July 2, 2019

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation CAISO Tariff Amendments to Enhance Local Market Power Mitigation and Reflect Hydroelectric Resource Opportunity Costs in Default Energy Bids

Docket No. ER19-___-000

Dear Secretary Bose:

The California Independent System Operator Corporation (CAISO) proposes this tariff amendment to include three separate and distinct measures that facilitate participation of fast ramping hydroelectric resources in the western energy imbalance market (EIM) by improving the local market power mitigation process and cost-based bids used for such resources being mitigated.[1]

First, the CAISO proposes to modify its real-time market local market power mitigation rules so the CAISO will no longer mitigate a resource in subsequent market intervals merely because the resource was mitigated in a prior interval. Rather, to the extent possible, the CAISO will evaluate in each interval whether the resource's bid should be mitigated. Second, the CAISO proposes to allow an EIM entity balancing authority area in the real-time market to limit dispatch of incremental net exports under certain conditions. These two changes will enhance the performance of the CAISO's local market power mitigation to prevent, to the extent feasible, dispatching resources at mitigated bids when the mitigation is not warranted. Third, the CAISO proposes to improve the calculation of cost-based bids used in the market power mitigation process, by introducing a new hydro default energy bid (hydro DEB) option based on

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[1] The CAISO submits the proposed tariff changes pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d.

opportunity costs that would apply to all hydroelectric resources with storage capability that participate in the CAISO markets or the EIM.

The three proposed changes are not interrelated and are severable from each other. The Commission should therefore consider the just and reasonableness of each proposed change separately. Any ruling regarding the justness and reasonableness of one of the proposed changes does not affect the justness and reasonableness of the other proposed changes.

The CAISO expects to implement the changes proposed in this tariff amendment no later than December 4, 2019.[2] The CAISO requests authority to provide notice of the actual effective date by providing the Commission and market participants at least fourteen days-notice.[3] However, the CAISO must begin preparing any hydro DEB's requested prior to the effective date of the changes to ensure scheduling coordinators[4] have a functional hydro DEB by the time the changes are implemented. Therefore, the CAISO respectfully requests that the Commission issue an order by September 30, 2019 approving an October 14, 2019 effective date for the tariff provisions regarding development of the hydro DEB. This will provide the CAISO and market participants with certainty regarding the hydro DEB parameters as they develop the hydro DEB.

I. Summary

The CAISO's local market power mitigation rules include measures to mitigate a supplier's energy bids when local market power exists. However, mitigation can also result in energy bids being mitigated when market power is not actually detected in the interval. Also, in the EIM, mitigation can result in a supplier's energy bids being mitigated in quantities greater than needed to resolve market power. This can require market participants to sell more energy than they would otherwise be willing to sell at their default energy bid.

The first situation arises because of existing rules extending mitigation to market intervals beyond those in which the market power mitigation process detected market power. This can occur throughout the mitigation process applied in all CAISO markets, including the EIM. The second situation is specific

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[2] Attachment K lists the requests effective dates for each of separate tariff provisions submitted in this tariff amendment.

[3] The CAISO has included an effective date of 12/31/9998 as part of the tariff records submitted with this filing. The CAISO will make a filing pursuant to Commission Filing Code 150 to provide notice of the actual effective date of these tariff records at least fourteen days prior to implementation.

[4] Under the CAISO tariff, scheduling coordinators are market participants that are registered with the CAISO and are the entities responsible for scheduling and bidding resources in the CAISO markets.

to the EIM. In this situation, the CAISO market dispatches a balancing authority area to export more energy than it was required to offer in the EIM only because the market mitigated a participating resource's energy bids. Both situations can produce uneconomic outcomes because sellers of the energy might not have offered energy bids or transmission into the market had they known they would have to sell at mitigated bid prices, which can be below their actual marginal costs. Given the voluntary nature of the EIM, these outcomes can result in a lower overall level of participation.

These situations are exacerbated by the CAISO's calculation of default energy bids, which often fail to reflect hydroelectric resources' actual marginal costs.

The CAISO proposes to address these issues by changing the market rules in three respects. First, the CAISO proposes to limit the instances in which it dispatches resources at mitigated bid prices when local market power mitigation is not actually triggered in a specific interval, but is a carryover of a determination made in a prior interval. The CAISO will make local market power mitigation process changes so that mitigation no longer extends beyond the interval being tested to the extent feasible. Also, the CAISO will update the price used in the market power mitigation process in each interval based on that interval's competitive locational marginal price (LMP).

Second, the CAISO proposes to limit incremental net exports from an EIM entity balancing authority area in market intervals when its participating resources' bids are mitigated, while recognizing the amount of energy the exporting balancing authority area was required to offer to the EIM. This will address situations where the CAISO market dispatches an EIM entity balancing authority area to export energy only because the market mitigated its participating resources' bids. Although the EIM is a voluntary market, an EIM entity balancing authority area has to offer a minimum amount of energy bids to be eligible to participate in energy transfers between balancing authority areas. Similarly, although market power mitigation is necessary to protect against market power within import-constrained areas, it is not appropriate to require export at mitigated bid prices in excess of what the supplier was initially required to offer to the EIM.

Finally, the CAISO has also come to appreciate that its existing methodologies for calculating default energy bids do not accurately reflect actual opportunity costs of hydroelectric resources with storage. The mitigation process enhancements described above will address deficiencies in the local market power mitigation process to avoid situations where the market dispatches resources in quantities greater than what is needed to resolve market power. However, there will still be cases where the CAISO must apply a resource's default energy bid, but the default energy bid does not reflect the resource's actual marginal costs. To address this issue, the CAISO proposes an additional default energy bid option for hydroelectric resources with storage that will be available to qualifying hydroelectric resources in the EIM and CAISO balancing authority areas.

The proposed changes were largely supported by stakeholders with a few exceptions discussed in this transmittal letter. Although the three sets of proposed tariff changes are independent of each other and severable, together they will address issues with the current rules that are either unnecessarily subjecting suppliers to market power mitigation or forcing sales from resources at less than their marginal cost. The enhancements proposed herein will make the CAISO markets fairer and more efficient and encourage participation of needed flexible resources.

II. Background

A. CAISO Markets and Timeline Description

The CAISO administers day-ahead and real-time wholesale electricity markets. Although the day-ahead market only includes the CAISO balancing authority area, the real-time market extends to balancing authority areas participating in the EIM, which currently include the CAISO and eight EIM entities. The real-time market includes the 15-minute granularity real-time unit commitment process (RTUC) and the five-minute granularity real-time dispatch (RTD).[5]

The real-time market conducts a multi-interval optimization for each of these real-time market components, therefore each run produces results for multiple market intervals.[6] The RTUC runs every fifteen-minutes and looks ahead from four to seven 15-minute intervals, depending on the run.[7] The STUC and the RTUC processes perform security constrained economic dispatch and unit commitment to produce start-up and shutdown instructions, and advisory schedules and prices that are not used for financial settlement. The second interval of each RTUC run produces financially binding energy, ancillary service, and flexible ramping product schedules and prices for the fifteen-minute market

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5 The real-time market also includes another process referred to as the short-term unit commitment process (STUC), which is not affected by this tariff amendment. *See* existing tariff section 34.6.

6 The multi-interval optimization also implies that a dispatch in the binding interval may be necessary to position the resource to address requirements in subsequent intervals.

7 *See* existing tariff section 34.3.1.

(FMM).[8] The CAISO market financially settles the FMM based on differences from day-ahead schedules or, in the EIM, from base schedules.[9] One of the RTUC runs is used to initially schedule imports and exports and is referred to as the hour-ahead scheduling process (HASP).[10]

The RTD conducts a security-constrained economic dispatch to produce binding energy dispatch instructions and prices, and flexible ramping product schedules, which runs every five minutes. The RTD looks out from nine to thirteen five-minute intervals, depending on the run. The first RTD interval is the binding market interval used for the final resource dispatch and financial settlement.[11] The results for the RTD intervals beyond the binding run are advisory and do not serve as the basis for settlements or dispatch. The CAISO financially settles the RTD based on differences from FMM schedules.

The real-time market executes two passes in each of the fifteen-minute RTUC runs. The first is the market power mitigation pass that tests for local market power and replaces submitted bids with mitigated bid prices. The second clears the market with the mitigated bid set established through the local market power mitigation pass.

The real-time market only executes one pass for each run of the RTD, not two passes like the RTUC process. The RTD performs a market mitigation process at the end of each run after it has calculated the dispatch and LMPs. Because of this, the local market power mitigation for a given RTD interval is based on the local market power mitigation test performed by the RTD in a previous run when the current binding interval was the first advisory interval.[12]

B. Local Market Power Mitigation

The purpose of local market power mitigation is to mitigate the market effects of energy bids above marginal costs when a transmission constrained areas are structurally uncompetitive. An area is structurally uncompetitive when market participants can exert market power by submitting bids above marginal costs that set the market clearing price. The local market power mitigation market

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8 *See* existing tariff section 34.4.

9 An EIM base schedule is an hourly forward energy schedule submitted by the EIM entity scheduling coordinator or an EIM participating resource scheduling coordinator that reflects EIM areas dispatches that are not dispatched through the CAISO real-time market (*i.e.*, the EIM).

10 *See* existing tariff section 34.2.

11 *See* existing tariff section 34.5.

12 As described in the next section, market power mitigation in a given RTD or RTUC interval can also be based on market rules that extend mitigation to additional intervals.

software includes a dynamic competitive path assessment that tests whether energy to relieve binding transmission constraints is competitive or non-competitive in the day-ahead and real-time markets, including in the RTUC and the RTD.[13]

Based on the results of the dynamic competitive path assessment, the market power mitigation process determines which bids to mitigate by decomposing the congestion component of each LMP determined in the market power mitigation process into competitive congestion and non-competitive congestion components.[14] The competitive congestion component is the sum of the products of the shift factors and the shadow prices for all competitive transmission constraints, and the non-competitive congestion component is the sum of the products of the shift factors and the shadow prices for all non-competitive transmission constraints. These calculations also include the shadow price of the power balance constraint for an EIM entity balancing authority area to which all resources within that balancing authority area have a shift factor of one.

If the non-competitive congestion component of an LMP calculated in the market power mitigation process is greater than zero, then a resource dispatched in that market power mitigation process is subject to local market power mitigation. If a resource's bid exceeds the competitive LMP at its location, the bid will be mitigated to the higher of the resource's default energy bid or the competitive LMP at its location for use in the CAISO market.

The CAISO's existing tariff provisions include rules requiring that when market power mitigation is triggered during an FMM interval, mitigation will be triggered for the balance of the hour.[15] If market power mitigation is triggered in the RTD, mitigation will be triggered in the following RTD interval or intervals corresponding to a fifteen-minute interval.[16] Also, if a resource is mitigated in an FMM interval, whether through mitigation originally being triggered in the interval or by being extended through the balance of the hour, mitigation is also applied in the corresponding RTD intervals.[17]

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13 *See* existing tariff section 39.7.2.

14 *See* proposed tariff section 34.1.5.

15 *See e.g.,* proposed tariff section 34.1.5.2.

16 The CAISO initially designed these market mitigation rules due to software limitations and with the intent of limiting the frequency of resources responding to rapid ramping instructions. Since the implementation of the original policy, the CAISO market software has been enhanced and the mitigation performance has been improved, eliminating the need for these limitations.

17 See proposed tariff section 34.1.5.3.

The current rules fix the mitigated bid price used when bid mitigation is extended to additional intervals. Unless the competitive LMP is lower in an interval than it was in the originally mitigated interval, then the mitigated bid price may decrease based on the lower competitive LMP.

The CAISO originally implemented these market power mitigation rules to protect against market power in an interval not detected by the market power mitigation process. The rules were necessary because of shortfalls in the performance of the market power test that the CAISO has since addressed.[18]

C. Energy Imbalance Market Transfer Limits

The CAISO' real-time market extends into other balancing authority areas through the EIM. The EIM allows other balancing authority areas in the Western Interconnection to participate in the CAISO real-time market for imbalance energy. The CAISO's market rules allowing EIM participation went into effect on October 24, 2014, for the first trading day November 1, 2014. Currently, there are eight entities[19] participating in the EIM and the CAISO expects to include the participation of eight more over the next 3 years.[20]

Participation in the EIM is voluntary, including the submission of energy bids. The EIM market rules also allow EIM participants to determine the amount of transmission they make available for EIM energy transfers. This limit establishes the amount of transfer that can occur between EIM entity balancing authority areas. The CAISO tariff contains rules governing how the EIM transfer limits are set and modeled in the EIM, using transmission capacity EIM participants make available to the real-time market.[21]

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[18] *See e.g.*, *California Indep. Sys. Operator Corp.*, 157 FERC ¶ 61,091 (2016).

[19] Including the CAISO, the following eight entities participate in the EIM: Balancing Authority of Northern California/Sacramento Municipal Utility District, Idaho Power Company, Powerex, Portland General Electric, Puget Sound Energy, Arizona Public Service, NV Energy, and PacifiCorp.

[20] Salt River Project, Seattle City Light, Los Angeles Department of Water & Power, Public Service Company of New Mexico, NorthWestern Energy, Turlock Irrigation District, Avista, and Tucson Electric Power. The Bonneville Power Administration is also engaged in a public process to consider joining the EIM: https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20190620-Western-Energy-Imbalance-Market-Letter-to-the-Region.pdf.

[21] *See* Existing tariff sections 29.7(e)-(f) and 29.17(f).

D. Default Energy Bids

The CAISO market's market power mitigation process uses default energy bids as cost-based bids for energy above the minimum load of resources when local market power mitigation is triggered in a market interval as described above.[22] When a resource's bid is mitigated, the CAISO market systems substitute the default energy bid for the resource's bid in the market clearing process and uses the default energy bid to determine the resource's bid cost recovery compensation.[23] Default energy bids also factor into the settlement of residual imbalance energy and exceptional dispatches in some circumstances.[24]

Under current tariff provisions, each scheduling coordinator can choose one of three options for calculating default energy bids for a resource: (1) the variable cost option; (2) the negotiated rate option; or (3) the LMP option.[25] For a natural gas-fired resource subject to the variable cost option, the default energy bid is based on incremental fuel costs, which is determined by using gas prices published in natural gas price indices. All default energy bids under the variable cost option include an adder of ten percent to the CAISO's calculation of costs based on the gas price indices.[26] The CAISO calculates default energy bids for the day-ahead and real-time markets, respectively, using the gas commodity price formulas.[27]

III. Stakeholder Process

The CAISO developed the proposed tariff revisions through an extensive stakeholder process, including several stakeholder meetings and three in-depth workshops over the course of about nine months. The materials associated with this stakeholder process are all available for reference on the CAISO website.[28]

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[22] *See* Existing tariff section 39.7.1, *et seq.*

[23] Existing tariff section 11.8, *et seq.*

[24] Existing tariff sections 11.5.5 and 11.5.6.

[25] Existing tariff sections 39.7.1 through 39.7.1.3. Further, a scheduling coordinator for a frequently mitigated unit has a fourth option for calculating default energy bids, the frequently mitigated unit option. Existing tariff section 39.7.1.4. The CAISO may also establish temporary default energy bids. Existing tariff section 39.7.1.5.

[26] Existing tariff section 39.7.1.1.

[27] Existing tariff section 39.7.1.1.1.3.

[28] The stakeholder process materials are available at: http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalMarketPowerMitigationEnhancements2018.aspx.

Stakeholders broadly support the proposed amendments. A few stakeholders expressed differing views, and in some very limited cases, concerns, regarding specific design elements. The CAISO prepared a detailed comment summary at the conclusion of the stakeholder process, which it believes addressed the concerns.[29] This transmittal letter addresses the substance of each key issue and stakeholder concerns that were not resolved through the stakeholder process.

The CAISO's Department of Market Monitoring (DMM) and Market Surveillance Committee (MSC) participated in the development of the CAISO's proposal and generally support it. The DMM engaged with the CAISO and stakeholders in developing the market design changes proposed in this filing. The MSC followed the stakeholder process and discussed the proposal at its open meeting on March 5, 2019. The MSC offered an opinion supporting the proposal while advising the CAISO to monitor market conditions, which the CAISO will do.

The EIM Governing Body approved one of the design elements within its primary approval authority on March 12, 2019,[30] and the CAISO Board of Governors approved the balance of the proposed design elements on March 27, 2019.[31]

IV. Tariff Amendments

The CAISO proposes three separate and distinct tariff changes to improve the efficiency of its markets and the effectiveness of its local market power mitigation procedures.[32] Each of these measures can be implemented independently, *i.e.*, no one change is integrated with or dependent upon another. Accordingly, the Commission should consider each proposed set of changes as severable.

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[29] *See* Matrix of Stakeholder Comments and the CAISO's response (May 24, 2019), which is provided in Attachment L with this filing.

[30] *See* Memorandum, EIM Governing Body, Decision on local market power mitigation enhancements proposal (March 5, 2019) (EIM Governing Body Memo), which is provided in Attachment E to this filing.

[31] *See* Memorandum, CAISO Board of Governors, Decision on local market power mitigation enhancements proposal (March 20, 2019) (Board Memo), which is provided in Attachment F to this filing.

[32] Two design elements described in the Draft Final Proposal will be filed separately by the CAISO as they concern matters best addressed in association with other proposals.

A. Enhanced Mitigation Process Timing Granularity

1. Need for Enhanced Timing of Mitigation

The current market rules, as discussed above, specify that when local market power mitigation is triggered during in the FMM interval, mitigation is also triggered for all the subsequent market intervals for the balance of the hour. The current rules specify that if local market power mitigation is triggered in the binding RTD interval, mitigation is extended to the rest of the 5-minute intervals within a fifteen-minute interval. Finally, the current rules specify that if local market power mitigation is applied in a fifteen-minute interval, whether through mitigation originally being triggered in the interval or through mitigation being extended through the balance of the hour, mitigation is also applied in the corresponding RTD intervals. The current market rules use the same mitigated bid price for all the market intervals to which mitigation is extended. The exception is if the competitive LMP is lower in a market interval than in the market interval that originally failed the market power test, then the mitigated bid price is based on the lower competitive LMP. Figure 1, below, illustrates the current market power mitigation process and these mitigation extension rules, showing the various market intervals for RTUC and RTD.

In Figure 1, "B1" indicates the binding market interval, and "A1," "A2," etc., indicate advisory market intervals. A circled red "M" indicates the intervals that the local market power mitigation process tests for market power. Finally, the red lines show how the bid mitigation process under the current rules extend mitigated bids to additional intervals if the market power mitigation process detects market power in an interval. The top two lines illustrate the local market power mitigation process in the RTUC, showing the market power mitigation run, labeled "MPM," and the market run, labeled "Market." The bottom lines illustrate the market power mitigation process for three successive RTD runs.

Figure 1 illustrates that the local market power mitigation process tests the binding interval used for the FMM in RTUC.[33] It shows market power being detected in the binding interval, and market power mitigation being extended to the end of the hour, labeled "*h*," in the RTUC market run. As described earlier, the market makes two passes for each RTUC market run. The first pass tests for market power and mitigates submitted bids to mitigated bid prices if market power is detected. The second is the market pass that produces schedules and LMPs based on bids, including bids mitigated in the first pass.

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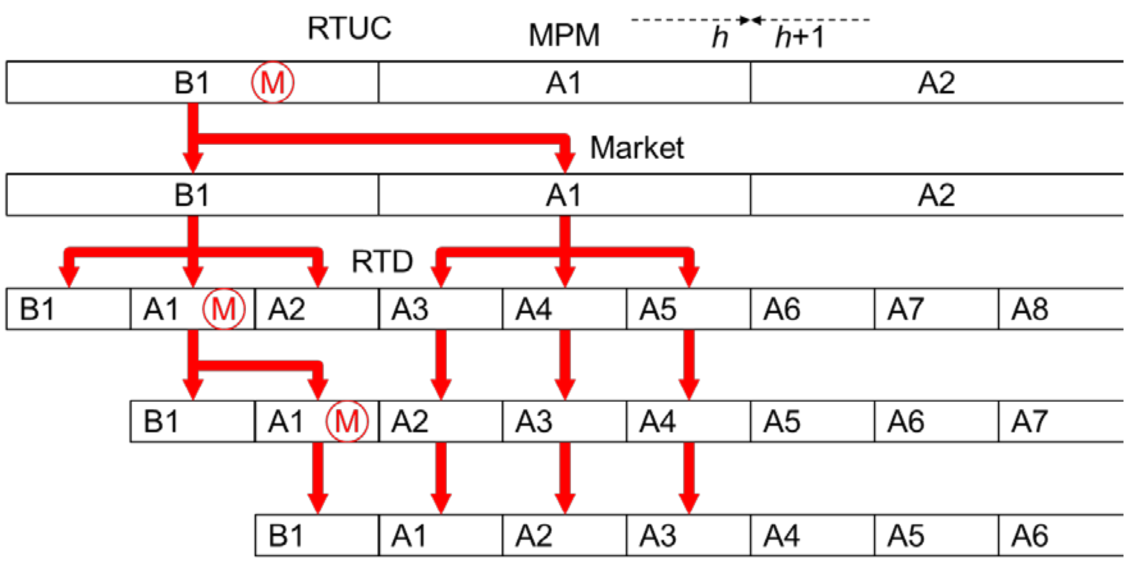
[33] Figure 1 does not show the first RTUC interval, referred to as the "buffer interval." Under the CAISO's proposed rule changes the buffer interval would continue to have mitigation extended from the binding FMM interval in the previous market run. This is because the market does not co-optimize energy, ancillary services, and the flexible ramping product in the buffer interval as it does in the other RTUC intervals.

Figure 1 shows mitigation being extended to the RTD intervals that correspond to the RTUC intervals in which mitigation was applied as specified in the current rules. Figure 1 also shows that in the RTD, the market power mitigation process tests the first advisory RTD interval. It then uses these results in its next run when the first advisory interval, A1, becomes the binding interval, B1. As described earlier, RTD does not have a separate market power mitigation pass.

Figure 1: Current Local Market Power Mitigation Extension Process



The current market rules that extend market power mitigation to market intervals beyond the interval that failed the local market power test can cause the market to dispatch resources at mitigated bid prices to export energy from a transmission constrained area only because the local market power mitigation process detected market power in an earlier market interval. This is undesirable. System conditions can change after an interval in which mitigation is applied such that there is no market power in subsequent intervals. Nonetheless, the current mitigation extension rules use mitigated bids in these intervals, and the market dispatches resources at mitigated bid prices despite the absence of market power. In particular, the current rules can result in resources exporting power to a competitive region at mitigated bid prices.

The example shown in Table 1, below, illustrates this impact of extending mitigation into market intervals beyond the one in which the market power mitigation process detected market power.

Table 1: Impact of Extending Mitigation into Subsequent Market Intervals

Interval	Submitted Bid ($/MWh)	Competitive LMP ($/MWh)	Default Energy Bid ($/MWh)	Market Power Detected	Mitigated Bid ($/MWh)	Mitigation Applied	Exporting from Area
1	60	30	25	Yes	30	No	No
2	60	60	25	No	30	Yes	Yes
3	60	62	25	No	30	Yes	Yes
4	60	59	25	No	30	Yes	Yes

The example in Table 1 lists four RTUC intervals in an hour and the accompanying conditions for a transmission constrained area. The example assumes there is a supply resource in the area with the listed energy bid price and default energy bid. Table 1 shows, for each market interval, the actual competitive LMP for the area, whether the market power mitigation process detected market power in the area, the mitigated bid price the market used, whether migration was applied, and whether the market was dispatching the resource to export energy from the area.

In the example, the area is import-constrained in interval 1 and market power is detected. The market power mitigation process reduces the $60/MWh submitted bid price bid price to $30/MWh, based on the greater of the competitive LMP or the resource's default energy bid. Table 1 shows that even though market power is <u>not</u> detected in intervals 2-4, the market power mitigation process extends the $30/MWh mitigated bid price to intervals 2-4.

Table 1 also shows that extending the mitigated bid price causes the CAISO market to dispatch the resource to export energy from the constrained area in intervals 2-4 at mitigated bid prices, despite the actual competitive LMP being higher. As Table 1 indicates, the actual competitive LMP in intervals 2-4 ranges from $59 to $62/MWh, which is much higher than the $30/MWh mitigated bid price the market uses in these intervals based on the competitive LMP in interval 1.

Table 1 illustrates that the market will dispatch the resource to provide energy at a mitigated bid price in intervals in which there is no market power and in which market power mitigation is applied, only because the market detected market power in an earlier market interval. This situation can be particularly pronounced in the EIM because the CAISO's market power mitigation provisions mitigate all resources in an EIM entity balancing authority area or group of balancing areas if the CAISO market area is dispatching generation to transfer power into the area, and the area is import-constrained. Conversely, the market does not apply mitigation at a system level for the CAISO balancing authority area.

In summary, the mitigated bid extension rules can result in EIM resources being forced to sell energy for transfers out of their balancing area at mitigated prices in market intervals in which no market power was detected. In these intervals, the area is not import-constrained, and the resources in the area do not have market power. Rather, in these later intervals, the market may be dispatching resources in the area to provide energy to transfer out of the area to a competitive region. Moreover, the mitigated bid price at which the market dispatches these resources can be lower than the resource's estimated marginal costs if the default energy bid fails to appropriately reflect such marginal costs.

2. Proposed Enhanced Timing of Mitigation

To address the aforementioned concern, the CAISO proposes to eliminate the current rules for balance-of-the-hour mitigation in the fifteen-minute interval and balance-of-the-fifteen-minute interval in the RTD. Further, the CAISO proposes that a resource mitigated in the fifteen-minute interval will not automatically be mitigated in the corresponding RTD intervals. The CAISO also proposes market rule changes so that the local market power mitigation process will calculate a mitigated bid price for each market interval based on the actual competitive LMP in each interval. To help ensure the market does not dispatch resources to export power from constrained regions at mitigated bid prices, the CAISO proposes a small adder to slightly increase the competitive LMP used in calculating mitigated bids.

Because the local market power mitigation process will no longer extend mitigation in the RTUC process to subsequent market intervals after an interval in which it detects market power, the CAISO also proposes that the market power mitigation process tests each fifteen-minute RTUC interval in the RTUC's horizon for market power and apply mitigation separately to each run. It is important to apply mitigation to each RTUC interval in which market power is detected to have consistent market results across the horizon. For example, the RTUC may not commit a resource because of its energy bid price when the resource has market power and the RTUC would have committed it at a mitigated bid price in all intervals.

Similarly, the CAISO proposes that the local market power mitigation process individually test the earlier market intervals in the RTD horizon, as described in more detail further below. However, because the RTD does not have a separate local market power mitigation run, mitigation from the first advisory interval will be passed to the binding interval in the next RTD run.

Table 2 illustrates how the proposed changes will limit extending mitigation into subsequent market intervals. This enhancement will minimize the CAISO dispatching resources to export energy from an area at mitigated prices only because mitigation was applied in an earlier interval.

Table 2: Impact of No Longer Extending Mitigation into Subsequent Market Intervals

Interval	Unmitigated Bid ($/MWh)	Competitive LMP ($/MWh)	Default Energy Bid ($/MWh)	Market Power Detected	Bid Used in Market ($/MWh)	Mitigation Applied	Exporting from Area
1	60	30	25	Yes	31	Yes	No
2	60	45	25	No	60	No	No
3	60	42	25	No	60	No	No
4	60	40	25	Yes	41	Yes	No

Table 2 shows the effect of the proposed market rule changes under the same market conditions as shown by Table 1. As in the first example, Table 2 also shows market power is detected in the first interval. However, in Table 2, the local market power mitigation process no longer extends mitigation to subsequent intervals after an interval in which it detects market power. Instead, the local market mitigation process tests each interval separately for market power and applies mitigation only in the intervals in which it detects market power.

In Table 2, the mitigated bid price is based on the competitive LMP for the interval, plus $1/MWh. The additional $1/MWh ensures the mitigated bid price is slightly higher than the competitive LMP outside the area where the resource is located. As described in the next section, this ensures resources in the area are not dispatched at mitigated bid prices to export power from the area to a competitive region.[34] Market power mitigation is only appropriate for energy to serve a constrained region, not for energy dispatched out of one area and into a competitive area.

Under the CAISO's proposed rule changes, market power mitigation will no longer be extended to subsequent intervals if market power is not detected in those intervals. In Table 2, market power is not detected in intervals two and three. Therefore, no mitigation is applied. Also, in these intervals, the resources' bid price used in the market is greater than the competitive LMP so the market does not dispatch the resource to export power out of the area where it is located.

However, unlike the previous example, assume in Table 2 that market power is detected in interval four. Under the current rules, local market power mitigation would be extended because of the mitigation in the first interval, and the mitigated bid price used in the market would be the mitigated bid price from

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[34] This example uses $1/MWh for simplicity but in practice this additional amount will not exceed $0.01/MWh.

the first interval or lower. Under the CAISO's proposed rules, the market would instead only apply mitigation to an interval if it detects market power in the interval. Under the CAISO's proposed rules, the market would also calculate mitigated bid prices based each interval's competitive LMP.

The example shows that, under these proposed changes, the mitigated bid price used in the market in interval four would be $41/MWh. This reflects the $40/MWh competitive LMP calculated for interval four plus $1/MWh.

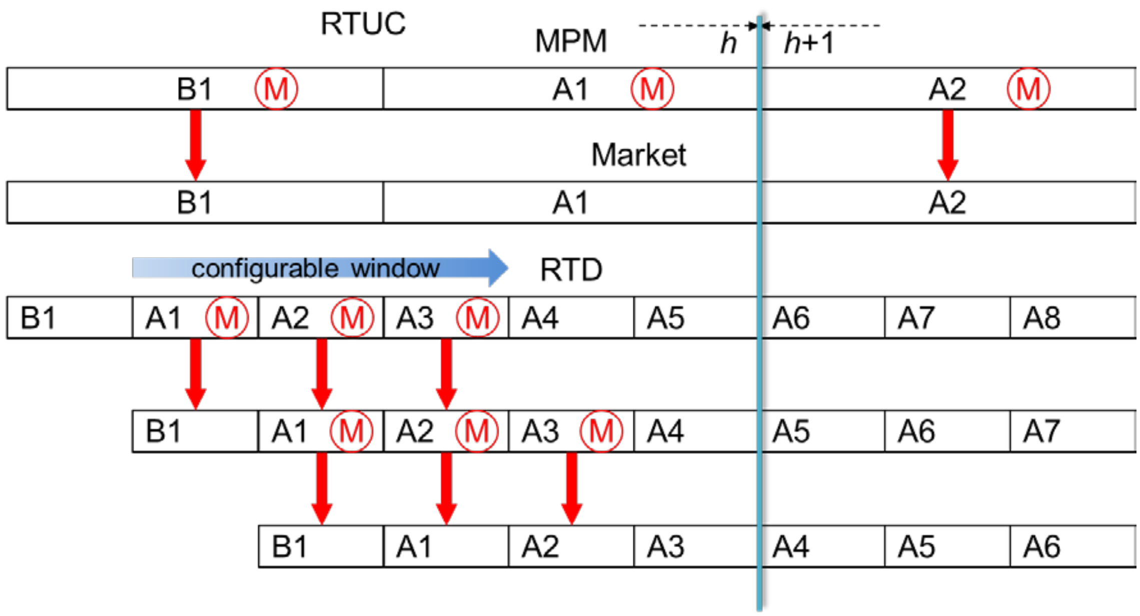
Figure 2, below, illustrates the CAISO's proposed changes to the mitigated bid extension rules, and uses the same format and nomenclature as Figure 1. Figure 2 shows that under the proposed changes the market power mitigation process will no longer simply test the binding interval in RTUC, B1, and extend mitigation to additional intervals if detected. Rather it will test each RTUC interval separately in the market power mitigation pass and apply mitigation in the market pass only to the intervals in which market power is detected. Figure 2 further shows the market testing intervals B1, A1, and A2, detecting market power only in B1 and A2, and consequently only applying mitigation in the market pass to B1 and A2.

Figure 2 illustrates how under the changes proposed in this amendment the market mitigation process will no longer mitigate bids in the RTD only because the corresponding RTUC interval was mitigated. The CAISO proposes only to mitigate bids in the binding RTD interval if market power is detected in that interval, when it is the first advisory interval in the previous RTD run.

The CAISO also proposes that the local market power mitigation process tests for market power and mitigates bids within a configurable window of the subsequent advisory RTD intervals. Similarly, and as explained for the RTUC above, it is important to have consistent mitigation results across the market horizon. However, since the RTD does not have a separate mitigation pass, it must always use the mitigated bids from advisory intervals in previous RTD runs. In other words, it cannot "undo" mitigation like the RTUC can. Consequently, to avoid excessive mitigation and consequences similar to those described above caused by the mitigation extension rules, the CAISO proposes to limit mitigation to a configurable number of the RTD intervals at the beginning of its horizon. Figure 2 also illustrates this configurable window.

The CAISO proposes to initially set the configurable number of advisory RTD intervals to three. At a minimum, two advisory intervals must be checked for mitigation. The first advisory interval becomes the binding interval of the next run, and the second advisory interval becomes the first advisory interval in the next run. Therefore, it is necessary to mitigate the bids for both of these intervals because they will be used to produce binding dispatch instructions and binding flexible ramping up and down awards in that next run. Also, because the CAISO determines flexible ramping awards as reserved ramp capability between the binding RTD interval and the first RTD advisory interval, given that flexible ramping awards depend on the energy costs between these intervals. The third advisory interval initially will be included in the mitigation check so all RTD intervals under a given FMM interval would potentially have mitigated bids. This provides consistent results between the FMM and the corresponding RTD intervals. Furthermore, the third advisory interval would also provide a buffer for potential bid mitigation whenever two RTD runs are lost due to events such as promoting software upgrades in the production system, which can result in market disruptions.

Figure 2: Proposed Market Power Mitigation Process Changes



Going forward, the CAISO will monitor the performance of the system and the local market power mitigation results, and will adjust the setting to fewer or more intervals as may be necessary to minimize the risk of under- or over-mitigation based on actual market results.

3. Adder to Create Price Separation when the DEB equals the Competitive LMP

If the local market power mitigation process mitigates a resource's bid to the competitive LMP, the market potentially could dispatch the resource to export energy from a constrained area at the mitigated bid price, because the resource's bid price at the competitive LMP could be the same price as LMPs outside of the constrained area. In such circumstances, the market software cannot differentiate between the mitigated resource's bid and the competitive resource's bids, and could impose mitigation based on its selection of the mitigated bids, which is founded on other factors. To avoid this issue, the CAISO proposes to add a few cents to the mitigated bid price established inside the constrained area to create reasonable price separation from the external competitive LMP. When the prices are equal, the market results can produce an import or an export. The adder precludes mitigated bids from supporting load in a competitive area (*i.e.*, export from constrained area). All else being equal, if the mitigated bid price is the same as the price in the competitive area, the mitigated resource can be dispatched upward and the competitive resources dispatched downward in the market pass, compared to the market power mitigation pass because they would have the same cost of meeting demand.

The CAISO proposes to state in its tariff that this adder will not exceed $0.01/MWh and will specify the actual adder used in the business practice manual.[35] The CAISO currently plans to use $0.001 for the price adder because it is sufficiently small to not affect prices materially, but large enough to cause the price separation sought between competitive and non-competitive areas.

Using a cost parameter added to the competitive LMP will have no more than a *de minimis* effect on LMPs under the limited circumstance when it is necessary to create price separation between the internal and external competitive LMPs. Scheduling coordinators can submit bids up to two decimal points (*i.e.*, $0.01/MWh). On the other hand, the cost parameters for the market software optimization are configurable to several more decimal points. Because the CAISO proposes to limit the cost parameter to an amount less than or equal to $0.01, the cost impact on the total LMP settlement will be miniscule. The CAISO's optimization, like any other process that seeks optimal economic or scientific solutions through complex algorithms with large numbers of inputs, can only work to a certain degree of precision. A cost added to the competitive LMP of less than $0.01/MWh is, therefore, an acceptable degree of system precision similar to disregarding insignificant shift factors or the bids themselves.

4. Stakeholder Concerns

The DMM raised some concerns about eliminating the extension of mitigation in the FMM to the corresponding three RTD intervals. The DMM expressed unease that this change potentially could cause a resource being scheduled at a mitigated bid price in the FMM, but then being dispatched downward and buying back that energy in the RTD at a higher unmitigated bid price. The DMM maintained that the relative advantages of the current policy versus the proposed policy may differ by market participant and by resource.

[35] *See Cal. Indep. Sys. Operator Corp.* 153 FERC ¶ 61,087 (2015), PP 45-47 (accepting a $.01 EIM transfer schedule cost so that the optimization could determine the optimal transfer path, with publication of the actual parameter value in the business practice manual).

The CAISO acknowledges that there could be cases when an offer price is mitigated to a lower level in the FMM than in the three RTD intervals. If this occurs, the seller might have to buy back its FMM schedule at the RTD market price. As the MSC observed, however, removing the extension of mitigation in the RTD when the FMM mitigation is triggered is the economically efficient outcome.[36] The MSC recognized that this causes a buy back at the RTD price, but emphasized that this is the economically efficient outcome if the supplier's submitted bid indeed represented its actual marginal costs. The CAISO did not adjust its proposal in response to DMM's comments and, consistent with the MSC's response, believes on balance that its proposal is just and reasonable.

B. Incremental Net Export Limit on Mitigated Resources

1. Need for Net Export Limit

The CAISO proposes addresses instances where the CAISO market increases exports out of (or decreases imports into) an EIM entity balancing authority area only because of a mitigated bid price. This can cause the market to dispatch resources in an EIM entity balancing authority area to export power at mitigated bid prices in quantities greater than they were required to offer to the EIM.

For the EIM to dispatch energy transfers in or out of a balancing authority area, the balancing authority area must pass a resource sufficiency evaluation in the market ensuring that it offered adequate energy bids to meet its demand, plus a flexible ramping product requirement. There is no requirement to offer a quantity of energy beyond that amount. Despite this, the existing market power mitigation process can mitigate a resource's bids when multiple balancing authority areas are import constrained, and a resource can be dispatched for additional exports at mitigated bid prices for greater quantities of energy than were required to be offered. This can discourage offering energy and transmission to the EIM.

As described earlier, the CAISO's real-time market schedules resources in each market interval based on two runs. The market completes the first run using a supplier's submitted energy bid. If market power is detected, the bid is mitigated to the resource's default energy bid. The market then conducts a second run to determine final schedules and prices. This can cause the market to dispatch additional energy from resources because of their mitigated bid prices, which can result in additional net exports from one balancing authority area to another within a constrained region, even though the additional supply is

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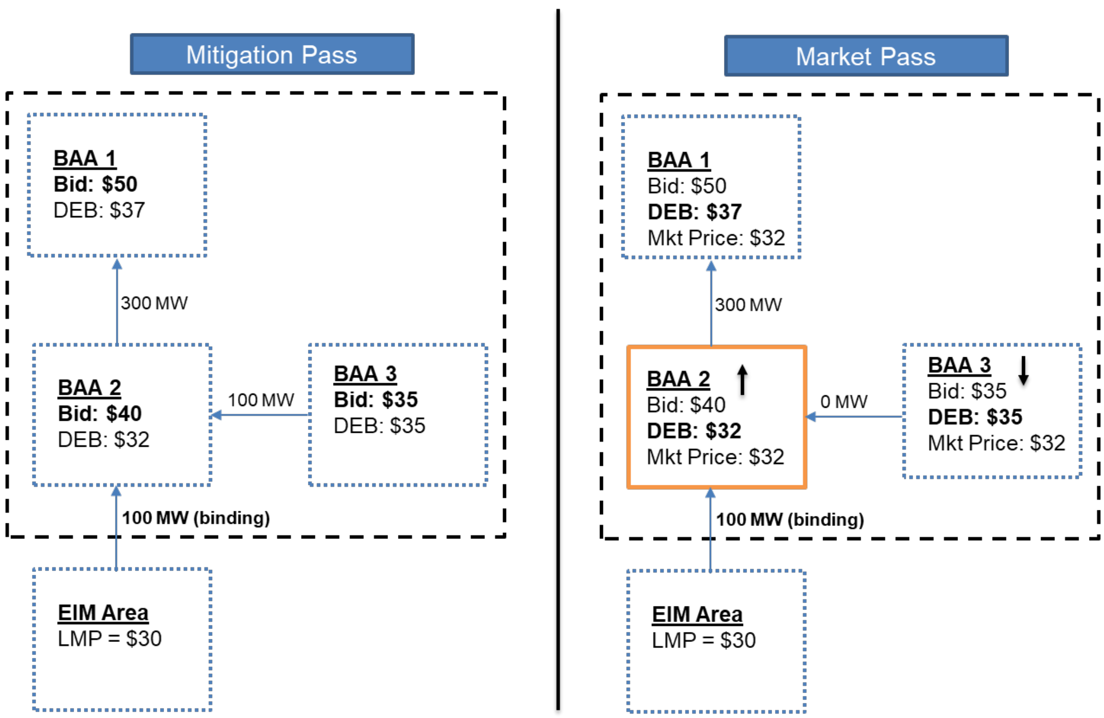
[36] Market Surveillance Committee, *Opinion on Local Market Power Mitigation Enhancements* (March 6, 2019), at pp. 13-14 (MSC Opinion), which is provided in Attachment H to this filing.

not needed to address market power in the region. Thus, the market may dispatch supply at mitigated prices in quantities greater than what market participants were required to offer to the EIM to meet the EIM entity balancing authority area's resource sufficiency evaluation.

To illustrate the issue, Figure 3 shows a simplified example of the FMM results for the market power mitigation pass and the market pass in a market run. In this example, three EIM entity balancing authority areas ("BAA 1," "BAA 2," "BAA 3") are in an import-constrained area. Figure 3 also shows the assumed submitted energy bid prices and the associated default energy bids for a hypothetical resource in each of the balancing authority areas.

Figure 3: Additional Exports Because of Energy Bid Mitigation



In this example, the combined region of BAA 1, BAA 2, and BAA 3 is import-constrained from the rest of the EIM area, with imports into the region from the broader EIM area at a 100 MW transfer limit. This triggers mitigation of all resources within the constrained region. Figure 3 shows that the mitigation pass, which uses the submitted energy bids, would dispatch 300 MW of transfers into BAA 1, which is supported by 100 MW of transfers into the constrained region from the broader EIM area, 100 MW of generation in BAA 2, and 100 MW of generation in BAA 3.

Figure 3 also shows that the market run results in a different dispatch because it replaces the resources' submitted bids with default energy bids. Replacing BAA 2's $40/MWh submitted energy bid with its $32/MWh default energy bid makes BAA 2's generation more economic than BAA 3's generation, which leads to a different dispatch. The market run dispatches the resource in BAA 2 100 MW relative to its dispatch in the market power mitigation run, dispatches the resource in BAA 3 downward 100 MW, making BAA 2 support 200 MW of the energy transfer into BAA 1, rather than 100 MW as in the market power mitigation pass.

This situation may not be desirable to BAA 2 if its resource's default energy bid does not accurately reflect its marginal costs. BAA 2 might have chosen not to offer the full 200 MW if it knew it would have to sell this amount at mitigated bid prices. Under the current rules, the only way an EIM entity can protect itself from such outcomes is by reducing the amount of energy it offers or the transmission it makes available to support EIM transfers. This is adverse to the overall interest of the EIM footprint because it would limit transfers even when market power mitigation is not triggered.

2. Proposed Net Export Limit

To address these circumstances, the CAISO proposes to add an optional feature for EIM entities to limit this additional dispatch of resources when their respective balancing authority area is subject to bid mitigation.

The optional feature would limit the additional dispatch to the net energy transfer out of the balancing authority area the market scheduled in the market power mitigation pass (or previous market run in RTD) using the submitted bids for an interval, plus the amount of flexible ramping product the market scheduled the balancing authority area to provide in excess of its flexible ramping product requirement.[37]

This optional feature would address instances where the CAISO market increases exports out of (or decreases imports into) an EIM entity balancing authority area only because of a mitigated bid price. As illustrated above, this occurs when the market mitigates all resources' bids in a group of EIM entity balancing authority areas only because the group of balancing authority area is import-constrained.

[37] Net exports increase when a balancing authority area has net exports out of the balancing authority area and gross exports to adjacent balancing authority areas increase and/or gross imports from adjacent balancing authority areas decrease.

This net export limit will be based on the amount of energy each balancing authority area is required to offer to the EIM in each market interval. It does this by basing the net export limit on the balancing authority area's flexible ramping product requirement and awards. This reflects that, although the EIM is a voluntary market, the EIM design assumes that flexible ramping capability is shared between balancing authority areas. The EIM resource sufficiency evaluation assumes this sharing by reducing the overall flexible ramping product requirement by an amount that reflects the diversity benefit of pooling multiple balancing authority areas' flexibility requirements.[38] The amount of a balancing authority area's flexible ramping product awards above its individual requirement reflects the amount of flexibility the market has determined is optimal for a balancing authority area to contribute to the EIM's overall system requirement.

As described above, for the EIM to dispatch energy transfers in or out of a balancing authority area, the balancing area must pass a resource sufficiency evaluation in the market ensuring that it offered sufficient energy bids to meet its demand, plus a flexible ramping product requirement. There is no requirement to offer a quantity of energy beyond that amount.

This rule would limit incremental net exports from the mitigated balancing authority area to the amount by which the sum of flexible ramping product uncertainty awards (*i.e.*, the portion of the flexible ramping product awarded through the CAISO market) in the EIM entity balancing authority area in the market power mitigation run exceeds the higher of zero or the EIM entity balancing authority area's corresponding upward uncertainty requirement less its EIM transfer import limit[39] plus the greater of (a) the net amount of its EIM transfer in the mitigation process prior to the real-time market process for the interval to which the mitigation process applies or (b) the net amount of its EIM transfer represented by the EIM base schedules at each of its EIM internal interties for the interval to which the mitigation process applies. Including the last two amounts ensures the market dispatches resources in the balancing authority area in the market run at least to the level they were dispatched in the mitigation run at submitted bid prices and ensures the dispatch respects EIM base schedules.

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[38] Existing tariff section 29.34(m).

[39] A balancing authority area's net import capability represents the amount of each EIM balancing authority area's uncertainty requirement that can be imported from other EIM balancing authority areas. The CAISO's proposed net export limit formulation subtracts a balancing authority area's net import capability from its uncertainty requirement to determine the amount of its uncertainty requirement that must be met by resources within its balancing authority area. *See* Business Requirements Specification. Local Market Power Mitigation Enhancements (LMPME), Dated April 1, 2019 at p. 11, available at http://www.caiso.com/Documents/BusinessRequirementsSpecification-LMPMEnhancements.pdf. The CAISO will include these implementation details in the Business Practice Manual for the EIM.

The CAISO will apply the proposed rule both in the FMM and RTD, so that every interval limit is determined separately. Each EIM entity would have the option to activate this rule so that the EIM transfer limitations are enforced after mitigation. Upon implementation, the default setting for the rule would be inactive for all EIM entities. EIM entities that choose to enforce the rule must make the appropriate designation in the update procedures for the CAISO master file.[40] Once the option is selected in the master file, the market will limit the net exports as discussed above in the actual market runs. The CAISO will publish a list of EIM entities that elected to limit incremental net EIM transfers.

Figure 4, below, illustrates how the net export limit will reduce the amount of additional dispatch for export energy that can occur under mitigation. It uses the same example as Figure 3, above, but enforces the proposed net export limit for BAA 2 in the market run.

As in the previous example, Figure 4 assumes BAA 2 has a 100 MW net energy transfer out of its balancing authority area in the market power mitigation pass, and mitigation is triggered. The example also assumes BAA 2 has a 40 MW flexible ramping product uncertainty award above its flexible ramping requirement. Figure 4 shows that the net export limit feature limits the upward dispatch of the BAA 2 resource at its default energy bid in the market run to 40 MW. The market pass also dispatches the BAA 3 resource down 40 MW. This is less than the 100 MW amount of redispatch that occurred in the previous example without the net export limit being enforced. The market determined in the mitigation run 40 MWs of uncertainty award in excess of BAA 2's flexible ramping requirement as the amount of flexible ramping capacity that is optimal for BAA 2 to make available to other balancing authority areas.

[40] EIM entities that elect to enforce the net export limit may need to ensure their respective OATT procedures appropriately respond to the corresponding transfer limitations.

Figure 4: Enforcement of Net Export Limit

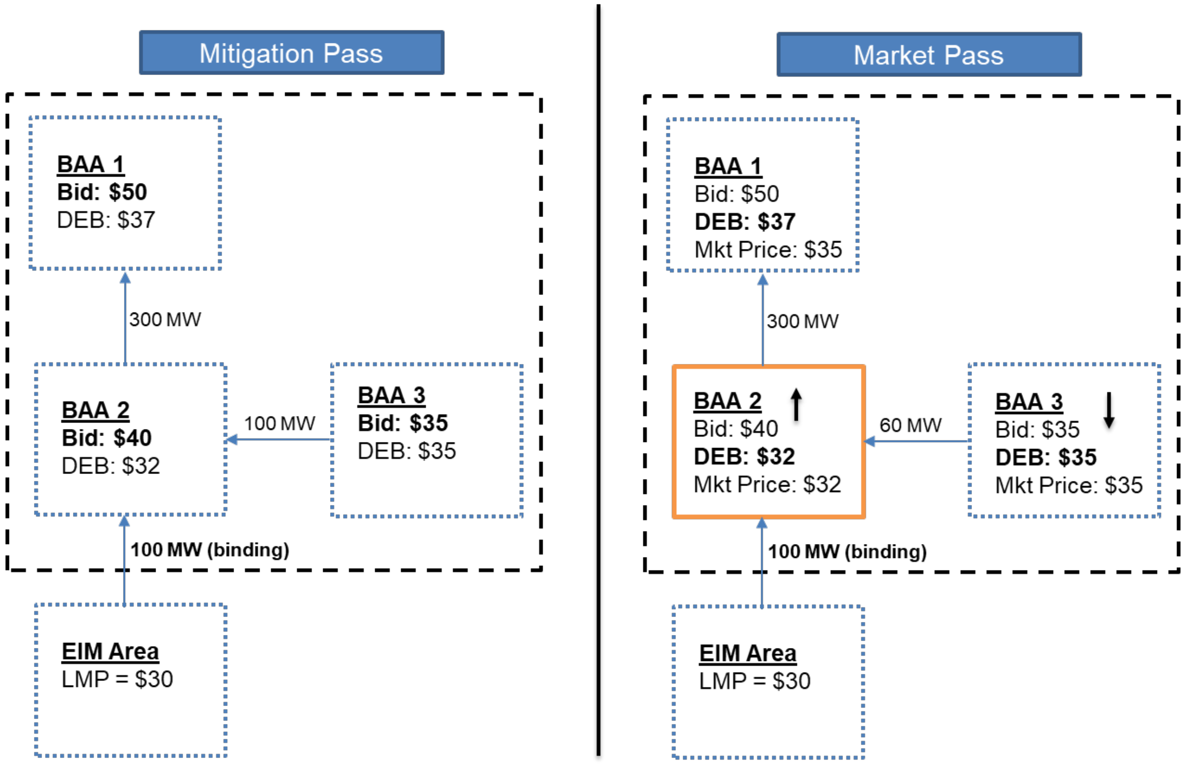
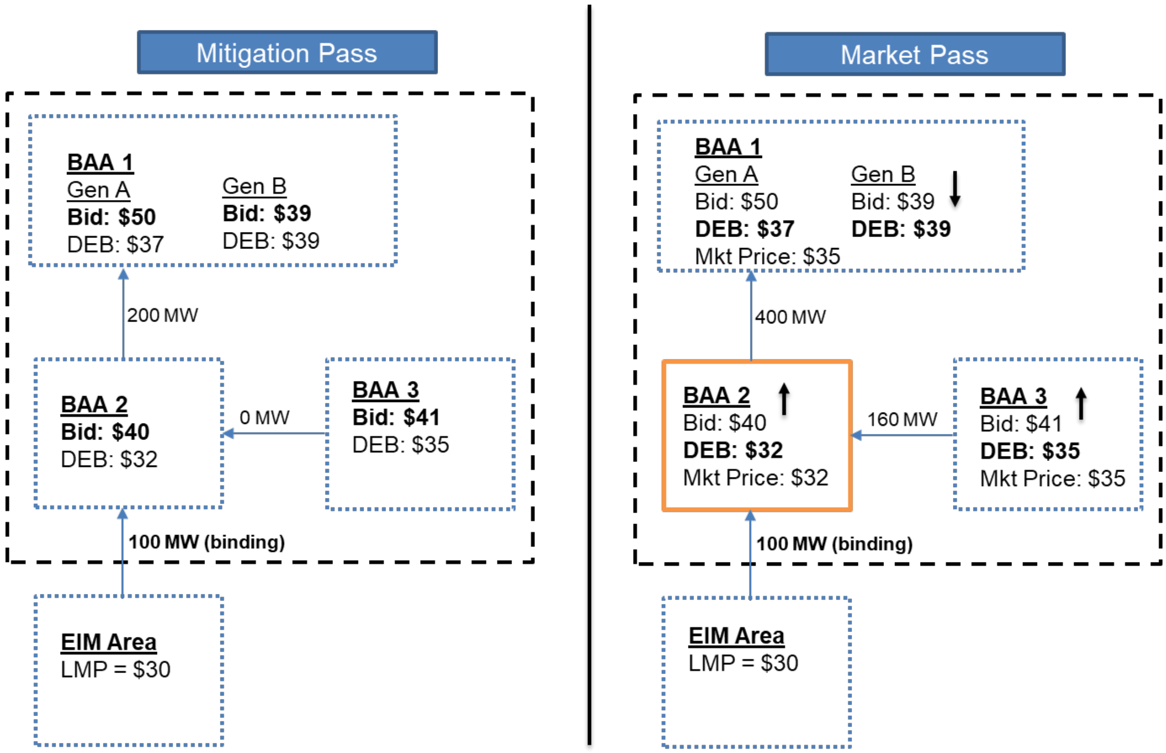


Figure 5, below, shows how the net export limit does not prevent the market from dispatching additional energy to wheel through a balancing authority area. This example is similar those presented in Figures 3 and 4, above, but has an additional generator in BAA 1 and a different bid price for the generator in BAA 3. This example assumes BAA 2 has elected to enforce the net export limit, but BAA 1 and BAA 3 have not.

As in the previous examples, all of the resources are mitigated to their default energy bids in the market run, and the net export limit for BAA 2 is set at 140 MW. Generation in BAA 2 is increased from 100 MW in the mitigation run to 140 MW in the market run based on default energy bids. However, energy that wheels through BAA 2 is not affected by the net export limit. Because generator B in BAA1 is less economic than BAA3 generation using default energy bids, generation in BAA 3 is increased by 160 MW in the market run, and generator B is dispatched lower by 160 MW. Thus, energy transfers wheeling through BAA 2 increase by 160 MW, unaffected by BAA 2's election to use the net export limit.

Figure 5: Enforcement of Net Export Limit Constraint Does not Affect Wheel Throughs



3. Congestion Revenue caused by the Proposed Net Export Limit

As the proposed EIM net export limit will restrict the net scheduled interchange of an entire balancing authority area, it will be imposed on all EIM participating generation within a balancing authority area collectively. When the net EIM transfer limit of a balancing authority area is binding in the market, the LMPs within that balancing authority area are different from the LMPs outside of that balancing authority area. The CAISO proposes to treat the congestion revenue associated with the net incremental export limit in the same manner as it treats congestion revenue of any internal transmission constraint, *i.e.,* the congestion revenue is included in the real-time congestion offset of the balancing authority area in which the constraint is located.[41]

[41] *See* Existing tariff section 11.5.4.1.1 (providing for congestion offset allocation for EIM interties); *Cal. Indep. Sys. Operator Corp.* 155 FERC ¶ 61,329 (2016) at P 35 (accepting the proposed congestion offset allocation changes for EIM interties); *see also* CAISO Transmittal Letter filed in ER16-1518-000 at pp 4-16 (explaining the methodology for congestion offset allocation at EIM interties).

This is similar to how the CAISO allocates congestion revenue when it imposes an incremental EIM export limit on the net EIM transfer of a given EIM entity balancing authority area under certain conditions, such as a contingency or when an EIM entity fails the hourly resource sufficiency evaluation.[42] This is different from how the CAISO allocates congestion revenue caused by the EIM transfer limit, which is a different limit that the CAISO may enforce on transfers between EIM entity balancing authority areas to reflect the available transmission rights that are released to the EIM. The EIM transfer limit may cause congestion revenue when the EIM internal intertie constraint between two EIM entities is binding. Under the CAISO tariff, the CAISO divides these congestion revenues between the two EIM entity balancing authority areas.[43] Accordingly, the CAISO does not propose to allocate the congestion revenue associated with the proposed EIM net export limit in the same way it allocates the congestion revenue associated with the EIM transfer limit because the net export limit is considered to be a constraint within a balancing authority area and treated as any other internal transmission constraint.

The CAISO acknowledges that the net export limit has a potential shortcoming in the RTD because the market power mitigation and pricing runs do not occur in the same market interval. In the RTD, market power mitigation is based on the previous market run. This shortcoming can manifest itself because the market will determine the net incremental transfer limit using the advisory interval from the previous market run, which can result in a transfer limit that would have been different had the market inputs from the binding interval been used. However, requiring a neighboring balancing authority area to sell power at mitigated prices in a voluntary market outweighs the potential limit on transfers of energy that may be needed by an importing balancing authority area to meet its load in real-time. On balance, and given that the importing balancing authority area can rely on internal resources and its available balancing capacity to meet its load, the outcome under the proposed rule is more just and reasonable than the current circumstance.

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[42] Existing tariff section 29.17(f); *see also* CAISO Transmittal Letter filed in ER16-1518-000 at p 9 (explaining that: "[b]ecause the addition of new EIM entities does not affect the allocation of congestion revenues attributable to an EIM balancing authority area's internal transmission limits or to an EIM external intertie that does not also operate as an EIM internal intertie, the CAISO did not propose to modify those allocations").

[43] Existing tariff section 11.5.4.1.1(c); *see also* CAISO Transmittal Letter filed in ER16-1518-000 at p 9 (explaining that: "[b]ecause transmission to which the intertie scheduling limit at an EIM internal intertie applies is effectively shared by the balancing authority areas, the CAISO proposed to maintain a proportional sharing of the credits attributable to congestion at those interties).

4. Stakeholder Concerns

The DMM questioned whether this feature is required to incent participation in the EIM, noting that other changes to the EIM design or changes to market conditions might incent maximum participation absent this provision. The CAISO believes that this rule builds upon the concept that the EIM is a voluntary market. It benefits EIM participating resources by limiting the quantity of sales at mitigated prices, thus limiting the risk that an EIM participating resource will be forced to sell additional energy to another EIM entity balancing authority area at mitigated prices beyond what is necessary to resolve market power. Thus, market participants will likely offer more energy into the EIM and make more of their transmission available than without this feature.

The MSC believes the incremental net export limit should be based on a balancing authority area's total flexible ramping product award, not just the portion that exceeds its flexible ramping requirement. However, the CAISO believes the amount of energy a balancing authority area should have to export beyond its obligation to share flexible ramping capability should be based on the results of the market at suppliers' submitted bid prices. This is because the participant voluntarily offered amounts of energy offered beyond that required to pass the EIM's resource sufficiency tests and the participant may not have offered such quantity if it knew it would be forced to sell the energy at a mitigated bid price. It is inappropriate for the market to dispatch a balancing authority area to export more energy at mitigated bid prices than it originally dispatched as flexible ramping exports at the supplier's submitted bid prices.

One stakeholder expressed concern that the CAISO's incremental net export limit may inappropriately allow an EIM entity to limit energy from being dispatched in the market during periods of mitigation when that energy had already been offered to the market. The stakeholder suggested that allowing participants to withdraw capacity during intervals of mitigation would permit noncompetitive outcomes. The CAISO actually considers the outcome differently. Without the option to enforce an incremental net export limit, some EIM entities may be in a position to reduce the transmission available for use by the EIM, which in turn could minimize the amount of energy available for sale or to wheel through these EIM entity balancing authority areas to other EIM entity balancing authority areas.[44] The proposal avoids this undesirable outcome

[44] The CAISO acknowledges that only some EIM entities can limit the transmission they make available for EIM transfers. Only those EIM entities using transmission made available through interchange rights pursuant to CAISO tariff section 29.17(f)(2) may determine the transmission they make available based on factors other than how much transmission is available through the well documented practice of calculating ATC. *Compare* CAISO tariff section 29.17(f)(2) and 29.17(f)(3) (distinguishing between transmission made available through interchange rights and available transfer capability, while expressly deferring to the EIM entity tariff only for the determination of available transfer capability).

without limiting energy transfers through the EIM entity balancing authority area that has elected for the CAISO to enforce a net incremental EIM export limit.

In addition, market participants may limit the amount of energy they offer to the EIM to avoid exporting power at mitigated bid prices irrespective of their obligations to make transmission available. The CAISO does not expect that an EIM participating resource would bid into the market with the objective of selling at mitigated prices if that mitigated price does not accurately reflect its costs. Because this initially was not the intention, the EIM participating resource is not really withdrawing anything from the market, rather, it is simply asking the market to recognize the price at which it is willing to sell. The election is through a CAISO master file change, which takes time and is not an hour-by-hour election. This process minimizes the potential for participants to chase prices using this feature.

Finally, the CAISO will set the default for this feature as unenforced, which requires each EIM entity balancing authority area to determine whether it may be appropriate for their circumstances. The CAISO will also notify all participants which balancing authority areas have elected to use the rule. This transparency will allow all interested entities, including the DMM, to monitor the effectiveness of this rule.

C. Hydroelectric Resources Default Energy Bid

1. Need for New Default Energy Bid Option

The current default energy bid calculation options do not include a transparent methodology that appropriately estimates the marginal costs of hydroelectric resources with limited water storage capability. Consequently, when such resources participate in the CAISO markets, they risk being subject to a default energy bid that undervalues their marginal costs when their bids are mitigated for market power.

The inability to reflect a hydroelectric resource's marginal costs appropriately creates a significant disincentive for these resources to participate economically in the CAISO markets.[45] Unlike many other resources that currently participate in the CAISO markets, operators of hydroelectric resources with storage capability make decisions to generate based on opportunity costs for water, including those created by water availability considerations driven by

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[45] *Challenges of Estimating Opportunity Costs of Energy-Limited Resources and Implications for Efficient Local Market Power Mitigation*, Kevin Wellenius and Susan L. Pope (May 9, 2018), at p. 9, available at https://www.caiso.com/Documents/FTIConsultingWhitePaper-Challenges-EstimatingOpportunityCosts-Energy-LimitedResources-etc.pdf.

regulatory, legal, or environmental requirements. Such disincentives pose a greater concern with the expansion of the EIM into the hydro-rich Northwest region of the Western Interconnection.[46] Forgoing the ability to capture the economic and operational benefits of the flexibility provided by hydroelectric resources is of particular concern given the critical need for flexible ramping capability to balance system needs. Reduced participation of these flexible, fast-ramping, hydroelectric resources will hamper the ability to obtain a least-cost solution for the EIM footprint as a whole, thereby reducing potential benefits.[47]

Marginal costs of hydroelectric resources with storage are primarily driven by opportunity costs regarding their limited water supply. This cost effectively is the equivalent of a thermal generator's fuel cost. Hydroelectric resources with a limited water supply have opportunity costs because they can only produce a limited amount of energy over a given time period. These opportunity costs represent the additional revenue a resource would receive if it conserves its water supply so that it can produce energy in the future when prices are highest and energy is most valuable to the system. These opportunity costs are created by the limited water supply of hydroelectric resources and the resulting need to use this water to generate energy only when prices and need are highest.

For example, if a resource only has enough water to produce energy during one month of the year, and energy prices in the highest-priced month are $75/MWh, the resource would have a $75/MWh opportunity cost. These opportunity costs are incurred over the time period of a hydroelectric resource's water storage horizon, or over a shorter time period when short-term water availability limitations are the limiting factor.

These opportunities for future revenues include those from bilateral transactions outside of the CAISO markets, including transactions to deliver energy at a different location than the hydroelectric resource. These opportunity costs are particularly important for hydroelectric resources in balancing authority areas outside of the CAISO that are participating in the EIM. In addition, an individual hydroelectric resource's opportunity costs can vary greatly day-to-day because of intermittent short-term limitations that arise due to regulatory or environmental constraints.[48] The timeframe over which future opportunities must

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[46] Currently, PacifiCorp, Idaho Power, Puget Sound Energy, and Powerex, all participate in the EIM with significantly, or in the case of Powerex, entirely, with large storage hydroelectric resources.

[47] Wellenius and Pope, at p. 10.

[48] *See e.g.*, Seattle City Light Default Energy bid Presentation – Energy Imbalance Market Offer Rules Technical Workshop, April 30, 2018, available at: http://www.caiso.com/Documents/SeattleCityLightDefaultEnergyBidPresentation-EnergyImbalanceMarketofferRulesTechnicalWorkshop.pdf; Powerex, Workshop Presentation, Mark Holman, "Examining Fourth DEB Options

be considered also depends on the timeframe over which operation of a hydroelectric resource or hydro system is optimized, which further depends on the storage capability of the resource. Depending on the storage capability, the resource may need to be optimized from as little as a few days to more than a year.

Stakeholders have stated that hydroelectric resource operators use models to calculate daily water availability for generating energy and resultant opportunity costs that are complex and take into account various probabilities for different water inflow considerations and that there is a high degree of subjectivity in interpreting the output of the models.[49] Stakeholders have further explained that these models are complex because they estimate water availability based on many factors that affect both reservoir inflows and outflows. These can include weather, upstream and downstream conditions including the status of other reservoirs in a hydroelectric system, and legal restrictions and obligations such as flow restrictions due to wildlife and other water use considerations. These models may accommodate hundreds of inputs and may imply opportunity costs that change drastically even *within* a single operating day. Resource operators value their marginal costs based on these complex models, which may vary as conditions vary. It is not practicable for the CAISO to replicate these calculations.

Operators of hydroelectric resources are particularly sensitive to a default energy bid that does not capture their marginal costs sufficiently because this may result in a hydroelectric resource being dispatched in periods when it is not optimal to use the resource's limited water supply. This may occur when local market power mitigation is triggered and a higher bid from a hydroelectric resource is mitigated to the default energy bid in multiple intervals. For example, if a hydroelectric resource's water supply is depleted early in an operating day, the hydroelectric resource may not be available for dispatch during higher-priced evening ramping hours when energy is most needed. This imposes an opportunity cost, which if not factored into the default energy bid, will discourage participation of such resources in the market, and may force the CAISO market to forgo generation in hours when it is most needed.

Additionally, a hydroelectric resource's water supply typically is not solely devoted to generating electricity to earn energy market revenues. Resources in the EIM may prioritize generation to serve their local load outside of the CAISO market, and all hydroelectric resource operators may prioritize managing local

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for Energy Limited EIM Participating Resources," July 19, 2018, available at http://www.caiso.com/Documents/PowerexPresentation-EnergyImbalanceMarketOfferRulesTechnicalWorkshop-Jul19-2018.pdf.

[49] *Id.*

water conditions, and only operate the resource to earn energy market revenues as a secondary objective.[50] Market participants may find it challenging to meet legal water flow requirements imposed by regulators when the CAISO market dispatches their hydroelectric resources too frequently. This may force market participants to self-schedule hydroelectric resources, restricting dispatch flexibility in the CAISO market.

Importantly, hydroelectric resources are generally fast-ramping and highly effective at managing the increasing ramping needs that must be met for reliable energy grid operations. Increased participation of fast-ramping resources allows the CAISO to respond to sudden energy needs from changing system conditions, which reduces the total number of power balance constraint violations. This in turn reduces price volatility and overall market prices.

The current variable cost option and LMP-based options for calculating default energy bids are not designed to estimate a hydroelectric resource's marginal costs that reflect the variables discussed above. The variable cost option is a formulaic calculation based on a resource's fuel consumption at various generation levels, fuel prices, and variable operating and maintenance costs. This option is not well suited for hydroelectric resources.

The current LMP-based default energy bid option calculates the resource's default energy bid based on the weighted average of the lowest quartile (*i.e.,* 25th percentile) of LMPs at the generators pricing node in periods the unit was dispatched over the preceding ninety days. Because the LMP-based options is based on a historical approach, it does not capture the variable marginal costs faced by hydroelectric resources, day-to-day or interval-by-interval, because of the factors discussed above.

The negotiated option seemingly could provide a venue for customized negotiated default energy bid that accounts for the variables discussed above by more accurately estimating the resource's marginal costs. Under the negotiated option, the CAISO has found acceptable values or formulas for non-thermal resources and thermal resources whose marginal costs vary based on factors beyond the cost of fuel. However, the negotiated option does not provide certainty for all hydroelectric resources because it is not transparent and does not provide a clear indication of how the resource's marginal costs will be valued. Further, based on recent experiences since the real-time market has been extended into other areas of the Western Interconnection, the CAISO does not

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50 Idaho Power Company Comments on Draft Final Proposal (February 8, 2019), at p. 3, available at: http://www.caiso.com/Documents/IPCComments-LocalMarketPowerMitigationEnhancements-DraftFinalProposal.PDF.

believe the negotiated option will yield a default energy bid that is acceptable to all hydroelectric resources regardless of their location.

Beginning April 1, 2019, resources qualified as use-limited resources can include a variable energy opportunity cost adder to their default energy bid.[51] This can consider a resource's availability limitations over a specified time horizon. This methodology calculates the resource's opportunity cost due to these limitations based on projected CAISO real-time market prices. However, this opportunity cost methodology used under the variable cost option was designed for use-limited resources and consequently only reflects monthly and annual use limitations. It does not reflect the short-term – potential daily – limitations that hydroelectric resources, including those with long-term storage, encounter. These opportunity cost adders can account for intertemporal energy sales at a unit's specific location, but they do not capture the potential opportunity for intertemporal energy sales outside of the CAISO's real-time energy market. Although this issue also exists for resources in the CAISO balancing authority area, it is particularly an issue for resources in the EIM entity balancing authority areas outside of the CAISO. These resources often enter into bilateral transactions for which the associated energy output from the resource is not settled in the CAISO market because the resource produces it pursuant to an EIM base schedule.

2. Proposed Default Energy Bid for Hydroelectric Resources with Storage Capability

To address the issues discussed above, the CAISO proposes a new default energy bid (*i.e.,* the hydro DEB) option that would be available to all hydroelectric resources with storage capability that can be bid-in and dispatched through the real-time market, including the EIM. The proposed hydro DEB would appropriately account for these resources' opportunity costs, while acknowledging such costs are inherently difficult to calculate precisely.

The proposed hydro DEB is designed to reflect hydroelectric resources' opportunity costs due to their limited water supply and water usage limitations, and it is based on a transparent formulaic approach that would apply to all hydroelectric resources equally based on the CAISO's validation of the resource's attributes and, if applicable, the market participant's access to transmission to make sales in alternative markets. The proposed formulaic approach reasonably captures many of the attributes and opportunity costs faced by hydroelectric resources with storage. This will improve the efficiency of the CAISO market's dispatch, set more appropriate LMPs, and provide just and

[5151] *See Cal. Indep. Sys. Operator Corp.,* 163 FERC ¶ 61,211 (2018), at P 32.

reasonable compensation when such resources are mitigated through the CAISO markets.

The proposed hydro DEB acknowledges that hydroelectric resource costs are inherently difficult to calculate precisely. Because the many factors affect the amount of water hydroelectric resources have available to support energy sales to the CAISO market can vary day-to-day, and even intra-day, hydroelectric resource opportunity costs can be highly subjective. This makes it impractical to calculate a specific hydroelectric resource's opportunity cost with a high degree of precision, even using a negotiated default energy bid. Consequently, the CAISO proposes a standard hydro default energy bid that approximates a hydroelectric resource's opportunity costs. This approach does not attempt to precisely model each resource's operation or costs; rather, it is based on the typical operation of a typical hydroelectric resource.

The proposed hydro DEB has three components: Long-Term/Geographic, Short-Term, and the Gas Floor*.* These three components respectively represent (1) opportunity costs created by the potential to sell a hydroelectric resource's limited energy production in the future, including in different bilateral markets; (2) short-term opportunity costs created by short-term water use limitations; and (3) the potential cost of replacement energy in the real-time market if the resource exceeds its short-term limitations.[52] The CAISO will calculate the hydro DEB for each resource once per day and separately for the day-ahead and real-time markets so that it reflects current conditions.

The hydro DEB is based on the greatest of these three components because each can separately reflect the marginal cost to operate a hydroelectric resource. A hydroelectric resource's marginal costs, or opportunity costs, can vary based on a particular day's, or hour's, energy prices, compared to anticipated prices in the future. For example, if the Long-Term/Geographic component is the highest value, this means prices in the future are anticipated to be higher than the current day's prices, and the resource's marginal costs are the opportunity cost of generating in the future. Alternatively, if the short-term component is the highest value, this means near-term prices are higher than anticipated prices in the future, and a resource's marginal costs are the opportunity costs of generating in the highest priced hours within the period of the hydroelectric resource's short-term use-limitations. The gas floor component serves as a fail-safe measure in case the short-term component is too low, and it will help ensure the CAISO market dispatches a hydroelectric resource within its short-term use-limitations and covers the cost of replacement energy if it does not.

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[52] Testimony of Gabriel Murtaugh (Murtaugh Testimony), at pp. 10-15, which is provided in Attachment J to this filing.

Reflecting opportunity costs of potential sales in bilateral markets outside of the CAISO market is particularly important for hydroelectric resources participating in the EIM in balancing authority areas outside of the CAISO. Market participants can sell the output of these resources in bilateral markets and not settle that energy in the CAISO market by submitting a base schedule to the EIM for the energy output. The CAISO market does not settle energy generated pursuant to a base schedule. Thus, the opportunity cost is based on bilateral prices and not CAISO market prices. Although market participants also can effectively sell energy from resources in the CAISO balancing authority area in the bilateral markets and be similarly insulated from CAISO market settlements, EIM base schedules are a more direct means to do so, and sales of energy in the bilateral market is reputably more frequent for resources in the EIM.

The hydro DEB will be available for any hydroelectric resource in the CAISO or an EIM area that has storage available and can be bid in and dispatched through the real-time market. In contrast, today market participants generally elect negotiated default energy bids for hydroelectric resources, which are negotiated separately and non-publically. The CAISO believes a standard hydro DEB option is important to treat hydroelectric resources comparable with gas-fired resources, which have a standard transparent cost-based option.

3. The Long-Term/Geographic Component

a. Description of the Long-Term/Geographic Component

The Long-Term/Geographic component of the hydro DEB represents opportunity costs created by hydroelectric resources' limited water supply and resulting need to use this water to generate energy only when energy prices and need are highest. This component ensures the CAISO market will not dispatch a hydroelectric resource in a market interval if energy prices are anticipated to be higher in a future month, thus conserve the resource's water. This component also considers opportunity costs arising from the market participant's potential ability to sell energy from the resource in the bilateral market at different prices than the CAISO market LMP. This potentially includes sales at different locations than the hydroelectric resource's location if the market participant has transmission to enable these sales.

The CAISO proposes to calculate the Long-Term/Geographic component based on the greater of: (1) the day-ahead on-peak price at the applicable electric pricing hub or hubs; (2) the on-peak balance of the month futures index price for the current month at the applicable electric pricing hub or hubs; and (3) the maximum on-peak monthly futures index price at the applicable electric pricing hub or hubs over the hydroelectric resource's water storage horizon.

Similar to its existing variable cost option default energy bid,[53] which has a 10 percent adder, the CAISO will multiply this value by 1.1 to account for variations between published price indices and prices of actual individual bilateral transactions. The Long-Term/Geographic component is based on the highest of these three prices because each of these three components separately can reflect a hydroelectric resource's opportunity cost.

As described in more detail further below, the CAISO will establish default electric pricing hubs for hydroelectric resources that will be used in calculating the Long-Term/Geographic and Short-Term components of the hydro DEB. These pricing hubs will reflect bilateral electricity trading price indices published by the Intercontinental Exchange. Hydroelectric resources will be assigned a default electric pricing hub for use in its hydro DEB based on the balancing authority area in which the resource is located. A hydro DEB for a specific resource may also use prices for a hub or hubs at a different location than the resource if the market participant has transmission that it enables it to make sales of energy from the hydroelectric resource at these other locations in the bilateral market.

b. Prices used in the Long-Term/Geographic Component

As described above, the Long-Term/Geographic component of the hydro DEB is based on the maximum of three prices. The first of these prices is the day-ahead on-peak price at the applicable electric pricing hub or hubs. If the market participant has transmission and is able to sell a hydroelectric resource's energy output at a different location, this price is based on prices from electric pricing hubs at this different location, or locations, in addition to the default electric pricing hub. This price reflects opportunity costs arising from potential energy sales at these locations in the bilateral market at prices different from the CAISO market's LMPs. For example, if a market participant in the Northwest has transmission to the Southwest enabling it to make incremental sales of energy from the resource at a location in the Southwest, then this price would consider Palo Verde electric pricing hub prices. This reflects the hydroelectric resource's opportunity cost of making energy sales in the Southwest using the transmission to the Southwest.

As explained further below, the Short-Term component of the hydro DEB includes the day-ahead on-peak price at the hydroelectric resource's default electric pricing hub. This price is only applicable to the Long-Term/Geographic component if the CAISO has approved an additional electric pricing hub, or hubs,

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53 Existing tariff section 39.7.1.1.

to be included in addition to the resource's default electric pricing hub in a resource's hydro DEB.

The second price considered by the Long-Term/Geographic component is the on-peak balance of the month futures index price for the current month at the applicable electric pricing hub, or hubs. This price reflects opportunity costs arising from the need to conserve a hydroelectric resource's limited water supply for higher priced periods later in the month. This price is only applicable to the Long-Term/Geographic component if the CAISO has approved additional electric pricing hub, or hubs, to be included in addition to the resource's default electric pricing hub in a resource's hydro DEB. The Short-Term component of the hydro DEB already includes this price at the hydroelectric resource's default electric pricing hub.

The third price considered by the Long-Term/Geographic component is the maximum on-peak monthly futures index price at the applicable electric pricing hub, or hubs, looking out over all the months within the hydroelectric resource's storage horizon. This represents the resource's opportunity cost of future energy sales. This opportunity cost can be created by using prices at the resource's location, or other locations, if the CAISO has approved using other electric pricing hubs in addition to the resource's default electric pricing hub in a resource's hydro DEB.

c. Storage Horizon Used in the Long-Term/Geographic Component

The storage horizon represents the length of time a hydroelectric resource can store its water supply and how far in the future the resource has opportunity costs that are impacted by using its limited water supply to generate energy on any particular day. The CAISO proposes to define the storage horizon as the length of time over a resource's hydro operation cycle between which its reservoir cycles from its maximum water level back to its maximum water level. The storage horizon ends when the hydroelectric resource's reservoir returns to its maximum level because after this it likely will have to spill water and no longer can store water to generate energy in the future.

As described earlier, the proposed hydro DEB acknowledges that hydroelectric resource costs are inherently difficult to calculate precisely. Thus, the maximum monthly futures index price is intended as a heuristic proxy to reasonably approximate a hydroelectric resource's opportunity costs. It is not intended as a precise calculation of these costs.

The hydro DEB uses the highest monthly futures index price over the period a hydroelectric resource has stored water to operate because the hydro DEB does not attempt to calculate precisely the amount of water that is available.

The hydro DEB only considers the number of months in a resource's storage horizon and does not attempt to calculate the total quantity of energy the resource could generate with its stored water. Also, the hydro DEB uses the highest monthly futures index price over the time period of the storage horizon because actual hourly prices are more volatile than monthly prices, and many actual hourly prices are likely to be greater than the monthly futures price. Because of these reasons, the highest monthly futures price over a hydroelectric resource's storage horizon is a reasonable representation of the resource's opportunity costs.

Scheduling coordinators will be required to compute a hydroelectric resource's storage horizon by comparing the hydroelectric resource's historic pond elevations for multiple years and observing the resource's typical cycling times. The specific calculation will be based on the average length of time over a resource's hydro operation cycle between which its reservoir cycles from its highest water level, back to its highest water level.

The CAISO will require the responsible scheduling coordinator[54] to submit a proposed value for the maximum storage length, include an attestation that this value corresponds to the definition of the maximum storage horizon, and provide corroborating information for validation by the CAISO. The CAISO will evaluate the scheduling coordinator's submission and consider any corroborating information submitted by the scheduling coordinator or otherwise available to the CAISO. Corroborating information may include several years of the hydroelectric resource's historic water levels and regulatory filings related to the operations of the resource.

d. Default Electric Pricing Hubs and Showing of Transmission Rights

The CAISO will establish electric pricing hubs for hydroelectric resources that it will use to calculate the Long-Term/Geographic and Short-Term components of the hydro DEB. The CAISO will use bilateral electricity trading price indices published by the Intercontinental Exchange for the electric pricing hubs. Each hydroelectric resource in the EIM will have a specific default electric pricing hub depending on which balancing authority area the resource is located. Initially these will be the Mid-Columbia, Palo Verde, Alberta, North-of-Path 15, and South-of-Path 15 pricing hubs. The CAISO will assign hydroelectric resources to these hubs depending on the balancing authority area in which they are located as shown Table 3 below.

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[54] The responsible scheduling coordinator is the market participant that is registered as the scheduling coordinator that bids and schedules the resource in the CAISO markets consistent with the CAISO tariff rules.

Table 3 Default Electric Pricing Hubs

Resource Area	Default Electric Pricing Hub
PacifiCorp West, Portland, Powerex, Puget Sound	Mid-Columbia
Arizona, Idaho, PacifiCorp East, NV Energy	Palo Verde
Northern California	North-of-path 15
Southern California	South-of-path 15

The CAISO will identify in its business practice manuals the applicable default electric pricing hubs that apply to each of the balancing authority areas in the CAISO markets, including the EIM. The CAISO will assign a default electric pricing hub to additional balancing authority areas that enter the EIM. The default electric pricing hub will be assigned based on the most accurate representation of the energy prices at the balancing authority area's location.[55] Adding an additional electric pricing hub will be contingent upon the CAISO confirming trading activity at the added hub is sufficiently liquid to provide a robust indication of prevailing prices.

The scheduling coordinator may also be eligible to select electric pricing hubs in addition to the local default electric pricing hub as specified in the CAISO business practice manual in the calculation of the Long-Term/Geographic component. Eligibility for additional electric pricing hubs beyond the default electric pricing hubs will be based on a consultative process with the CAISO and the scheduling coordinator showing firm transmission rights to one of the electric pricing hubs, or an electrically similar location.[56] The Alberta electric pricing hub will be an eligible electric pricing hub in addition to a resource's default electric pricing hub in the Long-Term/Geographic component.

The scheduling coordinator also must attest that it can use the transmission rights to make additional bilateral sales because its transmission rights are not fully committed. A demonstration of transmission rights means the resource actually is able to make sales at the different locations and therefore faces the opportunity cost of making such sales when considering sales in the

[55] A scheduling coordinator may also consult with the CAISO to revise the assigned default electric pricing hub, if it can be demonstrated that another electric pricing hub better represents local prices for a specific resource applying for the hydro DEB.

[56] Scheduling coordinators must show they hold either annual firm transmission rights for the resource, or demonstrate a practice of procuring monthly transmission rights by showing that they actually procured monthly the rights for the resource during the prior year.

CAISO markets. If the scheduling coordinator demonstrates they hold the requisite firm transmission rights that would make them eligible to select multiple electric pricing hubs, the CAISO will calculate the Long-Term/Geographic component based on the maximum of the electric pricing hub values, as determined each day.

Scheduling coordinators may demonstrate transmission to multiple locations, and the CAISO will evaluate the applicable transmission rights applicability to each geographic electric pricing hub based on the scheduling coordinator's showing.[57] If the CAISO finds the scheduling coordinator is eligible for multiple electric pricing hubs, the CAISO will use the maximum price value from among the multiple electric pricing hubs in calculating the Long-Term/Geographic component for those resources.

If the scheduling coordinator shows a lesser quantity of firm transmission rights than is needed to accommodate the maximum output of a hydroelectric resource, the resource will only be eligible for a weighted average of applicable electric pricing hub prices between the additional hub at a different location than the resource and the default electric pricing hub. In this case, the CAISO will use a weighted average of the prices because that represents the resource's potential revenue and resulting opportunity costs. For example, assume a 100 MW resource's default electric pricing hub is Mid-Columbia and it has 60 MW of firm transmission rights to Palo Verde: in this case 60 percent of the resource's output could earn Palo Verde prices in the bilateral market using the transmission rights and 40 percent would earn Mid-Columbia prices. Thus, the average of the two prices weighted based on the transmission available to the remote electric pricing hub, which represents the resource's potential revenue and resultant opportunity costs.

e. Obligation to Update Hydro DEB Attributes

Generally, the maximum storage horizons are attributes for a resource that will not change over time. A scheduling coordinator may justify this parameter to the CAISO initially when requesting this default energy bid, and it would not need to be reexamined later.[58] However, because transmission contracts can change over time, resources electing the hydro DEB would be required to resubmit documentation and attestations to demonstrate transmission rights annually. Additionally, each resource with a hydro DEB will be required to notify the CAISO if shown firm transmission is no longer available during the

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[57] The CAISO will evaluate and compare values for each electric pricing hub each day when computing the Hydro DEB.

[58] Acceptable documentation to verify maximum storage horizons must include analysis of historic reservoir conditions and a letter of attestation of available storage from the resource owner.

year. In this case, the applicable pricing hub that is an addition to the default hub will no longer be included in the hydro DEB. Failure to report these changes may result in sanctions under existing applicable market rules. The CAISO will retain the right to audit this data, request additional information as needed, and require a resource owner to attest to additional values and information submitted to the CAISO. If the CAISO determines that the scheduling coordinator provided inaccurate information, the CAISO may revoke eligibility for using the hydro DEB (if not justified by the accurate data) and/or refer the matter to the Commission.

4. The Short-Term Component

a. Description of the Short-Term Component

The Short-Term component of the hydro DEB accounts for hydroelectric resources' short-term water use limitations that have a timeframe ranging from daily to monthly. Even hydroelectric resources that have a long-term storage horizon can have water use limitations that arise under certain conditions that apply over a shorter period. Similar to their long-term limitations, hydroelectric resources have opportunity costs created by their short-term water use limitations.

If the Short-Term component is the highest priced component of the hydro DEB, then short-term prices are higher than anticipated prices in the future. If this is the case, the Short-Term component recognizes that these short-term opportunity costs make it optimal to dispatch hydroelectric resources with limited storage only in the highest priced hours, which is when they are also most valuable to the grid.

The CAISO worked with stakeholders to design the Short-Term component so that if the CAISO market dispatches a hydroelectric resource on a particular day, the market will implicitly recognize the hydroelectric resource's daily use-imitations, and consequently, it is unlikely to dispatch the resource during the day for more than four hours. Also, the CAISO has designed this attribute so the CAISO market dispatch will tend to conserve the use of a hydroelectric resource if energy prices are anticipated to be higher in the remainder of the month or in the upcoming month. This feature recognizes a hydroelectric resource's opportunity costs creates the need to conserve water for future use.

As described earlier, hydroelectric resources' short-term limitations can be due to weather, upstream and downstream conditions, including the status of other reservoirs in a hydro system, and legal restrictions and obligations, such as flow restrictions due to wildlife and other water use considerations. As discussed above, the amount of water a hydroelectric resource has available to support offers for energy to the EIM can also depend on the resource's electrical load obligations that it has to serve each day. These limitations can be transient and only exist under certain conditions.

The CAISO proposes to calculate the Short-Term component of the hydro DEB based on the greater of: (1) the day-ahead on-peak index price at the resource's local default electric pricing hub; (2) the on-peak balance of the month futures index price for the current month at the resource's local default electric pricing hub; and (3) the on-peak monthly futures index price at the resource's local default electric pricing hub for the next month. The first local default electric pricing hub price is considered by the Short-Term component and the day-ahead index price, which reflects a resource's opportunity costs over a day. The other two prices it considers, the balance of the month futures index price and the futures index price for the next month, reflects a resource's opportunity costs looking out through the next month.

The CAISO proposes to multiply these prices by 1.4 to ensure the Short-Term component price is high enough so a hydroelectric resource will not be dispatched too often on a particular day and to conserve its use if prices are anticipated to be higher later in the month or in the next month.

b. Multiplier Used in the Short-Term Component

The CAISO worked with stakeholders to develop this 1.4 multiplier in the Hydro DEB's Short-Term component. The CAISO determined a 1.4 multiplier was appropriate by analyzing the relationship between CAISO real-time market prices and electric pricing hub index prices.[59] A multiplier applied to electric pricing hub index prices is needed because the hydro DEB's Short-Term component uses electric pricing hub index prices but the CAISO market dispatches resources based on CAISO real-time market prices. Consequently, a multiplier applied to electric pricing hub index prices is needed to result in a default energy bid price that is high enough so that the CAISO market does not dispatch a hydroelectric resource such that it exceeds its short-term water use limitations.

CAISO real-time market prices typically are higher at certain times of the day than the corresponding electric pricing hub index price because the pricing hub index prices reflect sales of energy in multiple hour blocks. Conversely, real-time prices in the CAISO market vary by market intervals.

As described earlier, the approach for the hydro DEB does not attempt to precisely model each resource's operation. Rather, it but is rather based on the typical operation of a hydroelectric resource. A high degree of precision for each

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[59] *See* Murtaugh Testimony at p. 19.

resource would result in the CAISO "second-guessing" market participant's water management considerations. Thus, the CAISO and stakeholders determined it would be appropriate to calculate a single multiplier that would apply to all hydroelectric resources based on the typical maximum number of hours per day hydroelectric resources with storage can run before without exceeding their short-term water use limitations. These short-term water-use limitations are either daily limitations or limitations over a time span up to a month. Stakeholders generally came to the consensus that four hours per day was a reasonable typical value to accommodate short-term water use limitations.[60]

The CAISO's analysis to determine the 1.4 multiplier studied the frequency with which hypothetical calculated hydro DEBs would be higher than CAISO real-time market LMPs.[61] The CAISO's analysis shows that applying a 1.4 multiplier to Short-Term component of the hydro DEB brings it to a level that would result in the real-time market infrequently dispatching a resource more than four hours per day.[62] A 1.4 percent multiplier avoids dispatching the resource for more than four hours per day approximately 95-99 percent of the time. Additionally, the CAISO's analysis shows that, with a 1.4 multiplier, even if the CAISO market dispatches a resource using the hydro DEB more than four hours per day, it will not dispatch it more than six to eight hours.[63] The analysis shows that resources with more limiting short-term limitations (*i.e.*, should not be dispatched more than two hours per day) would be dispatched to exceed their limitations more frequently. However, based on the stakeholder process, the CAISO concluded that dispatch no more than four hours per day would address the short-term limitations most likely faced by hydroelectric resources. Thus, this multiplier should enhance the hydro DEB sufficiently to ensure the typical hydroelectric resource is not dispatched inefficiently such that it exceeds its short-term limitations and exceeds its opportunity costs.

5. The Gas Floor Component

The Gas Floor component provides a "fail-safe" measure when the Short-Term component is too low and would result in a CAISO market dispatching the resource in hours other than the highest priced, given the limited number of hours the resource can operate in a day. Alternatively, the Gas Floor component will ensure the supplier earns at least the cost of replacing energy from the hydroelectric resource with energy from a gas resource if the CAISO market dispatches the hydroelectric resource up to its use-limitation.

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60 *Id.* at pp. 16-17.

61 *Id* at p. 22.

62 *Id.* at pp. 23-24.

63 *Id.*

The CAISO will calculate the Gas Floor component as the most recent average heat rate for a typical gas turbine generator obtained from the Energy Information Administration. This average heat rate is multiplied by the gas price for the fuel region where the hydroelectric resource is located, and multiplied by 1.1.[64] The Gas Floor component represents the opportunity cost for replacing the generation from a hydroelectric resource if it exceeded its short-term water use limitations and replacing it with generation from a thermal resource. The thermal resource is assumed to be in the in the area of the hydroelectric resource. The Gas Floor component is calculated similarly to how the CAISO calculates a resource's default energy bid under the variable cost option for natural gas-fired resources, which is based on a resource's fuel usage, *i.e.*, "heat-rate," and prevailing gas costs.[65] Similar to the variable cost option default energy bid, the Gas Floor component uses a 10 percent adder to account for actual gas costs that may vary from published gas prices.

The Gas Floor component will use the heat rate of a typical similarly located gas turbine, as made available by the Energy Information Administration. This represents the type of resource most likely to replace hydroelectric generation during peak price periods. The CAISO will also use the gas price drawn from the gas price index for the fuel region where the hydroelectric resource is located to value the cost of the gas turbine's output, as this likely would be the gas cost for such generation. The CAISO will then apply a ten percent multiplier, as it does in calculating a gas-fired resource's default energy bid under the variable cost option. Because the ten percent adder is included in the variable cost option of the default energy bid calculation, it also reflects the costs the CAISO would otherwise observe in its markets to replace the hydroelectric resource's output if it were not dispatched.[66]

6. Stakeholder Concerns

Stakeholders were generally very supportive of the CAISO's proposed hydro DEB. After a robust stakeholder process on the proposed hydro DEB, the following concerns with the CAISO's proposal remained.

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64 *See* proposed tariff section 39.7.1.7.1.1.

65 Existing tariff section 39.7.1.1.1.

66 *See* existing CAISO Tariff Section 39.7.1.1. The 10% multiplier is based on the CAISO's current use of the Commission-approved multiplier used in the calculation of default energy bids for gas fired resources under the variable cost option. The multiplier is included in the calculation of default energy bids to capture a reasonable degree of variability around the calculation of a resource's marginal costs based on a fuel price index, which may or may not capture the actual fuel prices the resource faces in any given interval. *See California Indep. Sys. Operator Corp.,* 116 FERC ¶ 1045 (2006).

The MSC generally supported the hydro DEB proposal, but noted certain limitations. The MSC noted that because the hydro DEB is based on future energy prices to set opportunity costs, it may not always reflect actual opportunity costs based on actual storage and water levels.[67] One aspect of this is that the fixed storage horizon used to calculate the hydro DEB in all months of the year may not accurately reflect a hydroelectric resource's actual storage horizon when the resource is approaching spill conditions in the Spring. However, the MSC noted given "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," the MSC concluded they were not confident that a more accurate and practical design can be developed at this point in time.[68] Therefore, the MSC supports implementing the proposed procedure, and recommends that the CAISO monitor its performance over time, and make improvements. The CAISO agrees to monitor its performance closely and make any necessary changes based on what it learns from its observations.

The MSC also questioned the CAISO's proposal to allow scheduling coordinators to select additional electric pricing hubs for use in the calculation of the Long-Term/Geographic component, if such determination is based simply on the scheduling coordinator's demonstration that it holds transmission from the resource to the electric pricing hub or an electrically similar location.[69] The MSC expects that 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."[70] The MSC noted that the difference between the local and distant futures price should reflect the costs of transmitting the power to the distant hub, in which case the futures price at the local hub should also reflect the resource's opportunity costs, therefore obviating the need for the pricing indices at the additional distant hubs. The MSC expressed concerned that if the transmission market is not efficient or liquid, the local futures prices would not capture the resource's opportunity costs at distant locations. The MSC noted that the CAISO's proposed use of a distant electric pricing hub is appropriate if a participant can show it possesses "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."[71] The MSC does not believe merely demonstrating

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[67] MSC Opinion, at fn. 29.

[68] *Id.* at p. 5.

[69] *Id.* at pp. 6-7.

[70] *Id.* at p. 6.

[71] *Id.*

ownership of transmission rights should be sufficient evidence. Instead, the MSC believes that conceptually, it would be more appropriate to evaluate "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."[72] The MSC also noted that the scheduling coordinator should be required to show 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."[73]

The MSC recognized that there are complications in valuing transmission rights but argues "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,"[74] and the CAISO should not be the entity trying to estimate these costs. The MSC recommends that the CAISO "continue to examine questions concerning the value of firm transmission rights and their relevance to hydropower opportunity costs."[75]

The MSC ultimately concluded, however, that despite the concerns it raised regarding the hydro DEB, they support the CAISO's general approach for calculating the hydro DEB based on gas costs and forward prices for energy. The MSC preferred that if the CAISO used the forward prices, they be adjusted by opportunity costs for transmission provided by resource owners and verified by the CAISO. However, recognizing that this may not be practical, the MSC supported the hydro DEB as proposed in the near term, but recommended that the CAISO continue to work to refine this aspect of the proposal.[76]

The DMM questioned the validity of the CAISO's "proposal for using trading hubs that are significantly different (geographically and pricewise) from the geographically closest hub in the formulation of opportunity costs. The DMM also has some concerns about the provision that would allow DEBs to be based on up to 12 months of futures prices."[77]

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[72] MSC Opinion at p. 6.

[73] *Id.*

[74] *Id.* at p. 7.

[75] *Id.*

[76] *Id.* at p. 8.

[77] Department of Market Monitoring, *Local Market Power Mitigation Enhancements 2018 Draft Final Proposal* (February 11, 2019), at p. 6 (DMM Comments), which is provided in Attachment I to this filing.

Although the CAISO agrees that theoretically, default energy bids should only be based on prices at a resource's location, in practice not allowing suppliers to reflect the opportunity cost of sales at other locations would interfere with the bilateral market. The CAISO responded to the DMM's concerns in two ways. First, consistent with the MSC's recommendation, the CAISO agreed to include a requirement that the scheduling coordinator must not only demonstrate ownership of transmission rights to distant locations, but must also demonstrate that these rights are not fully committed and that there is an actual opportunity to use these rights.

Second, suppliers point out that in practice in the bilateral market transmission's value cannot be separated from energy's value because there is no robust market for their unused transmission. Stakeholders provided information demonstrating that there generally is no ability to bilaterally sell their used transmission rights. Stakeholders submitted comments demonstrating that energy purchased at local hubs is frequently not a substitute for energy produced by (or depleted from) a hydroelectric resource and that in bilateral markets energy commodity sales are often tied with transmission service, and are often inseparable. Stakeholders also demonstrated that secondary markets resales of transmission rights are lacking and infrequent, and prices in these market are very low.[78]

Through the stakeholder process, suppliers pointed out their energy sales for deliveries at locations other than their hydroelectric resources location are linked to the output of that hydroelectric resource[79] because energy purchasers often specifically purchase energy produced by hydroelectric resources to meet carbon reduction goals.

Related to concerns about using a fixed storage horizon for each hydroelectric resource to calculate hydro DEBs, the CAISO's proposal for a using a fixed storage horizon reasonably balances the practical considerations of implementation complexity and the difficulties in precisely modeling every individual hydroelectric resource's operation. More precise modeling would result in hydro DEBs that do not acknowledge the subjectivity in determining hydroelectric resource's opportunity costs. Related to the concern that the fixed

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78 *See e.g.*, *Powerex Comments*, at pp. 5-8, available at: http://www.caiso.com/Documents/PowerexComments-LocalMarketPowerMitigationEnhancements-DraftFinalProposal.pdf; Bonneville Power Administration Comments, available at: http://www.caiso.com/Documents/BPAComments-LocalMarketPowerMitigationEnhancements-DraftFinalProposal.pdf; *Public Power Council Comments*, available at: http://www.caiso.com/Documents/PPCComments-LocalMarketPowerMitigationEnhancements-DraftFinalProposal.pdf; *Seattle City Light Comments,* available at: http://www.caiso.com/Documents/SCLComments-LocalMarketPowerMitigationEnhancements-DraftFinalProposal.pdf.

79 *Id.*

storage horizon will be overstated as hydroelectric resources approach spill conditions in the Spring, any default energy bid price inflation due to using a fixed storage horizon will be small, and market power is not as much of a concern between December and March as it is in other months. In these months there is generally ample supply and energy prices are generally low – so there isn't much opportunity to exercise market power.

One stakeholder requested that the CAISO expand the definition of the hydro DEB to include both a ceiling and a floor to capture situations when market power is determined to exist in a region. The stakeholder's concern is that absent a must-offer obligation, resources in an export-constrained region could select the resource with the most negative hydro DEB floor and only offer to reduce that resource's output during periods when the region is export-constrained. The CAISO does not currently mitigate resources that bid below its marginal costs. The stakeholder described decremental market power, which is an entirely different issue than the CAISO addressed in the stakeholder process that preceded this tariff amendment. The CAISO has included a description of an initiative that would address this issue as a potential initiative in its draft 2020 Policy Initiative Catalog.

One stakeholder argued that the ten percent multiplier used in the Long-Term/Geographic component it is too low and does not reflect gas price volatility, and a higher multiplier such as 25 percent, would be more accurate. The stakeholder's concern is that if the multiplier is too low, resources would frequently be dispatched inefficiently. The stakeholder also commented the multipliers should be reevaluated regularly to reflect changing conditions, including water conditions.

The CAISO believes that a ten percent multiplier on the Long-Term/Geographic component is appropriate and consistent with current default energy bids for natural gas resource multipliers. In addition, in a separate stakeholder initiative, the CAISO will be proposing to update gas prices on the morning of the real-time market to account for gas price volatility.[80] The CAISO will make this change in a separate filing to implement its commitment cost and default energy bid enhancements, where the CAISO will amend those parts of the tariff more holistically.[81] Additionally, a ten percent multiplier is sufficient when combined with the 40 percent multiplier of the short-term floor component. As discussed above, the CAISO conducted a study to determine if the default energy bid, in its entirety, was sufficient to avoid dispatching hydroelectric resources too frequently. This study showed the 40 percent multiplier resulted in

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[80] Board Memo at p. 6.

[81] Additional information regarding the CAISO's commitment costs and default energy bid enhancements is available on the CAISO's website at: http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCosts_DefaultEnergyBidEnhancements.aspx.

dispatching most resources no more than four hours per day at least 95 percent of the time. Moreover, suppliers can still negotiate default energy bids for individual resources if the standard hydroelectric default energy bid does not account for a resource's limitations.

The CAISO does not believe a multiplier higher than ten percent is appropriate or necessary for the Long-Term/Geographic component to capture volatility. The Long-Term/Geographic component uses a simplified heuristic approach to estimate bilateral trade's opportunity costs. For example, it may establish an opportunity cost for a resource with a 12-month storage horizon based on the highest monthly index price looking out 12 months. The CAISO's proposed approach uses the highest priced month acknowledging that hourly prices can be higher or lower than the published index prices and to avoid the CAISO having to estimate a resource's actual water supply, which is impracticable. This approach of using the highest cost month in the storage horizon renders a higher multiplier unnecessary at this time.

The CAISO agrees that it should revise the multipliers if conditions change from those that it used to develop the proposed multiplier. The CAISO is proposing to include the multipliers in this tariff amendment.[82] The CAISO will monitor the performance of the multipliers and evaluate on an annual basis whether there is a need for modification. If the CAISO determines there is a need to modify the multiplier, it will conduct a tariff review stakeholder process and present its proposed changes and reasoning to stakeholders, and based on that outcome, the CAISO will amend its tariff to modify the multipliers.

Two stakeholders requested comparable treatment of opportunity costs regarding opportunities for other bilateral sales in calculating the default energy bids for other types of resources such as gas resources. These stakeholders argued that other resources, such as use-limited resources, may also face such opportunities that should be considered.

In response, the CAISO notes that it conducted robust stakeholder processes to develop appropriate commitment costs for use-limited resources in its Commitment Cost Phase 3 (CCE 3) initiative. The CCE 3 initiative developed an opportunity cost methodology for use-limited gas resources.[83] During that stakeholder process, no stakeholder pointed out that their gas resources had opportunity costs due to bilateral sales. The CAISO is now proposing to make opportunity costs in default energy bids available to hydroelectric resources because of the unique challenges and opportunities for bilateral sales these

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[82] Proposed tariff section 39.7.1.7, *et seq.*

[83] The CAISO's CCE 3 initiative was filed with the Commission on March 23, 2018, as Docket No. ER18-1169.

resources face and the risk of forgoing their participation in the CAISO markets absent an ability to capture those costs. The CAISO is not proposing changes to the default energy bids for gas resources in this tariff amendment and any such considerations are outside the scope of this proceeding. The Commission should consider the just and reasonableness of this proposal and not whether opportunity costs should be provided to other resources. However, in response to these comments by stakeholders, the CAISO has added a potential initiative to its policy initiative catalog that would consider gas-fired resources' bilateral opportunity costs and short-term limitations.

V. Effective Date

The CAISO expects to implement the changes proposed in this tariff amendment no later than December 4, 2019.[84] As part of this filing, the CAISO requests authority to provide notice of the actual effective date by providing the Commission and market participants at least fourteen days-notice.[85]

However, the CAISO will begin preparing any hydro DEB's requested prior to ensure market participants have a functional hydro DEB before the effective date of the changes. Therefore, the CAISO respectfully requests that the Commission issue an order by September 30, 2019, and approve an effective date of October 14, 2019, for the tariff provisions regarding development of the hydro DEB. This will provide the CAISO and market participants with certainty regarding the parameters for developing the hydro DEBs.

VI. Service

The CAISO has served copies of this filing upon the California Public Utilities Commission, the California Energy Commission, and all parties with scheduling coordinator agreements under the CAISO tariff. In addition, the CAISO has posted the filing on the CAISO website.

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[84] Attachment K lists the requests effective dates for each of separate tariff provisions submitted in this tariff amendment.

[85] The CAISO has included an effective date of 12/31/9998 as part of the tariff records submitted with this filing. The CAISO will make a filing pursuant to Commission Filing Code 150 to provide notice of the actual effective date of these tariff records at least 14 days prior to implementation.

VII. Contents of Filing

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Clean tariff sheets with a requested effective date of October 14, 2019;
Attachment B	Clean tariff sheets with a requested effective date of no later than December 4, 2019;
Attachment C	Marked tariff sheets with a requested effective date of October 14, 2019;
Attachment D	Marked tariff sheets with a requested effective date of no later than December 4, 2019;
Attachment E	EIM Governing Body Memorandum;
Attachment F	CAISO Board of Governors Memorandum;
Attachment G	Draft Final Proposal;
Attachment H	Market Surveillance Opinion;
Attachment I	Department of Market Monitoring Comments;
Attachment J	Testimony of Gabriel Murtaugh;
Attachment K	Table of Tariff Sections and Proposed Effective Dates; and
Attachment L	Matrix of Stakeholder Comments and the CAISO's Response thereo.

VIII. Correspondence

Pursuant to Rule 203(b) of the Commission's Rules of Practice and Procedure,[86] the CAISO requests that all correspondence, pleadings, and other communications concerning this filing be served upon the following:

Roger E. Collanton
General Counsel
Anna A. McKenna
Assistant General Counsel
John Anders
Assistant General Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel: (916) 608-7182
Fax: (916) 608-7222
Email: amckenna@caiso.com

IX. Conclusion

The CAISO respectfully requests that the Commission accept the amendment proposed in this filing and issue an order by no later than September 30, 2019 approving an October 14, 2019 effective date for the tariff provisions regarding development of the hydro DEB, and allow the CAISO to implement the remainder of the provisions by no later than December 4, 2019, as requested. If there are any questions concerning this filing, please contact the undersigned.

Respectfully submitted,

By: *[/s/ Anna A. McKenna]*

Roger E. Collanton
General Counsel
Anna A. McKenna
Assistant General Counsel
John C. Anders
Assistant General Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630

Attorneys for the California Independent System Operator Corporation

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86 18 C.F.R. § 385.203(b).

Attachment A – Clean Tariff Proposed to be Effective October 14, 2019

Local Market Power Mitigation Enhancements

California Independent System Operator Corporation

Tariff Changes Proposed to be Effective October 14, 2019
(*to be implemented with the remainder of the proposed changes)*

* * * * *

39.7.1.7 Hydro Default Energy Bid

Scheduling Coordinators may request a Hydro Default Energy Bid for a hydroelectric resource with storage capability located in the CAISO Balancing Authority Area or any EIM Entity Balancing Authority Area.

39.7.1.7.1 Computation

For each Trading Day, the CAISO will calculate the Hydro Default Energy Bid as the maximum of the (a) gas floor, (b) short-term component, and (c) long-term/geographic component, which are all calculated as specified below.

39.7.1.7.1.1 Gas Floor

The CAISO will calculate the gas floor as the most recent average heat rate for a typical gas turbine generator obtained from the Energy Information Administration, multiplied by the gas price for the fuel region applicable to the location of the hydroelectric resource, multiplied by 1.1.

39.7.1.7.1.2 Short-Term Component

The CAISO will calculate the short-term component as 1.4 multiplied by the maximum of:

(a) the day-ahead peak price at the applicable electric pricing hub;

(b) the on-peak balance of the month on peak futures price for the current month at the applicable electric pricing hub; and

(c) the on-peak monthly index on peak futures price at the applicable electric pricing hub for one (1) month after the current month.

39.7.1.7.1.3 Long-Term/Geographic Component

A Scheduling Coordinator may request that the long-term/geographic component be calculated based on multiple electric pricing hubs in addition to the default electric pricing hub consistent with Section 39.7.1.7.2.1. The CAISO will calculate the long-term/geographic component as 1.1 multiplied by the maximum of:

(a) the day-ahead on-peak price at the applicable electric pricing hub(s);

(b) the on-peak balance of the month futures prices for the current month at the applicable electric pricing hub(s); and

(c) the on-peak monthly index futures price at the applicable electric pricing hub(s) for all future months up to the maximum storage horizon after the current month.

39.7.1.7.2 Requirements

As part of its request for a Hydro Default Energy Bid, the Scheduling Coordinator must submit to the CAISO:

(a) Annually, for each month of the upcoming year and for each electric pricing hub requested that is not the default electric pricing hub, the Scheduling Coordinator must (1) demonstrate that it holds firm transmission rights to enable delivery from the hydroelectric resource's default market region to the requested electric pricing hub or to a delivery point that is similarly priced location; or (2) provide documentation that supports a historical practice of acquiring monthly firm transmission rights to the requested electric pricing hub(s) or similarly priced location. Scheduling Coordinators may demonstrate transmission rights to multiple locations and, based on the CAISO's evaluation of such information, the CAISO may include multiple electric pricing hubs, in addition to the default electric pricing hubs, in the long-term/geographic component of the Hydro Default Energy Bid for the affected resources. The Scheduling Coordinator will attest through its submission that it reasonably expects it will be able to use the demonstrated transmission rights to deliver incremental sales from the hydroelectric resource because the rights are not fully committed and that there is an actual opportunity to use these rights. If the CAISO includes multiple electric pricing hubs in the long-term/geographic component, the Hydro Default Energy Bid calculation will use the maximum of the electric price indices published for each electric pricing hub as determined for each Trading Day. On Trading Days for which there are no relevant published electric price indices at an electric pricing hub, the CAISO will use the most recently published index for the applicable electric pricing hub.

(b) For resources that Scheduling Coordinators demonstrate a quantity of firm transmission rights to a requested electric pricing hub or similarly priced location that is less than the hydro resource's capacity, the CAISO will include the requested electric pricing hub up to the quantity demonstrated transmission rights, and apply a proportional weighting of the resource's transmission rights to calculate a weighted average of those bilateral electric pricing hub prices when calculating the value of the long-term/geographic component of the Hydro Default Energy Bid.

(c) In the absence of supporting transmission rights information when calculating the Hydro Default Energy Bid, the CAISO will revert to the default bilateral electric pricing hub specified in Section 39.7.1.7.3.

(d) If during the term of the annual period the Scheduling Coordinator no longer has the firm annual transmission rights previously demonstrated, or can no longer continue a historical practice of acquiring monthly firm transmission rights, the Scheduling Coordinator must inform the CAISO within five (5) Business Days of no longer holding such firm transmission rights. .

(e) The CAISO may audit the Scheduling Coordinator and request additional information in support of the Scheduling Coordinator's assertions.

(f) If the CAISO determines the Scheduling Coordinator has submitted inaccurate information, the CAISO may revert the resource to the default electric pricing hubs as specified in Section 39.7.1.7.3.

39.7.1.7.2.2 Maximum Storage Horizon

The maximum hydroelectric resource storage horizon submitted by the Scheduling Coordinator must:

(a) Reflect the typical storage duration of a hydroelectric resource's reservoir, defined as the length of time between which the reservoir cycles from a maximum elevation to a new maximum elevation during a hydro cycle. The Scheduling Coordinator shall compute the reservoir's cycling time based on multiple years of reservoir elevation data.

(b) Be supported by (1) a written attestation by a representative who has the authority to bind the company stating that the value submitted to the CAISO as the maximum storage horizon is consistent with the requirements specified in Section 39.7.1.7.2 (a); or (2) corroborating information submitted to the CAISO, which may include several years of historic reservoir levels for the specific hydroelectric resource and regulatory filings related to the operations of the hydroelectric resource.

39.7.1.7.3 Default Electric Pricing Hubs

The default electric pricing hubs will be as specified in the Business Practice Manuals, which will also include a process for modifying or adding electric pricing hubs to the list of default electric pricing hubs.

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Appendix A

Master Definitions Supplement

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- Hydro Default Energy Bid

A Default Energy Bid for an eligible hydroelectric resource in accordance with Section 39.7.1.1.

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Attachment B – Clean Tariff Proposed to be Effective no Later than December 4, 2019

Local Market Power Mitigation Enhancements

California Independent System Operator Corporation

Tariff Changes Proposed to be Effective no Later than December 4, 2019

29.39 EIM Market Power Mitigation.

(a) **EIM Market Power Mitigation Procedure.** The CAISO shall apply the Real-Time Local Market Power Mitigation procedure in Section 39.7 to the Energy Imbalance Market, including EIM Transfer constraints into an EIM Entity Balancing Authority Area on an EIM Internal Intertie, except as provided in Section 29.39.

(b) **Competitive Path Assessment.** The CAISO shall conduct the competitive path assessment to determine for each EIM Entity Balancing Authority Area whether a path is competitive or non-competitive, consistent with Section 39.7.2, except that-

(1) EIM Participating Resource Scheduling Coordinators shall submit information required by the CAISO to perform the competitive path assessment;

(2) the competitive path assessment shall not exclude EIM Participating Resources from the test used to determine the competitiveness of Transmission Constraints on the basis that they may be net buyers of Energy in the Real-Time Market; and

(3) the CAISO may establish different Reference Buses for each Balancing Authority Area, which need not be within the Balancing Authority Area, for calculating the LMP decomposition which is used to trigger Bid mitigation, based on the topology of each Balancing Authority Area and consideration of the bus at which the Marginal Cost of Congestion component of Locational Marginal Prices is least influenced by market power.

(c) **Locational Marginal Price Decomposition.** The CAISO shall perform the Locational Marginal Price decomposition for each EIM Entity Balancing Authority Area using the results of the competitive path assessment and the Congestion pricing results of the pre-market run to determine which resources may have local market power due to Congestion on a non-competitive Transmission Constraint, consistent with Section 34.2.3 and 39.7.

(d) **Default Energy Bids.** The CAISO shall use the methods and standards set forth in Section 39.7 to determine Default Energy Bids for EIM Participating Resources, except that the CAISO will use the Market Services Charge and System Operations Charge reflected in the EIM Administrative Charge.

(e) **Incremental Net EIM Transfer Limit.**

(1) **Election.** An EIM Entity Scheduling Coordinator may elect for the CAISO to apply an upper limit to the net EIM Transfer consistent with the timelines that apply to Master File changes pursuant to Section 30.7.3.2.

(2) **Application.** In the applicable RTM process, incremental net EIM Transfers from an EIM Entity Balancing Authority Area that has made the election in Section 29.39(e)(1) will be limited when the MPM process triggers mitigation and EIM Transfers in the MPM process are constrained in the import direction to that EIM Entity Balancing Authority Area, or a group of EIM Entity Balancing Authority Areas that includes that EIM Entity Balancing Authority Area.

(3) **Limit.** The incremental net EIM Transfer upper limit will be: (a) the amount by which the sum of upward Uncertainty Awards in the EIM Entity Balancing Authority Area in the MPM process described in Section 34.1.5 prior to the RTM process for the interval to which the MPM process applies exceeds the higher of zero or the EIM Entity Balancing Authority Area's upward Uncertainty Requirement, less the net EIM Transfer import limit, plus (b) the amount that is the greater of:

(A) the EIM Entity Balancing Authority Area's net EIM Transfer in the MPM process described in Section 34.1.5 prior to the RTM process for the interval to which the MPM process applies; or

(B) the EIM Entity Balancing Authority Area's net EIM Transfer represented by the EIM Base Schedules at each EIM Internal Intertie for the interval to which the MPM process applies.

(4) **Publication.** The CAISO will publish a list of EIM Entity Balancing Authority Areas that have elected for the CAISO to apply an upper limit to the net EIM Transfer in accordance with the procedures and timelines for such publication

established in the Business Practice Manual for the Energy Imbalance Market.

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31.2.3 Bid Mitigation

If the non-competitive Congestion component of an LMP calculated in an MPM process is greater than zero (0), then any resource at that Location that is dispatched in that MPM process is subject to Local Market Power Mitigation. Bids on behalf of any such resource, to the extent that they exceed the Competitive LMP plus the Competitive LMP Parameter at the resource's Location for the DAM or RTM process interval for which the MPM process applies, will be mitigated to the higher of the resource's Default Energy Bid (or RMR Proxy Bid for Legacy RMR Units), as specified in Section 39, or the Competitive LMP plus the Competitive LMP Parameter at the resource's Location for the DAM and RTM process interval for which the MPM process applies. To the extent a Multi-Stage Generating Resource is dispatched in the MPM process and the non-competitive Congestion component of the LMP calculated at the Multi-Stage Generating Resource's Location is greater than zero, for purposes of mitigation, all the MSG Configurations will be mitigated similarly and the CAISO will evaluate all submitted Energy Bids for all MSG Configurations based on the relevant Default Energy Bids for the applicable MSG Configuration. The CAISO will calculate the Default Energy Bids for Multi-Stage Generating Resources by submitted MSG Configuration. Any market Bids equal to or less than the Competitive LMP plus the Competitive LMP Parameter will be retained in the DAM and RTM process.

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34.1.5 Mitigating Bids in the RTM

34.1.5.1 Generally

After the Market Close of the RTM, after the CAISO has validated the Bids pursuant to Section 30.7 and Section 34.1.4, and prior to conducting any other RTM processes, the CAISO conducts a MPM process. The results are used in the RTM optimization processes. Bids on behalf of Demand Response

Resources, Participating Load, and Non-Generator Resources are considered in the MPM process but are not subject to Bid mitigation. Bids from resources comprised of multiple technologies that include Non-Generator Resources will remain subject to all applicable market power mitigation under the CAISO Tariff, including Local Market Power Mitigation.

34.1.5.2 Fifteen-Minute MPM

The CAISO conducts the MPM process as the first pass of each fifteen-minute interval in the RTUC horizon starting with the unmitigated Bid set as validated pursuant to Section 30.7 and Section 34.1.4. The MPM process produces results for each fifteen-minute interval of the RTUC horizon and thus may produce mitigated Bids for any given resource for any fifteen-minute interval in the RTUC run horizon that applies to any CAISO Market Process that is based on a specific RTUC run. The determination as to whether a Bid is mitigated is made based on the non-competitive Congestion component of each LMP for each fifteen-minute interval of the RTUC run horizon, using the methodology set forth in Section 31.2.3. If a Bid is mitigated in the MPM pass for a fifteen-minute interval in the RTUC run horizon, the mitigated Bid will be utilized in the corresponding binding HASP and FMM process for the fifteen-minute interval. If a Bid is not mitigated in a fifteen-minute MPM pass, the CAISO will still mitigate that Bid in subsequent fifteen-minute intervals of the RTUC horizon if the MPM pass for the subsequent intervals determine that mitigation is needed.

34.1.5.3 Real-Time Dispatch MPM

The RTD MPM process produces results for each five-minute interval of a Trading Hour. The determination as to whether a Bid is mitigated is made based on the non-competitive Congestion component of each LMP for each five-minute interval, using the methodology set forth in Section 31.2.3. The RTD MPM process is performed for a configurable number of RTD advisory intervals after the binding RTD interval, and the mitigated Bids are used in the corresponding RTD intervals of the following RTD.

34.1.5.4 Reliability Must Run Resources

For a Condition 1 Legacy RMR Unit, the use of RMR Proxy Bids is determined based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Section 31.2.3 above. If a Condition 2 Legacy RMR Unit is issued a Manual RMR Dispatch by the CAISO, then RMR Proxy Bids for all of the unit's Maximum Net Dependable Capacity will be considered in the MPM process. For both Condition 1 and Condition 2 Legacy RMR Units, when mitigation is triggered, a RMR Proxy Bid is calculated using the same methodology described above for non-RMR Units. For a Condition 1 Legacy RMR Unit that has submitted Bids and has not been issued a Manual RMR Dispatch, to the extent that the non-competitive Congestion component of an LMP calculated in the MPM process is greater than zero, and that MPM process dispatches a Condition 1 Legacy RMR Unit at a level such that some portion of its market Bid exceeds the Competitive LMP at the Legacy RMR Unit's Location, the resource will be flagged as an RMR Dispatch if it is dispatched pursuant to a Legacy RMR Contract at a level higher than the dispatch level determined by the Competitive LMP. Both Condition 1 and Condition 2 Legacy RMR Units may be issued manual RMR Dispatches at any time to address local reliability needs or to resolve non-competitive constraints.

34.1.5.5 Competitive LMP Parameter

When a Bid is mitigated, the CAISO will add a cost, not to exceed $0.01/MWh, to the Competitive LMP used in the MPM process prior to the DAM or RTM process. The CAISO will set the Competitive LMP Parameter as low as possible while creating a reasonable price separation between the area where mitigation applies and other areas where mitigation does not apply. The CAISO will publish the value of the Competitive LMP Parameter in the Business Practice Manual.

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Appendix A

Master Definitions Supplement

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- Competitive LMP Parameter

A cost added to the Competitive LMP used in the MPM process in accordance with Section 34.1.5.5.

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Attachment C – Marked Tariff Proposed to be Effective October 14, 2019

Local Market Power Mitigation Enhancements

California Independent System Operator Corporation

Tariff Changes Proposed to be Effective October 14, 2019
(*to be implemented with the remainder of the proposed changes)*

39.7.1.7 Hydro Default Energy Bid~~[Not Used]~~

Scheduling Coordinators may request a Hydro Default Energy Bid for a hydroelectric resource with storage capability located in the CAISO Balancing Authority Area or any EIM Entity Balancing Authority Area.

39.7.1.7.1 Computation

For each Trading Day, the CAISO will calculate the Hydro Default Energy Bid as the maximum of the (a) gas floor, (b) short-term component, and (c) long-term/geographic component, which are all calculated as specified below.

39.7.1.7.1.1 Gas Floor

The CAISO will calculate the gas floor as the most recent average heat rate for a typical gas turbine generator obtained from the Energy Information Administration, multiplied by the gas price for the fuel region applicable to the location of the hydroelectric resource, multiplied by 1.1.

39.7.1.7.1.2 Short-Term Component

The CAISO will calculate the short-term component as 1.4 multiplied by the maximum of:

(a) the day-ahead peak price at the applicable electric pricing hub;

(b) the on-peak balance of the month on peak futures price for the current month at the applicable electric pricing hub; and

(c) the on-peak monthly index on peak futures price at the applicable electric pricing hub for one (1) month after the current month.

39.7.1.7.1.3 Long-Term/Geographic Component

A Scheduling Coordinator may request that the long-term/geographic component be calculated based on multiple electric pricing hubs in addition to the default electric pricing hub consistent with Section 39.7.1.7.2.1. The CAISO will calculate the long-term/geographic component as 1.1 multiplied by the maximum of:

(a) the day-ahead on-peak price at the applicable electric pricing hub(s);

(b) the on-peak balance of the month futures prices for the current month at the applicable electric pricing hub(s); and

(c) the on-peak monthly index futures price at the applicable electric pricing hub(s) for all future months up to the maximum storage horizon after the current month.

39.7.1.7.2 Requirements

As part of its request for a Hydro Default Energy Bid, the Scheduling Coordinator must submit to the CAISO:

(a) Annually, for each month of the upcoming year and for each electric pricing hub requested that is not the default electric pricing hub, the Scheduling Coordinator must (1) demonstrate that it holds firm transmission rights to enable delivery from the hydroelectric resource's default market region to the requested electric pricing hub or to a delivery point that is similarly priced location; or (2) provide documentation that supports a historical practice of acquiring monthly firm transmission rights to the requested electric pricing hub(s) or similarly priced location. Scheduling Coordinators may demonstrate transmission rights to multiple locations and, based on the CAISO's evaluation of such information, the CAISO may include multiple electric pricing hubs, in addition to the default electric pricing hubs, in the long-term/geographic component of the Hydro Default Energy Bid for the affected resources. The Scheduling Coordinator will attest through its submission that it reasonably expects it will be able to use the demonstrated transmission rights to deliver incremental sales from the hydroelectric resource because the rights are not fully committed and that there is an actual opportunity to use these rights. If the CAISO includes multiple electric pricing hubs in the long-term/geographic component, the Hydro Default Energy Bid calculation will use the maximum of the electric price indices published for each electric pricing hub as determined for each Trading Day. On Trading Days for which there are no relevant published electric price indices at an electric pricing hub, the CAISO will use the most recently published index for the applicable electric pricing hub.

(b) For resources that Scheduling Coordinators demonstrate a quantity of firm transmission rights to a requested electric pricing hub or similarly priced location that is less than the hydro resource's capacity, the CAISO will include the requested electric pricing hub up to the quantity demonstrated transmission rights, and apply a proportional weighting of the resource's transmission rights to calculate a weighted average of those bilateral electric pricing hub prices when calculating the value of the long-term/geographic component of the Hydro Default Energy Bid.

(c) In the absence of supporting transmission rights information when calculating the Hydro Default Energy Bid, the CAISO will revert to the default bilateral electric pricing hub specified in Section 39.7.1.7.3.

(d) If during the term of the annual period the Scheduling Coordinator no longer has the firm annual transmission rights previously demonstrated, or can no longer continue a historical practice of acquiring monthly firm transmission rights, the Scheduling Coordinator must inform the CAISO within five (5) Business Days of no longer holding such firm transmission rights. .

(e) The CAISO may audit the Scheduling Coordinator and request additional information in support of the Scheduling Coordinator's assertions.

(f) If the CAISO determines the Scheduling Coordinator has submitted inaccurate information, the CAISO may revert the resource to the default electric pricing hubs as specified in Section 39.7.1.7.3.

39.7.1.7.2.2 Maximum Storage Horizon

The maximum hydroelectric resource storage horizon submitted by the Scheduling Coordinator must:

(a) Reflect the typical storage duration of a hydroelectric resource's reservoir, defined as the length of time between which the reservoir cycles from a maximum elevation to a new maximum elevation during a hydro cycle. The Scheduling Coordinator shall compute the reservoir's cycling time based on multiple years of reservoir elevation data.

(b) Be supported by (1) a written attestation by a representative who has the authority to bind the company stating that the value submitted to the CAISO as the maximum storage horizon is consistent with the requirements specified in Section 39.7.1.7.2 (a); or (2) corroborating information submitted to the CAISO, which may include several years of historic reservoir levels for the specific hydroelectric resource and regulatory filings related to the operations of the hydroelectric resource.

39.7.1.7.3 Default Electric Pricing Hubs

The default electric pricing hubs will be as specified in the Business Practice Manuals, which will also include a process for modifying or adding electric pricing hubs to the list of default electric pricing hubs.

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Appendix A

Master Definitions Supplement

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- Hydro Default Energy Bid

A Default Energy Bid for an eligible hydroelectric resource in accordance with Section 39.7.1.1.

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Attachment D – Marked Tariff Proposed to be Effective no Later than December 4, 2019

Local Market Power Mitigation Enhancements

California Independent System Operator Corporation

Tariff Changes Proposed to be Effective no Later than December 4, 2019

29.39 EIM Market Power Mitigation.

(a) **EIM Market Power Mitigation Procedure.** The CAISO shall apply the Real-Time Local Market Power Mitigation procedure in Section 39.7 to the Energy Imbalance Market, including EIM Transfer constraints into an EIM Entity Balancing Authority Area on an EIM Internal Intertie, except as provided in Section 29.39.

(b) **Competitive Path Assessment.** The CAISO shall conduct the competitive path assessment to determine for each EIM Entity Balancing Authority Area whether a path is competitive or non-competitive, consistent with Section 39.7.2, except that-

(1) EIM Participating Resource Scheduling Coordinators shall submit information required by the CAISO to perform the competitive path assessment;

(2) the competitive path assessment shall not exclude EIM Participating Resources from the test used to determine the competitiveness of Transmission Constraints on the basis that they may be net buyers of Energy in the Real-Time Market; and

(3) the CAISO may establish different Reference Buses for each Balancing Authority Area, which need not be within the Balancing Authority Area, for calculating the LMP decomposition which is used to trigger Bid mitigation, based on the topology of each Balancing Authority Area and consideration of the bus at which the Marginal Cost of Congestion component of Locational Marginal Prices is least influenced by market power.

(c) **Locational Marginal Price Decomposition.** The CAISO shall perform the Locational Marginal Price decomposition for each EIM Entity Balancing Authority Area using the results of the competitive path assessment and the Congestion pricing results of the pre-market run to determine which resources may have local market power due to Congestion on a non-competitive Transmission Constraint, consistent with Section 34.2.3 and 39.7.

(d) **Default Energy Bids.** The CAISO shall use the methods and standards set forth in Section 39.7 to determine Default Energy Bids for EIM Participating Resources, except that the CAISO will use the Market Services Charge and System Operations Charge reflected in the EIM Administrative Charge.

(e) **Incremental Net EIM Transfer Limit.**

(1) **Election.** An EIM Entity Scheduling Coordinator may elect for the CAISO to apply an upper limit to the net EIM Transfer consistent with the timelines that apply to Master File changes pursuant to Section 30.7.3.2.

(2) **Application.** In the applicable RTM process, incremental net EIM Transfers from an EIM Entity Balancing Authority Area that has made the election in Section 29.39(e)(1) will be limited when the MPM process triggers mitigation and EIM Transfers in the MPM process are constrained in the import direction to that EIM Entity Balancing Authority Area, or a group of EIM Entity Balancing Authority Areas that includes that EIM Entity Balancing Authority Area.

(3) **Limit.** The incremental net EIM Transfer upper limit will be: (a) the amount by which the sum of upward Uncertainty Awards in the EIM Entity Balancing Authority Area in the MPM process described in Section 34.1.5 prior to the RTM process for the interval to which the MPM process applies exceeds the higher of zero or the EIM Entity Balancing Authority Area's upward Uncertainty Requirement, less the net EIM Transfer import limit, plus (b) the amount that is the greater of:

(A) the EIM Entity Balancing Authority Area's net EIM Transfer in the MPM process described in Section 34.1.5 prior to the RTM process for the interval to which the MPM process applies; or

(B) the EIM Entity Balancing Authority Area's net EIM Transfer represented by the EIM Base Schedules at each EIM Internal Intertie for the interval to which the MPM process applies.

(4) **Publication.** The CAISO will publish a list of EIM Entity Balancing Authority Areas that have elected for the CAISO to apply an upper limit to the net EIM Transfer in accordance with the procedures and timelines for such publication

established in the Business Practice Manual for the Energy Imbalance Market.

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31.2.3 Bid Mitigation

If the non-competitive Congestion component of an LMP calculated in an MPM process is greater than zero (0), then any resource at that Location that is dispatched in that MPM process is subject to Local Market Power Mitigation. Bids on behalf of any such resource, to the extent that they exceed the Competitive LMP plus the Competitive LMP Parameter at the resource's Location for the DAM or RTM process interval for which the MPM process applies, will be mitigated to the higher of the resource's Default Energy Bid (or RMR Proxy Bid for Legacy RMR Units), as specified in Section 39, or the Competitive LMP plus the Competitive LMP Parameter at the resource's Location for the DAM and RTM process interval for which the MPM process applies. To the extent a Multi-Stage Generating Resource is dispatched in the MPM process and the non-competitive Congestion component of the LMP calculated at the Multi-Stage Generating Resource's Location is greater than zero, for purposes of mitigation, all the MSG Configurations will be mitigated similarly and the CAISO will evaluate all submitted Energy Bids for all MSG Configurations based on the relevant Default Energy Bids for the applicable MSG Configuration. The CAISO will calculate the Default Energy Bids for Multi-Stage Generating Resources by submitted MSG Configuration. Any market Bids equal to or less than the Competitive LMP plus the Competitive LMP Parameter will be retained in the ~~IFM~~ DAM and RTM process.

* * * * *

34.1.5 Mitigating Bids in the RTM

34.1.5.1 Generally

After the Market Close of the RTM, after the CAISO has validated the Bids pursuant to Section 30.7 and Section 34.1.4, and prior to conducting any other RTM processes, the CAISO conducts a MPM process. The results are used in the RTM optimization processes. Bids on behalf of Demand Response

Resources, Participating Load, and Non-Generator Resources are considered in the MPM process but are not subject to Bid mitigation. Bids from resources comprised of multiple technologies that include Non-Generator Resources will remain ~~to be~~ subject to all applicable market power mitigation under the CAISO Tariff, including Local Market Power Mitigation.

34.1.5.2 Fifteen-Minute ~~Market~~ MPM

The CAISO conducts the MPM process as the first pass ~~for the first~~ of each fifteen-minute ~~(15)~~ interval in the RTUC horizon ~~for a Trading Hour~~ starting~~s~~ with the unmitigated Bid set as validated pursuant to Section 30.7 and Section 34.1.4. The MPM process produces results for each fifteen-~~ (15)~~ minute interval of the RTUC horizon~~Trading Hour~~ and thus may produce ~~up to four~~ mitigated Bids for any given resource for ~~the Trading Hour~~ any fifteen-minute interval in the RTUC run horizon that applies to any CAISO Market Process that is based on a specific RTUC run. The determination as to whether a Bid is mitigated is made based on the non-competitive Congestion component of each LMP for each fifteen-~~(15)~~ minute interval of the ~~applicable Trading Hour~~ RTUC run horizon, using the methodology set forth in Section 31.2.3 ~~above~~. If a Bid is mitigated in the MPM ~~process~~pass for a ~~the first~~ fifteen-~~ (15)~~ minute interval in the RTUC run horizon~~for a Trading Hour~~, the mitigated Bid will be utilized in the corresponding binding HASP and FMM process for the ~~for all market applications for that first~~ fifteen-~~ (15)~~ minute interval. If a Bid is not mitigated in a~~the first~~ fifteen-~~ (15)~~ minute MPM pass~~interval~~, the CAISO will still mitigate that Bid in subsequent fifteen-~~ (15)~~ minute intervals of the ~~Trading Hour~~ RTUC horizon if the MPM ~~runs~~ pass for the subsequent intervals determine that mitigation is needed. ~~For each Trading Hour, any Bid mitigated in a prior fifteen (15) minute interval of that Trading Hour will continue to be mitigated in subsequent intervals of that Trading Hour and may be further mitigated as determined in the MPM runs for any subsequent fifteen (15) minute interval.~~

34.1.5.~~3~~4 Real-Time Dispatch MPM

The RTD MPM process produces results for each five-~~ (5)~~ minute interval of a Trading Hour. The determination as to whether a Bid is mitigated is made based on the non-competitive Congestion component of each LMP for each five-~~ (5)~~ minute interval, using the methodology set forth in Section 31.2.3 ~~above~~. The RTD MPM process is performed for a configurable number of RTD advisory intervals after the binding RTD interval, and the mitigated Bids are used in the corresponding RTD intervals of the following RTD. ~~The input Bids to the MPM for the first of the three (3) RTD runs corresponding to a particular RTUC interval are the final Bids as mitigated pursuant to Section 34.1.5.2 for the RTD intervals corresponding to the applicable financially binding Fifteen Minute Market run. If a Bid is mitigated in the MPM process for the first five (5) minute interval for an applicable fifteen-minute (15) RTUC interval, the mitigated Bid will be utilized for all the corresponding RTD intervals in that fifteen-minute (15) RTUC interval. If a Bid is not mitigated in the first five (5) minute interval, the CAISO will still mitigate that Bid in subsequent five (5) minute intervals of the applicable RTUC interval if the MPM runs for the subsequent intervals determine that mitigation is needed. For each fifteen-minute (15) RTUC interval, a bid that is mitigated is maintained through the rest of the RTD intervals corresponding to the same RTUC interval as the original mitigated RTD interval. The input Bids to the RTD MPM process for the second of the three (3) RTD intervals corresponding to the RTUC interval will be the final mitigated bids used in the first RTD intervals. The input bids to the RTD MPM mitigation process for the third of the three RTD interval corresponding to the particular RTUC interval will be the final mitigated Bids used in the second RTD interval.~~

34.1.5.4~~5~~ Reliability Must Run Resources

For a Condition 1 Legacy RMR Unit, the use of RMR Proxy Bids is determined based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Section 31.2.3 above. If a Condition 2 Legacy RMR Unit is issued a Manual RMR Dispatch by the CAISO, then RMR Proxy Bids for all of the unit's Maximum Net Dependable Capacity will be considered in the MPM process. For both Condition 1 and Condition 2 Legacy RMR Units, when mitigation is triggered, a RMR Proxy Bid is calculated using the same methodology described above for non-RMR Units. For a Condition 1 Legacy RMR Unit that has submitted Bids and has not been issued a Manual RMR Dispatch, to the extent that the non-competitive Congestion component of an LMP calculated in the MPM process is greater than zero, and that MPM process dispatches a Condition 1 Legacy RMR Unit at a level such that some portion of its market Bid exceeds the Competitive LMP at the Legacy RMR Unit's Location, the resource will be flagged as an RMR Dispatch if it is dispatched pursuant to a Legacy RMR Contract at a level higher than the dispatch level determined by the Competitive LMP. Both Condition 1 and Condition 2 Legacy RMR Units may be issued manual RMR Dispatches at any time to address local reliability needs or to resolve non-competitive constraints.

34.1.5.5 Competitive LMP Parameter

When a Bid is mitigated, the CAISO will add a cost, not to exceed $0.01/MWh, to the Competitive LMP used in the MPM process prior to the DAM or RTM process. The CAISO will set the Competitive LMP Parameter as low as possible while creating a reasonable price separation between the area where mitigation applies and other areas where mitigation does not apply. The CAISO will publish the value of the Competitive LMP Parameter in the Business Practice Manual.

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Appendix A

Master Definitions Supplement

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- Competitive LMP Parameter

A cost added to the Competitive LMP used in the MPM process in accordance with Section 34.1.5.5.

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Attachment E – EIM Governing Body Memorandum

Local Market Power Mitigation Enhancements

California Independent System Operator Corporation

Memorandum

To: Energy Imbalance Market Governing Body

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

Date: March 5, 2019

Re: **Decision on local market power mitigation enhancements proposal**

This memorandum requires EIM Governing Body action.

EXECUTIVE SUMMARY

Management proposes several market enhancements to address market participant concerns that the ISO market's current market power mitigation process can result in the dispatch of resources at prices below their costs. This issue is particularly acute in the Western Energy Imbalance Market because of the Northwest's numerous hydro resources that have opportunity costs for energy sales because of their water limitations. Suppliers operating these resources may have disincentives to offer these needed flexible hydro resources to the EIM if they cannot reflect their costs.

First, Management proposes to create a standard default energy bid for hydro resources. The ISO's market power mitigation process reduces a market participant's submitted energy bid to a resource's default energy bid, calculated by the ISO, in the event it detects market power. Default energy bids are intended to reflect a resource's actual marginal costs of energy. Management proposes a new option for default energy bids specifically designed for hydro resources that better estimates these resources' actual costs, which typically consist of opportunity costs reflecting their limited water availability. Today, the ISO typically calculates default energy bids for hydro resources using formulas developed through confidential individual negotiations under negotiated default energy bid provisions. Market participants state that the current default energy bid formulas do not always account for the many frequently changing factors affecting water availability and can fail to account for the true value of their stored water.

Management's proposed hydro default energy bid accounts for the variability in the many factors affecting water availability and for market participants' ability to make bilateral sales of energy from these resources at a different location than the resource. This component is particularly important for suppliers that participate in the bilateral energy market in addition to the EIM. This standard hydro resource default energy bid provides the overall market with transparency into these resources' default energy bids and provides a standard starting point for any hydro resource negotiated default energy bids.

Second, Management proposes enhancements to the ISO's market power mitigation process to limit instances of resources being dispatched for additional energy only because the market power mitigation process mitigated the supplier's submitted bid to a resource's default energy bid. This includes a proposal to limit the EIM from dispatching additional energy from resources in balancing authority areas outside of the ISO under certain bid mitigation circumstances. This element of Management's proposal falls under the EIM Governing Body's primary approval authority. All of the other enhancements proposed in this memorandum fall under the EIM Governing Body's advisory role.

The enhancements described above are particularly important to encourage participation in the voluntary EIM. It is important to ensure that the market dispatches hydro resources based on their actual costs so that suppliers are encouraged to make these valuable, clean flexible resources available to the ISO market. Not only do hydro resources provide carbon-free energy, they are also valuable in managing the variability of other renewable resources.

Regarding gas-fired resources, Management also proposes enhancements that will allow the ISO market to use more up-to-date natural gas cost information to calculate default energy bids and commitment cost bid caps. Management's proposed enhancements modify an approach the ISO Board of Governors approved last year but Management has not yet filed with the Federal Energy Regulatory Commission.[1]

Finally, Management proposes to amend the listed natural gas price indices to reflect that the names of these indices have changed.

Management proposes the following motion:

> ***Moved, that the EIM Governing Body approves an optional feature to limit the EIM from dispatching additional energy from resources in balancing authority areas outside of the ISO in the event of bid mitigation, as described in the memorandum dated March 5, 2019.***

PROPOSAL

The following sections describe Management's proposal.

Hydro resource default energy bid

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[1] Management has not yet filed to implement the changes approved by the Board of Governors because it delayed their implementation until Fall 2019.

Management proposes to create a new default energy bid category specific to hydro resources with water storage. Management's proposed hydro resource default energy bid provides a reasonable estimate of hydro resources' opportunity costs due to their water availability limitations. This design acknowledges that the ISO cannot precisely determine a hydro resource's available water supply and attempting to do so could interfere with suppliers' operation of their water systems.

Hydro resources with a limited water supply have opportunity costs because they can only produce a limited amount of energy over a given time period. This opportunity cost represents the revenue a resource would receive if it conserves its water supply so that it can produce energy when prices are highest and energy is most valuable to the system. For example, if a resource only has enough water to produce energy during one month of the year, and energy prices in the highest-priced month are $75/MWh, the resource would have a $75/MWh opportunity cost.

There is not an existing standard default energy bid option to account for hydro resources' opportunity costs. Accounting for opportunity costs currently requires suppliers and the ISO to agree on a negotiated default energy bid, which has been problematic for many suppliers because the current default energy bid negotiation process has not resulted in default energy bids that accurately account for the value of their stored water.

Market participants have stated that there is a high degree of subjectivity in interpreting the output of the models that they use to calculate the water available for energy generation each day and their resources' resultant opportunity costs. They have explained that these models are complex because they estimate water availability based on many factors that affect both reservoir inflows and outflows. These can include weather, upstream and downstream conditions including the status of other reservoirs in a hydro system, and legal restrictions and obligations such as flow restrictions due to wildlife and other water use considerations. They have also stated that the amount of water they have available to support offers for energy to the EIM can also depend on their own electrical load they have to serve each day.

Because of these factors, the amount of water they have available to offer energy to the EIM can vary day-to-day, and even within the day, which means their opportunity costs can be highly subjective because they cannot be precisely calculated even with complex models. This can make it impractical to calculate a specific hydro resource's opportunity cost with a high degree of precision, even using a negotiated default energy bid. Consequently, Management proposes a standard hydro default energy bid that approximates a resource's opportunity costs by considering current gas prices and the resource's water storage horizon. This approach does not attempt to precisely model each resource's operation, but is rather based on the typical operation of a typical hydro resource.

A hydro resource's opportunity costs should also reflect the supplier's ability to make bilateral energy sales outside of the ISO market at other locations besides the resource's location. This would be the case if the supplier has Open Access Transmission Tariff rights to transmission from the resource's location to a different geographic location where it makes sales. The opportunity cost would reflect the sales price at the different geographic location. Management's proposed hydro resource default energy bid also reflects this opportunity cost.

Management proposes that the hydro default energy bid for a resource be calculated each day as the highest of the following three components:

- Short-term: this component reflects a hydro resource's opportunity costs due to short-term water availability limitations, ensuring the ISO market does not dispatch a hydro resource too often on any particular day. Even if a hydro resource has long-term water storage, it may have a limited amount of water available over the day on some or all days.

- Long-term/geographical: this component reflects a hydro resource's opportunity costs due to long-term water storage or the supplier's ability to make sales at another geographic location. This component ensures the ISO market will not dispatch a hydro resource conserving its water if energy prices are anticipated to be higher in a future month or are higher in the bilateral market at another geographic location.

- Gas floor: this component accounts for the supplier's energy replacement costs if the ISO market's dispatch exhausts a resource's short-term water availability. It also helps ensure the ISO market does not dispatch a hydro resource such that it exceeds its short-term water availability limitations in the event real-time energy prices are significantly higher than the day-ahead index used by the short-term component.

The hydro resource default energy bid uses the highest of these three components, which represents the limitations that are applicable on a particular day. For example, if the short-term component is highest, then energy prices are high on that day and the short-term component should set the level of the default energy bid so that the ISO market respects the resources' short-term limitations.

The short-term component approximates a resource's short-term opportunity costs based on anticipated energy prices ranging from the next day to the next month. Management proposes to set the default energy bid at a high enough price so that the ISO real-time market does not dispatch the resource more than four hours per day. Market participants generally came to a consensus that four hours per day represents a reasonable approximation of most hydro resources' short-term water limitations. The market will calculate this price using the higher of the day-ahead, balance of month, or upcoming month energy prices from published bilateral market energy price indices.

These prices will be from a fixed trading hub for each resource that is most representative of its EIM prices. The short-term component is then determined by increasing the price by a multiplier designed to limit the market dispatch of most hydro resources to no more than four hours per day.[2]

The long-term/geographical component uses the higher of day-ahead, balance of month, or upcoming month energy prices looking out for the number of months equal to the hydro resource's storage horizon. A resource's storage horizon will be the number of months, up to 12, between the times the hydro resource's water reservoir is historically at peak levels. This is the maximum amount of time that using water to produce energy affects a hydro resource's ability to produce energy in the future.

The gas floor component calculates the price of energy from a gas resource based on the natural gas published index price for the hydro resource's location and based on a typical natural gas-fired turbine generator's fuel consumption.

Limit dispatch at mitigated bid prices

Currently, the ISO market may dispatch a resource to provide energy when the resource appears economic because the market power mitigation process reduced the supplier's submitted bid price to a resource's default energy bid. Even with the proposed hydro default energy bid, there is the potential that the default energy bid may not fully account for a supplier's costs. Consequently, Management proposes enhancements that will reduce the frequency with which the EIM dispatches resources because it reduced the supplier's submitted bid to the resource's default energy bid.

The first of these enhancements addresses instances when the ISO market increases exports out of (or decreases imports into) an EIM balancing authority area only because of a mitigated bid price. This occurs when the market mitigates the bids of all resources' bids in a balancing authority area because the balancing authority area is in an import-constrained area.[3] The ISO real-time market schedules resources in each market interval based on two runs. The market completes the first run using a supplier's submitted energy bid. If market power is detected, the bid is mitigated to the resource's default energy bid. The market then conducts a second run to determine final schedules and prices. This can result in the market dispatching additional energy from resources because of their mitigated bid prices.

Management proposes to add an optional feature for EIM entities to limit additional dispatch of resources when their balancing authority area is subject to bid mitigation. The additional dispatch would be limited to the net energy transfer out of the balancing

[2] Based on current market conditions the multiplier is currently 1.4.

[3] This issue only extends to EIM balancing authority areas, which are subject to bid mitigation at a balancing authority area level, because they do not have a competitive number of suppliers at a system level under all conditions.

authority area the market scheduled in the first market run using the submitted bids for an interval, plus the amount of flexible ramping product the market scheduled the balancing authority area to provide in excess of its flexible ramping product requirement.

Management proposes that the dispatch limit be based on each balancing authority area's flexible ramping product requirement and awards to reflect that, while the EIM is a voluntary market, the EIM design assumes that flexible ramping capability is shared between balancing authority areas. This is accounted for in the EIM resource sufficiency test through the reduction of the overall flexible ramping product requirement by an amount that reflects the diversity benefit of pooling multiple balancing authority areas' flexibility requirements. The amount of a balancing authority area's flexible ramping product awards in excess of its individual requirement reflects the amount of flexibility that the market has determined is optimal for a balancing authority area to contribute to the EIM's overall system requirement.

This feature would enable an EIM balancing authority area to limit additional dispatch as a result of mitigation if they find their default energy bids do not accurately represent their costs. However, if an EIM balancing authority area believes its default energy bids accurately represent their costs, there is no economic reason to limit their economic dispatches with other balancing authority areas. In that circumstance, they would be unlikely to use this feature.

The second of these enhancements will prevent the ISO market from dispatching a resource to export power from a transmission-constrained region at mitigated bid prices only because the market detected market power when power was being imported to the region in an earlier market interval. These regions can include EIM balancing authority areas or other transmission-constrained regions, including within the ISO balancing authority area.

This situation is undesirable because the ISO market should not force a supplier to sell energy at mitigated bid prices in market intervals in which it does not detect market power. These enhancements will prevent this result by ensuring mitigated bid prices are at least as high as competitive prices outside of the region and by preventing the market from automatically mitigating a resource's energy bids in subsequent real-time market intervals when it detects market power in a single interval.

Natural gas prices

Management also proposes enhancements to allow the ISO market to use more up-to-date natural gas cost information to calculate default energy bids and commitment cost bid caps. These enhancements are focused on gas-fired resources but are also applicable to the gas floor component of the hydro default energy bid.

The ISO market calculates default energy bids for gas-fired resources based on published natural gas price indices. A supplier's actual gas costs may be higher than a published price if there is gas price volatility or if gas prices at the standard trading hubs that the published indices are based on are not representative of the prices at a particular resource's location.

Under enhancements approved by the ISO Board of Governors in 2018, but not yet filed with the Federal Energy Regulatory Commission, suppliers would be able to request that the ISO calculate a resource's default energy bid or commitment cost bid cap using the supplier's actual gas costs if they are greater than the published index price. This approach would be allowed to the extent the price change was no greater than 25 percent more than the published index price for Mondays and days after holidays and no greater than 10 percent more than the published index price for other days.

Management proposes to modify the above-described approach. For the real-time market, Management proposes that rather than using the fixed criteria of 25 percent and 10 percent more than the published index price, the ISO will approve supplier requests based on a gas price index published on the morning of the real-time market, and based on requests from suppliers for the ISO to review their gas procurement costs for a specific resource. These provisions would also extend to the day-ahead market.

The updated gas prices would also be used to calculate the gas floor component of the hydro resource default energy bids.

Management also proposes to change the gas price index the ISO market uses to calculate default energy bids and commitment cost bid caps for Mondays. The market currently uses a gas price index for Mondays based on purchasing gas in a package on Friday for delivery over the weekend and on Monday. However, suppliers can purchase gas separately for Mondays when demand for gas is especially higher than over the weekend. The gas price index publishers publish a separate Monday gas price when this occurs. Management proposes to use this Monday gas price when it is published and represents sufficiently liquid trading.

Finally, Management proposes to amend the natural gas price indices listed in the tariff to reflect that the names of these indices have changed.

STAKEHOLDER POSITIONS

Stakeholders generally strongly support Management's proposed hydro default energy bid, particularly those that operate hydro resources in balancing areas participating in the EIM outside of the ISO balancing authority area. They state that the proposed hydro default energy bid provides a reasonable estimation of hydro resources' opportunity costs and will prevent the ISO market's dispatch from interfering with their water management.

The ISO Department of Market Monitoring agrees with the general framework of the hydro default energy bid, but does not believe that the hydro default energy bid should incorporate prices at different locations than a resource's location. They state that this pricing aspect inappropriately mixes the value of transmission with energy prices. For example, for the ISO balancing authority area, the current ISO market nodal energy prices, reflecting energy value, are separate from transmission's value that the congestion revenue rights market reflects.

While Management agrees DMM's observation is true at a theoretical level, in practice not allowing suppliers to reflect the opportunity cost of sales at other locations would interfere with the bilateral market. Suppliers point out their energy sales for deliveries at locations other than their hydro resource's location are nonetheless linked to the output of that hydro resource. This is because energy purchasers often specifically purchase energy produced by hydro resources to meet carbon reduction goals. In addition, suppliers point out that in practice, in the bilateral market, transmission's value cannot be separated from energy's value because there is not a robust market for their unused transmission.

The ISO Department of Market Monitoring also opposes Management's proposal to base hydro resources' default energy bids on a storage horizon value that does not change throughout the year. They maintain this approach can inappropriately inflate a resource's default energy bid in the later months of the year when the horizon could extend past the winter months when a reservoir could no longer store water and the operator would instead have to let it flow through the reservoir.

Management believes its proposal for a using a fixed storage horizon reasonably balances the practical considerations of implementation complexity and the difficulties in precisely modeling every hydro resource's operation. For example, there is the possibility that some hydro resources do not face maximum storage limitations each year. In addition, any default energy bid price inflation due to using a fixed storage horizon will be small and market power is not as much of a concern in the later months of the year as it is in other months. Nevertheless, Management will monitor default energy bids produced under this approach and suppliers submitted bids to ensure this is the case.

Some stakeholders question the need to limit additional energy transfers between EIM balancing authority areas when the market mitigates resources' bids in an exporting balancing authority area. They believe this may result in limiting EIM benefits obtained through energy transfers or anomalous market outcomes.

Management addressed the potential to reduce EIM benefits by leaving it up to each balancing authority area participating in the EIM to decide if the market limits its exports in the event of bid mitigation. Management also notes that without the feature to limit transfers in the event of bid mitigation, EIM participants may reduce the amount of supply and transmission capacity they make available to the ISO market. Management has not identified any significant market anomalies that will result from the feature, but commits to monitoring the feature to identify any if they occur.

Stakeholders generally support the provisions to increase the accuracy of the natural gas prices the ISO market uses to calculate default energy bids and commitment cost bid caps.

The ISO Market Surveillance Committee generally supports Management's proposal, stating that the benefits of Management's proposal outweigh any drawbacks. However, they suggest that, in order to include a remote bilateral trading hub in a default energy bid, suppliers should have to demonstrate their transmission rights are not already fully committed and cannot be sold if unused. They also believe Management's proposal to limit to the EIM's additional dispatch because of bid mitigation should be based on a balancing authority area's total flexible ramping product award.

In response to the Market Surveillance Committee's suggestion that suppliers should have to demonstrate their transmission rights to a remote location are not already fully committed, Management commits to incorporate this requirement in the tariff provisions implementing its proposal. Management believes suppliers have already presented information in this initiative's stakeholder process demonstrating there generally is no ability to bilaterally sell such unused transmission rights.

Management respectfully disagrees with the Market Surveillance Committee's suggestion that additional dispatch because of bid mitigation should be based on a balancing authority area's total flexible ramping product award, rather than first subtracting the balancing authority area's flexible ramping product requirement. Management believes the amount of energy a balancing authority area should have to export should be based on the results of the market at suppliers' submitted bid prices. Consequently, Management does not believe it is appropriate for the market to dispatch a balancing authority area to export more energy at mitigated bid prices than it originally dispatched as flexible ramping exports at the supplier's submitted bid prices.

CONCLUSION

Management requests the EIM Governing Body approve the portion of Management's proposal that is under its primary approval authority, which is Management's proposal for the optional feature to limit the EIM from dispatching additional energy from resources in balancing authority areas outside of the ISO in the event of bid mitigation. This proposal is only applicable to balancing authority areas in the EIM outside of the ISO balancing authority area. This proposal will provide additional incentives for EIM participants to make supply and transmission available to the EIM by limiting resource dispatches to export power only because the market mitigated bid prices. Management also requests the EIM Governing Body provide advisory input to the ISO Board of Governors supporting the other proposed enhancements described in this memorandum.

Attachment F – CAISO Board of Governors Memorandum

Local Market Power Mitigation Enhancements

California Independent System Operator Corporation

Memorandum

To: ISO Board of Governors

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

Date: March 20, 2019

Re: **Decision on local market power mitigation enhancements proposal**

This memorandum requires Board action.

EXECUTIVE SUMMARY

Management proposes several market enhancements to address market participant concerns that the ISO market's current market power mitigation process can result in the dispatch of resources at prices below their costs. This issue is particularly acute in the Western Energy Imbalance Market because of the Northwest's numerous hydro resources that have opportunity costs for energy sales because of their water limitations. Suppliers operating these resources may have disincentives to offer these needed flexible hydro resources to the EIM if they cannot reflect their costs.

First, Management proposes to create a standard default energy bid for hydro resources. The ISO's market power mitigation process reduces a market participant's submitted energy bid to a resource's default energy bid, calculated by the ISO, in the event it detects market power. Default energy bids are intended to reflect a resource's actual marginal costs of energy. Management proposes a new option for default energy bids specifically designed for hydro resources that better estimates these resources' actual costs, which typically consist of opportunity costs reflecting their limited water availability. Today, the ISO typically calculates default energy bids for hydro resources using formulas developed through confidential individual negotiations under negotiated default energy bid provisions. Market participants state that the current default energy bid formulas do not always account for the many frequently changing factors affecting water availability and can fail to account for the true value of their stored water.

Management's proposed hydro default energy bid accounts for the variability in the many factors affecting water availability and for market participants' ability to make bilateral sales of energy from these resources at a different location than the resource. This component is particularly important for suppliers that participate in the bilateral energy market in addition to the EIM. This standard hydro resource default energy bid provides the overall market with transparency into these resources' default energy bids and provides a standard starting point for any hydro resource negotiated default energy bids.

Second, Management proposes enhancements to the ISO's market power mitigation process to limit instances of resources being dispatched for additional energy only because the market power mitigation process mitigated the supplier's submitted bid to a resource's default energy bid.

These enhancements to the market power mitigation process include a proposal to limit the EIM from dispatching additional energy from resources in balancing authority areas outside of the ISO under certain bid mitigation circumstances. This element falls under the EIM Governing Body's primary decisional authority as it applies to balancing authority areas other than the ISO.

The default energy bid and market power mitigation process enhancements described above are particularly important to encourage participation in the voluntary EIM. It is important to ensure that the market dispatches hydro resources based on their actual costs so that suppliers are encouraged to make these valuable, clean flexible resources available to the ISO market. Not only do hydro resources provide carbon-free energy, but they are also valuable in managing the variability of other renewable resources.

Regarding gas-fired resources, Management also proposes enhancements that will allow the ISO market to use more up-to-date natural gas cost information to calculate default energy bids and commitment cost bid caps. Management's proposed enhancements modify an approach the ISO Board of Governors approved last year but Management has not yet filed with the Federal Energy Regulatory Commission.[1]

Finally, Management proposes to amend the listed natural gas price indices to reflect that the names of these indices have changed.

Management proposes the following motion:

> ***Moved, that the ISO Board of Governors approves the local market power mitigation enhancements proposal described in the memorandum dated March 20, 2019; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposal described in the memorandum, including any filings that implement the overarching initiative policy but contain discrete revisions to incorporate Commission guidance in any initial ruling on the proposed tariff amendment.***

[1] Management has not yet filed to implement the changes approved by the Board of Governors because it delayed implementation until Fall 2019.

Management presented this local market power mitigation proposal to the EIM Governing Body on March 12, 2019. The EIM Governing Body approved Management's proposal to limit the EIM from dispatching additional energy from resources in balancing authority areas outside of the ISO under certain bid mitigation circumstances. This element of Management's proposal is on the ISO Board of Governor's consent agenda. The EIM Governing Body will also be providing advisory input to the Board regarding the remaining elements of this proposal.

PROPOSAL

The following sections describe Management's proposal.

Hydro resource default energy bid

Management proposes to create a new default energy bid category specific to hydro resources with water storage. Management's proposed hydro resource default energy bid provides a reasonable estimate of hydro resources' opportunity costs due to their water availability limitations. This design acknowledges that the ISO cannot precisely determine a hydro resource's available water supply and attempting to do so could interfere with suppliers' operation of their water systems.

Hydro resources with a limited water supply have opportunity costs because they can only produce a limited amount of energy over a given time period. This opportunity cost represents the revenue a resource would receive if it conserves its water supply so that it can produce energy when prices are highest and energy is most valuable to the system. For example, if a resource only has enough water to produce energy during one month of the year, and energy prices in the highest-priced month are $75/MWh, the resource would have a $75/MWh opportunity cost.

There is not an existing standard default energy bid option to account for hydro resources' opportunity costs. Accounting for opportunity costs currently requires suppliers and the ISO to agree on a negotiated default energy bid, which has been problematic for many suppliers because the current default energy bid negotiation process has not resulted in default energy bids that accurately account for the value of their stored water.

Market participants have stated that there is a high degree of subjectivity in interpreting the output of the models that they use to calculate the water available for energy generation each day and their resources' resultant opportunity costs. They have explained that these models are complex because they estimate water availability based on many factors that affect both reservoir inflows and outflows. These can include weather, upstream and downstream conditions including the status of other reservoirs in a hydro system, and legal restrictions and obligations such as flow restrictions due to wildlife and other water use considerations. They have also stated that the amount of water they have available to support offers for energy to the EIM can also depend on their own electrical load they have to serve each day.

Because of these factors, the amount of water they have available to offer energy to the ISO market, including the EIM, can vary day-to-day, and even within the day, which means their opportunity costs can be highly subjective because they cannot be precisely calculated even with complex models. This can make it impractical to calculate a specific hydro resource's opportunity cost with a high degree of precision, even using a negotiated default energy bid. Consequently, Management proposes a standard hydro default energy bid that approximates a resource's opportunity costs by considering current gas prices and the resource's water storage horizon. This approach does not attempt to precisely model each resource's operation, but is rather based on the typical operation of a typical hydro resource.

A hydro resource's opportunity costs should also reflect the supplier's ability to make bilateral energy sales outside of the ISO market at other locations besides the resource's location. This would be the case if the supplier has Open Access Transmission Tariff rights to transmission from the resource's location to a different geographic location where it makes sales. The opportunity cost would reflect the sales price at the different geographic location. This issue is particularly acute in the EIM because EIM participants often sell energy from their hydro resources outside of their respective balancing authority areas. Management's proposed hydro resource default energy bid also reflects this opportunity cost.

Management proposes that the hydro default energy bid for a resource be calculated each day as the highest of the following three components:

- Short-term: this component reflects a hydro resource's opportunity costs due to short-term water availability limitations, ensuring the ISO market does not dispatch a hydro resource too often on any particular day. Even if a hydro resource has long-term water storage, it may have a limited amount of water available over the day on some or all days.

- Long-term/geographical: this component reflects a hydro resource's opportunity costs due to long-term water storage or the supplier's ability to make sales at another geographic location. This component ensures the ISO market will not dispatch a hydro resource conserving its water if energy prices are anticipated to be higher in a future month or are higher in the bilateral market at another geographic location.

- Gas floor: this component accounts for the supplier's energy replacement costs if the ISO market's dispatch exhausts a resource's short-term water availability. It also helps ensure the ISO market does not dispatch a hydro resource such that it exceeds its short-term water availability limitations in the event real-time energy prices are significantly higher than the day-ahead index used by the short-term component.

The hydro resource default energy bid uses the highest of these three components, which represents the limitations that are applicable on a particular day. For example, if the short-term component is highest, then energy prices are high on that day and the short-term component should set the level of the default energy bid so that the ISO market respects the resources' short-term limitations.

The short-term component approximates a resource's short-term opportunity costs based on anticipated energy prices ranging from the next day to the next month. Management proposes to set the default energy bid at a high enough price so that the ISO real-time market does not dispatch the resource more than four hours per day. Market participants generally came to a consensus that four hours per day represents a reasonable approximation of most hydro resources' short-term water limitations. The market will calculate this price using the higher of the day-ahead, balance of month, or upcoming month energy prices from published bilateral market energy price indices. These prices will be from a fixed trading hub for each resource that is most representative of its EIM prices. The short-term component is then determined by increasing the price by a multiplier designed to limit the market dispatch of most hydro resources to no more than four hours per day.[2]

The long-term/geographical component uses the higher of day-ahead, balance of month, or upcoming month energy prices looking out for the number of months equal to the hydro resource's storage horizon. A resource's storage horizon will be the number of months, up to 12, between the times the hydro resource's water reservoir is historically at peak levels. This is the maximum amount of time that using water to produce energy affects a hydro resource's ability to produce energy in the future.

The gas floor component calculates the price of energy from a gas resource based on the natural gas published index price for the hydro resource's location and based on a typical natural gas-fired turbine generator's fuel consumption.

Limit dispatch at mitigated bid prices

Currently, the ISO market may dispatch a resource to provide energy when the resource appears economic because the market power mitigation process reduced the supplier's submitted bid price to a resource's default energy bid. Even with the proposed hydro default energy bid, there is the potential that the default energy bid may not fully account for a supplier's costs. Consequently, Management proposes two enhancements that will reduce the frequency with which the EIM dispatches resources because it reduced the supplier's submitted bid to the resource's default energy bid. The first of these enhancements falls under the EIM Governing Body's primary decisional authority and was approved by the EIM Governing Body on March 12, 2019.[3]

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[2] Based on current market conditions the multiplier is currently 1.4.

[3] Background on that element can be found in Management's March 5, 2019 memo to the EIM Governing Body https://www.westerneim.com/Documents/DecisionsLocalMarketPowerMitigationEnhancementsProposal-Memo-Mar2019.pdf

The second of these enhancements will prevent the ISO market from dispatching a resource to export power from a transmission-constrained region at mitigated bid prices only because the market detected market power when power was being imported to the region in an earlier market interval. These regions can include EIM balancing authority areas or other transmission-constrained regions, including within the ISO balancing authority area.

This situation is undesirable because the ISO market should not force a supplier to sell energy at mitigated bid prices in market intervals in which it does not detect market power. These enhancements will prevent this result by ensuring mitigated bid prices are at least as high as competitive prices outside of the region and by preventing the market from automatically mitigating a resource’s energy bids in subsequent real-time market intervals when it detects market power in a single interval.

Natural gas prices

Management also proposes enhancements to allow the ISO market to use more up-to-date natural gas cost information to calculate default energy bids and commitment cost bid caps. These enhancements are focused on gas-fired resources but are also applicable to the gas floor component of the hydro default energy bid.

The ISO market calculates default energy bids for gas-fired resources based on published natural gas price indices. A supplier’s actual gas costs may be higher than a published price if there is gas price volatility or if gas prices at the standard trading hubs that the published indices are based on are not representative of the prices at a particular resource’s location.

Under enhancements approved by the ISO Board of Governors in 2018, but not yet filed with the Federal Energy Regulatory Commission, suppliers would be able to request that the ISO calculate a resource’s default energy bid or commitment cost bid cap using the supplier’s actual gas costs if they are greater than the published index price. This approach would be allowed to the extent the price change was no greater than 25 percent more than the published index price for Mondays and days after holidays and no greater than 10 percent more than the published index price for other days.

Management proposes to modify the above-described approach. For the real-time market, Management proposes that rather than using the fixed criteria of 25 percent and 10 percent more than the published index price, the ISO will approve supplier requests based on a gas price index published on the morning of the real-time market, and based on requests from suppliers for the ISO to review their gas procurement costs for a specific resource. These provisions would also extend to the day-ahead market.

The updated gas prices would also be used to calculate the gas floor component of the hydro resource default energy bids.

Management also proposes to change the gas price index the ISO market uses to calculate default energy bids and commitment cost bid caps for Mondays. The market currently uses a gas price index for Mondays based on purchasing gas in a package on Friday for delivery over the weekend and on Monday. However, suppliers can purchase gas separately for Mondays when demand for gas is especially higher than over the weekend. The gas price index publishers publish a separate Monday gas price when this occurs. Management proposes to use this Monday gas price when it is published and represents sufficiently liquid trading.

Finally, Management proposes to amend the natural gas price indices listed in the tariff to reflect that the names of these indices have changed.

STAKEHOLDER POSITIONS

Stakeholders generally strongly support Management's proposed hydro default energy bid, particularly those that operate hydro resources in balancing areas participating in the EIM outside of the ISO balancing authority area. They state that the proposed hydro default energy bid provides a reasonable estimation of hydro resources' opportunity costs and will prevent the ISO market's dispatch from interfering with their water management.

The ISO Department of Market Monitoring agrees with the general framework of the hydro default energy bid, but does not believe that the hydro default energy bid should incorporate prices at different locations than a resource's location. They state that this pricing aspect inappropriately mixes the value of transmission with energy prices. For example, for the ISO balancing authority area, the current ISO market nodal energy prices, reflecting energy value, are separate from transmission's value that the congestion revenue rights market reflects.

While Management agrees DMM's observation is true at a theoretical level, in practice not allowing suppliers to reflect the opportunity cost of sales at other locations would interfere with the bilateral market. Suppliers point out their energy sales for deliveries at locations other than their hydro resource's location are nonetheless linked to the output of that hydro resource. This is because energy purchasers often specifically purchase energy produced by hydro resources to meet carbon reduction goals. In addition, suppliers point out that in practice, in the bilateral market, transmission's value cannot be separated from energy's value because there is not a robust market for their unused transmission.

The ISO Department of Market Monitoring also opposes Management's proposal to base hydro resources' default energy bids on a storage horizon value that does not change throughout the year. They maintain this approach can inappropriately inflate a resource's default energy bid in the later months of the year when the horizon could extend past the winter months when a reservoir could no longer store water and the operator would instead have to let it flow through the reservoir.

Management believes its proposal for using a fixed storage horizon reasonably balances the practical considerations of implementation complexity and the difficulties in precisely modeling every hydro resource's operation. For example, there is the possibility that some hydro resources do not face maximum storage limitations each year. In addition, any default energy bid price inflation due to using a fixed storage horizon will be small and market power is not as much of a concern in the later months of the year as it is in other months. Nevertheless, Management will monitor default energy bids produced under this approach and suppliers submitted bids to ensure this is the case.

Stakeholders generally support the provisions to increase the accuracy of the natural gas prices the ISO market uses to calculate default energy bids and commitment cost bid caps.

The ISO Market Surveillance Committee generally supports Management's proposal, stating that the benefits of Management's proposal outweigh any drawbacks. However, they suggest that, in order to include a remote bilateral trading hub in a default energy bid, suppliers should have to demonstrate their transmission rights are not already fully committed and cannot be sold if unused.

In response to the Market Surveillance Committee's suggestion that suppliers should have to demonstrate their transmission rights to a remote location are not already fully committed, Management commits to incorporate this requirement in the tariff provisions implementing its proposal. Management believes suppliers have already presented information in this initiative's stakeholder process demonstrating there generally is no ability to bilaterally sell such unused transmission rights.

Attachment A presents a summary of stakeholder comments and Management's responses.

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

CONCLUSION

Management requests the Board of Governors approve this proposal. The local market power mitigation enhancements proposal will encourage flexible resources to participate in the ISO and EIM market and improve the accuracy of the ISO's market power mitigation provisions, which will lead to more efficient real-time market price formation.

Attachment G – Draft Final Proposal

Local Market Power Mitigation Enhancements

California Independent System Operator Corporation

Local Market Power Mitigation Enhancements

Draft Final Proposal (Updated)

January 31, 2019

Prepared by
Brittany Dean
Elliott Nethercutt
Danielle Tavel
Donald Tretheway
Gabe Murtaugh

California Independent System Operator

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Version History

Date	Revision
1/16/2019	Initial release
1/31/2019	Section 3: Modified the EIM Classification of this initiative with four of the five elements falling within the EIM Governing Body's advisory to the Board. The element to limit economic displacement consists of a proposed rule that is uniquely available to EIM balancing authorities. Accordingly, this element falls within the EIM Governing Body's primary authority.
	Section 4.2: Revised responses to stakeholder comments for the use the use of the long term / geographic component of the hydro default energy bid.
	Section 4.4: Revised responses to stakeholder comments to align with the updated EIM Classification (Section 3).
	Section 6.2: Modified terms the default energy bid for hydro resources to represent a short term component and a long term / geographic component.
	Section 6.4: Specified that ICE's Monday-only index will be used for gas prices for the real-time market when it is available.
	Made minor modifications and corrections throughout the document.

1. Changes from the Revised Straw Proposal

The CAISO appreciates the written stakeholder comments received in response to the revised straw proposal and the November 28, 2018 stakeholder call. In response to this input, this draft final proposal includes the following modifications from the revised straw proposal:

- **Prevention of Economic Displacement between Mitigated Balancing Authority Areas (BAAs)**: The CAISO modified the proposed rule to limit transfers between balancing authority area's (BAA) during mitigated intervals. The proposed rule in this draft final proposal will limit BAA net exports to the greater of the quantity of base transfers or pre-mitigation transfers, plus the total of the flexible ramping-up awards in excess of the BAAs flexible ramping up requirement (reflecting the EIM design principle that ramping capability is shared between EIM balancing areas). This proposed rule will be optional, based on the preference of the EIM BAA.
- **Hydro Resource Default Energy Bid**: The CAISO has updated the hydro default energy bid. The revised calculation includes a gas floor price (based on the average heat rate of a gas peaking unit), a locational floor (with an updated multiplier of 1.40), and a long term / geographic floor (representing opportunities to sell energy in other geographic areas and future time periods). Additional analysis to support these changes has also been included within this draft final proposal.
- **Reference Level Adjustment – Reasonableness Thresholds and Hydro Resource Default Energy Bid**: The CAISO updated its proposed process for updating same-day gas prices used for real-time market reasonableness thresholds to include provisions for manual reference level consultations and/or basing them on same-day gas trading observed on the Intercontinental Continental Exchange (ICE). Additionally, the CAISO is proposing a process to update the gas floor default energy bid component for resources that opt to use the hydro default energy bid.

2. Introduction

The CAISO's local market power mitigation rules include measures to mitigate a supplier's energy bid when local market power exists. EIM participants have identified cases when mitigation results in the market dispatching their hydro resources at prices below their marginal costs and often in quantities greater than needed to resolve market power. In addition, market participants, including those with resources in the CAISO BAA, have raised concerns related to recent real-time gas price volatility.

This paper presents the CAISO's draft final proposal for several enhancements to address these concerns, including refinements to the reference level adjustment process recently developed as part of the *Commitment Cost and Default Energy Bid Enhancements* (CCDEBE) initiative.[1] The CAISO proposes five enhancements in this initiative, as detailed below.

Mitigation Process Enhancements

Market participants have expressed concerns about two situations that can arise because of the market power mitigation process in the CAISO's real time-market: (1) "flow reversal," and (2) "economic displacement."[2]

Flow reversal occurs in cases when an EIM BAA or group of BAAs are import-constrained in a market interval, triggering mitigation, which results in the BAA shifting to export at mitigated prices in the subsequent market run. This situation can result in mitigating bids for resources' exported power that does not have market power. The CAISO proposes to address this issue by changing the market rules so that the market updates the price used in mitigation in each interval based on that interval's competitive locational marginal price and no longer extending mitigation beyond the interval being tested. These modifications will largely eliminate cases of flow reversal and improve the market power mitigation process.

Economic displacement is similar to flow reversal in that it occurs when a group of BAAs are import-constrained in the real-time market's market power mitigation run. Economic displacement can occur when the real-time market increases transfers from one BAA to another, relative to its market power mitigation run, because they become more economic when resources' bids are mitigated. Although market power mitigation should protect against market power within the combined BAA "bubble" with import constraints, it is not appropriate to export greater quantities at the mitigated price than what was originally scheduled in the market power mitigation run.

The CAISO proposes to address this issue by limiting transfers between EIM BAAs in a manner that recognizes the EIM design principle that EIM BAAs share a portion of their ramping capability, thus reducing each EIM BAA's flexible ramping requirement. Accordingly, the CAISO proposes to limit transfers from mitigated BAA when exporting to the greater of: (1) the pre-mitigation transfer quantity, or (2) the base transfer quantity, plus the sum of the flexible ramping up awards determined in the market power mitigation run in excess of the BAA's flexible ramping up requirement, as adjusted for EIM diversity. This proposed rule would be available for all BAAs in the EIM that elect to use it.

[1] http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCosts__DefaultEnergyBidEnhancements.aspx.
[2] These situations are not applicable to resources within the CAISO BAA because mitigation for a congested EIM transfer constraint is only triggered when there is congestion between an EIM BAA or group of BAAs and the CAISO BAA.

Hydro Default Energy Bid

CAISO's existing methodologies for calculating default energy bids can inaccurately reflect the actual costs for hydro resources with storage. The mitigation process enhancements described above will address situations when the market dispatches resources in quantities greater than what is needed to resolve market power. However, there will still be cases when a resource's default energy bid is applied. To address stakeholder concerns, the CAISO proposes an additional default energy bid option for hydro resources with storage. This option will be available to qualifying hydro resources located in EIM and the CAISO BAAs.

Reference Level Adjustment

The CAISO proposes changes to its reference level adjustment process recently developed in its *Commitment Cost and Default Energy Bid Enhancements* (CCDEDE) initiative.[3] The CAISO proposes to update reasonableness thresholds based on same-day gas trading information it observes on ICE and/or on manual requests received from suppliers. The CAISO also proposes to update the gas price floor component of hydro default energy bids within an applicable fuel region if these requests indicate the gas price changes are applicable to an entire fuel region.

The CAISO also proposes when calculating day-ahead and real-time market reference levels to include gas prices based on a Monday-only index (when available), as reported by ICE.

Finally, the CAISO proposes to update the gas floor component of hydro default energy bids based on same-day gas trading and manual requests for reference level adjustments.

Gas Price Indices

The CAISO proposes consolidating the published gas-price indices that the real-time market uses to calculate gas-fired resources' reference levels.

3. EIM Decisional Classification

This initiative includes five elements. The first and second elements involve enhancements to two of CAISO's existing bid mitigation processes. The third introduces a new default energy bid option for hydro resources. The fourth element modifies the reference level adjustment process for gas resources. The fifth updates the CAISO tariff to reflect current gas publications for the real-time market.

[3] "Reference levels" are default energy bids and commitment cost bid caps that are based on the CAISO's calculations of a resource's costs.

The second element, the limitation of transfers in the bid mitigation process falls within the EIM Governing Body's primary authority, because it proposes changes to market rules that are EIM-specific. It would introduce a rule to prevent economic displacement by limiting transfers between mitigated regions of EIM BAAs. This rule will be optional for each EIM BAA, as determined by the appropriate authority.

All remaining elements fall within the EIM Governing Body's advisory role, because they propose to change market rules that apply uniformly throughout both the CAISO and EIM BAAs. Specifically, the first element would modify mitigated bid price calculations used in market power mitigation based on each interval's competitive locational marginal price and would modify the rules for extending mitigation beyond the interval being tested. The third element establishes a new default energy bid designed to approximate the opportunity costs for hydro resources with storage capability. This enhancement would apply uniformly to hydro resources in both the CAISO and EIM. The fourth element includes enhancements to the reference level adjustment process used by the real-time market and makes changes to the gas price index used to calculate reference levels in both the day-ahead and real-time markets. These changes would apply uniformly in both the CAISO and EIM BAAs. The fifth and final element introduces updates to the CAISO tariff to reflect current gas publications for the entire real-time market.

The CAISO's initial draft final proposal, posted January 16, stated that the second element, which is within the EIM Governing Body's primary authority, must be approved or rejected together with the first element. At the time, the CAISO believed incorrectly that both the flow reversal and transfer limitation rules must be implemented at the same time. After further review, the CAISO has determined that this is not the case, and that the second element is severable from all of the remaining elements.

Accordingly, the proposed decisional classification is that the EIM Governing Body will have primary authority over the second element, and an advisory role over the remaining elements.

Stakeholders are encouraged to submit remaining input regarding the responses to the updated proposed EIM classification of this initiative in their written comments—particularly if there are any questions or concerns.

4. Stakeholder Comments

Following the posting of the revised straw proposal on November 16, 2018, the CAISO held a call on November 28, 2018 to review and further discuss the latest updates to various elements of the initiative. Stakeholders submitted comments on the revised straw proposal on December 7, 2018. These comments are summarized below.

4.1 Mitigation Process Enhancements

Prevention of Flow Reversal

Bonneville Power Administration (Bonneville), PacifiCorp, Public Generating Pool (PGP), Powerex, Southern California Edison, and Six Cities support the proposed mitigation framework enhancements to address flow reversal, as introduced by the CAISO in the straw proposal for this initiative.[4] The Western Power Trading Forum (WPTF), Seattle City Light (SLC) also support the approach, but request additional analysis after implementation to evaluate how effective the nominal adder is for preventing cases of flow reversal. The CAISO anticipates it can fulfil this request through the Market Performance and Planning Forum at the appropriate time following implementation.[5]

NV Energy supports the updated design principle with a recommendation that the CAISO should monitor and identify potential adverse outcomes occur following implementation. NV Energy does not agree that there is a necessity for a competitive LMP adder in conjunction with the other market mitigation proposals in this initiative. If an adder is ultimately implemented, NV Energy recommends the inclusion of a price cap for the nominal price. This cap should be specified in the tariff so that stakeholders can identify and consider any potential issues from the magnitude of the adder.

The CAISO emphasizes that the proposed nominal adder will be as minimal as possible and tailored specifically to only create price separation between the competitive local marginal price and the default energy bid price, without impacts to market schedules or prices. With regard to a price cap on this proposed nominal adder, the CAISO proposes an approach similar to the EIM transfer cost.[6] The CAISO will specify a maximum adder of $0.10 in the tariff, and include the actual adder necessary to meet the objectives of the rule in the business practice manual which is planned to be $0.001 for the price adder.

The Department of Market Monitoring (DMM) supports eliminating the extension of mitigation in one 15-minute interval to the remaining 15-minute intervals in the hour. DMM also supports eliminating the extension of mitigation in one 5-minute interval to the remaining 5-minute intervals. However, DMM raises concerns about eliminating the extension of mitigation in the 15-minute market to the corresponding three 5-minute market intervals. DMM is concerned that a potential consequence of this change could result in a resource running at its day-ahead schedule, but forfeiting revenue to the CAISO in real time. DMM maintains the relative advantages of the current policy versus the proposed policy may differ by market participant and by resource. DMM

[4] http://www.caiso.com/Documents/IssuePaperandStrawProposal-LocalMarketPowerMitigationEnhancements.pdf.
[5] http://www.caiso.com/informed/Pages/MeetingsEvents/UserGroupsRecurringMeetings/Default.aspx.
[6] http://www.caiso.com/Documents/ConformedTariff-asof-Nov15-2018.pdf. See Section 29.17 EIM Transmission System (p. 729).

recommends that the CAISO solicit and consider additional stakeholder feedback on this issue.

The CAISO acknowledges that there could be cases when an offer price is mitigated to a lower level in the 15-minute market than in the three 5-minute market. If this occurs, the seller could have to buy back its 15-minute market schedule at the real time dispatch (RTD) market price. As the MSC observed at the August, 2018 meeting, the removal of extension of mitigation in the 5-minute real-time dispatch when in the 15-minute market mitigation is triggered is the economically efficient outcome. This does results in an buying back at the RTD price, but "this outcome would be preferable to the outcome in which the resource is dispatched based on a mitigated price that is lower than the competitive LMP price…"[7] This is because the resource loses less revenue by buying back than selling at the mitigated price.

Economic Displacement between Mitigated Balancing Authority Areas (BAAs)

Bonneville Power Administration (Bonneville), Idaho Power Company, PacifiCorp, Powerex, and WPTF agree with the updated approach provided by the CAISO in the revised straw proposal.

PGP also supports the updated approach, but requests that the CAISO consider third parties with participating resources within an EIM BAA. These entities may not want additional transfers to a neighboring BAA based on mitigated bids even if the BAA in which their resources are located decides not to use the proposed functionality to limit transfers to that scheduled in a market power mitigation run. Therefore, PGP requests the CAISO consider an approach that will allow these resource owners to determine whether or not to allow mitigated bids to result in additional transfers. However, that would not be feasible because the functionality must apply at the BAA level and not to individual resources. This is because all resources within a BAA must be mitigated when the BAA becomes import constraint because each resource has the same effect on the net transfers of the BAA.

PG&E and PGE share concerns that this proposed rule may be unnecessary, since other elements of this initiative will adequately address mitigation framework issues. PGE requests that the CAISO clarify how often an entity could update a BAA's application of this rule. The CAISO has proposed that the transfer limitation rule will be designated in the CAISO's Master File by the appropriate EIM entity for a given BAA.

SCL asks that the CAISO explore introducing a tool that can identify economic displacement in real-time, enabling entities to respond with changing market conditions. In order to accomplish this, the CAISO would need to develop a tool to compare market power mitigation schedules for each BAA with final market results for each interval, with results published to OASIS. The CAISO believes this is not feasible, since the election

[7] See slide 23: http://www.caiso.com/Documents/Presentation-EIMMarketPowerMitigationDiscussion-FTI-Consulting-Aug7_2018.pdf

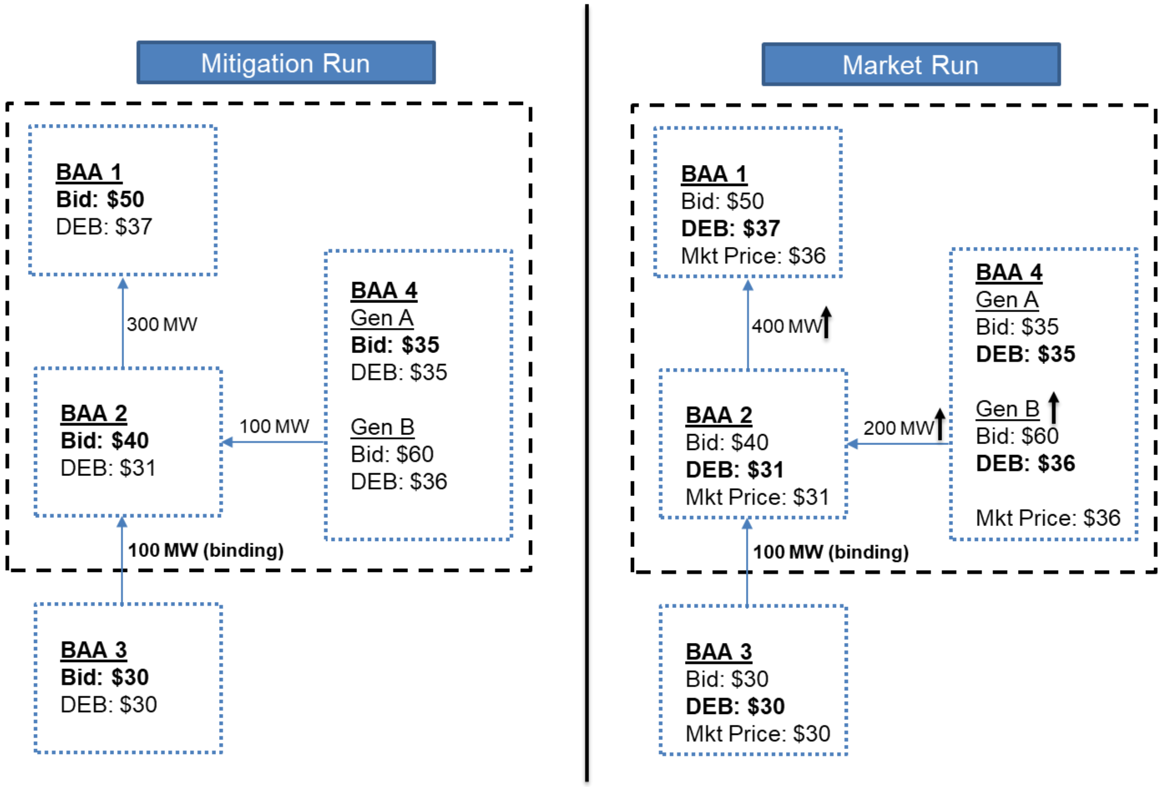
to enforce the transfer limitation rule must be implemented in the Master File, outside of the real-time market.

PG&E requests additional analysis on the implications of the congestion rents being returned to the source EIM BAA when economic displacement is being resolved. The allocation of congestion revenues is consistent with existing EIM principle that congestion revenues are returned to the BAA in which the constraint is located. The net transfer out constraint is located within the source BAA.

The Department of Market Monitoring (DMM) raised concerns related to the establishment of schedules in two different runs with different sets of inputs and prices. DMM is concerned this could lead to potentially unintended and undesirable outcomes, including prices that are inconsistent with the CAISO's dispatch instructions and incentives for resources to deviate from dispatch or to not bid their true marginal costs. DMM presented an example to illustrate these concerns. The CAISO has included a modified version of this example below.

In this example, there are four BAAs, each with a bid and a default energy bid for a marginal resource. Given the bids, the mitigation run will schedule 100 MW flowing from BAA 3 (CAISO) to BAA 2, and 100 MW flowing BAA 4 to BAA 2, and 300 MW flowing from BAA 2 into BAA 1. We assume load and base schedules in each area are such that with this dispatch, prices in each BAA will be at the marginal bid in that BAA. BAA 2 enforces the proposed rule to limit net exports in the market run to the pre-mitigation run quantities. In this example, those net exports are 100MW (300 MW transfer out, less 200 MW transfer in). The figure below illustrates this example:

Enforcing Transfer Limitations with Four Balancing Authority Areas (BAAs)



With the proposed rule enforced by BAA 2, resources will be protected from additional economic displacement, beyond the 100 MW offered in the mitigation run. As a result, transfers increase from BAA 2 to BAA 1 from 300 MW to 400 MW, while imports from BAA 4 increase from 100 MW to 200 MW. Thus, the net exports remain at 100 MW. In the absence of the proposed transfer limitation rule, BAA 2 could manually withhold transfer capability to prevent additional wheels to occur (because there would be no ETSRs to support the energy flow). Limiting the ETSRs to minimize exposure to selling at mitigated prices (*i.e.*, reducing economic displacement) would negatively impact other BAAs in two ways. First, the result would reduce available transfer capability, which increases the probability of binding transfers (triggering additional mitigation). It would also prevent the ability to wheel energy in accordance with prices between BAAs within the bubble. The proposed rule will enable BAA 4 to sell to BAA 1, while preventing economic displacement by using resources in BAA 2.

The CAISO acknowledges that there is an appearance that energy would flow from an area with higher price to an area with lower prices. In actuality, lower price energy is supporting a higher priced BAA because the energy wheels through BAA 2. This allows BAA 4 to sell to BAA 1 at $36, which sets the market price below the $37 default energy bid that load in BAA 1 would otherwise be charged. BAA 4 can avoid this outcome if it enables the proposed rule, which would then limit the export from BAA 4 to the pre-mitigated export of 100MW.

DMM's concern that the rule will still result in a resource selling below their bid is also an acceptable outcome when mitigation occurs. This rule benefits resources by limiting the quantity of sales at mitigated prices, thus limiting the impacts of economic displacement. DMM's concern regarding congestion rents have been explained within this proposal. All congestion rents will be allocated to the BAA where the constraint is located. Accordingly, in the above example, $5 of congestion rents will be paid to BAA 2 (since the price in BAA 2 is $31 and the price in BAA 1 is $36, resulting in a $5 price difference).

Finally, DMM requests clarification on the allocation of congestion rents between limited transfers from the mitigation run of a 15-minute interval and the transfer capability that the CAISO proposes to use in the corresponding 5-minute interval. If transfers are not limited in the 5-minute market, DMM is concerned this inconsistency could potentially incentivize strategic bidding behavior to leverage differences between the two markets.

The CAISO believes that since all real-time bids are submitted at T-75, the same bids are used in the 15-minute market and in the RTD. Therefore, there isn't an opportunity to implement a bidding strategy knowing that in one market (15-minute market) the rule has been triggered, and may not be triggered in a subsequent market (RTD).

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 noncompetitive outcomes.

As discussed above, the amount of transmission that is made available to support EIM transfers out of the EIM BAA is voluntary. As discussed above, the amount of transmission that is made available to support EIM transfers out of the EIM BAA is voluntary. Without the economic displacement rule, an EIM entity may seek to minimize the amount of energy that is sold to other EIM BAA's at mitigated prices by reducing transmission to support transfers. If this occurs, the EIM would be harmed more since wheel through transactions will also be limited because transmission is not available.

4.2 Hydro Resource Default Energy Bid

The CAISO received comments on the proposed default energy bid in the revised straw proposal. The CAISO modified the proposed default energy bid for hydro resources with storage in this draft final proposal. The proposal addresses much of the feedback received from stakeholders through the last iteration of the policy initiative process. Changes include consideration for opportunity costs for replacement energy from peaking gas resources, futures pricing over determined storage horizons, and sales opportunities at multiple price hubs. Below is a summary of responses to all stakeholder feedback:

Geographic Consideration

Several stakeholders – including Bonneville, Seattle City Light, Public Generating Pool, Idaho Power Company, Chelan, and the National Hydropower Association (NHA) – endorse expanding the allowance to elect multiple trading hubs to all hydropower resources – including those with short-term storage capability (less than four months). The CAISO has included multiple trading hubs for day-ahead and multiple monthly futures prices for all hydro resources in this draft final proposal. The default energy bid crafted in this draft final proposal maintains a limited group of potential locations that may be included in the calculations for the geographic component of the default energy bid. If 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. This proposal outlines that the maximum value of these futures prices is used in the default energy bid calculation, and this is consistent with a calculations for a resource's opportunity costs.

In addition to including multiple geographic hubs for all resources, the Idaho Power Company also suggests that the CAISO should not require firm transmission to be directly tied to the applicable geographic hub. The CAISO does not envision that firm transmission necessarily be demonstrated to directly sink at a geographic hub. The entity may also sink at an electrically similar geographic hub for consideration.

The NHA indicates resources with very short-term storage may face even greater operational challenges and energy availability limitations than resources with larger reservoirs and greater storage capability. Accordingly, the NHA recommends the CAISO use a separate formula for short-term storage resources that recognizes and incorporates the highest value hours over a 24-hour period. The CAISO responds by emphasizing that if this hydro default energy bid is insufficient, these resources have the option to proceed with a negotiated default energy bid to capture the specific nuances of their resource. Additionally, these resource may opt to receive a *Commitment Cost Enhancements – Phase 3* opportunity cost adder.[8]

PG&E specifically requests that the highest price hub should be used in the long term / geographic floor. The CAISO's revised proposed hydro default energy bid in this draft final proposal includes the highest prices hub that a resource has firm transmission to for calculation of the long term / geographic floor component.

The Department of Market Monitoring highlights that the value of firm transmission is not appropriately accounted for. The CAISO maintains that hydro resources with the

[8] http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostEnhancements.aspx.

ability to deliver energy to a specific hub, using firm transmission rights, also have the ability to earn revenues on that energy equal to those hub prices. These prices should be considered when contemplating opportunity costs, and includes energy sold at futures prices as well as near-term agreements.

Energy produced and delivered from hydro facilities may not be equivalent to other energy produced by different fuel types that a resource owner may purchase locally and deliver to a different energy hub. In practice, hydro power, with zero greenhouse gas emissions, is not fungible with generic power purchased at hubs specifically because this generic energy is not necessarily produced without greenhouse gas emissions. This difference is specific to renewable energy sold at remote locations.

Additionally, it may not be practical for a seller to purchase power in individual hours to deliver on a sale at a remote hub as suggested by the Department of Market Monitoring. For example, a resource in the Northwest may contract to sell energy via firm transmission for a few hours during particular high heat summer days, but not for all hours of a multi-hour block that may be available for purchase from a local hub. Thus, the purchase of a multi-hour block of energy to sell during a few specific hours may force the seller to price exposure in the other non-contracted hours for which it has to sell the energy. Bilateral sales from hydro resources participating in EIM in practice is frequently associated with the output of a specific generator.

Including the opportunity cost to make future sales at a remote hub is particularly important for hydro resources located in the energy imbalance market areas that may make decisions to offer availability into the voluntary energy imbalance market or withhold participation to make bilateral sales based on other available opportunities. It is particularly import to have these resources in the energy imbalance market because of their operational flexibility that makes them valuable for integrating other renewable variable energy resources and because of hydro resources' own non-greenhouse gas emitting characteristic.

DMM further expresses concerns with the criteria used to determine if a resource owner has the ability to sell energy at a different hub. The CAISO emphasizes that the availability of transmission is necessary for a resource to sell energy at any location, either electrically close or distant. Through his proposal CAISO is requiring demonstration of long term firm transmission rights before considering distant hubs as a component of opportunity cost for any resource. There could be instances when the demonstrated firm transmission rights are no longer available, *i.e.*, rights are sold or allocated, and thus may not be appropriate to include as an opportunity cost, even though the ability to sell at these locations may have previously existed and would appropriate to include in previous opportunity costs. CAISO will require that firm transmission rights previously demonstrated to the CAISO for means of a hydro default energy bid and subsequently sold be reported so that these components of the related default energy bids calculations can be updated appropriately.

PGP further argues that entities should not be required to demonstrate the prior year of purchased monthly transmission rights. The CAISO responds by emphasizing that the demonstration of firm transmission rights should not be overly burdensome for resource owners, but still allow resource owners to demonstrate other opportunities that will be included in the default energy bid calculation. Generally, the CASIO expects that demonstrating firm transmission on an annual basis accompanied with information on firm transmission sold during the year, will be sufficient for this process. The CAISO also proposes to have the authority to audit and request confirmation of changes as necessary, which may include the request for a sworn statements and documentation, to ensure that scheduling coordinators comply with this requirement. The CAISO would recognize that some resource owners may purchase firm transmission in monthly markets, and would allow for such resource owners to also have access to these opportunity costs.

Gas Price Floor

Idaho Power Company, Bonneville, PGP, and Chelan also request that the CAISO use a peaking gas heat rate to establish the price floor. The default energy bid proposed in this draft final proposal includes a heat rate for a peaking gas resource, with a 110% multiplier. This default energy bid includes a proxy peaking natural gas resource that represents the opportunity cost for generating energy at the same location of the hydro resource. The heat rate specified for this natural gas resource is 11,176 Btu/KW-hr for an average gas turbine resource in 2017, as reported by the Energy Information Agency. The CAISO will specify the applicable heat rate in the business practices manuals and will updated it through the business practice manuals change management process.

Southern California Edison suggests that the gas price index should capture the highest gas price in the BAA. The CAISO believes that the gas price index for a hydro resource should reflect the gas index for a similarly located gas resource in the geographic area. Reference levels for gas resources are based on the weighted average gas price, not the highest gas price in an area.

Methodology for Establishing a Multiplier

Several stakeholders provided input on the proposed price floor multiplier. PGP, Southern California Edison, and Bonneville support the application of a consistent methodology for establishing a multiplier, which would be updated annually. PGP emphasized that this methodology should be updated by the CAISO on regular cadence with criterion applied consistently for short- and long-term storage resources. The default energy bid proposed in this draft final proposal consists of one set of criteria that will be used to determine the short term floor and the multiplier for all hydro resources, with the inclusion of multiple hubs. The CAISO recognizes the importance of this default energy bid and the need for it to generate acceptable values for hydro resource owners. At this time, the CAISO does not feel that it is necessary to re-evaluate the multiplier on an annual basis. However, if this default energy bid no longer meets the objectives outlined in this paper, the CAISO may reevaluate and assess if the multiplier is appropriate. This may be necessary as market conditions change in the EIM, as markets offered by the CAISO expands (such as the EDAM), and if there are significant changes in transmission availability for CAISO run markets. The CAISO will take necessary action if critical feedback from market participant submissions through the normal the customer service representative process is received in the future on this component of the initiative.

Bonneville specifically suggests using a target availability of 4 hours per day at 99% efficiency. SCL and Chelan further recommend a multiplier that would result in a dispatch efficiency of 99% of all hours (instead of 95%), claiming that the inefficient water depletion during the remaining 5% is problematic. SCL also suggests the CAISO consider using Powerdex[9] bilateral prices, instead of PacifiCorp West EIM prices.

The Idaho Power Company recommends the application of a 1.65 multiplier for the proposed hydro default energy bid. Although the CAISO is trying to identify a multiplier that will result in a sufficiently high default energy bids, some hydro resources bidding at those levels will not be dispatched beyond their potential available hydro output in the short-term. For the analysis, which is very similar to prior analysis, the CAISO targets specific daily availability limits and percent of intervals that a resource that actually had this availability would be dispatched less than this level, based on historic energy imbalance market price data.

WPTF requested that the CAISO consider making the proposed default energy bid available to any resource with opportunity costs – including run-of-river resources. Currently, the CAISO is only considering this default energy bid for hydro resources with storage. Hydro resources that have the ability to store water, run or not run at different times of the day, and respond to dispatch instructions from the CAISO, will have the ability to elect this proposed default energy bid. There are other default energy bid options available for resources that use other fuel types. WPTF also requested additional detail on how this proposed hydro default energy will function with opportunity cost adders. Resources that elect to use this default energy bid will not be eligible to apply for an opportunity cost adder in addition to the formulation used for this default energy bid. The resources would still be eligible for an opportunity cost adder if they elected a variable cost default energy bid. CAISO understands that certain hydro resources may have costs that are not covered by this default energy bid on some occasions. If this frequency occurs, such resources may elect to use an opportunity cost adder or negotiated default energy bid.

[9] http://www.powerdexindexes.com/.

There was considerable deliberation by the CAISO for the availability and efficiency values. The CAISO feedback with specific recommendations for values to use for analysis. In this draft final proposal the CAISO presents analysis that was conservative in nature and is recommending that a multiplier of 1.40 be applied to the short term floor. Although a 95% efficiency still may leave some days when a resource is dispatched inefficiently, a resource with these constraints and actual opportunity costs will not necessarily be dispatched inefficiently this frequently for two reasons: First, resources with market based rate authority may bid above default energy bids. This may cause resources to be dispatched less frequently and resources will only be dispatched inefficiently when market power mitigation is frequently triggered and competitive LMPs are calculated at values less than the default energy bid. Second, this analysis considers a resource that has no firm transmission to another location. If a resource owner can demonstrate firm transmission to another location, this will increase the default energy bid and reduce the frequency that the resource is dispatched. Finally, the analysis presented shows that there are conceivable opportunity costs that a resource could have which would dispatch a hydro resource inefficiently (*i.e.*, too frequently). 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.

Chelan requests that the CAISO complete analysis to determine the multiplier using hourly Powerex data. The analysis proposed by Chelan may be useful in determining the effectiveness of this default energy bid as the EIM continues to develop. CAISO included additional analysis, analogous to that performed for EIM areas, with Powerdex data. This analysis showed that a resource with 4 hours of availability to generate energy would be dispatched less than this amount more than 95% of days during the data reviewed.

Powerex requests that Alberta be included as a geographic hub. The CAISO has included Alberta in the list of available geographic hubs for the proposed default energy bid included in this draft final proposal. The Alberta hub will be available for entities that can demonstrate that the hub is robust enough to be used in these calculations. The CAISO is currently performing analysis to make this determination.

Additional Analysis and Information

Pacific Gas & Electric askes the CAISO to include a table in this proposal to illustrate the different default energy bid options available to hydro resources. The CAISO has included this table in the background section of this proposal. PG&E also requests the CAISO conduct analysis using mitigation frequencies for a specific resource. The CAISO does not believe the analysis to establish a default energy bid based on opportunity costs should consider the frequency of mitigation. Rather, a default energy bid based on a resource's opportunity cost should reflect the resource's actual opportunity costs.

NV Energy does not oppose changes to the default energy bid to reflect actual lost opportunity costs, but questions whether it is appropriate to compare lost opportunity costs to the bilateral market. NV Energy points out that the proposed default energy bid may not include opportunity costs in the default energy bid and requests a comparison to the proposed hydro default energy bid to the lost opportunity costs calculated in Phase 3 of the *Commitment Cost Enhancements* initiative. The CAISO believes that the objective of the adders in the *Commitment Cost Enhancements – Phase 3* initiative are to determine an adder to an existing bid that would allow a specific resource to be dispatched at exactly the amount of available energy that resource had, given projected future local energy prices. In cases of such a calculation the opportunity cost of selling to external bilateral markets is already implicitly considered and less than the value that the energy would be sold into the EIM. Practically, a resource owner may sell some hydro capacity into the residual markets and the EIM market. Capacity considered in analysis for a *Commitment Cost Enhancements – Phase 3* opportunity cost bid adder would only consider the energy sold in the EIM market, and not that being sold into the bilateral market. A resource owner may find selling in the bilateral market advantageous as prices may be higher at geographically distant bilateral hubs, but want to participate in the EIM market to capture potential price spikes during periods of market tightness and the ability to meet sufficiency requirements. Further, if a resource owner does consider the opportunity to sell energy in the bilateral market as an opportunity cost for a hydro resource, that price should be considered and respected when a resource is dispatched.

DMM requests additional examples and data to support the proposed default energy bid. The CAISO has included additional analysis in this draft final proposal that was not included in the earlier versions of this paper, including three BAAs: PacifiCorp West, PacifiCorp East, and Puget Sound Energy.[10] These areas are representative of where hydro resources are located in the EIM markets and show that generally resources with daily limitations of 4 or more hours per day will not be dispatched more than their energy limits.

Finally, DMM requests that the CAISO provide additional guidelines on how the CAISO will review requests for customizable inputs. The CAISO explains in this draft final proposal that customizable inputs for the hydro default energy bid will include the maximum storage horizon and the long-term bilateral hubs applicable for the resource. The maximum storage horizon will be determined by the historical water cycling data for the resource. This will include requirements for the resource owner to submit documentation of historical cycling patterns for a resource. Section 6.2 provides several

[10] Generally prices in these areas are similar to others in the northwest, which may have limited EIM pricing data available because of the newness of these markets.

examples of such a determination. Resources will need to demonstrate the availability of firm transmission on an annual basis in order to be eligible for different geographic hubs in their default energy bids. They will also be required to announce to the CAISO if those transmission rights are sold or otherwise released during the year. As noted above, the CAISO proposes to have the authority to audit the SC and request for confirmation of changes, including attestations.

4.3 Reference Level Adjustments – Reasonableness Threshold

NRG is notes several possible shortcomings with the CAISO's proposed approach for reference level adjustments: First, NRG notes the reasonable thresholds are updated from a single morning-of same-day inspection of prices of the Intercontinental Exchange (ICE). This single static update may be insufficient to account for volatility in the same-day market. Second, whether the update adequately provides opportunity for market participants to reflect their expectations of same-day gas prices in their bids will depend on what morning-of, same-day price is used, and what kind of scalar is applied to the morning-of, same-day price used. The CAISO understands NRG concerns, but believes updating reasonableness thresholds using same-day gas trades observed on ICE would allow gas price increases to be captured and potentially used in the market through a reference level adjustment. The CAISO is limited to current market processes that only allow for reasonableness thresholds to be updated in the mornings. The CAISO cannot account for every single gas price volatility that may occur throughout same-day.

Six Cities and Puget Sound Energy support the latest proposal related to reference level adjustments. DMM cautions that many EIM areas have less liquid trading hubs, and published prices may not reflect their actual trading conditions. The CAISO observed that some gas hub areas are not sufficiently traded on ICE and has revised its proposal in Section 6.3.1 Gas Resources to account for these exceptions.

Puget Sound Energy requests the CAISO to revise its proposed elimination of the reference level adjustment for hydro resources proposal to update a resource's reasonableness threshold based on the resource's corresponding fuel region to account for day of/intra-day pricing and multiple appropriate index points. Bonneville also believes the proposed elimination proposal may be significantly harmful to hydro resources and suggest the CAISO include an intra-day gas price adjustment in the gas price floor. The CAISO agrees that hydro resources with the default energy bid should be able to account for changes in gas prices and has revised its proposal in Section 6.3.2 Hydro Resource Default Energy Bid.

Puget Sound Energy is further concerned that the proposal does not account for resources capable of dual fuel usage and requests a modification to ensure these resources can apply the correct reference level, as conditions warrant. The

Commitment Cost and Default Energy Bid Enhancements CDEBE policy accounts for resources described by Puget Sound Energy.[11]

4.4 EIM Decisional Classification

The CAISO received several comments on the CAISO's proposed EIM classification in the revised straw proposal. PacifiCorp, Powerex, and Seattle City Light support the proposed classification of the various elements, while SLC notes it is unlikely this initiative would have been undertaken without EIM entities that identified the concerns being addressed. Powerex also highlights how current governance can result in the EIM Governing Body having only a secondary role on an issue of primary importance to—and initiated by—entities outside of the CAISO. The Public Generating Pool does not agree with the proposed classification and recommends the entire initiative should fall under the primary decision making authority of the EIM Governing Body.

The CAISO responds to these concerns with the proposed EIM classification by emphasizing that most elements of this initiative – including the need for mitigation process enhancements – were identified by the CAISO. While EIM entities were the first to raise concerns that the default energy bids did not adequately reflect opportunity costs for hydro resources, the CAISO's exploration of the "EIM Offer Rules" led it to discover that mitigation rules were an issue throughout the market as whole. Moreover, the CAISO identified additional elements, beyond local market power mitigation, that are directed toward improving the market as a whole. These included reference level adjustment processes, gas price indices, and the introduction of the hydro default energy bid. Aside from the transfer limitation to address economic displacement, the remaining four elements are equally impactful to CAISO and EIM entities. Additionally, the Governing Body's authority guidance document for handling policy initiatives does not hinge on who identities issues. Rather, their authority hinges on whether an EIM specific design feature is core to the issue being addressed. For all of these reasons, the CAISO believes the primary driver for this initiative is to improve the performance of the entire market.

5. Principles

The CAISO believes the following market design principles are appropriate when considering design enhancements to the market power mitigation process, default energy bids, and the reference level adjustment process:

- Supply should not be forced to sell power below its bid price if it cannot exert market power. Supply bids should be mitigated to marginal costs to the extent supply has market power.

[11] See Revised Draft Final Proposal at page 37: http://www.caiso.com/Documents/SecondRevisedDraftFinalProposal-CommitmentCosts-DefaultEnergyBidEnhancements.pdf.

- EIM is a voluntary market but the design assumes sharing of ramping capability. In cases of mitigation involving EIM transfers to another BAA, entities should not be forced to sell energy at mitigated prices beyond: (1) the pre-mitigation transfer quantity or (2) the base transfer quantity. This quantity should be further adjusted to include the flexible ramping up awards in the market power mitigation run, less the BAAs flexible ramping up requirement.[12] Ultimately, the use of mitigated bids should not result in additional economic displacement of other supply.
- Mitigated bid prices should be based on a competitive locational marginal price in each interval that accurately reflects market conditions.
- The marginal costs used to calculate default energy bids for hydro resources should include opportunity costs for future market sales and for sales at other geographic locations.
- Gas prices used to calculate reference levels should account for real-time gas prices volatility so that the CAISO efficiently dispatches supply, resulting in accurate market prices that minimize the need for after-the-fact cost recovery.

6. Proposal

The CAISO proposes five enhancements in this initiative:

- Local market power mitigation process enhancements to prevent cases of flow reversal
- Local market power mitigation process enhancements to limit cases of economic displacement
- The introduction of a default energy bid for hydro resources
- Modifications to the reference level adjustment process
- Changes to the gas price indices used in the real-time market

Additional details on each element is provided in more detail below.

6.1 Mitigation Process Enhancements

The CAISO proposes to modify limited parts of the market power mitigation process to address stakeholders concerns associated with inappropriately mitigating energy bids in the EIM. The flow reversal proposal, described below, will also be applicable to resources within the CAISO BAA. These changes will reduce instances when a resource's energy bid is mitigated to its default energy bid.

[12] This adjustment recognizes that energy and flexible ramping up capacity should be fungible in the pricing run.

6.1.1 Prevention of Flow Reversal

Flow reversal occurs in cases when an EIM BAA or group of BAAs are import-constrained during a prior market interval, which triggers mitigation for the balance of the hour in the 15-minute market run (or balance of the 15-minute interval in the real-time dispatch). As system conditions change, this can result in a BAA exporting at mitigated bid prices for the remainder of the hour.[13] As a result, a resource within the mitigated BAA can be forced to sell at mitigated prices that could be lower than the resource's estimated marginal costs—particularly if the default energy bid fails to appropriately reflect these marginal costs.

Balance of the Hour Mitigation

The current market process can lead to flow reversal when the competitive locational marginal price used for mitigation in one market run is restricted from increasing in subsequent market runs. If a resource is mitigated in a prior 15-minute market run, the mitigated bid price will be applied for the remainder of the hour in both 15-minute market and real time dispatch. If a resource is mitigated in a prior real-time (5-minute) dispatch run, the mitigated bid will be applied for the remaining three intervals of the 15-minutes.

The resource's offers will be subject to mitigation at the higher of the resource's default energy bid or the competitive locational marginal price. While the actual competitive locational marginal price (*i.e.*, reflecting actual locational marginal prices in the current interval) can change in subsequent market runs, current rules do not allow the mitigated bid price to reflect increases in the actual competitive locational marginal price. If a resource is mitigated for the balance of an hour in the 15-minute market (or balance of the 15-minute interval in the real-time dispatch) the current rules fix a mitigated bid price unless the competitive locational marginal price decreases.

As a result, if a resource's offer is mitigated to a lower competitive locational marginal price than the actual competitive locational marginal price in the current interval, the resource can become more economic relative to other competitive supply. This can result in a BAA exporting power at mitigated prices that are lower than an appropriate level of mitigation.

The CAISO initially designed these market mitigation rules due to software limitations and with the intent of limiting the frequency of resources responding to rapid ramping instructions. The Department of Market Monitoring later confirmed the CAISO's understanding of the issue within comments submitted on October 4, 2018.[14] Since the implementation of the original policy, the CAISO market software has been enhanced

[13] Based on analysis performed by the Department of Market Monitoring, flow reversal has the potential to occur "up to 2% of all 15-minute intervals" and ".4% of all 5-minute intervals. The analysis performed by DMM underestimates the magnitude of the problem because Powerex is setting export limits to zero in hours where they believe flow reversal is most likely to occur. For more details on this analysis see pp.6 and 7 of the DMM's July, 2018 EIM Governing Body General Session Presentation https://www.westerneim.com/Documents/DepartmentofMarketMonitoringUpdate-Presentation-Jul2018.pdf

[14] http://www.caiso.com/Documents/DMMComments-LocalMarketPowerMitigationEnhancements-IssuePaper-StrawProposal.pdf

and the mitigation performance has been improved, making these measures no longer needed.

The CAISO proposes addressing the issue of flow reversal by eliminating current rules for balance of the hour mitigation in the 15-minute market (or balance of the 15-minute interval in the real-time dispatch) and modifying how the competitive locational marginal price is used in each interval. In addition, the CAISO proposes to update the mitigated bid price in each interval based on the current competitive locational marginal price. Further, the CAISO proposes that a resource mitigated in the 15-minute market will no longer automatically be mitigated in the 5-minute real-time dispatch in the corresponding intervals.

Mitigated Price Adder

As discussed at the August 3, 2018 Market Surveillance Committee meeting,[15] even if the competitive locational marginal price is calculated for each interval and market run, mitigated prices can result in a resource's default energy bid that is equal to the competitive locational marginal price. To address this concern the CAISO is proposing to add a small parameter to that the mitigated price established inside the constrained BAA or region to create price separation from the external competitive locational marginal price. The CAISO proposes to include a maximum price adder of $0.10 in the tariff, with the actual adder necessary to meet the objectives of the rule in the business practice manual. The CAISO currently plans to use $0.001 for the price adder.

The following mitigated bid calculation will be applied to resources assuming the market bid is higher than the default energy bid:

Mitigated Bid = MAX (Default Energy Bid, Competitive Locational Marginal Price + $0.001)

The parameter added to the competitive locational marginal price is nominal, used to establish price separation between competitive and non-competitive areas. This price separation will further prevent flow reversal from occurring in cases when a resource is mitigated to either the resource's default energy bid, or the competitive locational marginal price. For all of the following examples, a $1 adder will be used as the nominal price adder for illustration purposes only.

The examples below illustrate the current mitigation process of the market run for the 15-minute market, as well as the proposed changes to address the potential for flow reversal.

[15] The presentation is available at: http://www.caiso.com/Documents/Presentation-EIMMarketPowerMitigationDiscussion-FTI-Consulting-Aug7_2018.pdf

Example A: Mitigation Occurs in the First 15-Minute Market Interval

Current Mitigation Process

Interval	Unmitigated Bid	Actual Competitive LMP	Default Energy Bid	Market Power Detected	Mitigated Bid	Carry Through Rule	Flow Reversal
1	$60	$30	$25	Yes	$30	No	No
2	$60	$60	$25	No	$30	Yes	Yes
3	$60	$62	$25	No	$30	Yes	Yes
4	$60	$59	$25	No	$30	Yes	Yes

- Market power is detected in the first 15-minute market interval. The mitigated bid price for this resource is $30 because the actual competitive locational marginal price is greater than the submitted default energy bid of $25.
- The mitigated bid of $30, from the first interval, is carried through as the mitigated bid price for the remaining intervals in the hour based on the current balance of the hour rule.
- Flow reversal occurs in intervals two, three and four because the resource is forced to sell at its mitigated bid price of $30 in these intervals. This mitigated bid price is less than the actual competitive locational marginal price.

Proposed Mitigation Process

Interval	Unmitigated Bid	Actual Competitive LMP	Default Energy Bid	Market Power Detected	Mitigated Bid	Carry Through Rule	Flow Reversal
1	$60	$30	$25	Yes	$31	No	No
2	$60	$60	$25	No	$60	No	No
3	$60	$62	$25	No	$60	No	No
4	$60	$59	$25	Yes	$60	No	No

- Since market power is detected in interval one, the mitigated bid price is $31 because the actual competitive locational marginal price + $1 is greater than the default energy bid of $25.
- Market power is not detected in interval two; therefore, the mitigated bid price is based on the unmitigated bid of $60.
- Market power is not detected in interval three; therefore, the mitigated bid price is based on the unmitigated bid of $60.

- Market power is detected in interval four; therefore, the mitigated bid price is $60 because the actual competitive locational marginal price + $1 and the unmitigated bid price are equal.
- As a result of eliminating the balance of the hour mitigation rule, the mitigated bid price has flexibility to change and flow reversal does not occur even when market power is detected.

Example B: Mitigation Occurs in the Third 15-Minute Market Interval

Current Mitigation Process

Interval	Unmitigated Bid	Actual Competitive LMP	Default Energy Bid	Market Power Detected	Mitigated Bid	Carry Through Rule	Flow Reversal
1	$60	$30	$25	No	$60	No	No
2	$60	$45	$25	No	$60	No	No
3	$60	$26	$25	Yes	$26	No	No
4	$60	$50	$25	No	$26	Yes	Yes

- Market power is detected in the third 15-minute market interval. The mitigated bid price for this resource is $26 because the actual competitive locational marginal price is greater than the submitted default energy bid of $25.
- The mitigated bid of $26, from the third interval, is carried through as the mitigated bid price for the remaining interval in the hour based on the current balance of the hour rule.
- Flow reversal occurs in interval four because the resource is forced to sell at its mitigated bid price of $26 in this interval. This mitigated bid price is less than the actual competitive locational marginal price.

Proposed Mitigation Process

Interval	Unmitigated Bid	Actual Competitive LMP	Default Energy Bid	Market Power Detected	Mitigated Bid	Carry Through Rule	Flow Reversal
1	$60	$30	$25	No	$60	No	No
2	$60	$45	$25	No	$60	No	No
3	$60	$26	$25	Yes	$27	No	No
4	$60	$50	$25	No	$60	No	No

- Market power is not detected in intervals one and two; therefore, the mitigated bid price is based on the unmitigated bid of $60.
- Market power is detected in interval three; therefore, the mitigated price is $27 because the actual competitive locational marginal price +$1 is greater than the submitted default energy bid of $25.

- Market power is not detected in interval four; therefore, the mitigated bid price is based on the unmitigated bid of $60.
- As a result of eliminating the balance of the hour mitigation rule, the mitigated bid price has flexibility to change and flow reversal does not occur even when market power is detected.

Although the above example shows that with the implementation of the proposed rules, flow reversal will not occur when market power is detected, there is still a possibility that bids in another BAA are mitigated to below $27, thus causing flow reversal to occur. For this reason, the CAISO will enforce a net EIM transfer constraint in the third 15-minute market interval (after the market power mitigation run) to prevent a potential flow reversal.

6.1.2 Prevention of Economic Displacement between Mitigated Balancing Authority Areas (BAAs)

As described above, the changes to the balance of the hour (or 15-minute interval) mitigation rules will address flow reversal when a single BAA is import-constrained. However, additional rules are needed to address instances of "economic displacement" due to mitigated bid prices that can occur when a group of EIM BAAs become import-constrained, which triggers mitigation.

As observed in previous examples, market power mitigation can result in a different dispatch within BAAs in the constrained regions when mitigated bids are used. However, given the voluntary nature of the EIM, allowing for economic displacement of resources between EIM BAAs that occurs solely due to using mitigated bids should be addressed. Economic displacement due to mitigated bids occurs when energy from one resource is replaced with energy from another, beyond what is necessary to resolve market power. Mitigated bids that result in additional transfers in a voluntary market can be problematic – particularly in cases when the default energy bid is lower than a resource owner's estimate of current marginal costs. Economic displacement has the potential to reduce transfer capability within the EIM as BAAs may limit the amount they make available to limit economic displacement. It could potential also discourage additional EIM participation.

The CAISO proposes a market rule that would prevent economic displacement by not allowing transfers between two EIM BAAs to increase beyond a specified amount between then market power mitigation run and the market run for a specific interval. This rule would limit transfers from the mitigated BAA when exporting to the greater of: (1) the pre-mitigation transfer quantity or (2) the base transfer quantity, plus the sum of the flexible ramping up awards in the market power mitigation run in excess of the BAA's flexible ramping up requirement. The additional allowance recognizes that energy and flexible ramping up capacity are fungible in the next market run, and that flexible ramping up awards in excess of the requirement are procured for uncertainty that may materialize in other BAAs.

The proposed rule is presented formulaically below:

$$T_{BAA} \leq \max\left(T_{BAA}^{(Base)}, T_{BAA}^{(MPM)}\right) + \max\left(0, \sum_{i \in BAA} FRU_i^{(MPM)} - FRUR'\right)$$

T_{BAA}	Net EIM Transfer of the mitigated BAA
$T_{BAA}^{(Base)}$	Base net EIM Transfer of the mitigated BAA
$T_{BAA}^{(MPM)}$	Pre-mitigation (market power mitigation run) net EIM Transfer of the mitigated BAA (for RTD, the previous RTD run serves as the market power mitigation run)
$FRU_i^{(MPM)}$	Flexible ramping up award for resource i (in the MPM run)
$FRUR'$	Flexible ramping up requirement for the mitigated BAA, adjusted for EIM diversity and demand elasticity

This proposed rule will use the maximum of the transfer scheduled in the market power mitigation run or the base transfer. After the maximum value is identified, the rule will add the mitigated BAA's flexible ramping-up awards in excess of the adjusted flexible ramping-up requirement for the following reasons. It is appropriate to use the transfer scheduled in the market power mitigation run if it is a quantity greater than the base transfer amount because using a lower amount would undo the market results and potentially result in a solution in which the transfer is limited such that the receiving BAA was unable to meet its imbalance energy requirement. It is also appropriate to incorporate the sending BAA's flexible ramping up awards in excess of the flexible ramping up requirement because the EIM design assumes sharing of flexible ramping capacity between BAAs. Accordingly, each BAA's flexible ramping requirement used in the resource sufficiency test is reduced by a diversity benefit.

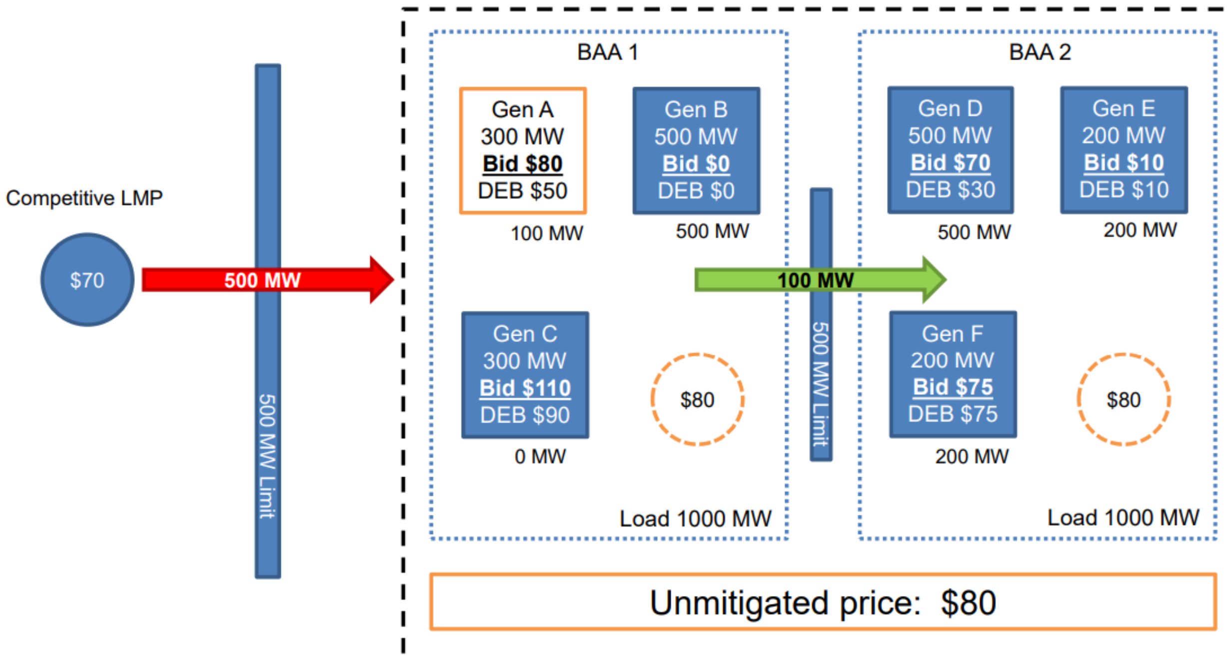
This rule will be applied apply in both the 15-minute market and real-time dispatch, so that every interval is tested separately. In the event the transfer constraint is binding in the pricing run, the congestion rents will accrue to the source EIM BAA. This is consistent with the current EIM treatment for congestion rents, in which congestion rents accrue to the BAA where the constraint is located (the transfer constraint is specific to the source BAA).

The CAISO proposes that application of this rule be optional to address EIM participant concerns that this rule could reduce transfers between EIM BAAs and consequently limit EIM benefits. Each EIM entity would have the option to activate this rule to enforce EIM transfer limitations after mitigation. Upon implementation, the default setting for the rule would be inactive for all EIM BAAs. Accordingly, BAAs that choose to enforce the rule would need to make the appropriate designation in the CAISO's Master File. EIM entities would therefore have the capability to enforce or disable this rule through the normal Master File registration process. Those EIM entities that elect to enforce it may need to ensure their respective OATT processes are aligned to appropriately respond to the corresponding transfer limitations.

Example C below presents a simplified case of economic displacement with this proposed rule applied to the mitigation process.

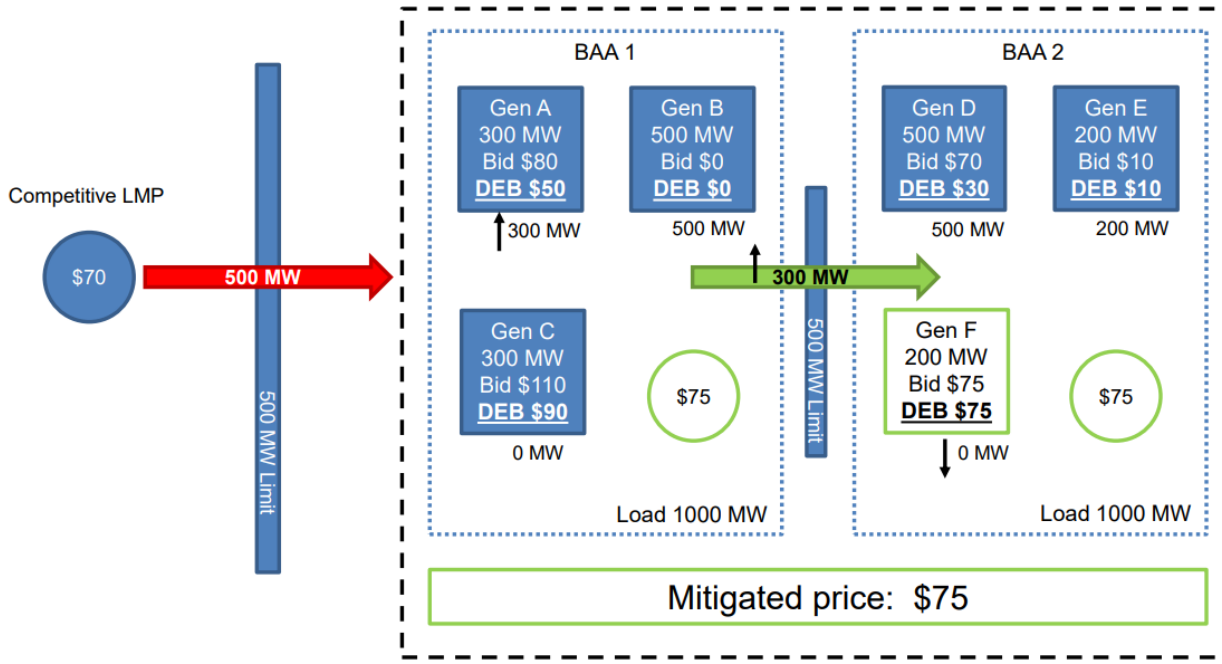
Example C

1. Market Power Mitigation Run



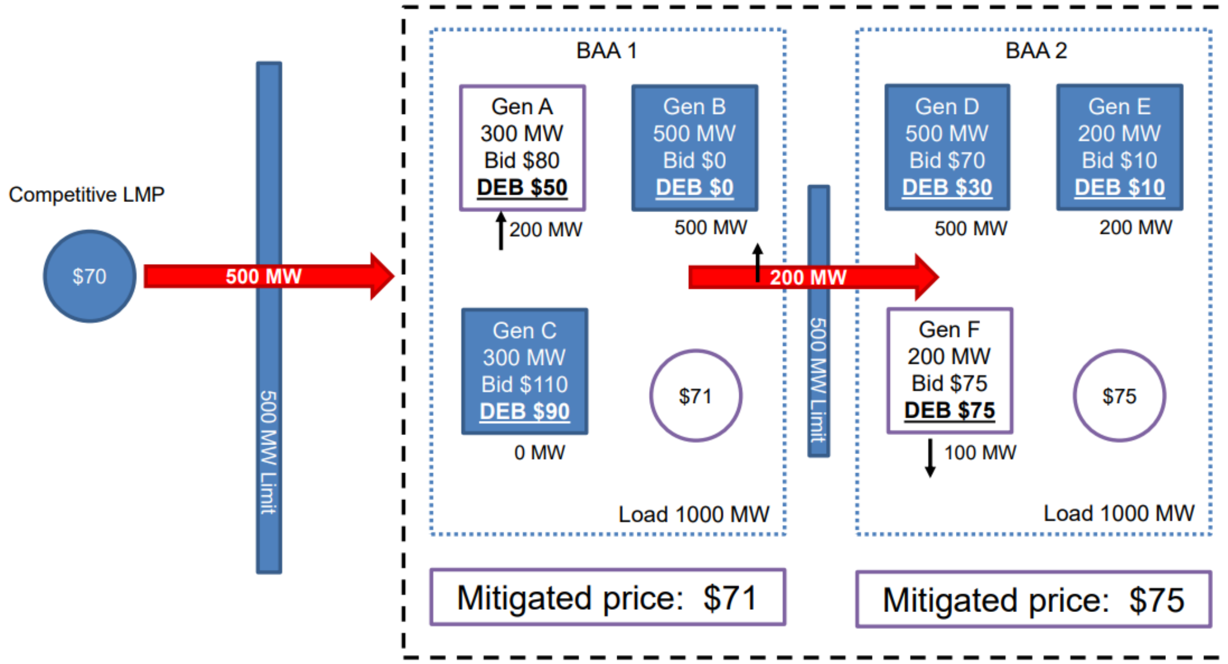
- BAA 1 and BAA 2 are in a constrained region, with a competitive locational marginal price of $70. Imports into the region are binding at 500 MW.
- BAA 1 is exporting 100 MW to BAA 2. The bids result in a price of $80 for both BAAs.

Market Run



- The default energy bids are examined in this market run, resulting in an increase in Generator A from 100 MW to 300 MW, and a decrease in Generator F, from 200 MW to 0 MW.
- This results in a price of $75 for both BAA 1 and BAA 2, as Generator F is the marginal generator for both BAAs (assuming BAA 2 could reduce imports to BAA 1).

Market Run with Proposed Rule

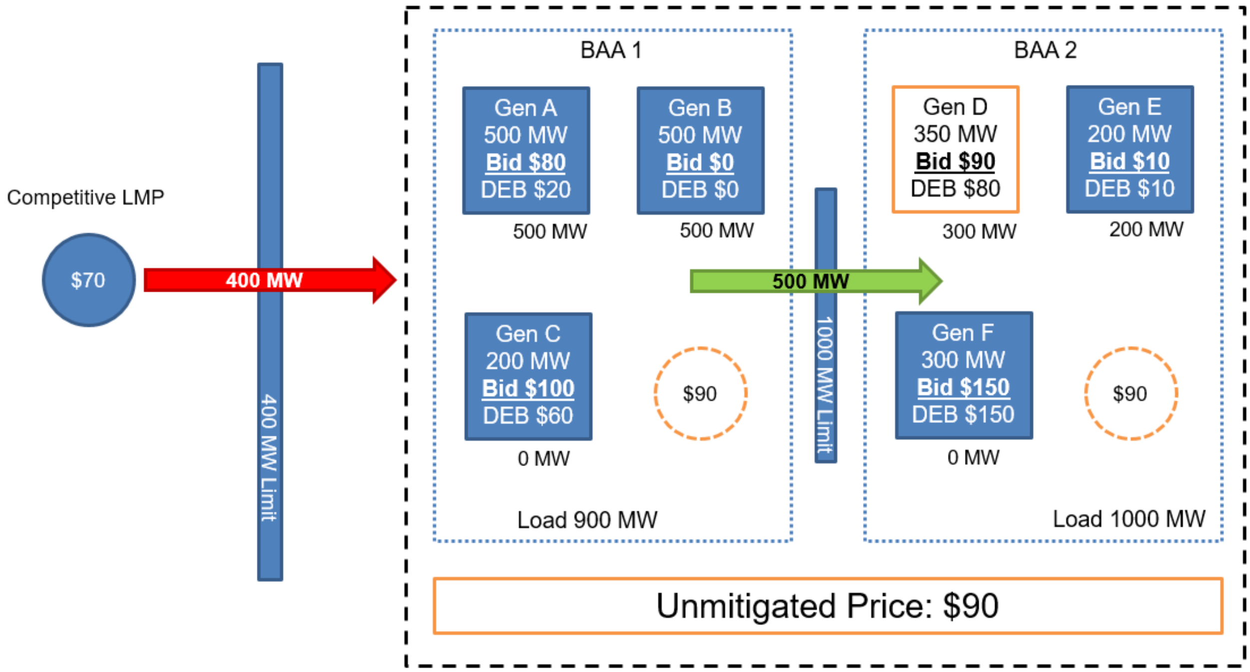


- By introducing a rule that would limit exports from any EIM BAA to the greater of: (1) base EIM transfer (assumed zero); or (2) pre-mitigation (MPM) export (100MW), plus the flexible ramping up awards in excess of the adjusted flexible ramping up requirement for the mitigated BAA.
- In this example, it is assumed that the flexible ramping upwards in BAA 1amount to 200 MW with an adjusted flexible ramping up requirement of 100MW. Accordingly, exports can increase from 100 MW in the market power mitigation run to 200 MW.

The rule does have shortcomings in the real-time dispatch, since the market power mitigation and pricing runs do not occur in the same interval. The transfer constraint quantity would be determined using the advisory interval from the previous market run. Consequently, changes in system conditions can result in a transfer that would have been different had the market inputs from the binding interval been used. The CAISO highlights this scenario below:

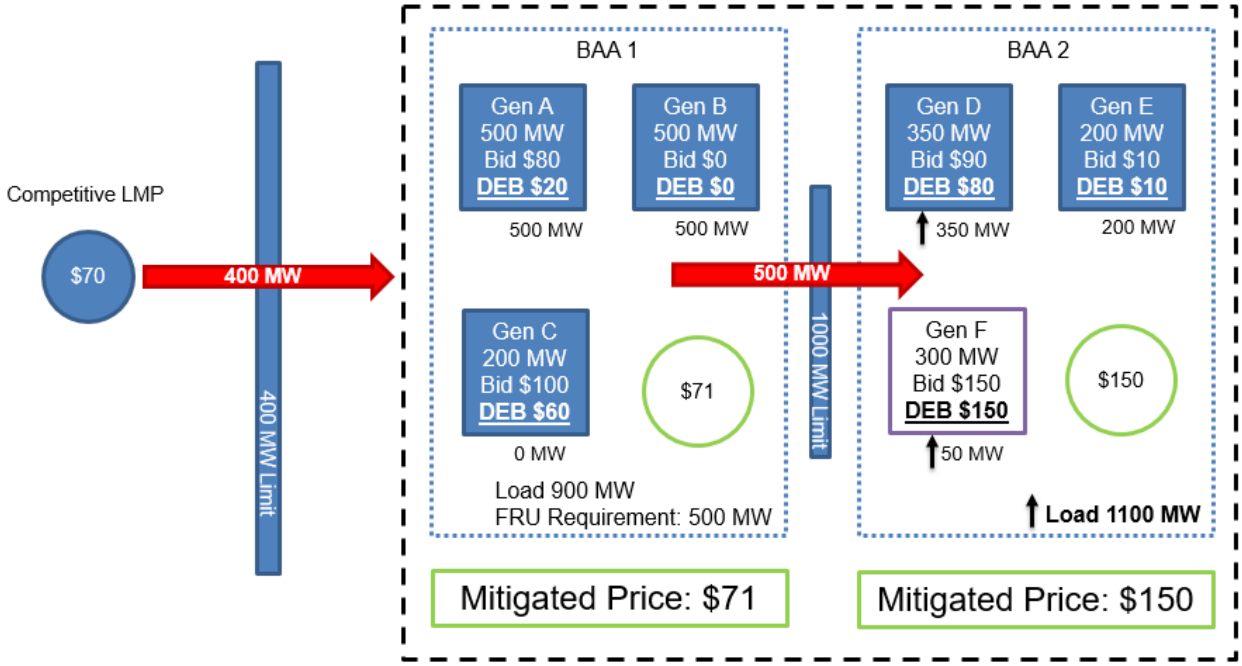
In this example, the advisory interval load forecast is lower than the actual load forecast in the binding interval. Since the transfer limit for BAA 1 is established based upon the lower load forecast this results in lower transfers than would have been scheduled had a the actual load forecast been used. This results in BAA 2 relying on internal resources alone to cover for the load change in the combined bubble.

RTD Market Power Mitigation Triggered in Advisory Interval of Prior RTD Run



- Assume imports into BAA 1 are binding at 400 MW, the base EIM transfer for BAA 1 is 0 MW, and the BAA 1 Flexible Ramping Up awards are 0 MW.
- Assume then Generator D has a capacity of 350 MW and that Gen F has an offer price and default energy bid of $150. Suppose that the unmitigated dispatch in the advisory interval was based on 1000 MW net load in BAA 2 and 900 MW in BAA 1 so there would be 500 MW of exports to BAA 2.
- The price would then be $90 in both BAA 1 and BAA 2 in the unmitigated dispatch.
- With the proposed mitigation process changes, prices and transfers would be used in the binding RTD.

Load Increases by 100 MW in BAA 2 Compared the Prior Market Run



- With the transfer from BAA 1 capped at pre-mitigation EIM transfer of 500 MW, the price in BAA 2 would rise to $150 set by Generator F, while the lower cost generation available in BAA 1 goes undispatched because of the binding limit (500 MW) on exports, even though the dispatch of resource C in BAA1 would be economic even at the unmitigated offer price ($100).
- The application of mitigation will raise the price paid by imbalance purchasers in BAA 2. Congestion rents in this example would be paid entirely to BAA 1.

The CAISO acknowledges these concerns and recognizes that limiting exports will create the potential caused by different loads and resource availability between the advisory runs and real-time dispatch runs. However, there is an inherent shortcoming of using the advisory interval for mitigation purposes in the real-time dispatch. Ultimately, while limiting transfers of energy that could potentially be needed by an importing BAA to meet load in real-time dispatch, this is inconsistent with requiring a neighboring BAA to sell it power in a voluntary market. Furthermore, the importing BAA can rely on internal resources, including those set aside as available balancing capacity to meet their load.

6.2 Hydro Resource Default Energy Bid

In response to stakeholders advocating for an alternate default energy bid for hydroelectric resources with limited generation capability, the CAISO proposes an additional default energy bid option. This new default energy bid option would capture opportunity costs for hydro resources to sell energy in markets outside of the CAISO and to generate replacement energy from a peaking resource. It also includes a floor that serves to ensure that the default energy bid is sufficiently large such that hydro resources with limited capability to run may not be dispatched more than energy available, dictated by short-term limitations, too frequently. This default energy bid will be available to hydro resources with storage in any of the BAAs – CAISO or energy imbalance market – that participate in the real-time market.

Accuracy of default energy bids reflecting opportunity costs are important anytime a resource's energy bid is mitigated to its default energy bid. If a default energy bid is lower than opportunity costs, it can cause a resource with limited availability to run inefficiently, or earlier than at optimal times. This in turn could result in reducing energy available to markets, or worse not offering any energy into the market and reducing overall market capability and efficiency.

The CAISO currently offers a default energy bid opportunity cost adder, which considers the limited availability of fuel for a resource over a specified time horizon. This default energy bid option allows hydro resources bidding at forecast future local prices to be optimally dispatched over that time horizon. Although these opportunity cost adders can account for intertemporal energy sales at a unit's specific location, they do not capture the potential opportunity for intertemporal energy sales outside of the CAISO's real-time energy market. They also do not reflect the short-term – potential daily – limitations that hydro resources, including those with long-term storage, encounter.[16]

Background

Hydro resources are unlike many other resources that currently participate in the CAISO and energy imbalance markets. Gas resources typically have default energy bids that are computed using heat rates, fuel costs, and other variable inputs which roughly approximates their marginal cost to operate at any given time during a day. Wind and solar resources generally can respond to dispatch instructions to reduce output when prices are sufficiently low, but produce as much energy as possible when prices are higher, unless otherwise instructed by the CAISO. Hydro resource owners may make decisions to generate based on opportunity costs for water, but may also be primarily concerned with other water flow considerations. Additionally, hydro opportunity costs tend to be very complicated to calculate and may change even within a specific day.

Models that hydro resource owners use to calculate daily generation quantities may be very complex and may take into account various probabilities for different water inflow considerations – which may depend on variable intraday weather, upstream conditions, and corresponding spill probabilities – as well as downstream conditions, and legal restrictions and obligations for water that may be moved past the facility. These models may consume hundreds of inputs and may imply opportunity costs that change drastically even *within* a single operating day. It is unreasonable to believe that the

[16] In addition to the opportunity cost adders, hydro resources are also eligible for variable cost, LMP, and negotiated rate default energy bids, like other resources participating in CAISO markets and the EIM.

CAISO would be able to replicate these calculations during all intervals, particularly since default energy bids are fixed over the course of the day.

Because of these considerations a hydro resource may be particularly sensitive to a default energy bid that dispatches the resource more frequently than the predicted generation quantities that result from the resource owner's model. This may occur when local market power mitigation is triggered and a higher bid coming from a hydro resource is mitigated to the default energy bid in multiple intervals, and the water allocation for the day is depleted. If this happens early in an operating day, the resource may be unable to run during the evening ramping hours, when energy prices are highest, because reservoir water was depleted earlier in the day. This discourages participation of such resources in the market, and may force the CAISO to forgo their participation in hours when their flexibility is most needed.

Additionally, hydro resource operators may not dispatch their resource based strictly on the opportunity cost of water, but may instead prioritize managing local water conditions, and may only operate the resource to earn energy market revenues as a secondary objective. Hydro resources that are often dispatched too frequently may find it challenging to meet legal water flow requirements imposed by regulators, and this could result in self-scheduled resources and reduced participation in real-time energy markets.

Most hydro resources are fast ramping and can be highly effective at managing the increasing ramping needs necessary for reliable energy grid operations. More participation of fast ramping resources allows the CAISO to respond to sudden energy needs from changing system conditions, which reduces the total number of power balance constraint violations. This in turn reduces price volatility and overall market prices, and effectively, energy prices faced by ratepayers.

Default Energy Bid Calculation

The CAISO proposes a new default energy bid option for hydro resources that reflects the following factors:

- Maximum storage horizon
- Ability to sell energy at different locations inside and outside their balancing area
- Opportunity costs of generation by substituting local gas resources
- Potential short-term limitations

This default energy bid would be available for any hydro resource in a CAISO or energy imbalance market area that has storage available and can be bid in and dispatched through the real-time market. This is in contrast today in which hydro bids largely use negotiated default energy bids negotiated separately and non-publically. The CAISO believes a standard hydro default energy bid option is important to treat hydro resources comparable with gas-fired resources, which already have a standard cost-based option. A standard hydro default energy bid will also add transparency to default energy bids for hydro resources.

When this default energy bid option is selected, the resource owner will be required to demonstrate the resource's maximum storage horizon, and will have the option of demonstrating the ability to make bilateral sales at additional locations.

The proposed default energy bid for a hydro resource with storage will have the following three components:

$$DEB = MAX(Gas\ Floor, ST\ Floor, LT\ Geo\ Floor)$$

And:

$$Gas\ Floor = (Peaker\ Heat\ Rate * GPI) * 1.1$$

$$ST\ Floor = MAX(DA\ Index, BOM\ Index, M\ Index_{+1}) * Mult$$

$$LT\ Geo\ Floor = MAX(DA\ Index, BOM\ Index, M\ Index_{+1}, \ldots, M\ Index_{+12}) * 1.1$$

Where, the *M Index* values in the long term / geographic (LT Geo) floor term of the calculations would be limited to the number of months within the resources storage horizon,[17] and

- *DA Index* – Day-ahead (DA) peak price at the trading hub
- *BOM Index* – Balance-of-month (BOM) futures price for the current month at the trading hub
- *M Index$_{+N}$* – Monthly index futures price at the trading hub for the successive months *N* after the current month
- *Mult* – A multiplier, specified as 1.4, applied to the short term floor to establish a default energy bid value sufficiently high to not deplete a resource too frequently
- *Gas Heat Rate* – Average heat rate for a typical gas resource[18]
- *GPI* – The specific gas price index for the resource[19]

The CAISO will calculate this default energy bid for each resource once per day. Most of the inputs for this formula are also updated each day to reflect current market conditions.

This proposed default energy bid calculation includes three components, the *Gas Floor*, *Short Term (ST) Floor*, and the *Long Term / Geographic Floor*. The gas floor and the

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[17] Any resource with one month of storage or less will receive a default energy bid that includes the *M Index$_{+1}$*, but not additional *M Index* terms. Resources with longer than 12 months of storage will receive a default energy bids with *M Ahead* terms from *M Index$_{+1}$* and additional months through *M Index$_{+12}$*.

[18] The heat rate used throughout examples in this paper is 11,176 Btu/kWh. This heat rate is cited by the Energy Information Agency as an average heat rate for a gas turbine resources in 2017: https://www.eia.gov/electricity/annual/html/epa_08_02.html.

[19] The process for any resource to set up a gas price index is already specified by the CAISO, and hydro resources applying for this default energy bid will be subject to the same process already in place.

long term / geographic floor components of the default energy bid represent the opportunity costs for the hydroelectric generator to substitute peak energy from a gas resource and opportunities to sell energy in geographic areas outside of the resource's local area potentially in future time horizons, respectively.

The short term floor is computed using local hub prices, which may be used as a rough proxy for average levels of energy imbalance market energy prices. A multiplier, of 1.40, will be applied to this calculated value so that it can be used to ensure the default energy bid is not higher than local energy imbalance market prices too frequently. This may prevent hydro resources using this default energy bid from being dispatched inefficiently or depleting water reserves too early in an operating day. The short term floor component of the default energy bid is used as a cap for acceptable bids for hydro resources. This 1.40 multiplier is based on the analysis described below with an intent of having the resource not dispatched more than 4 hours per day in a range of 95-99% of the time based on modeling EIM prices in various EIM BAAs compared to the representative bilateral hub prices.

The gas floor is calculated similar to a variable cost default energy bid for a gas resource. The heat rate for an average peaking resource is multiplied by the gas price index for a representative gas resource if it were at the same location. This calculation is completed by applying a 110% multiplier, similar to calculations for other default energy bids.

The long term / geographic floor is calculated as the maximum of the day-ahead, balance of month, and month ahead indices for the resource. Resources are eligible for future month-ahead prices, up to the amount of maximum storage horizon. For example, if a resource has three months of storage, the month ahead index for the successive month, two months in advance, and three months in advance are used. Hubs in addition to the local hub may be used in the calculation of the long term / geographic floor, and will be specified through a consultative process with the CAISO where demonstration of firm transmission rights to additional hubs is required. Further, if firm transmission rights are shown for multiple hubs, a resource will receive the maximum of these values, as determined each day.

Customizable Inputs

This default energy bid formula has two inputs that may be customized for each resource receiving this default energy bid. These include:

- Maximum storage horizon
- Long term bilateral hub

The maximum storage horizon represents the maximum length of storage a hydro resource has when cycling reservoirs during typical hydro year conditions. This component of the default energy bid is included to represent the total amount of time a resource could store energy, and the derivation of this value should be computed comparing historic pond elevations for multiple years for the hydro project and observing typical cycling times for the resource. The specific calculation may be the average length of time between each period when the water is at peak levels. This value represents the amount of time in the future that a resource may have an opportunity when selling energy at the current time.

For example, a hydro facility that has some available reservoir storage capacity but generally drains and fills (cycles) on a weekly basis throughout the year, would be a storage facility with less than one month worth of storage. For these resources, generally generating today means the loss of future energy sales at a later time during the same month, but generally does not mean the loss of sales perhaps more than 45 days in the future. In another example, a hydro facility with an annual pattern where reservoirs are emptied prior to spring months, run at maximum capacity or spill during the spring months, and run selectively during summer months when available prices are highest, may have multiple months of storage, but less than 12 months. A similar resource that does not need to run at full output during expected peak inflow may have 12 months or more of storage.

The CAISO will require resource owners to submit a proposed value for the maximum storage length, include an attestation that this value corresponds to the definition of the maximum storage horizon, and provide corroborating information for validation by the CAISO. Corroborating data may include several years of historic water levels at the specific hydro facility and regulatory filings related to the operations of the resource.

The CAISO proposes to offer five different bilateral energy-trading hubs for hydro resources with this default energy bid, which will be included in the long term / geographic floor component of the default energy bid. These include Mid-Columbia, Palo Verde, Alberta, north-of-path 15, and south-of-path 15.[20] Hydro resources with storage within particular energy imbalance market areas or areas within CAISO will be eligible for a default bilateral energy hub, indicated in the table below. CAISO will identify some default hubs that will be included in the long term / geographic floor component of the default energy bid calculation and will be the default value.

Table 1 below shows the mapping that will be used for default bilateral trading hubs.

[20] Additional bilateral hubs were considered, but to maintain ease of calculation CAISO has elected to offer these five hubs. CAISO included Alberta in the list of geographic hubs, and will offer this hub if it can be demonstrated that the hub is robust enough to be used in these calculations. CAISO is currently performing analysis to make this determination. This determination will be made if the trade volume at Alberta is within 10% of the lowest trade volume for the other hubs that will be offered.

Table 1: Default bilateral energy trading hubs

Resource Area	Default Bilateral Hub
PacifiCorp West, Portland, Powerex, Puget Sound	Mid-Columbia
Arizona, Idaho, PacifiCorp East, NV Energy	Palo Verde
Northern California	North-of-path 15
Southern California	South-of-path 15

In addition to the default bilateral hub, which will be used in the short term floor portion of the default energy bid, a resource owner will also have the opportunity to select additional bilateral hubs, for use in the long term / geographic floor component of the default energy bid. To do this, the market participant will be required to show the CAISO firm transmission from the resource to one of these hubs or an electrically similar location.[21]

Resource owners opting for this default energy bid will be required to request this default energy bid, specific maximum storage horizons, and applicable bilateral hubs from the CAISO. Generally, the CAISO believes that maximum storage horizons are attributes for a resource that will not change over time. This parameter may be justified to the CAISO initially when requesting this default energy bid, but would not need to be reexamined later.[22] However, because transmission contracts can change over time, resources electing this default energy bid would be required to resubmit documentation to demonstrate firm transmission rights on an annual basis. If a resource fails to submit documentation for a different bilateral hub, the default energy bid will automatically revert to one using the default bilateral hub. Additionally, each resource with this default energy bid will be required to submit documentation to the CAISO if shown firm transmission is no longer available during the year. Failure to report these changes may result in sanctions under existing applicable market rules. The CAISO will retain the

[21] Resources may demonstrate transmission to multiple locations, and the CAISO will make evaluations for each geographic hub and use the maximum value in calculating the default energy bid for those resources. Resources with less firm transmission rights than resource capacity will only be eligible for a weighted blend of bilateral prices between the hub with transmission rights and the default bilateral hub. Annual firm transmission rights need to be demonstrated by the resource owner, or demonstration of monthly purchases of the rights during the prior year. Values for each hub will be evaluated and compared on a daily basis by the CAISO when computing default energy bids for all resources.
When additional BAAs are added to the EIM markets, they will be assigned a default bilateral hub, based on anticipated EIM prices compared to existing default bilateral hubs.
A resource owner may consult with the CAISO to revise the assigned default bilateral hub, if it can be demonstrated that another hub better represents local prices for a specific resource applying for this default energy bid.

[22] Acceptable documentation to verify maximum storage horizons may include analysis for historic reservoir conditions and/or a letter of attestation of available storage from the resource owner.

right to audit this data, request additional information, and require a resource owner to attest to additional values and information submitted to the CAISO. If inaccurate information is disclosed to the CAISO and discovered, eligibility for the use of this default energy bid may be revoked and resource owners may be referred to FERC.

Analysis

This CAISO performed detailed analysis to inform potential bounds on the multiplier applied to the short term floor within the default energy bid for hydro resources with storage capability. The default energy bid is calculated for four different cases using actual EIM prices for the PacifiCorp East (PACE), PacifiCorp West (PACW), Puget Sound Energy (PSEI) BAAs, and the Powerdex hourly prices for Mid-Columbia. In each set of analysis additional information – including bilateral hub prices at the Mid-Columbia and Palo Verde trading hubs and gas price indices from October 2017 through September 2018 – was used to determine a potential appropriate multiplier for the short term floor component of the default energy bid. The steps of this analysis are outlined below:

1. Calculate a default energy bid for each day during the time period.
   a. The default energy bid was calculated for each day in the date range, using available historic data. The default energy bids for PacifiCorp West (PACW) and Puget Sound Energy (PSEI) BAAs, and the Powerdex hourly prices were calculated first with Mid-Columbia bilateral hub prices for both a 1 month storage horizon and a 3 month storage horizon. The default energy bids for PacifiCorp East (PACE) were calculated with Palo Verde bilateral hub prices for both a 1 month storage horizon and a 3 month storage horizon.
   b. The Sumas fuel region was used to calculate the gas floor for the default energy bids associated with the PacifiCorp West (PACW) and Puget Sound Energy (PSEI) BAAs, and the Powerdex hourly prices. The Kern fuel region was used to calculate the gas floor for the default energy bids associated with the PacifiCorp East (PACE).
2. Compare the daily default energy bid to real-time prices in the EIM market. [23]
3. Determine percentage of intervals that a resource would be dispatched if bidding into the market at default energy bids.

This analysis was carried out with a variety of multipliers applied to the short term floor component of the default energy bid to determine how frequently resources with different storage horizons would be dispatched in the market. This analysis focuses on a resource with 3 months of storage being dispatched less than a particular amount of

[23] This analysis considers the EIM prices as exogenous and does consider changes in resource bidding or new market outcomes because of different default energy bids applying to some subset of resources.

hours during each day, or that a resource with a particular amount of storage is dispatched at its available daily energy limitation or less.

If a hypothetical resource has 3 months of available storage and has generation capability of 4 hours per day, then **Table 2**, **Table 3**, and **Table 4** show that such a resource, bidding at this default energy bid with a 1.4 multiplier applied to the short term floor, would be efficiently dispatched more than 95% of days in PacifiCorp East, PacifiCorp West and in Puget Sound Energy. In fact, resources in PacifiCorp West and Puget Sound Energy would be dispatched efficiently during 99% of days. This analysis shows that a resource was capable of producing 4 hours per day that with a 1.4 multiplier the resource may be completely depleted through dispatch less than 1-in-20 days regardless of if the resource was in the PacifiCorp East, PacifiCorp West, or Puget Sound Energy balancing areas.

In practice, any specific resource may have 4 hours of available storage on one specific day, but may have more or less on a different day and therefore this analysis will not reflect how often any specific resource is or is not dispatched too frequently. Instead, the objective of this analysis is to suppose a hypothetical resource and determine how often that resource is or is not dispatched inefficiently. The intent of this is to reflect the uncertainty of calculating the availability of any specific hydro resource because of their varying and subjective limitations, and to develop a default energy bid that is a reasonable reflection of a wide variety of hydro resource's opportunity costs.

Resources with more storage duration or the ability to generate during more hours would have a sufficiently high default energy bid during a greater percentage of intervals. Similarly, this multiplier would not be sufficient this frequency of intervals if the same resources had less storage availability or less energy that could be produced during a given time frame. CAISO attempted to identify a multiplier that could be applied that would be sufficiently high, to not distort dispatches for some resources that may be frequently mitigated. This default energy bid is not meant to be a prescriptive exact calculation that covers the opportunity costs for any potential resource at all times, and acknowledge that this default energy bids may be insufficient for some subset resources. These resources may find that a default energy bid or an opportunity cost adder may be more appropriate to capture certain resource limitations.

When reviewing this analysis it is important to note that resources with market based rate authority are not required to bid in at default energy bids, and may bid lower or higher than these values. Resources are dispatched based on bids, and if mitigated default energy bids, which implies that a resource may be dispatched below their available energy more or less frequently than indicated in these tables depending on their market bids. Further, it is important to note that CAISO will only insert default energy bids for a resource when local market power mitigation is triggered for that resource. Mitigation is triggered more frequently in some areas than in others, but also may not drive the results shown in the tables below. CAISO policy changes outlined in

Section 6.1 detail how the local market power mitigation framework will be changed in this initiative, and may decrease the frequency that the mechanism is triggered.

Finally, **Table 5** below shows a similar resource subject to Powerdex hourly prices. The CAISO received feedback that indicated that Powerdex hourly prices may be more representative of future prices in the Northwest that hydro resource may face when more market participants join EIM, more transmission is available in EIM, and the day-ahead enhancement initiative is complete. Results for these prices, over the same time period show the same results, that the same resource, with a 1.4 multiplier applied to the short term floor, may only be inefficiently dispatched during 3% of intervals.

Table 2: Percent a resource is dispatched less than potential daily availability (PACE prices)

Multiplier	Resource Storage Duration (Hours/Day)			
	2 Hrs.	**4 Hrs.**	**6 Hrs.**	**8 Hrs.**
120%	68%	89%	95%	98%
130%	73%	92%	97%	99%
140%	77%	95%	98%	99%
150%	82%	97%	99%	99%
160%	88%	98%	99%	100%

Table 3: Percent a resource is dispatched less than potential daily availability (PACW prices)

Multiplier	Resource Storage Duration (Hours/Day)			
	2 Hrs.	**4 Hrs.**	**6 Hrs.**	**8 Hrs.**
120%	80%	94%	100%	100%
130%	84%	97%	100%	100%
140%	88%	99%	100%	100%
150%	91%	99%	100%	100%
160%	94%	99%	100%	100%

Table 4: Percent a resource is dispatched less than potential daily availability (PSEI prices)

Multiplier	Resource Storage Duration (Hours/Day)			
	2 Hrs.	**4 Hrs.**	**6 Hrs.**	**8 Hrs.**
120%	80%	95%	99%	100%
130%	85%	97%	100%	100%
140%	88%	99%	100%	100%
150%	91%	99%	100%	100%
160%	93%	99%	100%	100%

Table 5: Percent a resource is dispatched less than potential daily availability (Powerdex)

Multiplier	Resource Storage Duration (Hours/Day)			
	2 Hrs.	**4 Hrs.**	**6 Hrs.**	**8 Hrs.**
120%	88%	94%	97%	99%
130%	91%	96%	98%	99%
140%	93%	97%	99%	99%
150%	95%	98%	99%	99%
160%	96%	99%	99%	100%

This proposal allows for the default energy bid to incorporate the features outlined above, including allowing for the length of fuel storage, ability to sell energy at different locations outside of a CAISO or EIM area, opportunity cost of generation using substitute local resources, and the ability to dispatch a resource less than the amount of available energy.

6.3 Reference Level Adjustment - Reasonableness Thresholds

The CAISO's recent *Commitment Costs and Default Energy Bid Enhancements* (CCDEBE) policy initiative established a process in which resource owner will be able to request a before-the-market adjustment to a resource's start-up cost bid cap, minimum load cost bid cap, or to its default energy bid (*i.e.*, its cost reference levels as calculated by the CAISO).[24] This process was established in recognition that the CAISO's calculated reference levels based on published price information may not always reflect individual supplier's cost expectations.

For a resource owner to request an adjustment to a resource's reference level under this process, the supplier's cost expectations must be based on actual price quotes and its expected cost must be greater than the CAISO-calculated reference level. Suppliers must retain sufficient documentation supporting the need for a reference level adjustment request.[25]

The CAISO would screen these reference level adjustment requests using an automated process based on "reasonableness thresholds." The CAISO would automatically approve any request to adjust a reference level up to a resource's reasonableness threshold.

In CCDEBE, the CAISO proposed to calculate these reasonableness thresholds each day by increasing the gas prices used in calculating each resource's reference levels by 10%, except for Mondays and days after holidays, in which case the CAISO would increase the gas price by 25%. The CAISO obtains these gas prices from published price indices. This process recognized that individual suppliers' actual costs can vary from the published price indices, and that, due to the nature of gas trading, this variation is greater on Mondays and days after holidays.

The CAISO has not yet filed the tariff changes resulting from the CCDEBE initiative with FERC. It plans to do so in 2019 so it can implement them in Fall 2019. Based on recent gas market trends, the CAISO proposes a modification to the reference level adjustment process for gas resources developed in CCDEBE described above, and proposes a modification to the gas index used for the day-ahead market. Finally, the CAISO is proposing a reference level adjustment process for resources using the hydro default energy bid. These changes are described in the following subsections.

6.3.1 Gas Resources

As stated above, the CAISO proposes to amend the reasonableness threshold rules for gas resources developed in CCDEBE to better account for gas price volatility.[26] The CAISO believes this is appropriate given recent large differences in the price for same-

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[24] California ISO will not support adjustment requests to the transition component. Instead, a supplier should submit the request to adjust the start-up costs of the multi-stage generators configurations. The verified amounts will be used in the estimated proxy cost option for transition costs

[25] For conditions that would warrant a supplier's cost expectations to differ from their administratively calculated cost estimates, see: Second Revised Draft Final Proposal Commitment Cost and Default Energy Bid Enhancements, 36

[26] Commitment Cost and Default Energy Bid Enhancements Second Revised Draft Final Proposal, Section 5.4 http://www.caiso.com/Documents/SecondRevisedDraftFinalProposal-CommitmentCosts-DefaultEnergyBidEnhancements.pdf

day gas purchases relative to the gas price indices the CAISO uses. Currently, the CAISO uses separate gas prices in the day-ahead and real-time markets.

For the real-time market, the CAISO calculates a gas price by averaging at least two published gas prices.[27] The CAISO calculates the gas price each day for the next day's real-time market between 7:00 and 10:00 pm using natural gas prices published earlier on the same day based for next-day gas trading. The CAISO uses these gas prices in a daily "fuel region" calculation, which it then includes to calculate each resources' bid cost reference levels. The CAISO then uses these reference levels in the next day's real-time market.[28] As these gas prices reflect next-day gas trading from the previous day rather than same-day gas trading on the operating day, there may be different suppliers actual costs to procure gas for real-time market dispatches.

For the day ahead market, the CAISO uses the volume weighted average hub prices that ICE publishes between 8:00 and 9:00 am. The CAISO uses this gas price to calculate bid cost reverence levels for the day-ahead market run that day for the following day.

The CAISO would use separate processes to establish reasonableness thresholds for the day-ahead and real-time markets as described below.

Real-Time Market

If the CAISO determines that the same-day gas prices differ significantly from the indices published the preceding evening, rather than basing reasonableness thresholds used by the real-time market only on gas indices published the previous evening, the CAISO proposes to update the reasonableness thresholds used by the CAISO's real-time market in the morning.[29] Reasonableness thresholds will be updated based a combination of same-day gas price information on ICE or through individual reasonableness threshold adjustment requests received from resource owners.

The CAISO proposes to review same-day gas prices on ICE each morning and individual reasonableness threshold adjustment requests each morning. If there is sufficient information on ICE, and/or based on individual reasonableness threshold adjustment requests, to indicate that same-day gas prices are greater than 10% compared to the next-day gas price index from the previous evening, the CAISO will automatically recalculate all resources' reasonableness thresholds in the applicable fuel regions.[30] Otherwise, the CAISO would update the reasonableness threshold for an individual resource making an adjustment request.

An updated reasonableness threshold will apply throughout the remainder of the day for the real-time market. The CAISO will update gas price indices and recalculate

[27] Natural Gas Intelligence, SNL Energy/BTU's Daily Gas Wire, Platt's Gas Daily, and the Intercontinental Exchange.
[28] California ISO Business Practice Manual, Market Instruments, Appendix C, Fuel Region Gas Price Calculations Rules
[29] For days in which there is trading on ICE, i.e. non-holiday weekdays.
[30] Both energy and commitment cost reasonableness thresholds would be recalculated.

reasonableness thresholds beginning with the next upcoming real-time market bid submission window.

To the extent the CAISO's review of same-day gas prices does not account for some individual resource's reasonableness thresholds, these resources may request a manual consultation with the CAISO. The CAISO proposes resource owners may request a manual consultations when same-day gas prices are more than 10% or $0.50, whichever is highest, more than the next-day gas price index based on the indices used that are published the previous evening.[31]

At the time of the manual consultation request, resource owners will be required to provide cost justification supporting an adjustment greater than a resource's reference level. Resource owners must retain the same documentation for bids above a resource's reference levels that are approved because of an automatic reasonableness threshold adjustment request. Bidding up to a supplier's reasonableness threshold is not a safe harbor and adjustment requests must be based on expected costs. Acceptable documentation to justify a supplier's increased real-time natural gas costs include the following:

- Invoices for gas purchased in real-time that demonstrate an incremental gas costs above the gas price that was used to develop a supplier's reference levels.
- Quotes from gas suppliers for real-time gas that demonstrate an incremental gas cost above gas price that was used to develop a supplier's reference levels.
- Evidence of other deals transacted in real-time at a price above the gas price that was used to develop reference levels.
- An offer to buy gas in real-time on a trading platform at or above the gas cost that was used to develop reference levels, where the offer was posted for a reasonable period of time but was not accepted. The documentation required would include the name of the trading platform, the price offered to buy the gas, the time the offer was placed and the time the offer was removed or rescinded.
- Other evidence of real-time gas costs temporarily above the gas reference index will also be considered.
- Suppliers may propose other methods of demonstrating temporarily increased gas costs to the CAISO.

If the requested amount appears to reflect current costs, the CAISO will approve the manual reasonableness threshold adjustment request. As outlined in the CCDEBE initiative, for the CAISO to consider these to reflect current costs, they should generally reflect multiple price quotes and the CAISO would calculate the cost as the weighted average of the quotes. If approved, the resource's revised reasonableness threshold

[31] The CAISO anticipates it would establish windows for manual consultations such as up to 8 am on business days

would be reflected in the soonest bid submission window after processing the updated gas prices.[32]

If the CAISO has sufficient information either through same-day gas trades ICE and/or manual consultations (e.g. three different gas price information from three different sources), the CAISO proposes to adjust reasonableness thresholds for other resources in the same fuel region. The CAISO would use a weighted average of the gas prices for updating reasonableness thresholds for a fuel region.

Day-Ahead Market

The CAISO also proposes to change the way it accounts for differences between Monday gas prices and the published price index the CAISO currently uses for the day-ahead market. As part of the CAISO's request to FERC to extend the temporary Aliso Canyon Phase 3 measures through 2019, NRG has raised concerns with the gas price index the CAISO uses for the day-ahead market run on Sunday for Monday. In response to NRG's comments, the CAISO proposes to adjust its use of the gas price index in its day-ahead market for Mondays by including ICE's Monday-only index, when it is available.[33] ICE only publishes this index when there is significant trading on Friday's for gas deliveries on Monday only. This is typically for Monday's when gas demand is anticipated to be significantly higher than normal. Otherwise, gas trading for Mondays is typically conducted as part of a Saturday-Sunday-Monday package.

With this change, the CAISO believes, similar to the change proposed above for calculating real-time market reasonableness thresholds, it will no longer need to increase gas prices used to calculate reasonableness thresholds for the day-ahead market by 25% for Mondays. Instead, the CAISO will calculate reasonableness thresholds for the day-ahead market by increasing the gas price used in the calculation by 10%. The CAISO will retain the reasonableness threshold of 25% for other days without an index published in the day-ahead time frame, *i.e.*, days after holidays.

6.3.2 Hydro Resource Default Energy Bid

The CAISO proposes a reference level adjustment for the hydro default energy bid based on changed gas prices that reflect its gas floor component. In order for the calculation to account for changes in gas prices and be an accurate gas floor price used in the default energy bid calculation, it is appropriate to update the gas component if gas prices increase significantly relative to the index price otherwise used by the market.

The CAISO proposes to adjust hydro default energy bids if the CAISO has sufficient information to update a gas fuel region, as described above. The CAISO will adjust hydro default energy bids for all hydro resources in that same fuel region based on

[32] Both energy and commitment cost reasonableness thresholds would be recalculated.
[33] The CAISO is separately proposing to enhance the temporary Aliso Canyon measures to include the ability to use the Monday-only index. http://www.caiso.com/Documents/WhitePaper-TemporaryUse-GasPriceIndex-Day-AheadMarket.pdf

updated gas prices when the CAISO updates the gas resource reasonableness threshold for a fuel region. For example, assume hydro resource A's default energy bid uses the gas hub Sumas. Gas resource B, C, and D's default energy bid also uses the gas hub Sumas. The only way hydro resource A's gas floor component could be adjusted would be if gas resources B, C, and D were to request and have their reference level adjustment approved. The CAISO understands that most hydro resources do not purchase gas. Further, if a hydro resource were to request a reference level adjustment, they would likely be unable to provide the necessary documentation to have their request validated and approved by the CAISO. Therefore, the only way for CAISO to determine if sufficient information is available to update a hydro resource's default energy bid is through manual consultations with gas resources in the same fuel region and/or through same-day gas trading observed on ICE.

The CAISO understands that some resource owners may control a hydro resource and a gas resource. To address these instances, the CAISO would allow the supplier to request a manual reference level adjustment for their hydro default energy bid based on the supplier's gas resource's increased real-time natural gas costs.[34]

6.4 Gas Prices Indices

The CAISO proposes to remove references to ICE in the CAISO tariff regarding gas price indices for the real-time market because an index published by ICE is no longer available. S&P Global Platts, another gas index, now contains information about Intercontinental Exchange trades through their daily and monthly North America natural gas indices. The CAISO will continue to reference S&P Global Platts as a source of gas indices that now contains information about ICE trades.

The CAISO also proposes to modify the requirement for the CAISO to use a minimum of two gas indices to determine the blended gas price use in the CAISO markets. The CAISO is proposing to allow the gas price index to be determined with as few as one index available from the various index providers. The publications the CAISO uses today include the following: Natural Gas Intelligence, SNL Energy/BTU's Daily Gas Wire, and Platt's Gas Daily.

Finally, similar to the proposal for the day-ahead market described above, the CAISO proposes to use ICE's Monday-only index for the real-time market on Mondays, when it is available.

The CAISO does not propose to modify the current practice of updating every weekday morning the gas price index for day-ahead market calculations using the information available from ICE trades.

[34] The adjustment would be subject to the supporting documentation requirements as described above.

7. Stakeholder Engagement

Table 6 outlines the proposed schedule to complete policy for the EIM Identified Market Power Mitigation Enhancements.

Table 6

Date	Milestone
January 16, 2019	Draft Final Proposal posted
January 23, 2019	Stakeholder call
February 8, 2019	Stakeholder written comments due
March 12, 2019	EIM Governing Body meeting
March 28, 2019	Board of Governors meeting

7.1 Stakeholder Comments

Stakeholders should submit their written comments to initiativecomments@caiso.com by close of business on February 8, 2019.

Appendix

Background

The purpose of this section is to provide context needed to understand the CAISO's issue/straw proposal presented in Section 6, Proposal. The CAISO will present this context by discussing the following:

- *Commitment Cost and Default Energy Bids Enhancements*– Before Market Reference Level Adjustment Requests
- California ISO's Local Market Power Mitigation Design
- Stakeholder Comments following the *EIM Offer Rules* stakeholder workshops[35]

Commitment Cost and Default Energy Bids Enhancements –

Before Market Reference Level Adjustment Requests

The CAISO recently completed a policy initiative titled, *Commitment Costs and Default Energy Bid Enhancements*, which evaluated the CAISO's market rules relating to supplier's bidding flexibility. The CAISO plans to file the tariff revisions needed to implement the changes resulting from this initiative in 2019 prior to implementing them in fall of 2019.

Through the *Commitment Costs and Default Energy Bid Enhancements* initiative, the CAISO determined the existing reference level (*i.e.*, default energy bids and commitment cost caps) design did not always accurately reflect suppliers' costs. To address stakeholder's concerns, the initiative developed provisions for suppliers to have the ability to request adjustments to reference levels used by the market. These reference level adjustments may be used to adjust a resource's startup cost, minimum load cost, or energy cost (default energy bid). Suppliers can only request an adjustment when conditions arise that drive the supplier's actual cost away from the CAISO's administratively calculated cost estimates. The supplier must be able to provide documentation supporting justification of their new cost using actual and current information.[36] Suppliers are prohibited from utilizing reference level adjustments for strategically placing bids to inflate market revenues or create uplift.

After a supplier submits a reference level adjustment request, the CAISO will verify the requested amount before a market run.[37] To verify an adjustment request, the CAISO

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[35] For details regarding the *EIM Offer Rules* stakeholder workshop, see: http://www.caiso.com/informed/Pages/MeetingsEvents/MiscellaneousStakeholderMeetings/Default.aspx

[36] Suppliers will not be required to submit this documentation to the CAISO for every adjustment request; however, it must be available upon request.

[37] If the CAISO is unable to verify an adjustment before the market run, the CAISO will determine whether costs were actual costs incurred above the adjusted reference level through the after-market verification process.

will use an automatic screen comparing the requested amount against a "reasonableness threshold." This reasonableness threshold establishes an amount the CAISO will automatically verify for a resource's reference level adjustment. The reasonableness threshold is different based on if a resource is gas-fired or non-gas-fired. For gas resources, the reasonableness threshold includes a gas price volatility scalar of either 125% or 110%.[38] For non-gas resources, the reasonableness threshold is 110%.[39]

Assume a supplier would like to request an adjustment to their default energy bid. Their default energy bid is $25 and they believe their costs are now $35. The supplier would submit the adjustment request; the CAISO would then verify the request through the automatic screen using the reasonableness threshold. The reasonableness threshold for this resource is $40. The supplier's adjustment amount of $35 would pass the reasonableness threshold and the $35 would be used in the market.

*** Value unknown to SC*

DEB	Adjustment Request	Reasonableness Threshold**
$25	$35	$40

Adjustment Request	Reasonableness Threshold**
$35	$40
Used in market	Request passed threshold

Assume the same supplier would like would like to request an adjustment to their default energy bid. Their default energy bid is $25 and they believe their costs are now $35. The supplier would submit an adjustment request; the CAISO would then verify the request through the automatic screen using the reasonableness threshold. The reasonableness threshold for this resource is $30. The supplier's adjustment amount of $35 would fail the reasonableness threshold. The CAISO would limit their adjustment to

[38] The volatility scalars will vary depending on the day. For Monday and days without a published index when the market would fall back on the prior day's published index (e.g. weekdays after holidays), the volatility scalar will be 125%. For all other days the volatility scalar will be 110%.
[39] The scaled fuel equivalent costs are calculated by applying a volatility scalar to Master File registered fuel equivalent cost values.

the reasonableness threshold amount of $30. The remaining $5 would be eligible for after the market review (ex-post) and could be potentially be recovered through the bid cost recovery process.

*** Value unknown to SC*

Reference Level	Adjustment Request	Reasonableness Threshold**
$25	$35	$30

Adjustment Request	Reasonableness Threshold**
$35	$30
Ex post review	Used in market

Extra $5 could be recovered

The CAISO provided after the market review and after-the-fact cost recovery mechanism for any reference level adjustment that was limited because a supplier's adjustment request exceeded the reasonableness threshold. However, a supplier's cost recovery is limited to actually incurred costs that exceed either: a cap or mitigated price level.[40]

CAISO's Local Market Power Mitigation Design

Each organized electric market has a methodology used to detect market power and trigger bid mitigation when it is detected. This section will describe the CAISO's current market power mitigation methodology and bid mitigation.

The CAISO evaluates market power through a market structure assessing two quantitative measures for energy.[41] The CAISO's market power mitigation test is most commonly referred as a three pivotal supplier test.[42] To assess transmission competiveness, the CAISO must first determine if there is sufficient supply to meet

[40] May not include any adders above cost such as a risk related adder or unrecovered costs through market revenues.
[41] Pending FERC approval of tariff changes resulting from the *Commitment Cost and Default Energy Bid Enhancements (CCDEBE)* initiative, the CAISO will also evaluate commitment cost market power.
[42] Structure refers to the ownership of available supply (or capacity) in a market.

demand. Competitiveness is assessed through the dynamic competitive path assessment which includes the three pivotal supply test.[43]

The three pivotal supplier test evaluates a local area in the market at a given constraint and determines if the constraint is competitive or uncompetitive. The three largest suppliers are removed and the local area is re-assessed to determine if there is sufficient supply to meet demand in the area. If there is enough supply to meet demand without the three largest suppliers in the area, the supplier is not pivotal and the constraint is competitive. If there is not enough supply to meet demand without the three largest suppliers, the suppliers are pivotal and the constraint is uncompetitive. Suppliers in an uncompetitive constraint may exercise market power and are subject to mitigation procedures.[44] For example, assume there are seven different suppliers in a locally constrained area with load of 500 MW. The three largest suppliers in the area have a total supply of 650 MW. The test would determine if the remaining suppliers have enough supply to meet the load of 500 MW. If the remaining four suppliers did not have enough supply to meet load, the constraint would be deemed uncompetitive. After the pivotal supplier test is complete, the residual supply index determines the ratio of supply from non-pivotal suppliers to demand. If the residual supply index is less than 1.0, then an uncompetitive level of supply is available.[45]

After the dynamic competitive path assessment is completed, the CAISO then determines what portion of the marginal congestion component of a resource's node is from the uncompetitive transmission constraints, known as the locational marginal price decomposition method. A positive non-competitive congestion component indicates the potential of local market power. The non-competitive congestion component of each locational marginal price is calculated as the sum over all non-competitive constraints of the product of the constraint shadow price and the shift factor of the resource to the constraint. Every resource with a locational marginal price non-competitive congestion component greater than zero is subject to mitigation.

Bids for these resources are mitigated down to the higher of the resource's default energy bid, or the "competitive locational marginal price" at the resource's location.[46] The locational marginal price is equal to System Marginal Energy Cost (SMEC) + Competitive Congestion Component + Non-Competitive Congestion Component + LOSSES. The competitive locational marginal price is equal to SMEC + Competitive Congestion Components + LOSSES.

A resource's energy cost reference level (*i.e.*, default energy bid) for gas or non-gas suppliers is calculated using one of the following four options:

[43] Determines if there is sufficient residual supply of counterflow to meet the demand for counterflow on a given constraint.
[44] Exercising market power may include a supplier inflating their energy prices, commitment costs, or withholding capacity.
[45] Demand Response Resources, Participating Load, and Non-Generator Resources are considered in the market power mitigation process, but are not subject to mitigation.
[46] The locational marginal price established in the locational marginal price mitigation run minus the non-competitive congestion component thereof (competitive LMP = $LMP_i - LMP_i^{NC}$).

1. Variable Cost Option (CAISO Tariff Section 39.7.1)
2. Negotiated Rate Option (CAISO Tariff Section 39.7.1.3)
3. Locational Marginal Price Option (CAISO Tariff Section 39.7.1.2)
4. *Variable Cost Option plus Bid Adder* (CAISO Tariff Section 39.7.1.4 for frequently mitigated units)[47]

A supplier for each resource ranks the variable cost, negotiated, or locational marginal price options as their preferred method order for calculating their default energy offer. If a supplier does not provide a ranking preference, the above order applies as the ranking default.[48]

The negotiated option requires the supplier to provide cost information to establish an approved rate formulation. Suppliers who elect to have their rate negotiated, first submit a proposed default energy bid (*i.e.*, energy reference level) along with supporting documentation. If denied, the CAISO and the supplier will enter into negotiations for sixty days. During this period, if the supplier and the CAISO agree to a rate, it will generally become effective within eleven business days.[49] The negotiated default energy offer will remain in effect until it is modified by FERC; modified by mutual agreement between the CAISO and supplier; or the negotiated rate expires, is terminated, or is modified in accordance with any FERC order.[50] The CAISO files these values in a confidential report with FERC each month.

Day-Ahead Market

The day-ahead market power mitigation process occurs prior to the integrated forward market and consists of single market run in which all modeled transmission constraints are enforced. The purpose of the day-ahead market power mitigation process is to determine which supply offers need to be mitigated before the integrated forward market runs.

Real-Time Market

The CAISO's real-time conducts a market power mitigation process in the Real-Time Unit Commitment (RTUC) run and in the 5-minute real-time dispatch run (RTD).[51]

Hour-Ahead Scheduling Process

[47] Only applies to a "Frequently Mitigated Unit that is eligible for a Bid Adder may select a fourth Default Energy Bid option, which is equal to the Variable Cost Option plus the Bid Adder as described in Section 39.7.
[48] California ISO Business Practice Manual, Market Operations, Section 6.5.4 Default Energy Bids
[49] California ISO Tariff Section 39.7.1.3.1 Submission Process: http://www.caiso.com/Documents/Section39_MarketPowerMitigationProcedures_asof_May2_2017.pdf.
[50] *Id.*
[51] Pending FERC approval of *Commitment Cost and Default Energy Bid Enhancements,* market power mitigation will occur in Short-Term Unit Commitment run (STUC).

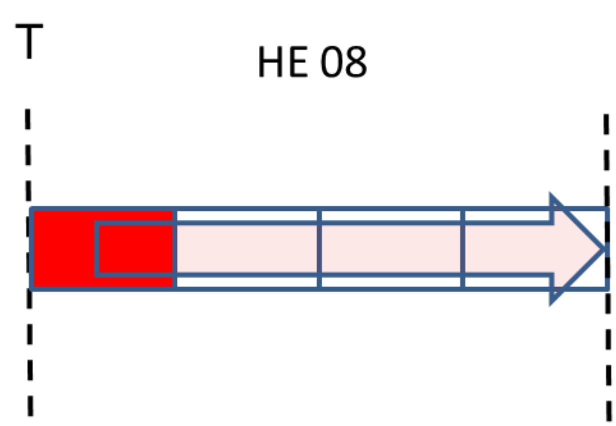
The hour-ahead scheduling mitigation process uses results from real-time unit commitment run (RTUC). The hour-ahead scheduling process uses a single mitigated supply offer for the entire trading hour is calculated using the minimum supply offer price of the four mitigated bid curves from the 15-minute levels at each supply offer.[52] The purpose of the hour-ahead scheduling process is to estimate the 15-minute market results for scheduling hourly import supply offers.

15-Minute Market

The 15-minute market mitigation process uses results from real-time unit commitment run (RTUC). For the 15-minute market, mitigation begins with a resource's unmitigated supply offer for the first 15-minute interval of a trading hour.[53] After the mitigation runs, the market receives mitigation results for each 15-minute interval of a trading hour (*i.e.*, four 15-minute intervals in an hour is equal to four separate mitigated supply offers for the hour).

If mitigation occurs to a supply offer in the first 15-minute, the remaining intervals within the trading hour are mitigated using the mitigated supply offer from the first interval as illustrated below in **Example 1**.

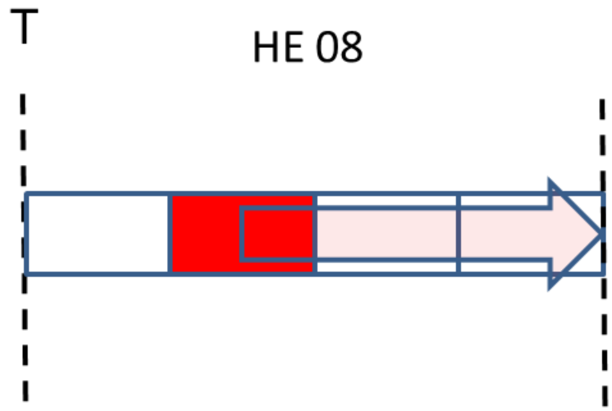
Example 1: Market power is determined for a resource in the first 15-minute interval of the 15-market indicated in red.



If market power is not detected in the first interval of the 15-minute market, but is detected for the second interval, a resource's supply offer will be mitigated for the second interval and all remaining intervals of the trade hour. The same logic would apply if market power was not detected for the first or second interval of the 15-market, but was detected for the third interval. Example 2 illustrates this logic below.

[52] California ISO Business Practice Manual, Real-Time Market, Section 34.1.5.3 Hour-Ahead Scheduling Process MPM.
[53] There are four (4) 15-minute intervals in an hour.

Example 2: Market power is determined for a resource in the second 15-minute interval of the 15-market indicated in red.



5-Minute Market

The 5-minute market, also known as real-time dispatch, receives mitigation results from the corresponding 15-minute interval. The 5-minute market will mitigate further using the results from the previous run where the current binding interval was the first advisory interval. Then, the market will determine if the next 5-minute interval has market power and if the supply offer should be mitigated. If market power is detected in a 5-minute market, the corresponding 15-minute interval will be mitigated.

Attachment H – Market Surveillance Committee Opinion

Local Market Power Mitigation Enhancements

California Independent System Operator Corporation

Opinion on
Local Market Power Mitigation Enhancements

by

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

Members of the Market Surveillance Committee of the California ISO

March 6, 2019

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-

[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

[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]

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[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.

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[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]

[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.

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[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.

[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]

[31]Ibid., p. 17.

[32]Ibid., Section 6.3.1

Attachment I – Department of Market Monitoring Comments

Local Market Power Mitigation Enhancements

California Independent System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Executive Director, Market Monitoring

Date: March 20, 2019

Re: **DMM Comments on proposed local market power mitigation enhancements**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

The Department of Market Monitoring (DMM) supports Management's proposed enhancements to the ISO's local market power mitigation rules. The proposed changes should effectively address concerns about bid mitigation of hydro resources raised by some EIM participants and entities considering whether to join EIM.

Several of the changes included in the proposal should encourage increased participation by entities with gas-fired and hydro resources. One of these changes will allow the ISO to update bid caps used in energy market power mitigation each operating day based on gas market conditions and observed prices in the same day gas market. This provision is important to deal with volatile gas prices within the ISO, as well as for EIM entities with gas generation. Another change will eliminate the extension of mitigation from a prior interval to subsequent intervals when mitigation would not otherwise be triggered. This will significantly reduce the total intervals in which mitigated bids are used, while ensuring that bid mitigation is still applied in intervals when congestion occurs on uncompetitive constraints.

Several other elements of the proposal involve potential trade-offs between the benefits of market power mitigation versus the potential for increased participation in the EIM by hydro resources. These include the provision allowing EIM areas to choose to have exports automatically limited when mitigation occurs and provisions that would allow default energy bids for hydro units in the Northwest to be set based on prices in the Southwest and up to 12 months of futures prices.

Although DMM has concerns about these provisions, we support the proposal in light of (1) the specific nature of hydro resources, (2) the lack of a must-offer obligation in the EIM and (3) the potential benefits from increased participation by entities with hydro resources.

COMMENTS

DMM has provided detailed written comments and analysis of the changes in mitigation rules being proposed throughout the stakeholder process.[1] This memo summarizes DMM's comments on key elements of the ISO's *Final Draft Proposal.*[2]

Updating gas prices used in energy bid mitigation

Under Management's proposal, the ISO will have the ability to raise bid caps used in energy market power mitigation each operating day based on gas market conditions and observed prices in the same day gas market. This provision is important to account for periodic spikes in the same day gas market prices within the ISO, as well as for EIM entities with gas generation.

This provision partially addresses one of DMM's recommended changes to the ISO's Commitment Costs and Default Energy Bid Enhancements (CCDEBE) proposal that was approved the Board in March 2018.[3] In this initiative, the ISO is proposing to adjust gas prices used in reasonableness thresholds used to mitigate energy bids. DMM continues to recommend that the ISO also develop the ability to increase start-up and minimum load bids used in the real-time market when prices in the same day gas market increase significantly above next day gas price indices used to set commitment cost bid caps.

Eliminating carryover of mitigated bids to subsequent intervals

The ISO proposes to eliminate the extension (or *carryover*) of mitigation from one 15-minute or 5-minute interval to subsequent intervals in that hour or 15-minute period. This carryover of mitigation originally stemmed from a combination of software issues and concerns about accuracy of earlier mitigation designs. Given the current levels of mitigation accuracy, DMM supports the proposal to eliminate the carryover of a resource's mitigated bids from one interval into subsequent intervals. This provision will reduce the impacts of bid mitigation and further improve market power mitigation

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[1] *Comments on Local Market Power Mitigation Enhancements Draft Final Proposal*, Department of Market Monitoring, February 11, 2019. http://www.caiso.com/Documents/DMMComments-LocalMarketPowerMitigationEnhancements-DraftFinalProposal.pdf

[2] *Local Market Power Mitigation Enhancements Draft Final Proposal*, California ISO, January 31, 2019: http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements-UpdatedJan31_2019.pdf

[3] Memo to ISO Board of Governors, re: Department of Market Monitoring Comments on CCDEBE Proposal, March 14, 2018, pp. 1, 4-6. http://www.caiso.com/Documents/Decision_CCDEBEProposal-Department_MarketMonitoringMemo-Mar2018.pdf

accuracy. Analysis by DMM performed as part of this initiative indicates that this change could reduce the frequency of mitigation by as much as 20 percent.[4]

Limiting net exports when mitigation is triggered

The ISO proposes to give each EIM entity the option of limiting the net exports out of its balancing area when resources in the area are subject to bid mitigation. This provision is designed to ensure that energy is not transferred from one EIM area to another area due to market power mitigation lowering the market bids submitted by EIM participants.

As illustrated in DMM's prior comments on the Draft Final Proposal, this provision could either increase or decrease market efficiency.[5] To the extent that a resource's market bids accurately reflect the resource's marginal opportunity costs, but default energy bids are lower than the resource's actual marginal costs, the net export constraint would increase market efficiency.

However, if a resource's market bids *exceed* actual marginal opportunity costs and default energy bids are not lower than the unit's actual marginal costs, the net export constraint may reduce market efficiency. Under this scenario, the limitation on net exports would also reduce how transfers from one EIM area may help mitigate uncompetitive conditions in another EIM area. This represents a change in the current market design, under which the application of bid mitigation in one balancing can help to mitigate potential market power in an adjacent balancing area.

Another concern about the proposal to limit exports when mitigation is triggered involves how congestion revenues are allocated when this export limit is binding. When the proposed net export constraint triggered by mitigation is enforced and binding, the ISO proposes to allocate 100 percent of the constraint's congestion rents to the exporting balancing area – rather than allocating congestion revenue equally between the exporting and importing areas.

The ISO's rationale for allocating 100 percent of congestion revenues to the exporting area in this scenario is that the ISO allocates congestion rents this way for net export constraints that are triggered when an EIM area fails to meet a downward flexible ramping sufficiency test. DMM's concerned that under both these scenarios, allocating 100 percent of congestion revenues to the exporting area may create incentives for inefficient scheduling and bidding. However, alternatives that DMM has considered for allocating net export constraint congestion rents may create outcomes that are potentially even more problematic. Therefore, DMM does not currently have a proposal for an alternative allocation scheme.

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[4] *Market Power Mitigation Issues*, Energy Imbalance Market Offer Rules Technical Workshop, July 19, 2018, slides 5-6. http://www.caiso.com/Documents/DMMPresentation-EnergyImbalanceMarketOfferRulesTechnicalWorkshop-Jul19-2018.pdf

[5] *Comments on Local Market Power Mitigation Enhancements Draft Final Proposal*, p. 4.

In practice, DMM believes the net export constraint should be unnecessary given the relatively high default energy bids for hydro resources that will result under the ISO's proposal. Thus, the use and impacts of the net export constraint represents an issue that warrants ongoing monitoring and the ISO should be prepared to make any adjustments that may be appropriate given actual market experience.

Default energy bids for hydro resources

The ISO is proposing a special default energy bid that will be available to all hydro resources which is designed to ensure that when mitigation is triggered, mitigated bids are not below the resource's opportunity costs. The new approach being proposed is similar to the approach currently used for many hydro resources which have selected the negotiated default energy bid option incorporated in the ISO tariff. However, DMM questions the addition of two additional provisions in the default energy bid calculation which may not be needed to reflect the actual opportunity costs of many hydro resources.

- The first of these provisions allows opportunity costs for hydro resources in the Northwest to be based on prices in the Southwest (i.e. Palo Verde hub). DMM has questioned this provision because higher prices often occurring in the Southwest reflect the *value of transmission* from the Northwest to the Southwest, rather than the *value of energy* in the Northwest.

- The second of these provisions would allow hydro resources indicating they have 12 months of storage capability to have default energy bids based on futures prices 12 months in the future. DMM has questioned this provision on the basis that this 12 month period often extends beyond the current hydro cycle and into the summer of the next year hydro year.

DMM's comments on the *Final Draft Proposal* includes an analysis of the proposed default energy bid for hydro resources with and without these provisions. A summary of this analysis is included as attachment 1 to this memo. As shown in Figures 1 and 2:

- Both of the hydro default energy bids are almost always greater than the resource's LMP (see Figures 1 and 2). Without inclusion of the Palo Verde prices in the *Geo Floor*, LMPs exceed the DEB in only 1 percent of intervals. With Palo Verde prices included in the calculation, the LMPs exceed the DEB in only 0.4 percent of intervals.

- The combined effect of using prices at Palo Verde and 12 months of futures price adds about $10/MWh to the default energy bids in the late winter and spring months, raising it from an average of about $40/MWh to about $50/MWh (see Figure 1). During these months, the default energy bid would frequently be set by futures prices at Palo Verde for August 2018 (plus the 10 percent adder included in the formula).

- Beginning in September 2018, these provisions add about $20/MWh, raising the default energy bids from a range of about $55 to $65/MWh to about $75 to $85/MWh (see Figure 2). During these months, the default energy bid would frequently be set by futures prices at Palo Verde for August 2019 (plus the 10 percent adder included in the formula).

As show in Figure 3 and Table 1:

- Under both default energy bid formulas, the default energy bid would be greater than the LMP during less than 2 hours during 98 percent of days.

- Based on 2018 prices, the default energy bid under both formulas would exceed the LMP during 4 to 5 hours on only one or two days of the year, and would never exceed the LMP during more than 5 hours on any day.

Based on this analysis, DMM believes that under the ISO's proposed methodology the standard default energy bids available to hydro resources in the Northwest will be high enough to allow hydro units to avoid being dispatched in all but a very small percentage of intervals and hours per day – *with* or *without* the use of prices at the Palo Verde hub and a full 12 months of futures prices.

Thus, the proposed approach appears to create very minimal risk that a hydro resource would be depleted, unless it was extremely energy limited on numerous days and was also subject to mitigation during a significant portions of hours in which high prices occurred.

In the event participants view the standard default energy bid options for hydro resources as inadequate for any resource, participants can and should continue to propose alternative more customized approaches under the negotiated default energy bid option of the ISO tariff. Under this option, default energy bids can be calculated based on actual projected energy limits for the following operating day.

At the same time, including these two provisions in the methodology results in a limited increase in the default energy bid during the spring and fall months and still provides significant protection against the potential for the exercise of market power.

CONCLUSION

DMM supports the overall proposal in light of (1) the special nature of hydro resources, (2) the lack of a must-offer obligation in the EIM, and (3) the competitive benefits that can come with increased participation by entities with hydro resources.

DMM's analysis shows that the new default energy bid for hydro resources being proposed is high enough that resources could still bid high enough to rarely be dispatched even when subject to mitigation, while being low enough to significantly mitigate market power (or the ability to significantly raise prices) when market conditions are uncompetitive.

DMM notes that the special default energy bid offered for hydro resources would not be appropriate for other resources. Under the ISO tariff, default energy bids used in mitigation for all other resources are designed to be reasonable estimates of a resource's actual marginal cost – including opportunity costs based on the actual characteristics of each resource. For other energy limited energy resources, such as gas-resources with environmental limitations, opportunity costs can and should be based on actual energy limits of the resource over a specific time period (e.g. daily, monthly or annual). This can be done using the negotiated default energy bid option in the ISO tariff.

The impact of several provisions of the proposal merit ongoing review after implementation and the ISO should be prepared to make any adjustments that may be warranted based on market conditions. These provisions include (1) the option to have net exports automatically limited when bid mitigation is triggered in an area, and (2) the options to have default energy bids for resources in the northwest based on Palo Verde prices and a full 12 months of futures prices. The impact of these provisions can be readily monitored based on market data and results available to the ISO and DMM.

Attachment 1

Analysis of proposed default energy bid for hydro resources

This analysis compares the default energy bid that would have resulted from this methodology for a typical hydro resource in the Northwest to 15-minute energy imbalance market prices in the 2018 calendar year.

Figures 1 and 2 compare the default energy bids that would result under the proposed approach for a hydro unit in the Northwest (PacifiCorp West) to 15-minute locational market prices (LMPs) for a resource in that area during the 2018 calendar year.

- The blue line shows the default energy bid that includes the Palo Verde trading hub and 12 months of futures data in the *Geo Floor*.
- The orange line shows the default energy bid based on 12 months of futures data for Mid-C, but does not include Palo Verde prices in the *Geo Floor.*

As shown in Figures 1 and 2:

- Both of the hydro default energy bids are almost always greater than the resource's LMP (see Figures 1 and 2). Without inclusion of the Palo Verde prices in the *Geo Floor*, LMPs exceed the DEB in only 1 percent of intervals. With Palo Verde prices included in the calculation, the LMPs exceed the DEB in only 0.4 percent of intervals.
- The combined impact of using prices at Palo Verde and 12 months of futures prices adds about $10/MW to the default energy bids in the late winter and spring months, raising it from an average of about $40/MWh to about $50/MWh (see Figure 1). During these months, the default energy bid would frequently be set by futures prices at Palo Verde for August 2018 (plus the 10 percent adder included in the formula).
- Beginning in September 2018, these provisions add about $20/MWh, raising the default energy bids from a range of about $55 to $65/MWh to about $75 to $85/MWh (see Figure 2). During these months, the default energy bid would frequently be set by futures prices at Palo Verde for August 2019 (plus the 10 percent adder included in the formula).

Figure 1. Hydro DEBs based on prices at Palo Verde vs. Mid-C (Jan-June 2018)

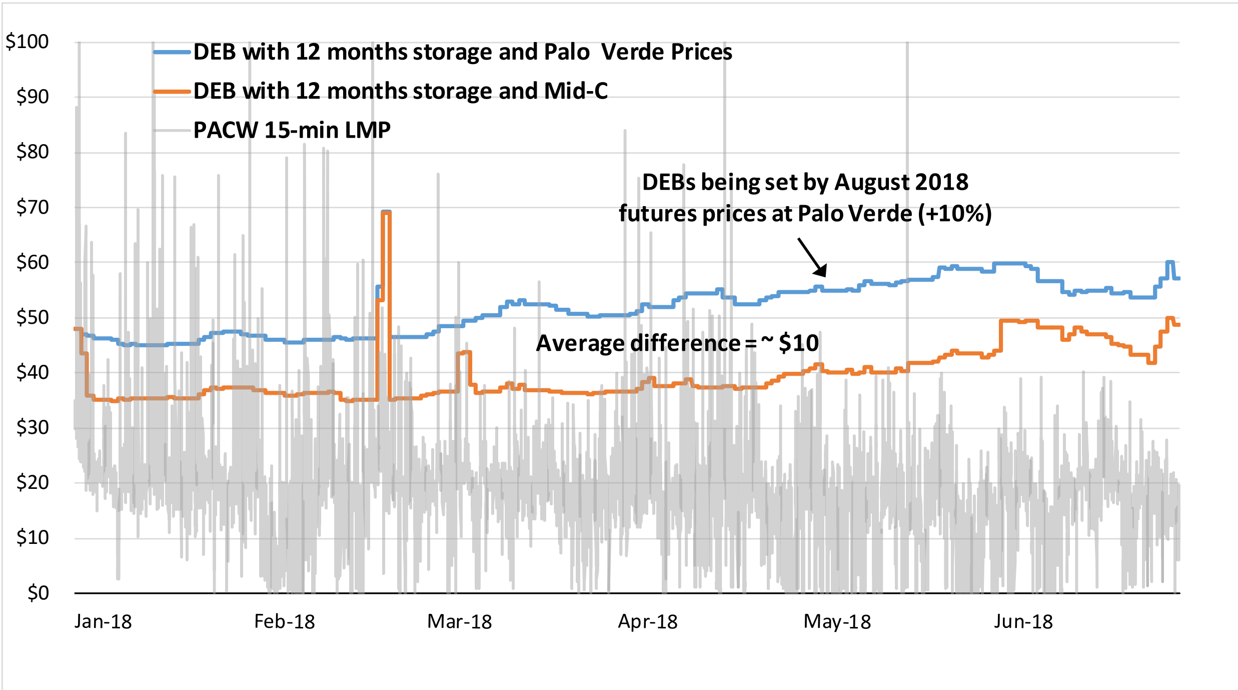

Figure 2. Hydro DEBs based on prices at Palo Verde vs. Mid-C (July-Dec 2018)

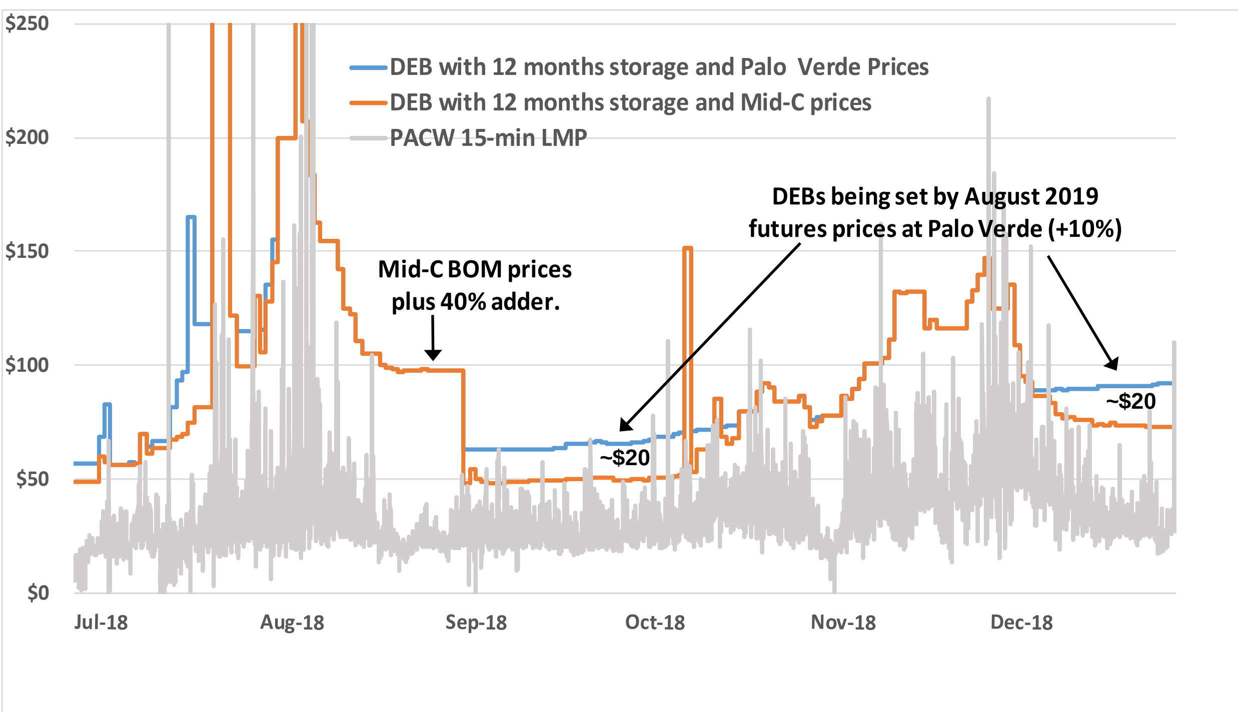

Figure 3 shows the total number of hours per day in 2018 that the LMP in the PacifiCorp West area would be higher than the standard default energy bid for a hydro unit in this area under four different scenarios. These scenarios include different combinations of default energy bid based on futures prices for either 6 or 12 months, and with and without Palo Verde prices included in the *Geo Floor* of the formula.

Table 1 compares the total number of hours per day that EIM prices in the PacifiCorp West area during 2018 would be higher than default energy bids based on (1) Mid-C prices and 6 months storage, compared to default energy bids that include (2) Palo Verde prices and a full 12 months of futures prices.

As show in Figure 3 and Table 1:

- Under both default energy bid formulas, the LMP would be greater than the default energy bid during less than 2 hours during 98 percent of days.

- Based on 2018 prices, the LMP under both formulas would exceed the default energy bid during 4 to 5 hours on only one or two days of the year, and would never exceed the default energy bid during more than 5 hours on any day.

Figure 3. Total Hours per day with LMP greater than hydro DEB (2018 data for PacifiCorp West area)

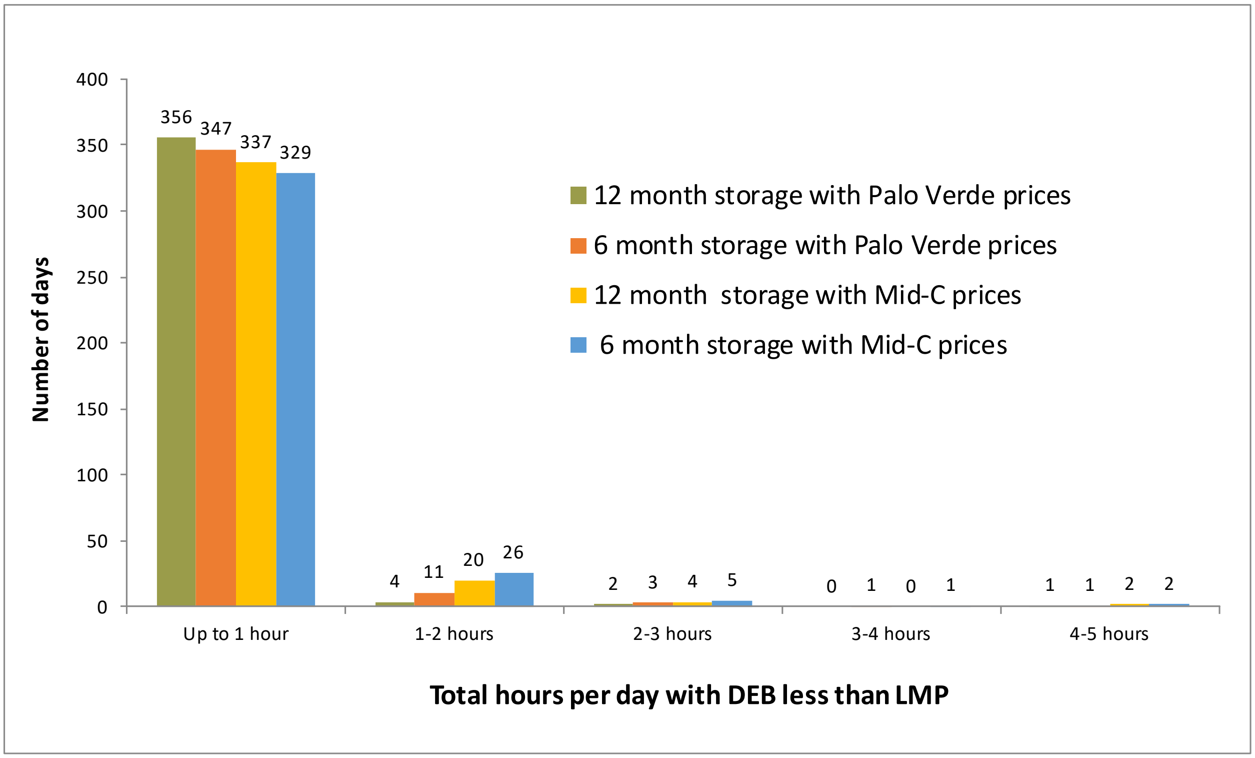

Table 1. Hours per day LMP > hydro DEB

	Mid-C hub and 6 months of futures prices		Palo Verde hub and 12 months of futures prices	
Hours/day LMP > DEB	Days	Percent	Days	Percent
1 hour or less	329	90.6%	356	98.1%
1-2 hours	26	7.2%	4	1.1%
2-3 hours	5	1.4%	2	0.6%
3-4 hours	1	0.3%	0	0.0%
4-5 hours	2	0.6%	1	0.3%
More than 5 hours	0	0.0%	0	0.0%
	363		363	

Attachment J – Testimony of Gabriel Murtaugh

Local Market Power Mitigation Enhancements

California Independent System Operator Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER19-___-000**

TESTIMONY OF
GABRIEL MURTAUGH
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

Q. Please state your name, title, and business address.

A. My name is Gabriel Murtaugh. I am employed as a Senior Infrastructure and Regulatory Policy Developer for the California Independent System Operator Corporation (CAISO). My business address is 250 Outcropping Way, Folsom, CA 95630.

Q. Please describe your educational and professional background.

A. I have a Bachelor's degree in computer science and engineering, a Master's degree in Economics, and additional research experience in Economics. Prior to my current position at the CAISO, I was an analyst for two years for Potomac Economics, the external market monitor for the Midcontinent Independent System Operator (MISO). There I reviewed general market performance, behavior of market participants – including bidding strategies and market activities – and assessed and reported on non-competitive behavior of those market participants. Prior to that, I worked at SNL Financial (now S&P Global) for three years.

Q. What are your responsibilities as Senior Infrastructure and Regulatory Policy Developer?

A. As a senior infrastructure and regulatory policy developer, I am responsible for developing CAISO policy that relates to infrastructure and regulatory oversight. These responsibilities include creating principles for policy initiatives and policy direction. This is all completed through robust stakeholder processes through which we vet policy proposals and receive and incorporate stakeholder input. After completion of the stakeholder process, my group and I are responsible for submitting final proposals to the CAISO Board of Governors and the EIM Governing Body, as appropriate for approval, prior to filing with the Commission any necessary amendments to the CAISO tariff.

Q. What is your previous experience at the CAISO?

A. Immediately prior to working in the policy department at CAISO, I worked in CAISO's internal Department of Market Monitoring (DMM), as a senior analyst for three years. My primary responsibility was the publication of the Annual Report, covering detailed CAISO market activity for the entire year. DMM monitors the efficiency and effectiveness of the CAISO markets and provides recommendations market design and operational inputs, and reviews potentially detrimental market behavior. The Annual Report focused on these objectives.

Additionally, I was the DMM liaison for market participants in the western energy imbalance market (EIM) and I was responsible for constructing and implementing negotiated default energy bids for supply resources. This included obtaining detailed operating conditions for resources, particularly hydroelectric resources, determining the best way to capture or replicate marginal costs of operations, and creating software to format and deliver this information to the CAISO market software.

Q. What is the purpose of your declaration?

A. The purpose of my testimony is to describe the analysis the CAISO conducted to develop and support the short-term component of a standard default energy bid for hydroelectric resources with storage capability (*i.e.,* the hydro DEB). The short-term component measures the opportunity costs of a hydroelectric resource with short-term storage capability based on prevailing prices of bilateral trades for replacement energy. These bilateral trades are measured at a representative electric pricing hub where the resource is located. Because prices in the CAISO real-time market vary based on system and grid conditions, the CAISO determined it is necessary to ensure the hydro DEB is sufficiently high to avoid dispatching hydroelectric resources, with limited storage, too frequently based on actual prevailing real-time market prices. I will describe the analysis the CAISO conducted to establish the appropriate multiplier included in the short-term component of the hydro DEB to meet this goal. This analysis was completed using historical CAISO market prices. As a result of this analysis the CAISO proposes to set the multiplier to 1.4 (*i.e.,* a 40 percent multiplier).

I. Background

Q. Please give a brief overview of default energy bids.

A. The CAISO operates a wholesale market in which buyers and sellers transact energy. In order to maintain competitive markets, the CAISO employs measures to mitigate supplier market power. One such measure is the market's automated local market power mitigation (LMPM) process that is a part of the CAISO's day-ahead and real-time markets. The CAISO markets begin the LMPM process after energy bids are submitted and completes it before the market determines prices, schedules, and dispatch instructions. The LMPM process identifies if any supplier has the potential to exercise market power based on its resource's location. For example, if there is not enough competitive capacity to meet demand in a constrained area, the LMPM process determines the constrained area to be uncompetitive. Suppliers with resources located in uncompetitive constrained areas may exercise market power by inflating their energy bids. If the LMPM process detects market power, it will reduce a supplier's submitted energy bid to the greater of the resource's default energy bid or a calculated competitive locational marginal price (LMP). The CAISO market generally calculates default energy bids based on estimates of resources' marginal costs to produce energy.

Q. How does the CAISO calculate the existing default energy bid options?

A. The CAISO currently has three methodologies for calculating default energy bids for resources: the (1) variable cost option; (2) LMP option; and the (3) negotiated rate option. Each of these options involves calculating the default energy bid each day, separately for the CAISO's day-ahead and real-time markets.

Q. Please describe the variable cost option.

A. The variable cost option uses each resource's fuel requirements and costs to calculate its default energy bids. This default energy bid represents the incremental (*i.e.*, marginal) cost to operate the resource at a particular energy production level. The calculation for natural gas-fired resources uses incremental fuel costs (the resource's incremental "heat rate" (*i.e.*, its fuel requirement) multiplied by a natural gas price), a standard variable operations and maintenance cost, the CAISO's grid management charge, and greenhouse gas allowance costs, if applicable. The calculation includes a 10 percent adder to the sum of these costs. In addition to these costs, if applicable to the resource, the calculation also adds a frequently mitigated unit adder and/or an opportunity cost adder. The CAISO also has a non-natural gas-fired resource option calculated the same way but uses non-gas fuel or fuel equivalent costs.

Q. Please describe the LMP option.

A. The LMP option uses historic prices at the resource's location to calculate default energy bids for resources. This methodology is calculated based on a weighted average of the lowest quartile of LMPs at the resource's location during the market intervals when the CAISO market scheduled or dispatched the resource to provide energy during the previous 90 days.

Q. Please describe the negotiated option.

A. The negotiated rate option uses customizable inputs to determine default energy bids. The specific methodology for this default energy bid option is negotiated between the CAISO (through the CAISO's Department Market Monitoring) and the supplier. During the negotiation, the supplier provides cost information to the CAISO to develop a resource-specific cost calculation. If the negotiation yields a default energy bid acceptable to the CAISO and the market participant, the CAISO then uses the default energy bid in the market. The CAISO submits an informational report to FERC reflecting the agreed upon negotiated default energy bid. If the market participant is not satisfied with the outcome of the negotiation, it may submit a proposed default energy bid to FERC pursuant to Section 205 of the Federal Power Act.

Q. What were concerns raised by market participants who schedule and bid hydroelectric resources with these current default energy bid options?

A. Market participants, particularly those participating in the EIM balancing areas outside the CAISO, raised concerns that the current default energy bid formulas often do not account for hydroelectric resources' opportunity costs that exist due to their limited water supply. The current variable cost option accounts for energy opportunity costs if the supplier applies for, and the CAISO confirms, the use limitations for a specific resource. However, this opportunity cost methodology used under the variable cost option was designed for use-limited gas resources and consequently can only reflect monthly and annual use limitations. However, hydroelectric resources often have shorter term limitations that may arise during a single day. These potential limitations could significantly vary over time and result in variable opportunity costs. The variable cost option default energy bid is a precise calculation that does not account for the numerous and variable factors affecting water availability, resulting in the calculated opportunity cost being lower than actual opportunity costs during many periods. Market participants expressed a similar concern with opportunity cost based default energy bids developed under the negotiated option. The variable cost option default energy bid also does not account for the opportunity costs of bilateral sales outside the CAISO market, which is a particular problem for hydroelectric resources in balancing authority areas outside of the CAISO participating in the EIM.

Q. Can you explain what opportunity costs represent and the reason hydroelectric resources with water storage have opportunity costs?

A. Hydroelectric resources with a limited stored water supply may have short-term and long-term opportunity costs. These resources have long-term opportunity costs because they can only produce a limited amount of energy over a given interval. The opportunity cost represents the additional expected revenue a resource would receive if it conserves its water supply and produces energy when prices are highest and energy is most valuable to the system. For example, if a resource only has enough water to produce energy during one month of the year, and energy prices in the highest-priced month are $75/MWh, then if the resource was to produce at any time before that month it would have an opportunity cost of the difference between $75/MWh and the price at which the energy was sold. Long-term opportunity costs for these resources are further complicated by constraints in addition to limited availability of water. This applies to resources in the EIM balancing authority areas in particular where hydroelectric resources may have additional opportunities to sell energy in bilateral energy markets. Hydroelectric resources typically also have short-term limitations that may be daily or hourly and arise due to water use limitations imposed by environmental limitations, obligations for water use besides electrical generation, environmental constraints, or other constraints. These short-term limitations can either always exist or arise only under certain conditions. The opportunity costs due to these short-term limitations can be higher than the resource's opportunity costs due to long-term limitations. This imposes opportunity costs on the resource if it is unable to operate for the remainder of the period applicable to the limitation, such as for the remainder of the day. Therefore, the decision to sell energy from a hydroelectric resource into the CAISO market is based on numerous factors, which requires careful consideration of all constraints and opportunities facing the resource.

Q. Why is it important for a default energy bid for a hydroelectric resource to include opportunity costs?

A. It is important that a hydroelectric resources' default energy bid reflect its opportunity costs so that the CAISO market does not schedule or dispatches these resources sub-optimally during intervals when market power mitigation is triggered. When market power mitigation triggers, prices may be reduced to their default energy bid. If opportunity costs are not fully reflected in the default energy bid the CAISO market may issue schedules or dispatches that cause water supply to not be available in the future when energy prices are higher. Further, if the default energy bids do not appropriately reflect opportunity costs the CAISO market may produce schedules or dispatches that interfere with the supplier's ability to comply with environmental limitations or other water obligations. Either scenario may cause suppliers to make the resource unavailable to the CAISO market, leaving the CAISO with less supply to meet system and local energy and ramping needs.

Q. How does the CAISO's proposed hydro DEB resolve their concerns?

A. The CAISO proposes a standard hydro DEB for hydroelectric resources with storage capability that is based on a formula that reasonably estimates the hydroelectric resources' opportunity costs based on their water availability limitations. It also accounts for market participants' ability to make bilateral sales of energy from their hydroelectric resources, including sales at a different location than the resource. This design acknowledges that the CAISO cannot precisely determine a hydroelectric resource's available water supply and attempting to do so could interfere with the supplier's operation of their water systems.

Q. What resources are eligible for this proposed hydro DEB calculated?

A. The hydro DEB will be available to hydroelectric resources with storage in any of the balancing authority areas that participate in the CAISO's real-time market, including EIM balancing authority areas.

II. <u>Proposed Hydro DEB</u>

Q. How will the proposed hydro DEB calculated?

A. The default energy bid will be calculated each day as the greatest of three components, the: (1) long-term/geographic component; (2) short-term component; and (3) gas floor. My testimony is focused on the multiplier the CAISO proposes to include in the short-term component.

Q. What is the hydro DEB intended to capture?

A. The hydro DEB is intended to capture the opportunity costs of a hydroelectric resource with limited water for use to produce energy and potential opportunities to sell that energy in the future, including in the bilateral market outside the CAISO market. The proposed hydro DEB is designed in a customizable fashion to produce a value that represents these costs for most hydroelectric resources with storage in the fleet. The three components respectively represent the ability to sell energy in different markets and during different periods in the future, a value reflecting CAISO market real-time price volatility, and the potential cost to procure replacement energy in the real-time market. Since each of these three components can reflect the marginal cost to operate a resource, the highest of these three values is used to calculate the hydro DEB. For example, if the long-term/geographic component is the highest value, then prices in the future are anticipated to be higher than the current day's prices, and the resource's marginal costs are the opportunity cost of generating in the future. Alternatively, if the short-term component is the highest value, than the current's day prices are higher than anticipated prices in the future and a resource's marginal costs are the opportunity costs of generating in the highest priced hours of the day given the resource's short-term use limitations.

Q. Please describe the long-term/geographic component.

A. The long-term/geographic component reflects that a hydroelectric resource's opportunity costs for generating and consuming water today may preclude energy sales in future months, based on their storage horizon, and at other geographic locations. This component ensures the CAISO market will not dispatch a hydroelectric resource prematurely when anticipated energy prices are higher in a future month or another geographic location.

Q. How will the CAISO calculate the long-term/geographic component?

A. To calculate the long-term/geographic floor, the CAISO identifies the maximum of the day-ahead, balance-of-month, and month-ahead futures energy index prices.

These index prices will be from electric pricing hubs specific to the resource for which the hydro DEB is calculated. The month-ahead futures prices will include future months through the resource's maximum storage horizon. For example, if a resource's storage horizon is three months, the month-ahead index prices for the next three months are included. The future indices used are representative of the expected prices a resource might receive in the future.

Q. How will the storage horizon be determined?

A. The CAISO will expect that market participants use multiple years of historic reservoir operations data to determine a resource's storage horizon. The maximum storage horizon corresponds to the typical amount of time, in months, between cycles of peak reservoir water elevation levels during periods with typical hydro conditions. These values are bound between 1 and 12 months. For example, if a resource can store water for several days but no longer, it would receive a 1 month maximum storage horizon. If the resource typically needed to run or spill in the spring it may have a 9 month maximum storage horizon. If, however, the resource typically could store water between multiple years and did not need to run in the spring, it might have a 12 month maximum storage horizon.

Q. **Will there be default pricing hubs that apply to the long-term/geographic components?**

A. Yes. As a default, the local pricing hub is always included in the long-term/geographic component. Each balancing authority area in the CAISO energy markets will be mapped to a specific bilateral electric pricing hub, specified in the business practice manuals, to be used in the short-term and long-term/geographic floor of the hydro DEB. As a general rule, the CAISO will map balancing areas to an electric pricing hub with prices that roughly or best represent prices in the balancing authority area based on available EIM transmission and historic energy transfers. At this time, the CAISO is considering Mid-Columbia, Palo Verde, Alberta, north-of-path 15, and south-of-path 15 as the applicable default electric pricing hubs, provided that the CAISO can confirm the trading activity at these hubs is sufficiently liquid to provide a robust indication of prevailing prices. After the maximum of the three prices is determined, the CAISO will apply a multiplier to that price to compute the short-term component. As discussed above, this multiplier is intended so that the price of the short-term component is high enough so that the CAISO market generally only dispatches a resource within a limited number of hours per day. The CAISO calculated the value of the multiplier by estimating hypothetical resource dispatch based on a comparison between historic real-time prices and the assumption that the resource bid into the market at the calculated hydro DEB.

Q. Will the hydro DEB account for opportunities to make sales at multiple locations in the bilateral market?

A. Yes. Because sales may be made either at a local electric pricing hub or at a distant electric pricing hub, hubs in addition to the local hub may be included in the calculation of the long-term/geographic component. What additional hubs can be included will be determined through a consultative process between the scheduling coordinator and the CAISO. The scheduling coordinator will need to demonstrate that they hold firm transmission rights to the alternative hubs. It is reasonable to consider these hubs, because owners with firm transmission rights, would be able to sell energy from the resource's location to remote locations at specific times, including specific hours, in the future and capture price differences between these two markets.

Q. Please describe the short-term component.

A. The short-term component approximates a resource's short-term opportunity costs based on anticipated energy prices ranging from the next day to the next month. This component of the hydro DEB considers volatility of CAISO real-time markets and limitations for typical hydroelectric resources in the fleet. The hydro DEB is constructed assuming historic price volatility so that anticipated dispatch will be below typical short-term use limitation, during most scenarios.

Q. How will the CAISO calculate the short-term component?

A. The CAISO will consider the maximum of: the day-ahead on-peak price at the applicable electric pricing hub; the on-peak balance of the month futures price for the current month at the applicable electric pricing hub; and the on-peak prompt month futures price at the applicable electric pricing hub for one month after the current month. The prices for these three calculations will be at a specific mapped electric pricing hub. Similar to the long-term/geographic component, each balancing authority area in the CAISO energy markets will be mapped to a default electric pricing hub, based on where the hydroelectric resource is located.

Q. What is the intent of the multiplier applied to the short-term component?

A. The multiplier in the short-term component is designed to produce a price high enough to prevent most hydroelectric resources from being dispatched more than their short-term water limitations. This is necessary because the hydro DEB is calculated based on electric pricing hub index prices that reflect potential sales at fixed prices for energy delivery that spans multiple intervals. Because real-time market prices in CAISO vary by market interval and typically are higher in certain intervals than corresponding electric pricing hub index prices, the multiplier is intended to increase the electric pricing hub index prices so that they are high enough to avoid dispatching the hydroelectric resource too frequently. When testing the hydro DEB to ensure that most resources would indeed be typically dispatched less than their storage capability, the CAISO was able to adjust this parameter to create higher or lower values for the hydro DEB, resulting in less or more frequent dispatch. Arriving at a multiplier that best met this criteria was a key part of the analysis that the CAISO performed, and is described further in this testimony.

Q. What is the maximum number of hours per day hydroelectric resources with storage capability should be dispatched to avoid these issue?

A. Each resource is different and the CAISO could not establish tailored values for each and every hydroelectric resource. However, through this stakeholder process that preceded this tariff amendment, the CAISO concluded that four hours per day represented a reasonable approximation of most hydroelectric resources' short-term water limitations. These short-term limitations may result from environmental restrictions on river flow, downstream hydro implications, pre-arranged flow agreements, or other similar considerations. For example, on October 10, 2018, Powerex presented at a working group for the LMPM enhancements initiative. This presentation covered topics specifically related to the hydro DEB. In this presentation, they outlined the complexities of modelling these resources and stressed how critical it was that these resource's limited water not be depleted inefficiently or at suboptimal times. Powerex emphasized that this could occur if a resource had a default energy bid significantly below true opportunity costs that change even on an intra-day basis. Further, they articulated potential negative impacts, operationally and financially, that a resource could face if water was depleted inefficiently, and expressed that this would be unacceptable to most hydroelectric resource operators. Finally, they presented data on ranges of hypothetical hydroelectric resources with a range of energy storage between 4 and 12 hours of per day. From that analysis the CAISO adopted the lower end of this range, or a resource with typical 4 hours of storage per day to be a conservative representation of the short-term constraints that incorporates most hydroelectric resources on the grid. Stakeholders largely supported this assumption, which was discussed in later public stakeholder meetings, and the accompanying analysis performed by the ISO. (*See* slides 17, 18, 28 and 29: http://www.caiso.com/Documents/PowerexPresentation-LocalMarketPowerMitigationEnhancementsWorkingGroup_Oct10_2018.pdf)

Q. What is the multiplier value applied to the short-term component?

A. The CAISO determined a multiplier value based on past prices in the CAISO markets that would ensure that the resource would be dispatched at their hydro DEBs no more than 4 hours per day in at least 95 percent of cases. That multiplier came out to 1.4. Below I describe the analysis my team conducted to arrive to the 1.4 value. The frequency of 95 percent was chosen to so that a typical hydro resource would infrequently exceed its short term limitations.

Q. Did the CAISO consider unique multipliers for each resource?

A. No. The goal was not to create a default energy bid that would necessarily be prescriptive to each resource as are some of the negotiated default energy bids, but rather to create a default energy bid that could be used by most hydroelectric resources that would capture their costs. We concluded that a single multiplier could achieve this for a representative resource with four hours of storage. Further, stakeholders generally supported the hydro DEB formulation and the analysis performed.

Q. Please describe the gas floor component.

A. The gas floor component accounts for the supplier's costs to supply energy from gas-fueled resource if the CAISO dispatch exhausts a hydroelectric resource's water supply during a day. This is intended to reflect a cost the supplier may face if a resource's short-term water availability is depleted. This can help to ensure the CAISO market does not dispatch a hydroelectric resource in excess of its short-term water availability limitations in the event real-time energy prices are significantly high because of high real-time gas prices. The CAISO will calculate the gas floor component similar to how it calculates variable cost default energy bids for gas resources based the product of a proxy of the heat rate for an average natural gas peaking resource and the prevailing gas price index for a representative gas resource at the same location as the hydroelectric resource.

II. Analysis to Determine the Multiplier for the Short-Term Floor Component of the Hydro DEB

Q. Please describe what the CAISO set out to determine through this analysis?

A. This analysis was to determine by how much prices for hydroelectric resources would have to be multiplied to ensure that resources would generally not be dispatched for more than four hours per day, based on the relationship of historic prices reported at electric pricing hubs and real-time market prices where the resource is located. This analysis was set up to show that generally a resource that could only produce 4 hours of energy per day would be dispatched more than that amount infrequently, if bidding at the hydro DEB.

Q. Please describe the analysis the CAISO conducted to determine the multiplier applied to the short-term component.

A. To determine the multiplier, the CAISO performed detailed analysis on several hypothetical resources. Specifically, the CAISO chose to model resources from the PacifiCorp East, PacifiCorp West, and Puget Sound Energy balancing authority areas, using CAISO real-time market prices from the respective areas. These represent a variety of prices for actual hydroelectric facilities that exist across the footprint of the CAISO's real-time energy market. The CAISO also modeled a hypothetical resource receiving Powerdex hourly prices at the Mid-Columbia trading hub. Powerdex is a service that offers hourly index prices, instead of multi-hour blocks, at several key electricity hubs within the Western interconnection. This ‘Powerdex’ resource could be representative of potential hydroelectric resources located in balancing authority areas that are scheduled to join or may potentially join EIM in the future. It may also represent how existing EIM area prices may change in the future when and if additional transmission is available in that market. Finally, this may reflect future price conditions as CAISO energy markets continue to evolve, such as development of a more robust day-ahead market that may include EIM areas.

Q. What limitations did you assume for the hypothetical resources?

A. In reality each hydroelectric resource is highly complex and use limitations may rapidly change, including within intra-day periods. It is also likely that some resources would optimally run for less than 4 hours during some days. Stakeholder engagement on this initiative indicated that the assumptions used to determine this hydro DEB, including the assumption of 4 hours of hydro availability per day, was acceptable for calculating the default energy bids for hydroelectric resources. However, the hydro DEB is not meant to necessarily be sufficient to prevent all hydroelectric resources from running inefficiently during all days, but rather it is meant to be sufficient for most resources on most days.

Q. How did you determine the expected amount of time the hypothetical resource would be dispatched?

A. The CAISO completed analysis for each hypothetical resource. As part of this analysis, the CAISO calculated hydro DEBs for each day in a 1-year span, using the methodology outlined in this testimony, and comparing those hydro DEBs to historic real-time market prices during that same period. In comparing these two values, the CAISO could determine an expected amount of time that a resource would be dispatched during a given day if the resource bid at the hydro DEB each day.

Q. How did you calculate the hydro DEBs for the hypothetical resources?

A. The CAISO calculated the hydro DEBs for each day using an appropriate energy price index reported at certain electric pricing hubs. The CAISO used Mid-Columbia electric pricing hub for the hypothetical resources in PacifiCorp West, Puget Sound Energy, and the resource modelled with Powerdex prices. The CAISO used the Palo Verde hub prices for the hypothetical resource in PacifiCorp East. The CAISO assumed that each resource had three months of available storage and did not have firm transmission to other electric pricing hubs when calculating the hydro DEBs. The CAISO used the natural gas prices for the Sumas fuel region to compute the gas floor of the hydro DEBs for the hypothetical resources in PacifiCorp West, Puget Sound Energy, and the resource modelled with Powerdex prices. The CAISO used the natural gas prices from the Kern region to compute the gas floor for the hypothetical resource located in PacifiCorp East.

Q. What were the calculated hydro DEBs compared to?

A. These calculated hydro DEB values were compared to 15-minute real-time EIM energy prices in PacifiCorp West, Puget Sound Energy, and PacifiCorp East areas for the respective representative hydroelectric resources. The default energy bid values calculated for the resource modelled with Powerdex prices were compared to the hourly Powerdex prices.

Q. How did you determine 1.4 was the appropriate multiplier?

A. We compared the hydro DEBs calculated for the hypothetical resources and real-time market as described above using different multipliers. The CAISO evaluated how often a hydroelectric resource with a specific daily energy limitation would not exceed that daily water limitation, using different multipliers that could be applied to the short-term component of the hydro DEB and different water storage limitations. Several simplifying assumptions were made to evaluate the data. These assumptions included that: historic prices at the hydroelectric resource's balancing authority area are applicable and that these prices would not change based on the bidding patterns of the hydroelectric resource; the resource owner always knows and bids at the calculated hydro DEB during all intervals; and the resource is able to ramp immediately to maximum output from 0 MW and from 0 MW to maximum output.

Q. What did the results show?

A. Tables 1-4 below shows the results of the analysis. Table 1 below shows the results for a hydroelectric resource in the PacifiCorp East balancing authority area. The CAISO also constructed similar charts for the other areas including: PacifiCorp West, Puget Sound Energy areas and one for a representative resource receiving hourly Powerdex prices, which are presented below in Tables 2- 4 below. The cells highlighted in orange show that a hydroelectric resource with 4 hours of storage duration per day receiving a hydro DEB with a 1.4 multiplier applied to the short-term component, would be dispatched 4 hours per day or less, for at least 95% of all days in all the regions. In fact the representative resources in PacifiCorp West and Puget Sound Energy were dispatched less than 4 hour per day during 99% of all days, and the representative resource modelled with Powerdex prices was dispatched less than 4 hours during 97% of intervals. The representative resource from PacifiCorp East was dispatched less than 4 hours during 95% of intervals. Based on these results, the CAISO concluded that with a multiplier of 1.4, each of these representative resources would be dispatched less than 4 hours per day during 95% or more of all days.

Table 1: Percent a resource is dispatched less than potential daily availability (PACE prices)

Multiplier	Resource Storage Duration (Hours/Day)			
	2 Hrs.	4 Hrs.	6 Hrs.	8 Hrs.
120%	68%	89%	95%	98%
130%	73%	92%	97%	99%
140%	77%	95%	98%	99%
150%	82%	97%	99%	99%
160%	88%	98%	99%	100%

Table 2: Percent a resource is dispatched less than potential daily availability (PACW prices)

Multiplier	Resource Storage Duration (Hours/Day)			
	2 Hrs.	4 Hrs.	6 Hrs.	8 Hrs.
120%	80%	94%	100%	100%
130%	84%	97%	100%	100%
140%	88%	99%	100%	100%
150%	91%	99%	100%	100%
160%	94%	99%	100%	100%

Table 3: Percent a resource is dispatched less than potential daily availability (PSEI prices)

Multiplier	Resource Storage Duration (Hours/Day)			
	2 Hrs.	4 Hrs.	6 Hrs.	8 Hrs.
120%	80%	95%	99%	100%
130%	85%	97%	100%	100%
140%	88%	99%	100%	100%
150%	91%	99%	100%	100%
160%	93%	99%	100%	100%

Table 4: Percent a resource is dispatched less than potential daily availability (Powerdex)

Multiplier	Resource Storage Duration (Hours/Day)			
	2 Hrs.	4 Hrs.	6 Hrs.	8 Hrs.
120%	88%	94%	97%	99%
130%	91%	96%	98%	99%
140%	93%	97%	99%	99%
150%	95%	98%	99%	99%
160%	96%	99%	99%	100%

Q. Is this analysis conservative?

A. Yes. This analysis is conservative in several ways. First, nearly all resources in the market are not precluded from bidding above their default energy bids. As I previously explained, a resource is only mitigated to a default energy bid when the LMPM tool detects that a resource could exercise market power. Otherwise, a resource bidding above a default energy bid will be dispatched no more than a resource bidding at the default energy bid. Therefore a resource that has little opportunity to exercise market power may be able to significantly reduce the amount of intervals dispatched by the market by simply raising bids above the default energy bid. Historically, the LMPM tool has not detected frequent market power at most resource locations. Resources may also have additional bilateral hubs or additional higher representative gas prices than the ones modelled in this analysis. Firm transmission rights to additional bilateral hubs or higher gas prices would imply higher calculated hydro DEBs, and thus would reduce the frequency that a resource is dispatched in the market.

Q. Does the multiplier need to be updated annually to meet its objective and generate acceptable values for hydroelectric resource owners?

A. No, the CAISO does not believe that it is necessary to re-evaluate the multiplier on an annual basis. The analysis performed shows that the multiplier is sufficient with recent historic prices, and expected future prices. However, reassessment may be necessary as market conditions change, as markets offered by the CAISO expand, and if there are significant changes in transmission availability for CAISO markets. If the default energy bid no longer fulfills its purpose as outlined in this testimony, the CAISO may consider updating the multiplier.

Q. Thank you. I have no further questions.

I, Gabriel Murtaugh, affirm under penalty of perjury that the statements in this declaration are true and correct to the best of my knowledge, information, and belief.

_***/s/ Gabriel Murtaugh***___

Gabriel Murtaugh

Executed this 1st day of July, 2019

Attachment K – Table of Tariff Sections and Proposed Effective Dates

Local Market Power Mitigation Enhancements

California Independent System Operator Corporation

Table of Tariff Sections and Requested Proposed Effective Dates

Tariff Section	Proposed Effective Date
Section 29.39	December 31, 9998
Section 31.2.3	December 31, 9998
Section 34.1.5.1	December 31, 9998
Section 34.5.1.2	December 31, 9998
Section 34.1.5.3 (proposed to be deleted)	December 31, 9998
Section 34.1.5.3 (formerly Section 34.1.5.4)	December 31, 9998
Section 34.1.5.5	December 31, 9998
Section 39.7.1.7	October 14, 2019
- Competitive LMP Parameter, *Appendix A*	December 31, 9998
- Hydro Default Energy Bid, *Appendix A*	October 14, 2019

Attachment L – Matrix of Stakeholder Comments and CAISO Response

Local Market Power Mitigation Enhancements

California Independent System Operator Corporation

Response to Stakeholder Comments on Draft Tariff Language

Local Market Power Mitigation Enhancements 2018

Tariff Section	Stakeholder	Stakeholder Comment	CAISO Response
N/A	NV Energy	NV Energy asks will a third-party EIM Participating Resource be permitted to continue to sell into the EIM at their respective Default Energy Bid price, if they are located in the Balancing Authority Area of an EIM Entity that has elected to implement the Net EIM Transfer Limit option? NV Energy states in other words is the election only applicable to the merchant of the EIM; is it a customer-by-customer choice; or does the EIM Entity's protection of its own merchant sales restrict potential sales by third parties?	An election by the EIM entity scheduling coordinator for the CAISO to apply an upper limit to the net EIM transfers would apply equally to all resources in the EIM entity balancing authority area.
N/A	NV Energy	NV Energy questions will the transmission, either capacity donated by the EIM Interchange Rightsholder or ATC identified by the EIM Entity, continue to be available for import and wheel through, even if the EIM Entity elects the Net EIM Transfer Limit option?	An election by the EIM entity scheduling coordinator for the CAISO to apply an upper limit to the net EIM transfers would not restrict the transmission capacity available for increased imports or wheeling. It only would limit increased net EIM transfers out from the EIM entity balancing authority area.
N/A	NV Energy	NV Energy comments that it supports the Competitive LMP Parameter limit being set at $0.01 in the CAISO Tariff.	See the CAISO's response below.
29.39(e)	NV Energy	NV Energy comments that the draft new section 29.39(e) of the CAISO tariff, the CAISO proposes that the timelines for an EIM Entity to opt into or out of the Net EIM Transfer Limit program will be included in the EIM Business Practice Manual.	The CAISO will clarify in the tariff that the timeline will be the same as the master file timeline changes.

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		NV Energy further comments that this is a practice that can significantly affect rates, terms, and conditions of service and is readily susceptible to specification. NV Energy further states, accordingly, under FERC's "rule of reason" policy, the timeline should be in the tariff and not the BPM.	
29.39(e)	NV Energy	NV Energy comments that the CAISO tariff should require the CAISO to post a list of the EIM Entities that have imposed the Net EIM Transfer Limit. NV Energy states that this election should be transparent to all market participants. Moreover, certain of the FERC-jurisdictional EIM Entities may elect not to implement this limit as a condition of their continued ability to sell at market-based rates in the EIM. NV Energy states that the posting requirement will give regulators the visibility and assurance that the commitment is being implemented.	The CAISO will include a tariff requirement to publish a list of EIM entities that have requested application of these limits. This detail will be documented in the BPM.
29.39(e)(1)	Bonneville Power Administration	Bonneville comments that the language "from above" is confusing in this context and could be interpreted to reference either 1) a "cap" (a limit from above); or 2) the EIM Entity Scheduling Coordinator that is the subject of the sentence. Bonneville interprets the phrase "from above" to refer to the EIM Entity Scheduling Coordinator's BAA, but questions whether it should instead refer to the EIM Entity's BAA. In either case, Bonneville believes the language should be modified to remove the ambiguity.	The CAISO will remove the phrase "from above" and rephrase the reference to this mathematical limit to the "net" incremental EIM transfers. The CAISO proposes these further clarifications: (e) Incremental Net EIM Transfer Limit. (1) Election. An EIM Entity Scheduling Coordinator may elect for the CAISO to apply an upper limit to the ~~incremental~~ net EIM Transfer ~~from above after the MPM process for the EIM Entity Balancing Authority Area pursuant to the election~~ consistent with the procedures and timelines that apply to Master File changes pursuant to Section 29.39(e)(4) ~~established in the Business Practice Manual for the Energy~~

California ISO

Tariff Section	Stakeholder	Stakeholder Comment	CAISO Response
		Bonneville suggests the following potential revision: “(e) (1) “…An EIM Entity ~~Scheduling Coordinator~~ may elect for the CAISO to limit the incremental net EIM Transfer from its EIM Entity Balancing Authority Area ~~above~~ after the MPM process…”	~~Imbalance Market~~. (2) Application. In the applicable RTM process, ~~I~~incremental net EIM Transfers from an EIM Entity Balancing Authority Area that has made the election in Section 29.39(e)(1) will be limited when the MPM process triggers mitigation and EIM Transfers in the MPM process are constrained in the import direction to that EIM Entity Balancing Authority Area, or a group of EIM Entity Balancing Authority Areas that includes that EIM Entity Balancing Authority Area. (3) Limit. The incremental net EIM Transfer upper limit will be: (a) the amount by which ~~be~~ the sum of ~~the~~ Flexible Ramping Up awards in the EIM Entity Balancing Authority Area prior to the applicable RTM~~process for the interval~~ to which the MPM process applies~~, which is in excess of~~ exceeds the EIM Entity Balancing Authority Area’s corresponding adjusted Flexible Ramping Up requirement, where the Flexible Ramping Up requirements is adjusted for EIM diversity benefit and the portion of the cleared Flexible Ramping Up Demand curve, plus (b) the amount that is the greater of: (A) the net EIM Transfer in the MPM process described in Section 34.1.5 prior to the RTM process for the interval to which the MPM process applies; or (B) the net EIM Transfer represented by the EIM Base Schedules at each EIM Internal Intertie for the interval to which the MPM process applies.

California ISO

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			(4) Publication. The CAISO will publish a list of EIM Entity Balancing Authority Areas that have elected for the CAISO to apply an upper limit to the net EIM Transfer in accordance with the procedures and timelines for such publication established in the Business Practice Manual for the Energy Imbalance Market.
29.39(e)(1)	Six Cities	Six Cities states that in the second line, the phrase "from above" is confusing. "From above" what? Six Cities asks if there a reference missing?	See the CAISO's response above.
29.39(e)(3)	Idaho Power Company	Idaho Power Company comments that this tariff language is unclear and hard to follow. Idaho Power Company provides suggested edits to try to clarify and align the language with the language published in the draft final proposal. Idaho Power Company comments that if these changes do not reflect the intent, then this should be revised in a different manner to provide clarification. "(3) **Limit.** The incremental net EIM Transfer limit will be the amount by which the sum of the Flexible Ramping Up awards in the EIM Entity Balancing Authority Area prior to the RTM process for the interval to which the MPM process applies, ~~which is in excess of~~ exceeds the EIM Entity Balancing Authority Area's corresponding Flexible Ramping Up requirement, plus the greater of: (A) the net EIM Transfer in the MPM process described in Section 34.1.5 prior to the RTM process for the interval to which the MPM process applies; or	The CAISO will revise this provision accordingly with further clarifications. See above.

California ISO

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		(B) the net EIM Transfer represented by the EIM Base Schedules at each EIM Internal Intertie for the interval to which the MPM process applies."	
29.39(e)(2)	Powerex	Powerex provides the following suggested edits: "In the applicable RTM process, ~~I~~incremental net EIM Transfers from an EIM Entity Balancing Authority Area that has made the election in Section 29.39(e)(1) will be limited when the MPM process triggers mitigation and EIM Transfers in the MPM process are constrained in the import direction to that EIM Entity Balancing Authority Area, or a group of EIM Entity Balancing Authority Areas that includes that EIM Entity Balancing Authority Area."	The CAISO will revise this provision accordingly. See above.
29.39(e)(3)	Powerex	Powerex states that it supports the CAISO's proposed tariff language, Powerex believes that one passage in Section 29.39(e)(3) is ambiguous and requires clarification. That section states that: "The incremental net EIM Transfer limit will be the sum of the Flexible Ramping Up awards in the EIM Entity Balancing Authority Area *prior to the RTM process for the interval to which the MPM process applies*…" Powerex believes that the intent of the italicized language is unclear and should be clarified.	The CAISO will modify this phrase as follows: "The incremental net EIM Transfer limit will be the sum of the Flexible Ramping Up awards in the EIM Entity Balancing Authority Area prior to the applicable RTM ~~process for the interval~~ to which the MPM process applies . . ." See above.
29.39(e)(3)	Powerex	Powerex provides the following suggested edits:	The CAISO does not agree. There are no limits enforced in the MPM process (which is defined

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		"The incremental net EIM Transfer limit in the MPM process will be the sum of the Flexible Ramping Up awards in the EIM Entity Balancing Authority Area prior to the RTM process for the interval to which the MPM process applies, which is in excess of the EIM Entity Balancing Authority Area's corresponding Flexible Ramping Up requirement, plus the greater of…"	as the first of the two market runs for each market interval in the fifteen-minute market). The prior clarification is sufficient.
31.2.3	Bonneville Power Administration	Bonneville comments that the commingling of the DAM and RTM markets together in this sentence, along with the use of "and" is confusing. Bonneville states that it recognizes that each market has its own MPM process, and that each MPM process only affects intervals in its respective market. Bonneville states that the sentence is technically accurate, but for clarity Bonneville suggests explicit separation of the DAM and RTM in these sentences or, at a minimum. Bonneville provides the following potential revision: "…to the extent that they exceed the Competitive LMP plus the Competitive LMP Parameter at the resource's Location for the DAM or~~and~~ RTM process interval for which the MPM process applies, will be mitigated to the higher of the resource's Default Energy Bid, as specified in Section 39, or the Competitive LMP plus the Competitive LMP Parameter at the resource's Location for the DAM and RTM process interval for which the MPM process applies.…"	The CAISO will revise this provision accordingly.

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31.2.3	Southern California Edison	Southern California Edison provides the suggestion to state DAM or RTM process or both given DAM or RTM each has its own MPM.	See the CAISO's response above.
34.1.5.1	Southern California Edison	Southern California Edison suggests the removal of "to be" as a clean-up to the language. Southern California Edison provides the following suggested edit: "Bids from resources comprised of multiple technologies that include Non-Generator Resources will remain ~~to be~~ subject to all applicable market power mitigation under the CAISO Tariff, including Local Market Power Mitigation."	The CAISO will revise this provision accordingly.
34.1.5.2	Powerex	Powerex provides the following suggested edit: "If a Bid is mitigated in the MPM process for a~~ny~~ fifteen (15) minute interval for a Trading Hour, the mitigated Bid will be utilized in the RTM process for that first fifteen (15) minute interval. "	The CAISO will revise this provision accordingly.
34.1.5.3	Idaho Power Company	Idaho Power Company comments that the sentence being added, and particularly reference to "these intervals," is unclear. Idaho Power Company requests the CAISO to clarify the sentence and explain what intervals are being referred to.	The CAISO will provide an explanation of this provision during the tariff meeting. The CAISO also proposes to clarify that sentence as follows: The RTD MPM process is performed for a configurable number of RTD ~~each~~ advisory intervals ~~within a configurable time frame from~~ after the binding RTD interval, ~~to mitigate Bids used in~~ and the mitigated Bids are used in the corresponding RTD~~, the following RTD for these intervals~~.

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34.1.5.3	Seattle City Light	Seattle City Light requests clarification of the term "configurable" as it relates to the timing of the Real-Time Dispatch Market Power Mitigation process.	See the CAISO's response above.
34.1.5.5	Bonneville Power Administration	Bonneville notes that there is language that incorrectly suggests that the Competitive LMP Parameter may be used to create price separation between the DAM and RTM markets. Bonneville notes that the price separation should be created between the area where mitigation applies and the areas where mitigation does not apply. Bonneville suggests the following potential revision: "…The CAISO will set the Competitive LMP Parameter as low as possible while reasonably creating price separation ~~in the DAM and RTM process~~ between the area where mitigation applies and other areas where mitigation does not apply."	The CAISO will revise this provision as follows: When a Bid is mitigated, the CAISO will add a cost, not to exceed $0.01/MWh, to the Competitive LMP used in the MPM process prior to the DAM or ~~and~~ RTM process. The CAISO will set the Competitive LMP Parameter as low as possible while ~~reasonably~~ creating a reasonable price separation ~~in the DAM and RTM process~~ between the area where mitigation applies and other areas where mitigation does not apply. The CAISO will publish the value of the Competitive LMP Parameter in the Business Practice Manual.
34.1.5.5	Idaho Power Company	Idaho Power Company requests that the CAISO clarify which Business Practice Manual is being referenced.	The CAISO does not reference specific BPMs in the broader CAISO tariff.
34.1.5.5	Seattle City Light	Seattle City Light states that it believes the max competitive LMP parameter, as described in the final LMPM proposal, should be set at $.10 not $.01.	The CAISO believes that establishing the ceiling as low as possible while achieving the price separation objective is beneficial for all market participants. Indeed, a prior stakeholder process referenced a $0.10 with respect to the inclusion of an EIM transfer schedule cost, which was later reduced in the subsequent FERC proceeding to $0.01. Lowering the ceiling now will benefit market participants and potentially avoid concerns that FERC may have in adding a larger cost to the competitive LMP. This was clarified

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			by the CAISO in the draft final proposal stakeholder comment matrix.
34.1.5.5	Southern California Edison	Southern California Edison suggests changing the language to reflect $0.01/MWh as the adder to the LMP ($/MWh). Southern California Edison provides the following suggested edit: "When a Bid is mitigated, the CAISO will add a cost, not to exceed $0.01/MWh, to the Competitive LMP used in the MPM process prior to the DAM and RTM process."	See the CAISO's response above.
39.7.1.7	Powerex	Powerex is proposing revisions to the draft tariff language that are designed to further clarify the calculation of the hydro DEB in a manner consistent with the draft final proposal. Powerex provides the following proposed edits: "Scheduling Coordinators may request a Hydro Default Energy Bid for a hydro resource~~s~~ with storage capability ~~located in the CAISO Balancing Authority Area or any EIM Entity Balancing Authority Area~~that is subject to bid mitigation."	The CAISO will not accept the proposal to include the "that is subject to bid mitigation" because resources that are not subject to mitigation may also require a DEB. For example, an EIM non-participating resource may require a DEB if used in the ABC process. The CAISO will accept the following changes: "Scheduling Coordinators may request a Hydro Default Energy Bid for a hydro resource~~s~~ with storage capability…"
39.7.1.7.1	Bonneville Power Administration	Bonneville states that the word "and" should be used instead of "or." Bonneville provides the following potential revision: "…The CAISO will calculate the Hydro Default Energy Bid as the maximum of the gas floor, the short-term component, and~~or~~	The CAISO will make this change.

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		the long-term/geographic component…”	
39.7.1.7.1	Idaho Power Company	Idaho Power Company suggests adding (a), (b), and (c) to provide additional to the sentence. Idaho Power Company suggests that the sentence be structured as follows: “**39.7.1.7.1 Computation** The CAISO will calculate the Hydro Default Energy Bid as the maximum of (a) the gas floor, (b) the short-term component or (c) the long-term/geographic component as specified in the subsections below.”	The CAISO will accept the change and make the following clarifications **39.7.1.7.1 Computation** For each Trading Day, t~~T~~he CAISO will calculate the Hydro Default Energy Bid as the maximum of the (a) gas floor;~~,~~ ~~the~~(b) short-term component; ~~or~~ and (c) the long-term/geographic component, as specified in the subsections below.
39.7.1.7.1	Powerex	Powerex suggests the following suggested edits: “For each Trading Day, ~~T~~the CAISO will calculate the Hydro Default Energy Bid as the maximum of the gas floor, the short-term component ~~or~~ and the long-term/geographic component as specified in the subsections below.”	The CAISO accepts the change. See above.
39.7.1.7.1.1	Idaho Power Company	Idaho Power Company comments that the description of the average heat rate for a typical peaking gas resource should include a reference to the source that the CAISO will use for the data. Idaho Power Company suggests the following edits: “**39.7.1.7.1.1 Gas Floor** The CAISO will calculate the gas floor as the average heat rate for a typical peaking gas resource, obtained from the Energy Information Administration for the most recent year available, multiplied by the gas price for the fuel region applicable for the	The CAISO proposes the following clarification: **39.7.1.7.1.1 Gas Floor** The CAISO will calculate the gas floor as the average heat rate for a typical ~~peaking~~ gas turbine generator~~resource~~, multiplied by the gas price for the fuel region applicable to ~~for~~ the location of the hydro resource, multiplied by 1.1. The heat rate used will be the most recent average heat for gas turbine resources as cited by the Energy Information Administration~~Agency~~.”

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		location of the hydro resource, multiplied by 1.1. The heat rate used will be the most recent average heat for gas turbine resources as cited by the Energy Information Agency.”	
39.7.1.7.1.1	Powerex	Powerex provides the following suggested edits: “The CAISO will calculate the gas floor as the average tested heat rate for a ~~typical peaking~~ gas turbine resource, as published by the Energy Information Administration (EIA), multiplied by the gas price for the fuel region applicable for the location of the hydro resource, multiplied by 1.1.”	See the CAISO’s response above.
39.7.1.7.1.1	Seattle City Light	Seattle City Light recommends that CAISO add language that clarifies the heat rate used for the gas price floor will be the most recent average heat for gas turbine resources as cited by the Energy Information Agency. Seattle City Light states that this was the heat rate source agreed to in the final LMPM proposal.	See the CAISO’s response above.
39.7.1.7.1.2	Bonneville Power Administration	Bonneville suggests itemizing the elements of the Short-Term component for clarity and suggests specifying the on-peak balance of month index and the on-peak monthly index futures price. Bonneville provides the following potential revision: “The CAISO will calculate the short-term component as ~~the maximum of the Day-Ahead peak price at the applicable electric pricing hub, the balance of the month futures~~	The CAISO accepts the change with the following further clarifications. The CAISO will calculate the short-term component as ~~the maximum of the Day-Ahead peak price at the applicable electric pricing hub, the balance of the month futures prices for the current month at the applicable electric pricing hub, and the monthly index futures price at the applicable electric pricing hub for one (1) month after the current month, multiplied by~~ 1.40 multiplied by the maximum of:

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		~~prices for the current month at the applicable electric pricing hub, and the monthly index futures price at the applicable electric pricing hub for one (1) month after the current month, multiplied by~~ 1.40 multiplied by the maximum of: A. the Day-Ahead peak price at the applicable electric pricing hub, B. the on-peak balance of the month futures price for the current month at the applicable electric pricing hub, and C. the on-peak monthly index futures price at the applicable electric pricing hub for one (1) month after the current month."	A. the day-ahead peak price at the applicable electric pricing hub; B. the on-peak balance of the month on peak futures price for the current month at the applicable electric pricing hub; and C. the on-peak monthly index on peak futures price at the applicable electric pricing hub for one (1) month after the current month.
39.7.1.7.1.2	Powerex	Powerex provides the following suggested edits: "The CAISO will calculate the short-term component as the maximum of the Day-Ahead on-peak price at the applicable ~~electric pricing hub~~Default Trading Hub, the balance of the month on-peak futures price~~s~~ for the current month at the applicable electric pricing hub, and the monthly ~~index~~ on-peak futures price at the applicable ~~electric pricing hub~~Default Trading Hub for one (1) month after the current month, multiplied by 1.40."	The CAISO proposes to modify Section 39.7.1.7.3 to refer to default electric pricing hubs. The CAISO accepts the other clarifications. See above.
39.7.1.7.1.2	Southern California Edison	Southern California Edison asks if the term "Day-Ahead" should be lower case because the term "Day-Ahead" is a defined term in the CAISO tariff and implies it is a CAISO-generated price.	The CAISO accepts this change. See above.

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39.7.1.7.1.3	Bonneville Power Administration	Bonneville suggests itemizing the elements of the Long-Term/Geographic Component for clarity and suggests specifying the on-peak balance of month index and the on-peak monthly index futures prices. Bonneville provides the following potential revision: "The CAISO will calculate the long-term/geographic component as 1.1 multiplied by the maximum of: A. the Day-Ahead peak price at the applicable electric pricing hub, B. the on-peak balance of the month futures prices for the current month at the applicable electric pricing hub, C. and the on-peak monthly index futures price at the applicable electric pricing hub for future months up to the maximum storage horizon after the current month~~,~~ ~~multiplied by 1.1~~."	The CAISO accepts this change with the following clarifications: The CAISO will calculate the long-term/geographic component as 1.1 multiplied by the maximum of: A. the d~~D~~ay-a~~A~~head on-peak price at the applicable electric pricing hub(s);~~,~~ B. the on-peak balance of the month futures price~~s~~ for the current month at the applicable electric pricing hub(s);~~,~~ C. and the on-peak monthly index futures price at the applicable electric pricing hub(s) for all future months up to the maximum storage horizon after the current month,~~ multiplied by 1.1~~. A Scheduling Coordinator may request that the long-term/geographic component be calculated based on multiple electric pricing hubs in accordance with Section 39.7.1.7.2.1. The CAISO specified in the Draft Final Proposal that the applicable day-ahead price would be on-peak. It is appropriate to pick the on-peak price because the default hydro bid should reflect the opportunity cost that is likely to arise and because on-peak prices are likely to be the highest, if we chose off-peak prices, the Hydro Default Energy Bid would not sufficiently cover those critical hours. This same principle applies to the balance of the month and monthly price. The CAISO erroneously did not specify the on-peak reference for all of the components in the equation on page 35 of the Draft Final Proposal, but it had intended to apply the same logic all prices equally.

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39.7.1.7.1.3	Powerex	Powerex provides the following suggested edits: "The CAISO will calculate the long-term/geographic component as the maximum of the Day-Ahead on-peak price at the applicable electric pricing hub, the balance of the month on-peak futures price~~s~~ for the current month at the applicable electric pricing hub, and the monthly ~~index~~ on-peak futures price at the applicable electric pricing hub for all future months up to the maximum storage horizon after the current month, multiplied by 1.1."	The CAISO accepts this change. See above.
39.7.1.7.2.	Powerex	Powerex provides the following suggested edits: "As part of its request for a Hydro Default Energy Bid, the Scheduling Coordinator must submit the following information to the CAISO…"	The CAISO accepts this change.
39.7.1.7.2.1	Powerex	Powerex states that Section 39.7.1.7.2.1 states that a Scheduling Coordinators must make an annual demonstration that they have firm transmission rights and/or a historical practice of purchasing firm transmission rights to a given electric pricing hub. Powerex comments that in order to take into account the fact that the transmission reservations currently held or historically acquired by a market participant may vary over the course of the year, Powerex requests clarification that Scheduling Coordinators that make such a submission may provide a month-by-month breakdown	The CAISO will clarify as follows: Annually, and for each electric pricing hub requested that is not the default electric pricing hub, the Scheduling Coordinator must (1) demonstrate that ~~(1) they have~~it holds annual ~~purchased~~ firm transmission rights to enable delivery from the hydro resource's default market region ~~location~~ to the requested electric pricing hub or to ~~hubs or~~ a delivery point that is ~~represented b~~a similarly priced location;~~,~~ ~~similarly priced location~~or (2) provide documentation that supports a historical practice of purchasing ~~qualifying~~ monthly firm transmission rights for the annual period to the requested electric pricing hub(s) or similarly priced location. Scheduling

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		of their transmission rights to relevant electric pricing hubs. Powerex believes that allowing Scheduling Coordinators to submit a showing that includes monthly transmission availability strikes an appropriate balance between ensuring that the DEB represents the opportunity costs of a resource while limiting the additional data collection and computational burden imposed on the CAISO.	Coordinators may demonstrate transmission rights to multiple locations and, based on the CAISO's evaluation of such information, the CAISO may include multiple electric pricing hubs, in addition to the default electric pricing hubs, in the long-term/geographic component of the Hydro Default Energy Bid for the affected resources. The Scheduling Coordinator must attest in its ~~their~~ submission that it reasonably expects it ~~they~~ will use the demonstrated ~~the full quantity of the~~transmission rights to deliver incremental sales from the hydro resource. If the CAISO includes multiple electric pricing hubs in the long-term/geographic component, the Hydro Default Energy Bid calculation will use the maximum of the electric pricing hub as determined each Trading Day. On Trading Days for which there are no relevant published electric price indices at an electric pricing hub, the CAISO will use the most recently published index for the applicable electric pricing hub.
39.7.1.7.2.1	Powerex	Powerex provides the following suggested edits: "**39.7.1.7.2.1 Transmission Rights Showing for Multiple Electric Pricing Hubs in Long-Term/Geographic Component** A Scheduling Coordinator may request that the long-term/geographic component be calculated based on multiple electric pricing hubs (in addition to the Default Trading Hub) to the extent the Scheduling Coordinator demonstrates that it has transmission rights to each of the requested additional electric	The CAISO accepts this additional requirement with further clarifications to Section 39.7.1.7.1.3. See above.

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		pricing hubs consistent with this section."	
39.7.1.7.2.1(a)	Bonneville Power Administration	Bonneville requests clarity on the intention of this sentence. If the intent is to stress that the source of incremental sales should be the hydro resource, and not, say, market purchases, then Bonneville suggests including language to that effect. As written, the language is somewhat discordant with the concept of opportunity cost, since, if a seller uses the full quantity of its transmission rights to non-default locations, the price at those locations, by definition, cannot represent an opportunity cost. In addition, the use of the term "full quantity of the transmission rights" seems to imply that all available transmission must be used to support the incremental sale. BPA seeks clarity that the specific quantity of transmission must match or be greater than the incremental sales. Bonneville suggests striking the following sentence: (a) "…The Scheduling Coordinator must attest in their submission that they will use the full quantity of the transmission rights to deliver incremental sales from the hydro resource."	The CAISO will clarify this section. See above.
39.7.1.7.2.1(a)	Idaho Power Company	Idaho Power Company suggests minor edits to provide clarity. The proposed edits are as follows: "Annually the Scheduling Coordinator must (1) demonstrate that ~~(1) they have~~ it has purchased firm transmission rights from the hydro resource location to the requested	The CAISO accepts this change with further clarifications. See above.

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		electric pricing hub or hubs or a similarly priced location, or…”	
39.7.1.7.2.1(a)	Idaho Power Company	Idaho Power Company suggests deleting the word “qualify” because it introduces ambiguity. Idaho Power Company also asks what are qualifying rights. Idaho Power Company suggests the following edits to mirror the language from (1) to make it clear that the historical rights demonstrated may also be available to the hub(s) or similarly priced locations. “…(2) provide documentation that supports a historical practice of purchasing ~~qualifying~~ firm transmission rights to the requested pricing hub or hubs or similarly priced location.”	The CAISO accepts this change. See above.
39.7.1.7.2.1(a)	Idaho Power Company	Idaho Power Company comments that the intent of the attestation regarding the use of the full quantity of transmission rights to deliver incremental sales is unclear. Idaho Power Company states that the language does not seem to be supported by the draft final proposal. Idaho Power Company provides the following suggested edits: “The Scheduling Coordinator must attest in ~~their~~ its submission that ~~they~~ it will use the full quantity of the transmission rights to deliver incremental sales from the hydro resource.”	The CAISO accepts this change. See above.
39.7.1.7.2.1(a)	Idaho Power Company	Idaho Power Company comments that the CAISO tariff should address how the multiple hubs would be used if there is sufficient transmission. Idaho Power Company suggests adding a sentence based on the	The CAISO accepts this change. See above.

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		draft final proposal in order to clarify this important point. Idaho Power Company provides the following proposed edits: "…sales from the hydro resources. If CAISO includes multiple electric pricing hubs in the long-term/geographic component, the Hydro Default Energy Bid calculation will use the maximum of the values for each hub as determined each day."	
39.7.1.7.2.1(a)	Powerex	Powerex comments that under Section 39.7.1.7.2.1(a), a Scheduling Coordinator seeking to add an electric pricing hub to the list of hubs that will be included in the calculation of the long-term component of its DEB must attest that it "will use the full quantity of the transmission rights to deliver incremental sales from the hydro resource." Powerex believes that this language must be modified, in keeping with feedback in the stakeholder process, to only require that a Scheduling Coordinator attest that it "reasonably expects to use the demonstrated transmission rights to deliver incremental sales from the hydro resource." Powerex notes that as was discussed during the stakeholder process, hydro resources with storage have limited energy and must make trade-offs between many market opportunities, including selling limited supply during the highest priced hours and days and at the highest priced locations. Powerex states that as a practical matter, it is thus not feasible that an entity would use	The CAISO accepts the proposed change. See above.

Tariff Section	Stakeholder	Stakeholder Comment	CAISO Response
		all of its transmission rights to deliver its hydro energy to every location to which it has transmission rights during each and every hour of the year. Powerex therefore believes that any attestation requirement should only require that the Scheduling Coordinator affirm that the relevant transmission rights are reasonably expected to enable potential market opportunities for the resource during the applicable year.	
39.7.1.7.2.1(a)	Powerex	Powerex provides the following suggested edits: "(a) Annually, and for each electric pricing hub requested that is not the Default Trading Hub, the Scheduling Coordinator must demonstrate that (1) ~~they have purchased~~ hold firm transmission rights to enable delivery from the hydro resource's default market region ~~location~~ to the requested electric pricing hub or ~~hubs or~~ to a ~~similarly priced location~~delivery point that is represented by such pricing hub, or (2) provide documentation that supports a historical practice of purchasing qualifying firm transmission rights. Scheduling Coordinators may demonstrate transmission rights to multiple locations and, based on the CAISO's evaluation of such information, the CAISO may include ~~multiple~~ additional electric pricing hubs (in addition to the Default Trading Hubs specified in Section 39.7.1.7.3) in the long-term/geographic component of the Hydro Default Energy Bid for the affected resources. The Scheduling	The CAISO accepts this change with further clarifications. See above.

Tariff Section	Stakeholder	Stakeholder Comment	CAISO Response
		Coordinator must attest in ~~their~~ its submission ~~that they will~~ it reasonably expects to use the ~~full quantity of the~~ demonstrated transmission rights to deliver incremental sales from the hydro resource."	
39.7.1.7.2.1(a)	Six Cities	Six Cities states that the basis for the last sentence of the sub-section is not clear. Six Cities requests that the Cg AISO please explain the reason for the proposed requirement that the full quantity of transmission rights must be used to deliver incremental sales from the hydro resource.	See clarification provided above.
39.7.1.7.2.1(b)	Bonneville Power Administration	Bonneville interprets this passage to mean that the transmission rights portfolios of participants be employed (in calculating the appropriate proportional weights) in calculation of the weighted average price of the bilateral trading hubs. Further, the term "capacity" may have different practical meaning for hydro resources that are energy limited than it does for thermal resources. Bonneville requests clarifying language that distinguishes between "energy limited hydro generation" and a more traditional usage of the term capacity. Bonneville suggests the following potential revisions: "For resources with less firm transmission rights than the resource's capacity, the CAISO will use a proportional weighting of the resource's transmission rights to calculate a weighted average of those bilateral trading hub prices…"	The CAISO accepts this change with further clarifications. (b) For resources that demonstrates a quantity of firm transmission rights to a requested pricing hub or similarly priced location that is less than the hydro resource's capacity, the CAISO will include the requested electric pricing hub up to the quantity demonstrated transmission rights, and apply ~~use~~ a proportional weighting of the resource's transmission rights to calculate a weighted average of those bilateral electric pricing hub prices when calculating the value~~s~~ of ~~in~~ the long-term/geographic component of the Hydro Default Energy Bid.

Tariff Section	Stakeholder	Stakeholder Comment	CAISO Response
39.7.1.7.2.1(b)	Idaho Power Company	Idaho Power Company comments that the word "fewer" would be more clear in the context of that sentence as opposed to "less." Idaho Power Company provides the following proposed edit: "For resources with ~~less~~ fewer firm transmission rights than the resource's capacity, the CAISO will use a proportional weighting of those bilateral prices when calculating values in the long-term/geographic component of the Hydro Default Energy Bid."	The CAISO accepts the proposed changes with further clarifications. See above.
39.7.1.7.2.1(b)	Powerex	Powerex provides the following proposed edits: "(b) For resources ~~with less~~ that demonstrate a quantity of firm transmission rights to a requested electric pricing hub that is less than the hydro resource's capacity~~,~~ ~~the~~ CAISO will ~~use~~ include the requested electric pricing hub up to the quantity of demonstrated transmission rights, and apply a proportional weighting of ~~those bilateral~~ the electric pricing hub prices when calculating the value~~s~~ of ~~in~~ the long-term/geographic component of the Hydro Default Energy Bid."	The CAISO accepts the proposed changes. See above.
39.7.1.7.2.1(c)	Powerex	Powerex provides the following proposed edits: "(c) In the absence of supporting transmission rights information when calculating the Hydro Default Energy Bid, the CAISO will revert to the ~~d~~Default ~~bilateral electric pricing~~ Trading ~~h~~Hub specified in	The CAISO proposes to use the term "electric pricing hub" instead of "Default Trading Hub."

Tariff Section	Stakeholder	Stakeholder Comment	CAISO Response
		Section 39.7.1.7.3."	
39.7.1.7.2.1(f)	Idaho Power Company	Idaho Power Company notes that the term "electric pricing hub" has been used throughout the draft tariff language as opposed to "Trading Hubs." Idaho Power Company suggests using one term throughout the tariff to provide clarity. Idaho Power Company goes on to note that the definition of "Trading Hub" is a defined term in the CAISO tariff and is defined as "An aggregation of network Pricing Nodes, such as Existing Zone Generation Trading Hubs, maintained and calculated by the CAISO for settlement and trading purposes posted by the CAISO on its CAISO Website." Idaho Power Company states that "electric pricing hub" seems more appropriate in this context, since the default hubs include Mid-C and Palo Verde, which to Idaho Power Company's understanding are not "maintained and calculated by CAISO", as the term Trading Hub is defined in CAISO's tariff. Idaho Power Company provides the following suggested edits: "If the CAISO determines the Scheduling Coordinator has submitted inaccurate information, the CAISO may revert the resource to the default ~~Trading Hubs~~ electric pricing hubs as specified in Section 39.7.1.7.3."	The CAISO agrees. The CAISO will clarify and use the term "electric pricing hub" throughout the tariff.

Tariff Section	Stakeholder	Stakeholder Comment	CAISO Response
39.7.1.7.2.1(c)	Powerex	Powerex provides the following proposed edits: "(f) If the CAISO determines the Scheduling Coordinator has submitted inaccurate information, the CAISO may revert the resource to the ~~d~~Default Trading Hub~~s~~ as specified in Section 39.7.1.7.3."	See the CAISO's response above.
39.7.1.7.2.2(a)	Idaho Power Company	Idaho Power Company suggests deleting the word "typical" because it seems inconsistent with how the storage horizon is described in the draft final proposal. Idaho Power Company provides the following suggested edits" "Reflect the ~~typical~~ storage duration of a hydro resource's reservoir, defined as the length of time when cycling from its maximum reservoir elevation to a new maximum reservoir elevation during typical hydro year, and should be computed comparing historic reservoir elevations for multiple years for the hydro resource and observing typical cycling times for the hydro resource."	The CAISO accepts the change with further clarifications. (a) Reflect the typical storage duration of a hydro resource's reservoir, defined as the length of time between which the reservoir cycles from a ~~when cycling from its~~ maximum ~~reservoir~~ elevation to a new maximum ~~reservoir~~ elevation during a ~~typical~~ hydro cycle. The Scheduling Coordinator shall ~~yearand should be~~ compute the reservoir's cycling time based on ~~dcomparing historic reservoir elevations f~~multiple years of reservoir elevation data~~. for the hydro resource and observing cycling times for the hydro resource~~."
39.7.1.7.2.2(a)	Powerex	Powerex provides the following proposed edits: "(a) Reflect the ~~typical~~ maximum storage duration of a hydro resource's reservoir, defined as the length of time when cycling from its maximum reservoir elevation to a new maximum reservoir elevation during ~~typical~~ a hydro year, and should be computed comparing historic reservoir elevations for multiple years for the hydro	The CAISO partially accepts this change. See above.

California ISO

Tariff Section	Stakeholder	Stakeholder Comment	CAISO Response
		resource and observing typical cycling times for the hydro resource."	
39.7.1.7.2.2(a)	Six Cities	Six Cities comments that as included in the draft, the subsection number appears to be out of sequence. Six Cities states that it appears the sub-section number should be 39.7.1.**7**.2.2(a).	The CAISO accepts this change. The CAISO will further verify all the numbering.
39.7.1.7.2.2(a)	Six Cities	Six Cities provides the following suggested edit: "(a) Reflect the typical storage duration of a hydro resource's reservoir, defined as the length of time when cycling from its maximum reservoir elevation to a new maximum reservoir elevation during a typical hydro year, and should be computed comparing historic reservoir elevations for multiple years for the hydro resource and observing typical cycling times for the hydro resource."	See the CAISO's response above.
39.7.1.7.2.2(b)	Bonneville Power Administration	Bonneville states that as the language is written, it is somewhat unclear what "legally" is referring to. Bonneville suggests changing "that can legally" to "who has authority to" to clarify. Bonneville suggests the following potential revisions: "Be supported by (1) a written attestation by a representative who has the authority to ~~that can legally~~ bind the company stating that the value submitted to the CAISO as the maximum storage horizon is consistent with the requirements specified in this section 39.7.1.7.2 (b), or (2) corroborating	The CAISO accepts this change with further clarifications. "(b) Be supported by (1) a written attestation by a representative who has the authority to ~~that can legally~~ bind the company stating that the value submitted to the CAISO as the maximum storage horizon is consistent with the requirements specified in ~~this s~~Section 39.7.1.7.2(~~b~~a);~~,~~ or (2) corroborating information submitted to the CAISO, which may include several years of historic reservoir levels for the specific hydro resource and regulatory filings related to the operations of the hydro resource."

California ISO

Tariff Section	Stakeholder	Stakeholder Comment	CAISO Response
		information submitted to the CAISO, which may include several years of historic reservoir levels for the specific hydro resource and regulatory filings related to the operations of the hydro resource."	
39.7.1.7.2.2(b)	Idaho Power Company	Idaho Power Company comments that it appears that the reference should be to subsection (a) since subsection (b) does not describe the requirements given that (a) does. Idaho Power Company provides the following suggested edits: "Be supported by (1) a written attestation by a representative that can legally bind the company stating that the value submitted to the CAISO as the maximum storage horizon is consistent with the requirements specified in this section 39.7.1.7.2(~~b~~a), or…"	The CAISO accepts this change with further clarifications. See above.
39.7.1.7.3	Idaho Power Company	Idaho Power Company suggests using "electric pricing hubs" for consistency, as opposed to "Trading Hubs." Idaho Power Company also suggests revising the sentence to provide greater clarity and to avoid using the term "hydro resource area," which is unclear. Idaho Power Company provides the following proposed edits: "The default ~~Trading Hubs~~ electric pricing hubs are as follows~~for each hydro resource area shall be designated as~~:"	The CAISO agrees. The CAISO will further provide that the default electric pricing hubs in the business practice manuals. **39.7.1.7.3 Default Electric Pricing ~~Trading~~ Hubs** The default electric pricing hubs will be as specified in the Business Practice Manuals, which will also include a process for modifying or adding electric pricing hubs to the list of default electric pricing hubs. ~~Trading Hubs for each hydro resource area shall be designated as:~~ ~~(a) PacifiCorp West, Portland, Powerex, Puget Sound will be in the Mid-Columbia Trading Hub.~~

Tariff Section	Stakeholder	Stakeholder Comment	CAISO Response
			~~(b) Arizona, Idaho, PacifiCorp East, NV Energy will be in the Palo Verde.~~ ~~(c) Northern California will be in the North-of-path 15.~~ ~~(d) Southern California will be in the South-of-path 15.~~
39.7.1.7.3	Powerex	Powerex suggests modifying Section 39.7.1.7.3 to expressly identify the Alberta hub as an electric pricing hub that is available to storage hydro resources. In order to avoid the need to update this tariff language as new market participants are added to the EIM, Powerex also recommends modifying Section 39.7.1.7.3 to provide that the Default Trading Hub and any additional electric pricing hubs approved for a given hydro resource will be set out in the CAISO's Master File.	The CAISO will modify the tariff to specify that eligible and default electric pricing hubs will be specified in the business practice manuals.
39.7.1.7.3	Powerex	Powerex provides the following suggested edits: "**39.7.1.7.3 ~~Default Trading~~Eligible Hubs** A Scheduling Coordinator may elect one or more of the following as a ~~The d~~Default Trading Hub~~s for each hydro resource area shall be designated as:~~ ~~(a) PacifiCorp West, Portland, Powerex, Puget Sound will be in the~~ or electric pricing hub: Mid-Columbia Trading Hub;~~.~~ ~~(b) Arizona, Idaho, PacifiCorp East, NV Energy will be in the~~ Alberta; Palo Verde~~.~~ ~~(c) Northern California will be in the~~;	See the CAISO's proposed changes above.

Tariff Section	Stakeholder	Stakeholder Comment	CAISO Response
		North-of-path 15; and ~~.~~ ~~(d) Southern California will be in the~~ South-of-path 15 Each resource's Default Trading Hub and any approved electric pricing hubs shall be reflected in the CAISO's Master File for the relevant resource."	
39.7.1.7.3	Seattle City Light	Seattle City Light recommends that CAISO add language that clarifies the process for establishing default trading hubs when additional BAAs are added to the EIM market and the process for revising the assigned default trading hub.	See the CAISO's proposed changes above.
39.7.1.7.3	Six Cities	Six Cities comments that in sub-sections (a) through (d), use of the phrase "in the" is confusing. Six Cities suggest deleting "in the" from all sub-sections.	See the CAISO's proposed changes above.
39.7.1.7.3(a)-(b)	Idaho Power Company	Idaho Power Company comments that it believes Mid-C is a more appropriate default electric pricing hub as that is the hub which prices at its points approximate most of the year. Idaho Power Company does, in certain times of year, sell at locations on its system that has prices that approximate Palo Verde . But, Idaho Power Company notes that it sells at prices more like Mid-C during the majority of the year. Idaho Power Company provides the following suggested edits: "(a) Idaho Power Company, PacifiCorp West, Portland General Electric, Powerex, and Puget Sound Energy will be in the Mid-Columbia ~~Trading Hub~~electric pricing hub. (b) Arizona Public Service Company~~,~~	The CAISO will consider this further through the BPM process. However, the CAISO believes the default electric price hubs should be established based on which hub is most reflective of pricing in the entity's geographic area. The BPM will also have a process through which the entity may demonstrate eligibility for other hubs in their long-term/geographic component.

Tariff Section	Stakeholder	Stakeholder Comment	CAISO Response
		~~Idaho~~, PacifiCorp East, and NV Energy will issue ~~be in~~ the Palo Verde electric pricing hub."	
39.7.1.7.3(c)-(d)	Idaho Power Company	Idaho Power Company suggests for adding either "Trading Hub" or "electric pricing hub" to the end of (c) and (d); however, it is unclear which term would be more appropriate. Idaho Power Company makes this suggestion in order to provide consistency. Idaho Power Company provides the following proposed edits: "(c) Northern California will ~~be~~ issue in the North-of-path 15. (d) Southern California will ~~be~~ issue in the South-of-path 15."	See the CAISO's proposed changes above.
39.7.1.7.3(c)-(d)	Southern California Edison	Southern California Edison comments that while Section 39.7.1.7.2.1(c) provides internal resources (as well as external resources) do not need to provide supporting transmission rights to be mapped to the resource's Default Trading Hub. Southern California Edison suggests that for an internal resource, the determination of its Default Trading Hub should be one that the resource is electrically close. Southern California Edison provides the example that the Default Trading Hub for Big Creek should be SP15 rather than NP15. Southern California Edison goes on to state that for this reason, changes to these subsections are needed for clarity.	See the CAISO's proposed changes above.

Tariff Section	Stakeholder	Stakeholder Comment	CAISO Response
		Southern California Edison provides the following suggested edits: “(c) the North-of-path 15 for Northern California ~~will be in the North-of-path 15~~unless the resource is electrically closer to the South-of-path 15 under which it will be the South-of-path 15. (d) the South-of-path 15 for Southern California ~~will be in the South-of-path 15~~unless the resource is electrically closer to the North-of-path 15 under which it will be North-of-path 15.”	
Appendix A - Hydro Default Energy Bid	Southern California Edison	Southern California Edison suggests to change this term to something more specific, such as Hydro With Storage Capability Default Energy Bid.	The suggested term is too long. The definition specifies a resource is not eligible for this default energy bid if they do not have storage capability.