrate this and how strict a burden of proof should be required? In this sense, while we concede the merits of the general concept, we do not feel that the mere ownership of transmission rights should be sufficient evidence to allow a firm to base all its default energy bids upon a distant hub. The conceptually correct test would be whether the supplier typically makes incremental sales supported by its hydro generation at the distant hub at times when prices are high at the distant hub. While the ownership of firm transmission rights from the supplier's resources to the distant hub might be one element of such a showing, the mere ownership of a token amount of firm transmission to the distant hub does not establish that incremental supply can be sold at market prices at the distant hub.

We also think that there should be a showing that such rights cannot be sold at a reasonable price, used to support spot sales, or otherwise earn revenues that would represent an opportunity cost for selling at the distant market. If the use of firm transmission rights to support sales at the distant hub would have an opportunity cost at the time of year when prices at the distant hub would be used to calculate hydro opportunity costs, this opportunity cost of transmission should be deducted from the distant hub prices in the DEB calculation. Indeed, if the transmission and energy spot markets are reasonably liquid, the local hub price is likely to be an adequate approximation of the distant price minus the opportunity cost of transmission for resources located at

[15] Ibid., pp. 37-38.

[16]Ibid., p. 38

the local hub. This is also true even if there is a green premium at the distant hub, as long as there is competition in the green energy market.

Stakeholders have argued that inefficiencies in bilateral markets for transmission, energy, and green energy markets mean that these conclusions do not hold at present. Our recommendation is the following: as a condition for using a distant hub's energy prices in a DEB calculation, the resource owner should provide information on the opportunity cost of transmission rights it holds. If a resource owner wants to argue that the opportunity cost of the firm rights it holds is zero over the relevant time frame of the DEB calculation, and that some of those rights would go unused if the resource produces energy in today's real-time market instead of waiting, the owner should provide evidence for this assertion to the ISO. Alternatively, the owner should suggest a value for those rights that is based on verifiable information. We do not believe that the ISO should, as a default, assume this value is zero just because the owner possesses firm rights.

Furthermore, we are reluctant to endorse a perspective that says that because market imperfections exist that prevent efficient trading of renewable energy credits, transmission, and energy, the ISO should help embed these inefficiencies in the West by providing an incentive to maintain those inefficiencies in order to support higher DEBs. We would rather see incentives provided to increase the liquidity of these markets. It is for this reason that we recommend that an estimate of the opportunity cost of transmission rights be deducted from prices at distant hubs if those prices are to be included in the DEB formula.

However, we recognize that estimation of the value of bilateral transmission rights is likely to be difficult, and that it may be impractical to do so at present. One significant complication in applying the opportunity cost of transmission rights to a distant hub from the local hub, even if that cost could be estimated, is that some resources may not be located at or electrically close to their assigned "local" hub. Consequently, their opportunity cost of point-to-point firm rights that would enable them to convey their power to the distant hub will be difficult to determine, since the likelihood of a liquid market for such rights from their location is even lower than between recognized hubs in the West. Another complication is that transmission rights might be traded for particular hours that might not correspond to when the resource would sell the energy that corresponds to the opportunity cost being calculated. All these complications mean that the value of transmission rights would be difficult to estimate and verify. However, this does not obviate our basic point: transmission rights should be presumed to have some opportunity cost that should be deducted from prices at the distant hub, and the burden should be upon the resource that wants to use a distant hub to propose and document the basis for such a cost. We do not recommend that the ISO itself estimate these costs.

If it is impractical to estimate the opportunity costs of transmission rights, or to require market parties to do so as a condition of using distant hub prices in the DEB calculations, we recommend that the ISO continue to examine questions concerning the value of firm transmission rights and their relevance to hydropower opportunity costs. First, does reliable data exist on the value of firm transmission rights for delivery to major western trading hubs? Second, does that data provide the basis for useful checks upon avoided cost estimates provided by resource owners? Stakeholders have provided comments asserting that there is little value in unused rights and no liquid market to sell them. This raises additional questions such as: are unused rights the norm, or the exception? If they are the norm, then why do the owners of those rights consistently acquire more than are needed? If they are not the norm and so rights are usually fully used, at what times do they tend to be fully used? At such times, there is in fact an opportunity cost, if only in the form of alternative uses that the owner could put them to. If they tend to be fully used during times of peak energy prices at distant hubs, this would indicate that those prices should not be used to determine energy opportunity costs in DEB calculations.

Despite the above concerns with some of the details of DEB calculation for hydropower plants, we do support the general approach that is proposed based upon gas costs and forward prices for energy. The risk that the DEBs are too low is partially mitigated by the flow restrictions discussed above, as well as the option that resources have for customized negotiated. DEBs. We prefer that the forward prices used in the DEB calculations be adjusted, if practical, by opportunity costs for transmission provided by resource owners and checked by the ISO, as described above. If this is not practical, we would support implementation of the proposal, at least for the near term, but the CAISO should continue to work to refine this aspect of the proposal.

Other Recommendations. Concerning some other aspects of the proposal, the MSC supports the proposed changes in how the competitive LMP will be used in the calculation of mitigated bids. An example is the use of that LMP plus a small value at the mitigated bid, if greater than the DEB in order to lower the risk of a large increase in the resource's schedule in the market run. The committee also supports the procedures proposed for updating gas prices, given the quality of price data that is likely to be available in non-CAISO BAs.

II. **Changes to Real-Time Market Power Mitigation Process**

II.A General Comments Concerning Imposition of Quantity Limitations in Market Run in Order to Limit Risk of Uneconomic Expansion of Output

If a resource's offer price is mitigated, it may be dispatched to higher output level in the market run (where its offer is set to the DEB) relative to its dispatch in the mitigation run of the market software (which uses the unmitigated offer). If the DEB materially understates the resource's actual marginal cost, the increased output may be inefficient, since this increase could be at the expense of other supplies whose costs are lower than the true cost of the mitigated resource. In the case of limited energy resources, a consequence could be overuse of the resource, leaving too little energy for later. Such an outcome could have adverse reliability impacts if, for example, a dry, hot summer results in higher than expected loads while at the same time too little water has been saved to meet those loads because understated DEBs caused the water to be used to replace lower cost thermal generation earlier in the summer.

The proposal would lessen the risk of uneconomic expansion of output by limiting changes in the net overall exports of the resource's BA as follows, if the exporting BA elects to impose those limits.

- If the BA is importing on net in the market power mitigation run, it will be constrained from becoming a net exporter in the market run, except to the extent that those exports come from flexible ramping product awards.[17]
- If the BA is exporting on net in the market power mitigation run, it will be constrained from exporting more in the market run, except to the extent that those export increases come from flexible ramping product awards.

It is implicitly assumed that the changes in net flows from or to the BA between the market power mitigation pass and the market pass are directly related to changes in the dispatch of mitigated resource(s) in that BA or flexiramp resources.[18] Although the mitigated resource with a DEB that is less than its actual cost might experience some uneconomic increase in output between the market power mitigation pass and the market pass as a result of the application of market power mitigation, the amount of the increase is intended to be limited by these inter-BA flow restrictions. Thus, this rather blunt instrument can be viewed as an escape valve that provides some assurance to EIM entities that if DEBs get seriously out of line with actual costs for some resources, there will be some protection against uneconomic overuse of those resources.

Some MSC members believe that an implicit assumption of this quantity limitation is that if mitigation would result in decreasing a bid so much that the resource's BA would flip from importing to exporting, then this would be evidence that a DEB is too low relative to actual costs, and market inefficiencies would likely result.

We have the following observation regarding this possible assumption. If the mitigated supplier's BA imports are congested such that local prices are higher than in export markets, then it is well-known from economic theory of power markets that a supplier with low costs within an importing market might choose to raise its offer sufficiently such that imports hit their upper bound, allowing local prices to increase.[19] In fact, it can be profit-maximizing for a large producer that is not subject to market power mitigation to adopt such a strategy even if under competitive pricing its region would be exporting rather than importing.[20] If such a supplier is mitigated, the resulting dispatch might not only decrease imports, but also change the region from an importing to an exporting region, which can be more efficient. The upshot is that mitigation that results in a switch from net imports to net exports for a BA within a constrained region or expansion of exports is not, in theory, sufficient to show that a DEB is too low if the supplier may possess market power but does not believe it would be subject to effective market power mitigation. Blanket restrictions on increases in a BA's exports between the market power mitigation

[17] Ibid., Section 6.1.1.

[18] Of course, due to complex network effects, it is possible that some of the change in flows is actually a result of increased output from non-mitigated resources within the BA, but the magnitude of these changes is implicitly considered to be small by the proposal.

[19] E.g., Borenstein, S., Bushnell, J. and Stoft, S., 2000. The competitive effects of transmission capacity in a deregulated electricity industry. *RAND Journal of Economics*, *31*(2), pp.294-325; Gabriel, S.A., Conejo, A.J., Fuller, J.D., Hobbs, B.F. and Ruiz, C., 2013, *Complementarity Modeling in Energy Markets*, Springer, NY, Ch. 7.

[20] Ibid.

pass and the market pass in order to prevent over-dispatch of energy-limited resources will not necessarily increase market efficiency.

We note that that this is one reason why internal ISO resources are not proposed to have the option of such quantity restrictions on exports from subareas within constrained regions within the ISO.[21] However, there are three crucial differences between non-ISO BAs and within-ISO constrained areas that make these quantity limitations reasonable for the EIM.

- First, there may be much more uncertainty concerning costs in other BAs. This is due, first, to the poorer quality of public data on natural gas costs for individual resources not located at major natural gas trading hubs outside the CAISO and, second, the presence of substantial amounts of hydro resources whose opportunity costs are very difficult to estimate. There is a significant risk of adverse efficiency and reliability impacts when mitigation is triggered and applied if DEBs materially understate costs.
- Second, EIM markets are voluntary markets and understated DEBs will not only result in reduced market efficiency due to inefficient dispatch decisions, the mere potential for understated DEBs can reduce economic efficiency by reducing participation in the EIM. Hence, a balance is necessary between the risk of discouraging participation by market parties in the EIM (and the resulting possible loss of market efficiency) and any theoretical market efficiency improvements from mitigated resources being used, in effect, to meet load in other BAs. Thus, if a BAA wanted to limit its exports if mitigated, it could do so on its own either by not offering the generation capacity voluntarily in the first place (aside from the requirement to offer sufficient flexible capacity). We also understand that some Transmission Owners can limit the transmission capacity they offer for use in the EIM. The ISO cannot prevent such unilateral actions by a BA, so giving the BA an option to request that the ISO to impose export constraints will be more transparent and might avoid risks of even less efficient outcomes if instead the BA doesn't make capacity available in the first place.
- Third, generation used by the large regulated load serving entities within California is generally exempted from energy offer price mitigation but the application of the 3-pivotal supplier test within the EIM does not take account of load serving obligations and is applied at the BA level, rather than across the entire constrained region, with the consequence that there is more potential in the EIM region outside the CAISO for the application of market power mitigation to resources lacking market power.[22]

[21] Another reason is that the DEB floor within the ISO is at the competitive LMP for the market, which is intended to avoid the outcome in which mitigation results in exports from the constrained region that triggered mitigation. The competitive LMP, however, will not limit exports from particular subregions within the constrained region, which is the effect of the export limits proposed by the CAISO. Note that the DEB floor outside of the ISO is also the competitive LMP, which is intended to avoid exports from constrained regions in the EIM.

[22] The CAISO uses a 3-pivotal supplier test to determine whether there are uncompetitive paths between BAs, and if supplies within BAs should be mitigated. Some stakeholders have observed that the way in which the test is used, the application of the 3-pivotal supplier test separately to each BA within a constrained region may result in more frequent mitigation than is appropriate, because it does not account for competition from supply in other BAs within the constrained area when it consists of more than one BA. Furthermore, the application of the pivotal supplier test does not take into account load-serving obligations. For instance, there could be 12,000 MW of load in a region, 11,970 MW of which is served by, say, the base schedules of 5 vertically integrated suppliers, while 1000 MW of

We are sympathetic to stakeholder concerns that a process that allows BAs to elect such quantity limits has the potential to adversely affect the short-run efficiency of the markets.[23]   However, we believe that as long as the EIM supply capacity and, perhaps, transmission are offered voluntarily, providing EIM entities with the option to impose this constraint is a less worse outcome than the application of mitigation based on underestimated DEBs that would reduce participation in the EIM and risks magnifying the inefficiencies that could result from too-low DEBS.

II.B. Potential for Unexpected Consequences

For two reasons, there is significant risk of unintended consequences from the export limit. First, the imposition of inter-BA constraints is a blunt instrument to limit the risk that particular mitigated resources will be overused due to too-low DEBs. Second, as DMM observed,[24] whenever a market sets a schedule based on one set of inputs (unmitigated offers in the EIM mitigation run would set the limits on exports) while prices are based on another set of inputs (mitigated offers in the market run), there is a possibility of providing incentives to strategically bid or otherwise attempt to affect market outcomes. We discuss some possible unintended consequences below.

Effects on BA Prices and Distribution of Congestion Rents. One set of unintended consequences results from the BA-wide impacts of the export constraint upon prices, and the distribution of congestion rents from the export constraint. BAs may have resources owned by several entities. If an imposed export constraint has a positive shadow price, then vertically integrated utilities who act as the BA will see lowered prices for their supply resources, which will be more or less compensated by lower prices paid by its consumers as well accrual of congestion rents from the export limitation. If there are a significant amount of resources that are independently owned within the BA, then there will be a significant monetary transfer from those resources (which will receive lower prices but, in theory, no share of the congestion rents) to the vertically owned utilities. In theory, the BA and the independent resources could strike a bargain, but we

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additional supply is available from other sources in the EIM to meet the last 30 MW of imbalance demand. In this circumstance, the pivotal supplier test would be failed by a wide margin, but in fact the vertically integrated utilities cannot withdraw the supply used to cover their base schedules and leave their 11,970 MW of load unserved. Another logical shortcoming is that import capability from other BAs is not considered in the residual supply calculation used by the test if the constrained region is broader than a single BA, which would also tend to inflate the frequency of the test failing and mitigation being imposed.

These weaknesses of the current mitigation design have not been a serious issue to date because it is only with the expansion of the EIM that the potential for constrained regions that include multiple balancing areas and larger number of suppliers has begun to develop. It will become more important to address these issues as the EIM continues to expand, and addressing them may reduce the need to apply the export limit.

[23] E.g., "*NV Energy does not support the CAISO's updated design principle to address economic displacement due to concerns that the rule inappropriately allows a participating EIM entity to elect to 'pull capacity out of the market that it had previously offered voluntarily, during periods of mitigation.' NV Energy suggests that by allowing participants to withdraw capacity during intervals of mitigation, the CAISO will be allowing occurrences of non-competitive outcomes*" (Draft Final Proposal, op. cit., p. 12).

[24] "Local Market Power Mitigation Enhancements Revised Straw Proposal, Comments by Department of Market Monitoring," December 10, 2018 , p. 2.

note that the outcome of any negotiation is uncertain, and the vertically integrated utilities start from a favored position.[25]

Thus, we have a concern that a BA run by a vertically integrated utility could increase economic benefits to its consumers (accounting for revenues received by its resources and congestion rents) by using the export limitations to, in effect, decrease prices to its consumers while at the same time restricting exports and possibly exercising market power with respect to neighboring BAs. The incentive to do so would be greater if a significant portion of this BA's supply was from generation it does not own.[26]

However, we also note that because the EIM is voluntary a BA could achieve roughly the same outcome simply by offering less transmission, and that the EIM revenues are likely to be a small portion of the independent resource's revenue stream; the latter of course can (and we hope would) change under the proposed day-ahead market enhancements now under development. We also note that the crediting of congestion rents is a FERC jurisdictional issue. In addition, if there is evidence that an EIM entity is abusing export limits in order to exercise buyer-side market power, then the ISO could file with FERC to end the use of this option for that entity. There would be no such concern for BAs in which there is no independent generation that does or could participate in the EIM.

Possible Reduced Effectiveness of Flexible Ramp Product. A second set of unintended consequences could be to limit the effectiveness of flexible ramp product in one BA to assist with unexpected ramps in other BAs. Therefore, we recommend adjustment of the constraint on p. 25 of the proposal to ensure that the flexibility of the system is not compromised by too tight of a right-hand side. In particular, consideration should be given to eliminating the *FRUR'* term from that equation, since our interpretation that all of the flexibility-up resources required for a given BA are intended to support not just its own flexibility needs but also to provide support for the rest of the EIM when not needed internally. If the ISO prefers to be cautious and not do so, then on-going monitoring of the performance of the flexible ramping product in the EIM should include consideration of whether export limits result in consistent holding back of BA flexiramp capacity that is turned out to be unneeded by that BA. More generally, we reiterate that the export limits should be used rarely if at all if DEBs are appropriately calculated, and that if a BA chooses to invoke it frequently then that is indication of a problem that needs to be fixed.

[25] A counter argument is that the allocation of the congestion rents is covered by the EIM entities' FERC tariff, and hence anyone who is adversely impacted can raise the issue at FERC. Therefore, it can be argued that this issue is not a problem the CAISO needs to address or even should address. However, even given this FERC oversight, the issue exists and FERC oversight of the BAA operators tariff does not address the distribution of rents between BAs.

[26] In a presentation at the Jan. 25, 2019 MSC meeting, it was shown that in some circumstances there could be multiple sets of prices consistent with a market dispatch under the inter-BA limits, and that there would be clear motivation for the BA with the mitigated resource to obtain one of the set of prices rather than the other. ISO staff expressed the opinion that, in reality, the potential for multiple sets of prices to be consistent with a dispatch (technically termed a "degenerate" solution) is relatively small and can be dealt with in the existing software by small adjustments of the constraints.

Inter-Interval Consequences in RTD. A third set of unintended consequences could arise from changes in market conditions from one 5-minute interval to the next in the real-time dispatch (RTD) market. The present proposal would base the inter-BA flow limitations in one interval's binding market run upon the advisory interval's results for the previous interval. The result could be overly tight constraints on inter-BA transfers in the market run because of changes in load or supply availability from the previous advisory dispatch for the same interval. This could perversely result in the application of mitigation causing prices in the market dispatch to be raised above the level that would have prevailed had there been no mitigation.

These unintended consequences only arise if EIM entities find it necessary to actually exercise their option to impose the export limit, while the existence of the option to implement the export limit if DEBs are materially understated has the potential to increase participation in the EIM without the limit ever being utilized. Hence, we can support the availability of this option to encourage participation in the EIM, with the following caveat: if the ISO observes EIM entities making extensive use of this option, that is a sign of potential inefficiency that the CAISO needs to address by identifying and correcting the underlying problem.

Concern about Interaction of Mitigation in the Fifteen Minute and RTD Markets. Concern has been expressed by DMM about possible inefficiencies resulting from over-mitigation through too-low DEBs in the 15-minute market, followed by the mitigated resource finding it optimal to buy back its obligation in RTD, even if RTD prices are higher than 15-minute prices.

While the proposed modifications in the way the competitive LMP is updated could indeed result in a supplier buying back power sold at prices impacted by offer price mitigation in the FMM at higher prices in the 5-minute market, this would be the preferable outcome for the supplier if its offer price in the latter market reflects the value of the power. The seller would incur losses from the sale of power at mitigated prices in the FMM, but the losses would be reduced by being able to buy back the power for less than its value (i.e., the purchase price would be less than or equal to its offer price) to the market participant in the 5-minute market.

For example, suppose offer price mitigation were applied to a hydro resource in the FMM requiring that water worth $100 be used to generate power that would be sold at price of $30. If the seller's offer price was similarly mitigated to $30 in the real-time market, the water would be used to generate power and the resource owner would lose $70 as a result of its offer price being mitigated to less than the value of the water. If, however, the competitive LMP rose to $60 in the 5-minute market, the seller's offer price would be $60 in RTD, rather than $30 in the FMM. If the clearing price was $50 in RTD, the seller would not be dispatched at the $60 offer price and would instead buy back its FMM schedule at a $50 price. The sale of power at $30 in FMM, then buying the power back at $50 in RTD would cause the supplier to lose $20, but this $20 loss is much less than the $70 it would lose if it had to release water worth $100 to generate power worth only $30.[27]

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[27] The updating of the competitive LMP would reduce the profits of suppliers seeking to exercise market power, but the ISO should be concerned with the impact of mitigation on suppliers offering supply at their cost, not suppliers seeking to exercise market power. Thus, if the actual costs of the suppler in the example above was $30, then it would lose $20 buying back its output at a price of $50, but the supplier could avoid this loss by offering its supply at its actual cost.

It would of course be preferable to set more appropriate default energy bids so water with a value of $100 would not be scheduled to generate power worth only $30 in the FMM. Other parts of the proposed design seek to improve DEBs so this happens less often. But as long as there is a potential for default energy bids to understate the actual value of energy limited resources, it will be economically efficient to update the competitive LMP in RTD, and this updating will also reduce the losses of suppliers that offer their output at prices that reflect their costs.

III. DEB Option for EIM Use-Limited (Hydropower) Resources

III.A. General Comments

With the expansion of the EIM to encompass BAs in the Pacific Northwest and Canada that have a substantial amount of hydro resources, it is necessary to tackle the very difficult conceptual issue of assessing the opportunity costs of such resources. DEBs are needed for the application of market power mitigation, but estimating hydro opportunity costs can be fiendishly difficult, particularly in the face of within-day environmental and hydraulic operating constraints, especially for resources in series (cascading); longer-term uncertainties in inflows and market prices; and possible premiums that hydro resources can earn in certain markets because of their fossil-fuel free nature. Any procedure to set DEBs for such resources has to balance the risk of setting DEBs that understate opportunity costs, leading to inefficient overuse of hydro resources (e.g., high generation early in the summer, leaving inadequate water in storage for later summer and fall) and discouragement of participation in the EIM with the risk of setting DEBs that are so high they permit the exercise of material market power.

A crucial question is whether the penalties for over-mitigation and under-mitigation are asymmetric. Since the EIM is voluntary and all participants are required to have enough supply to cover their base schedules, we believe that this is one factor favoring DEBs that may err somewhat on the high rather than low side. This is because we share the concern that DEBs that are too low will motivate hydro owners to remove some of their flexible resources from the EIM dispatch and use them to support base schedules that foregoes the value of their flexibility. From the entire region's point of view, this would make less efficient use of these resources and undermine the essential goal of closer integration of the West's power markets in order to facilitate the integration of large amounts of renewable energy.

We agree with the Department of Market Monitoring that the proposed general approach to calculating hydro DEBs is broadly reasonable.[28] There are, however, important details as there are in any market power mitigation system, and we comment on three of them below.

[28] "The general approach that the ISO has proposed for its new hydro resource default energy bid option is very similar to the approaches that have been used for some time in negotiated DEBs for similar resources. Therefore, DMM is supportive of the overall approach." DMM Comments, op. cit., p. 4.

III.B. Length of Time

The hydro DEB procedure would differentiate between short-term (small storage) and long-term (large storage) resources, with the former having a time horizon of weeks to a few months over which it can allocate stored water, and the latter having a year (or even longer) time horizon. For the latter, it is proposed to consider forward prices as far as twelve months in the future.

As a basic principle, if it can be predicted when in the future the reservoir will either be full and spill, then prices in periods beyond that time cannot represent opportunity costs, because water unused now cannot be saved to be used at those times. We note that determining the appropriate pricing horizon can be difficult, because of uncertain inflow forecasts. The proposal assumes that 12 months is the maximum horizon for long term storage resources, and that one month is the minimum horizon for resources with less storage. These values are quite rough approximations of the actual horizon because in reality the expected number of months until spill or emptying depends on the month of the year. For instance, it is much shorter at the beginning of the winter, a handful of months before the spring melt, than it is at the end of the spring freshet when the summer and fall still lie ahead. The simplified approach also does not account for the storage status. A near-empty reservoir during a winter with low snow pack will be much less likely to need to spill in the coming spring compared to a half-full reservoir during a high snow pack year. Similarly, a large reservoir with low water levels in June in a low hydro year will need to apply higher opportunity costs than if the reservoir had a high water level at the end of June.

A system in which the storage time horizon depends on the month of the year and how much water is in storage relative to typical conditions would be much more complicated than what the ISO proposes. We suggest however that as a first approximation that the calculation of the opportunity cost of long term storage could be limited to a time horizon that ends at the conclusion of the next high inflow season (spring freshet) and not be extended to include forward prices for the following summer, unless reservoir levels are unusually low so that spillage during the inflow season is unlikely.[29] If this is too complex to implement immediately, we suggest that it be analyzed after implementation of the present proposal to see whether it might make a significant difference in DEBs. However, if such a tailored system would increase the risk of underestimated DEBS and thus resource overuse, then the simpler (and more generous) present proposal can be retained.

We recommend that the CAISO implement the proposed DEB procedure (perhaps modified somewhat to reflect month of the year, as suggested above), closely monitor how it is performing, and be prepared to make changes over time as issues are identified. Given the complexity of hydro operations and its constraints, and large uncertainties in future flows and prices, it is unreasonable to expect that the CAISO's initial design will work exactly as intended to accurately estimate opportunity costs.

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[29] Another important detail in these designs is the timing of recalculation of opportunity costs. Opportunity costs calculated based on forward prices will decline after the peak month prior to the next spill cycle, but actual opportunity costs may remain high because less water will be left in storage to cover the remaining period. The CAISO will need to work out how to handle this effect if it recalculates opportunity costs on a daily basis without considering the amount of water left in storage.

III.C. Use of Alternate Pricing Hubs

A vexing problem is which pricing hub should be relied on to provide monthly forward power price indices as proxies for the opportunity costs upon which hydro generation DEBs would be based. This issue has two aspects.

The first aspect concerns resources that are not located at a liquid trading hub for which assessments of forward prices are available. It may not be clear which hub is most relevant for determining opportunity costs; the geographically closest hub may be not be accessible regularly due to congestion. Or a resource may be able to switch sales between hubs as flow directions, prices and congestion change, as is expected to occur as often as twice daily or more as solar resources increase in California. A reasonable approach in such situations is for the resources to document, based, e.g., on past sales and congestion patterns, which hub or hubs are relevant. This is, however, a time-consuming option that would take significant resources to administer by the ISO.

The second aspect concerns the use of multiple hubs, especially more distant hubs. Stakeholders have argued that if a resource owner has firm transmission rights to a distant hub, then prices at that location can be the relevant opportunity cost, if higher than local prices. DMM has disagreed, arguing that if energy can be freely bought and sold both at the location of the resource and at the remote hub used for the forward price then, in effect, then the use of such rights to sell power at the distant hub has an opportunity cost that should be deducted from the power value at distant locations when calculating the opportunity cost of hydro generation. Stakeholders and the ISO's rebuttal of that position have pointed to the illiquidity of energy markets for resources not located at trading hubs who may not be able to buy the power needed to use their transmission rights; the predominance of multi-hour block sales of energy; and the premium that green energy obtains in some markets rather than others.

We disagree with the statement in the draft final proposal that "(i)f a resource owner has firm transmission availability to sell energy at multiple locations, these would be missed opportunities for energy sales at any of these hubs. Therefore the maximum price at any of those hubs should be included in the resource's default energy bid."[30] This assumes that there will be unused transmission rights: i.e., "use it or lose it", such that if unused they can't be sold to someone else at a reasonable price, While this may often be the case for firm transmission source at resources not located at trading hubs, there is also an implicit assumption that the amount of rights exceeds the amount of power sold to the remote hub by the resource on days with high prices at the distant hub, so that the transmission has zero opportunity cost and incremental power generated with hydro generation could be sold at the distant hub. Just because a resource owner holds some amount of long-term firm transmission rights doesn't mean that there are any to spare at zero marginal cost that could be used to support more sales, nor does it mean those rights can't be sold to someone else.

[30] Final draft proposal, op. cit., p. 13

It is likely to be the case that transmission rights markets, as well as markets for spot power are illiquid for resources not located at trading hubs. Nevertheless, in general, we are reluctant to have the ISO recognize and reward any inefficient incentives that result from inefficient transmission rights systems, for fear that this would encourage perpetuation of these inefficiencies. We do not believe that two identically situated generators should get different opportunity costs just because one went out and acquired some firm transmission rights. If spare illiquid rights exist such that distant hub energy prices become relevant opportunity costs, we would rather that the ISO encourage market parties to seek ways to make transmission rights and energy markets more liquid in the interest of improving the functioning of the West's markets.

We now address the justification based on illiquid markets for green power/renewable energy credits, such that green power receives a credit in one market but not in another. Under what circumstances might a premium for green power in one location and absence in another mean that multiple locations should be considered?   If there are multiple green resources competing for transmission rights to a hub where such resources get a premium, then in the liquid transmission rights markets we would like to see encouraged, the transmission price would reflect that and/or traders would be willing to buy green power at the local location and resell it elsewhere, so that that a green resource would realize the same net revenues locally as in the more distant market. We recognize that this is not the situation presently in the West. However, we are skeptical of rules that might allow a resource in the Pacific Northwest to make very high offers in the winter based on high Palo Verde prices in the summer, including a possible green premium. Furthermore, it is California that presently pays green premiums most consistently, and transmission rights into California in essence face a liquid transmission market because interties are priced by the ISO's locational marginal pricing system both for day-ahead and real-time sales, so this argument is not relevant in that case.

Our recommendation is as follows. It is necessary in many cases for resources to be able to use distant hubs to determine forward prices for use in the DEB procedure because there may be no nearby hub that is relevant. We agree with the ISO that the holding of firm transmission rights is a relevant factor to consider in deciding what distant hubs to consider. However, we recommend that use of distant hub prices not be allowed as a default or under just a showing of firm transmission rights, but that there be a greater showing burden be placed on resources that want to use further hubs in addition to much nearer hubs. This burden should include a demonstration to DMM's satisfaction that the transmission rights are in fact "use it or lose it" with zero opportunity cost through the relevant time horizon. This is fundamentally a market definition question, and the ISO is trying to develop simple rules to define these markets when a complex economic analysis would actually be necessary. We appreciate the need for transparency, predictability, and practicality of market rules, but we believe that the present proposal is overly generous in terms of what is required of a resource owner in order to use distant hubs.

III.D. Other Issues

Regarding the calculation and proposed use of a 140% multiplier for forward energy prices, we don't have any justification to propose an alternative multiplier as being obviously better. For instance, we don't have empirical evidence that 4 hours/day is the correct duration of production to consider when calculating the probability of overuse under a given multiplier. We can well imagine that it is too few hours for many resources for much of the year, but too many hours for the same resource during, e.g., late summer. We are reluctant to recommend a more complicated method--for instance considering different number of hours in different months of the water year--since that would multiply the number of somewhat arbitrary assumptions without assurance that better outcomes would occur.

Therefore, we suggest monitoring outcomes under the design proposed by the ISO (including examining the hours per day that different resources run and the rate at which reservoirs are depleted) with the object of assessing whether the multipliers used are broadly reasonable and cover the risk of overuse for the great bulk of resources. This recommendation is consistent with the draft final proposal's statement that "this default energy bid is not necessarily meant to be sufficient for all resources, particularly those with very limited water availability, but rather a solution that may work for most hydro resources. In cases where this default energy bid is insufficient, the CAISO will continue to offer Commitment Cost Enhancements – Phase 3 opportunity cost adders and negotiated default energy bids."[31] We further suggest that a less generous multiplier be used if a resource is consistently run above levels required for environmental flows or for other non-power uses for many more than 4 hours per day. Also, it might be reasonable to use average daily gas prices for such resources rather than peak gas prices, as proposed in the draft final proposal, but not in earlier versions.[32]

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[31]Ibid., p. 17.

[32]Ibid., Section 6.3.1