Storage Bid Cost Recovery and Default Energy Bid Enhancements

~~Draft~~ Final Proposal for Track 1

October ~~4~~31, 2024

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1. Introduction

Grid-scale energy storage assets have been deployed quickly onto the California Independent System Operator's (ISO) footprint in recent years, going from about 500 MW in 2020 to approximately 10,000 MW by July 2024. These assets have the potential to advance California's goals to further renewable integration by absorbing excess renewable energy during periods of low demand in order to later inject that energy back into the grid when demand increases.

Energy storage has unique operational characteristics compared to conventional thermal generators and variable energy resources (VERs). Energy storage assets are defined by their flexibility, responsiveness, and energy-limited nature, as fuel availability is endogenous to the electric market. As such, the ability of an energy storage resource to provide energy products and services when scheduled is determined by its ability to secure the state of charge (SOC) needed to support its awards and schedules. Energy storage resources' bids reflect these unique operational characteristics and do not result merely from their costs to produce energy in a given interval. Rather, they also reflect storage resources' desire to be dispatched at a given time based on their opportunity costs in future intervals.

In 2022, the ISO noted that the then-applicable provisions related to bid cost recovery (BCR) for energy storage did not align with the overall objectives and intent of the BCR construct. Specifically, the ISO noted that a combination of ancillary service awards or self-provisions for regulation-down in the real-time market, coupled with relatively high energy bids, resulted in unusually high BCR payments to storage resources.[1] The ISO found, and Federal Energy Regulatory Commission (FERC) agreed, that storage resources' high bids did not represent the resources' actual bid costs but rather reflected economic unwillingness to discharge, essentially avoiding energy dispatch in certain intervals. Further, the absence of bid cost recovery payments for providing ancillary services would not incentivize resources to bid in ways that would undermine the market's efficiency. Instead, the opportunity to receive bid cost recovery payments incentivized high bidding that undermined market efficiency.[2]

In filing for this change, the ISO noted that it would initiate a stakeholder process after the FERC filing to assess whether other potential changes may be more appropriate to address the BCR issue.[3] This position was then echoed by FERC, which noted the ISO offered to monitor the impacts of the bid cost recovery provisions to energy storage resource settlements and continue to engage with stakeholders to examine whether any other longer-term enhancements might be made to the tariff to address this issue.[4]

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[1] CAISO, "Tariff Amendment to Prevent Unwarranted Bid Cost Recovery Payments to Storage Resource, and Request for Effective Date One Day After Filing" ("ASSOC Filing"), September 2022, p. 10.
[2] CAISO, ASSOC Filing, September 2022, p. 12.
[3] CAISO, ASSOC Filing, September 2022, p. 13.
[4] *California Independent System Operator Corp.*, 181 FERC ¶ 61,146 p. 14 (2022).

As the number of energy storage resources continued to grow within the ISO's footprint, additional concerns related to how BCR provisions apply to energy storage resources were raised by stakeholders. In 2023, the Department of Market Monitoring (DMM) published a special report on battery storage, which noted that there are a number of situations where batteries may receive inappropriate or inefficient BCR.[5]

Earlier this year, the ISO initiated a stakeholder process to consider enhancements to bid cost recovery as it applies to storage resources because the concerns about unwarranted bid cost recovery payments to storage exist regardless of the recently proposed changes to allow energy storage resources to bid above the soft energy cap under certain circumstances.[6] As such, the ISO seeks to address this matter expeditiously, meeting the ISO's prior commitment to the Board of Governors, the Western Energy Markets (WEM) Governing Body, and FERC.

2. Changes from the Revised Straw Proposal

The ~~draft~~ final proposal includes several significant changes and details not included in the draft final proposal and the revised straw proposal. Most of these changes are in direct response to stakeholder comments.

Several stakeholders requested the ISO provide additional clarity on how the different potential solutions compare to each other. A series of numerical examples have been included in Appendix A. These examples are simplified scenarios based on dispatch observed in the market by ISO staff. These examples do not represent actual settlement outcomes for any existing resources. Given the focus of the draft final proposal on closing design gaps related to strategic bidding concerns, these examples are constructed to focus on scenarios where resources may bid in a manner that would capture unduly high BCR payments. In addition, the final proposal includes an updated version of the Addendum posted by the ISO after the October 9th, 2024, stakeholder meeting.

Some stakeholders offered updated alternative solutions that could enhance or replace the Proposed Solution put forth by the ISO in the IPSP. A description of each alternative solution, as well as a summary of the stakeholder feedback received on each potential solution, is included in Section 5. The ISO has modified references to these alternatives per stakeholder requests within their written comments submitted October 23rd, 2024.

Several stakeholders have noted that instances in which resources have been subject to local market power mitigation (LMPM) in intervals prior to their day-ahead (DA) schedules may merit specific BCR provisions that ensure they are made whole. Stakeholders requested additional analysis on the impact

[5] DMM, "Special Report on Battery Storage", July 2023, p. 20.

[6] CAISO, Board of Governors Memo regarding the Tariff Amendment on Price Formation Enhancements, May 2024, p. 6.

of mitigation. A discussion on mitigation in the context of the Proposed Solution and other alternative solutions, as well as updated analysis, is included in Section 6.1.

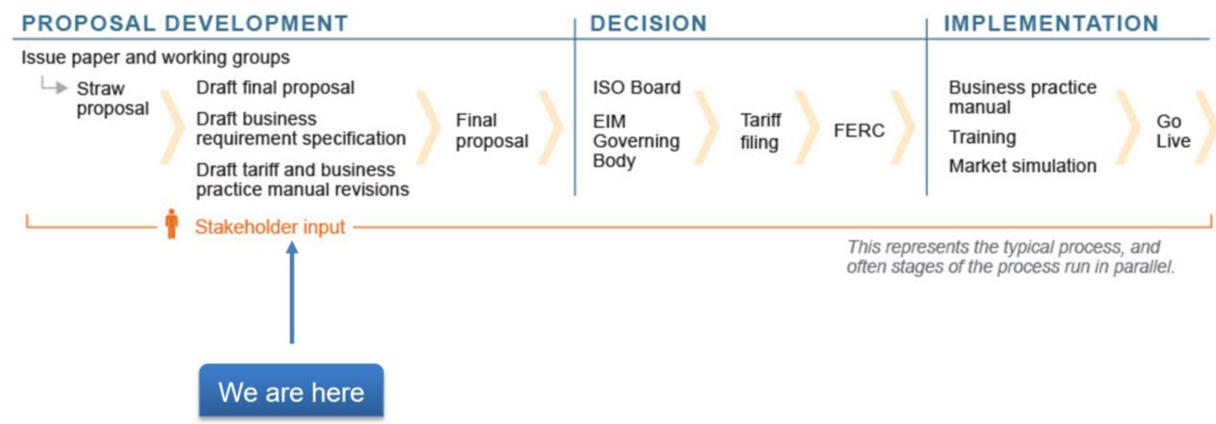
Several stakeholders have noted that features of the ISO's market design could drive outcomes and dispatch instructions that result in the buy- or sell-back of day-ahead schedules, specifically calling out multi-interval optimization (MIO). A discussion of MIO in the context of the Proposed Solution and other alternative proposals, including updated examples, is included in Section 6.2.

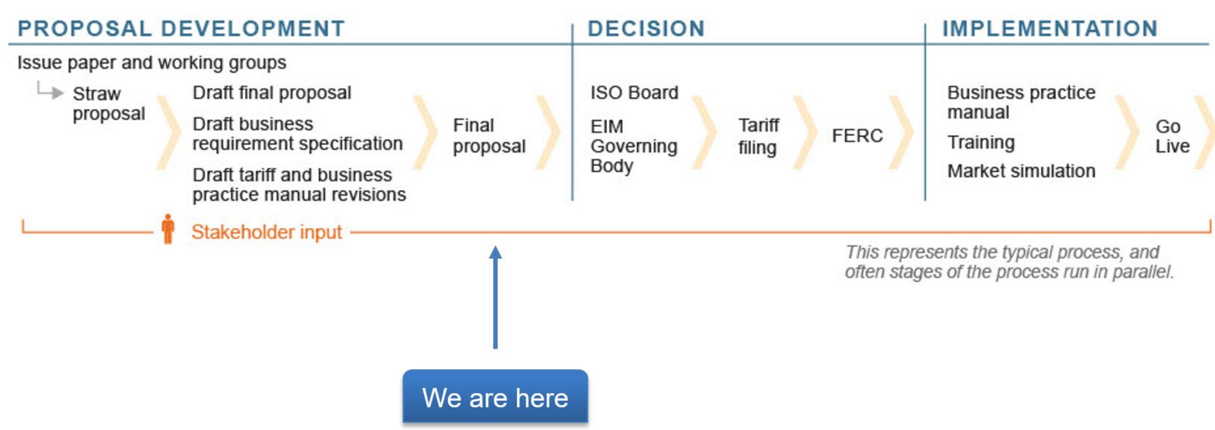
The draft final proposal also include~~ds~~d a new section, Section 7, which summarize~~s~~d the near-term interim solution the ISO will seek to implement to address concerns related to strategic bidding unduly inflating BCR payments. The present final proposal adds additional detail as requested by stakeholders in their written comments submitted October 23rd, 2024.

3. Stakeholder Process

With the publication of these materials, the ISO is at the ~~Draft~~ Final Proposal stage in the Storage BCR & DEB Enhancements Track 1 Initiative. Figure 1 shows the typical process for a stakeholder initiative.

Figure 1: Stakeholder Process Milestones





The purpose of this ~~Draft~~ Final Proposal is to address comments provided by stakeholders following the publication and discussion of the draft final proposal, as well as to ~~provide a comparison of the different potential solutions considered to date and provide a description of the near-term solution the ISO seeks to implement to address some of the issues within the scope of Track 1 of this initiative. The ISO will publish this Draft Final Proposal, hold a meeting to discuss it with stakeholders, and solicit written feedback~~summarize the proposal that will be taken to the ISO Board of Governors and Western Energy Markets' Governing Body.

Table 1. Updated Track 1 Timeline [7]

Milestone	Date
Workshop issue slides posted	July 1, 2024
Stakeholder workshop on issue	July 8, 2024
Workshop stakeholder comments due	July 18, 2024
Second stakeholder workshop on issue	July 22, 2024
Issue Paper & Straw Proposal (IPSP) posted	July 26, 2024
Stakeholder meeting on IPSP	August 5, 2024
IPSP stakeholder comments due	August 8, 2025
Stakeholder meeting on Alternative Proposals	August 19, 2024
Meeting on Alternative Proposals comments due	August 26, 2024
Revised Straw Proposal (RSP) posted	September 4, 2024
Stakeholder meeting on RSP	September 11, 2024
RSP stakeholder comments due	September 23, 2024
Draft Final Proposal (DFP) posted	October 4, 2024
Stakeholder meeting on DFP	October 9, 2024
DFP stakeholder comments due	October 2~~1~~3, 2024
Materials for the Joint Board of Governors and Governing Body Meeting posted	October 31, 2024
Joint Board of Governors and Governing Body Meeting	November 7, 2024

[7] All dates are tentative until confirmed through a notice in the ISO's Daily Briefing.

4. Track 1 Issues: Unwarranted Storage BCR

BCR is the process by which the ISO ensures scheduling coordinators (SCs) are able to recover start-up, minimum load, transition, and energy bid costs. In order to recover start-up and minimum load costs and transition costs, a unit must be committed by the ISO. For purposes of determining BCR eligibility, the ISO uses a concept called commitment period. A commitment period consists of the consecutive time periods within a trading day when a resource is online, synchronized to the grid, and available for dispatch. A commitment period is comprised of the self-commitment period and ISO commitment period. The self-commitment period is when a resource submits energy self-schedule or ancillary services (AS) self-provision. During the self-commitment period, resources are not eligible for BCR of start-up, minimum load, or transition costs, but are eligible for BCR of awarded Energy and AS. The portion of a commitment period that is not a self-commitment period is called a ISO commitment period. Resources are eligible to receive BCR for start-up costs, minimum load costs, transition costs, awarded Energy and AS during a CAISO commitment period.

To calculate BCR, the commitment costs and the energy and AS bid costs are used as inputs to calculate a resource's net difference between costs and revenues in separate pre-calculations for the Integrated Forward Market (IFM), the Residual Unit Commitment (RUC) process, and the Real-Time Market (RTM) (*i.e.,* IFM Net Amount, RUC Net Amount, and RTM Net Amount). If the difference between the total bid costs and the market revenues is positive in the relevant market, then the net amount represents a shortfall. If the difference is negative in the relevant market, the net amount represents a surplus. For each resource the IFM, RUC, and RTM shortfalls and surpluses are then netted over all hours of a trading day, with the IFM shortfalls and surpluses netted separately from the RUC and RTM shortfalls and surpluses. Thus, RUC or RTM surpluses over the entire trading day are netted with RTM or RUC shortfall, respectively, incurred over the entire trading day. For either IFM or the combined RUC and RTM netting, if the net amount over the trading day is positive (a shortfall), then the resource receives a BCR uplift payment equal to the net trading day amount.

As such, BCR is designed to provide "uplift payments" to a resource when revenues from the sale of energy and AS do not cover the resource's start-up, minimum load, transition costs, and energy bid costs over the course of a day.[8] The rationale behind BCR is to incentivize efficient bidding by allowing for the recovery of commitment costs. Without BCR, resources would have an incentive to add a risk premium to their offers, leading to inefficient market outcomes, with higher overall costs for energy.[9]

BCR was initially designed with conventional thermal assets in mind. For conventional thermal assets, commitment costs include start-up and minimum load costs, among others. This is because when a thermal power plant starts up, it incurs certain costs such as fuel costs to reach the desired output level. In addition, thermal resources may also have minimum load requirements, meaning that they have a limited turndown range that requires them to run at a specific percentage of their maximum continuous

[8] CAISO, ASSOC Filing, September 2022, p. 3.
[9] *Ibid.*

rating. Since conventional resources with a day-ahead schedule may incur some costs prior to the intervals when they are expected to generate electricity (*i.e.,* during the commitment period), BCR is a necessary mechanism to recover those costs if the resource faces a shortfall over the trading day.

Storage resources, in contrast, are fundamentally different from conventional thermal assets. As recognized by FERC in its Order Accepting the ASSOC Constraint filing, storage resources have neither start-up nor minimum load costs, and generally have fast ramp rates, thus lacking the conventional drivers for BCR (*i.e.,* commitment). Although they may have other opportunity costs, they generally lack the intertemporal constraints that warrant bid cost recovery. Energy storage resources' bids do not result merely from their costs to produce energy in a given interval; instead, they also reflect storage resources' desire to be dispatched at a given time based on their opportunity costs in future intervals. As a result, the bids submitted by storage resources are not equivalent to those submitted by conventional thermal assets as they do not only represent actual bid costs but also include an implied opportunity cost.

Moreover, the BCR construct, in general, does not adequately consider attributes common among storage resources, such as SOC constraints, which determine whether an asset can support its awards and schedules. This results in materially different treatment with regards to conventional generators. For example, if a conventional thermal asset is unable to perform and fulfill its day-ahead schedule due to unavailability (*i.e.,* an outage), the expected energy from that asset is categorized as derate energy, thus making it ineligible for BCR. In contrast, when a storage resource is unable to meet its day-ahead schedule due to physical limitations, like having a SOC that cannot support the schedule, the market can instruct the storage asset to a 0 MW dispatch due to the SOC being binding, resulting in the buy-back or sell-back energy to be categorized as Optimal Energy (OE) which is eligible for BCR. Given these conditions, some BCR payments to storage resources have materialized despite not being aligned with the intent of BCR. In particular, the ISO is aware of a significant rise in BCR payments related to the buy- and sell-back of day-ahead schedules driven by limited or insufficient SOC.

This differentiated treatment of unavailable energy between conventional and storage assets creates two concerns:

- **Concern 1:** Storage assets are not exposed to real-time (RT) prices for deviating from day-ahead schedules.
- **Concern 2:** Storage assets are incentivized to bid strategically to maximize the combined BCR and market payment.

A buy-back of a discharge day-ahead schedule can occur when a storage asset's real-time SOC is too low to support the day-ahead award. Conversely, a sell-back of a charge day-ahead schedule can occur when a storage asset's real-time SOC is too high to support the day-ahead award.

In the RTM, SCs bids can bid in a manner that would unduly maximize BCR payments through buy-back or sell-back of the day-ahead schedule. This behavior could materially hinder the reliability of the ISO's grid because energy storage resources would be unavailable when needed in real-time. This construct also creates economic inefficiency, as it removes exposure to real-time prices, thus minimizing incentives to reflect real time market conditions in supply offers. Finally, the current BCR paradigm as it applies to storage resources can lead to undeliverable day-ahead market awards, since scheduling coordinators may bid in a manner that would artificially inflate BCR payments to maximize pursuit of unwarranted real-time BCR revenue without exposure to real time conditions and prices.

For buy-backs of the day ahead schedule, the storage asset starts the RTM with a day ahead schedule with bids to discharge. In the RTM, grid conditions may materially differ from the day ahead market. If storage resources submit bids that do not reflect RT conditions and opportunity costs, this may lead to dispatch being possible prior to the intervals with day-ahead schedule awards. It is crucial to underscore that, given the current BCR construct, storage resources are insulated from RT price exposure and, as such, have little incentive to bid in a manner that reflects those conditions and would allow for the preservation of SOC to meet day-ahead schedules in future intervals. As a result, if resources are dispatched early in the day such that their day-ahead schedule for the peak period is now infeasible, those assets must buy-back the now infeasible day-ahead schedule. The buy-back results in the storage resource receiving BCR to make the resource whole for the hours that were bought back. Importantly, the cost being recovered is based on the difference between the RT bid and the RT locational marginal price (LMP). As such, this resource could execute a bidding strategy that seeks to maximize that difference in the periods when a buy-back is triggered, leading to unduly high BCR payments. By bidding at low prices that tend towards the bid floor, a storage asset may make more money by triggering BCR and failing to support its day-ahead schedule than by bidding in a manner that would ensure delivering said day-ahead schedule or being efficiently available for re-dispatch in the RTM.

For sell-backs of the day ahead schedule, the mechanism works in reverse. Here, the storage asset starts the RTM with a day ahead schedule with bids to charge. In the RTM, grid conditions materially differ from the day ahead market. As noted before, storage resources are insulated from RT prices and as such have no incentive to bid in a manner that would reflect RT conditions and opportunity costs, potentially resulting in dispatch to charge earlier in the day relative to their day-ahead schedules. Thus, if earlier dispatch resultant from the bids causes the asset to charge earlier than its day-ahead schedule, their initial day-ahead schedule to charge is now infeasible, triggering a sell-back of said day-ahead schedule. Since the BCR construct today calculates the difference between the RT bid and the RT LMP, the resource could bid strategically to maximize this difference just as in the prior case. As such, a resource could execute a bidding strategy that seeks to trigger sell-backs, then bid consistently high (at or near the bid cap) in order to maximize its BCR revenue. This, just like the prior example, can result in circumstances where the asset is better off by triggering BCR and bidding strategically to maximize it than by bidding in a manner that would ensure support of its day-ahead schedule or being efficiently available for redispatch in the RTM.

The dynamics described above and exemplified in Appendix A create incentives that are not aligned with the intent of BCR, as assets might be incentivized to bid and operate in the RT market in a manner that would trigger buy- or sell-backs of their day-ahead energy schedules in order to capture outsized BCR payments. In addition, the current BCR construct as it applies to energy storage assets results in inefficient outcomes that could materially hinder the reliability of the ISO's grid. The BCR construct results in inefficiency as it removes exposure to real-time prices, thus minimizing incentives to reflect real-time market conditions in supply offers while also potentially creating incentives to pursue unwarranted real-time BCR revenue at the expense of day-ahead awards without any exposure to RT conditions and prices.

Considering the sensitive nature of the information contained herein, the ISO is actively monitoring storage BCR awards to ensure unwarranted payments do not increase to untenable levels following the dissemination of this information or any of the examples contained in these materials.

5. Proposals considered for Track 1

This section provides an overview of the solutions put forth by the ISO and stakeholders to address the issues in scope for Track 1 of the present initiative.

5.1. ISO Proposed Solution

As noted previously, when a storage resource is unable to meet its day-ahead schedule due to physical limitations, like having a SOC that cannot support the schedule, the market dispatches the storage asset at 0 MW due to the SOC being binding, resulting in the energy to be categorized as OE, which is eligible for BCR. The ISO's proposed solution involves redefining dispatch unavailable due to SOC constraints in the binding interval as “non-optimal energy,” which would be ineligible for BCR. The ISO proposes to identify whether storage resources can support their awards and schedules in the real-time binding interval on a resource-by-resource basis.

If a given storage resource’s SOC at the start of the binding interval is equal to its minimum or maximum value, with consideration of the ASSOC constraint, the end-of-hour SOC constraint, upper and lower charge limits, and the attenuated SOC constraint, then the market would rerate or derate the PMax or PMin to 0 in order to capture that the asset is completely full or empty. This, in turn, would lead to the reclassifying any energy associated with buy-backs or sell-backs in that binding interval as non-optimal due to physical limitations as it is not available for dispatch. As a result the ISO would exclude the energy associated with that interval from the BCR calculation.

The proposed solution would align the treatment of unavailable energy from a storage asset to that of a conventional thermal asset, which has its expected energy categorized as derate energy when it is unable to perform and fulfill its day-ahead schedule due to unavailability (*i.e.,* an outage), thus making it ineligible for BCR.

During the present initiative, the ISO ~~has~~ identified significant challenges with the design of the proposed solution due to the impact of multi-interval optimization (MIO). These issues, as well as the complications they present for the proposed solution and other alternatives, are covered in detail in section 6.2.

5.1.1. Stakeholder Feedback on the ISO Proposed Solution

In comments submitted August 16th, the California Public Utilities Commission's Energy Division (CPUC ED) expressed support for the Proposed Solution, noting that the issue at hand merits urgent resolution as the issue introduces inefficiencies into the market and could increase costs for ratepayers. In comments submitted August 26th, the DMM also expressed support for this proposal, noting that it, contrary to any of the alternative proposals put forth by stakeholders, would address opportunities for strategic bidding, market inefficiencies, and diminished reliability. DMM argues that this is because the Proposed Solution would fix the core issue that current BCR rules create: an incentive for batteries to bid below expected opportunity costs in real-time and in a manner that can result in battery capacity being discharged prior to the peak net load hours.

Similarly, in their August 26th comments, the California Public Utilities Commission's Public Advocates Office (Cal Advocates) also supported this proposal as it simultaneously addresses each of the three risks underscored by DMM. Cal Advocates noted that the Proposed Solution is the most effective and viable option to address the need to protect ratepayers from the high costs and risks that the current BCR rules create. In contrast, Cal Advocates argued that the alternative proposals from the CESA and Vistra fail to mitigate both risks identified by DMM. In this context, Cal Advocates also stated that adoption of the Proposed Solution on an interim basis would be acceptable if the ISO includes broader reform of BCR rules for energy storage in the scope of a subsequent track of the initiative.

Following the September 11th stakeholder meeting, in which the ISO noted the difficulties associated with the proposed solution and other alternatives given the impacts of MIO, Cal Advocates noted that they originally supported the ISO's proposed solution since it was "a measured and sufficiently well-targeted approach" relative to the DMM's recommendation to eliminate most RT BCR for energy storage resources. Nevertheless, since the ISO has determine that the minimum or maximum SOC triggering condition may not occur due to the complex inter-temporal dynamics of MIO, Cal Advocates is now of the position that the ISO should adopt DMM's ready-to-hand recommendation to eliminate most RT BCR for energy storage as an interim solution. Cal Advocates reasons that such approach is the only remaining near-term solution that would simultaneously resolve the concerns of unwarranted BCR payments due to insufficient SOC and gaming to unduly inflate BCR payments. Cal Advocates would support a sunset provision for the interim rule to encourage CAISO and parties to work to develop a mutually agreeable solution to comprehensively reform BCR rules.

In their September 23rd comments, DMM stated that, while they understand that the ISO has identified potential challenges to implementing the proposed solution due to the MIO and associated challenges with identifying intervals that have binding SOC constraints, they encourage the ISO to explore alternate methods of identifying SOC insufficiency for a given interval, rather than shifting the Track 1 focus to implementation of an alternate solution that would only modify the inputs to the BCR calculation. DMM goes on to recommend exploring the possibility of calculating the SOC available at the beginning of an interval to meet day-ahead schedules in that binding interval, or over a determined number of future intervals. DMM notes that the proposed solution would address current inefficient bidding incentives, and establish a more appropriate default rule of not paying BCR due to insufficient SOC. Starting from this new default position, the ISO and stakeholders may then wish to consider the specific and narrow circumstances in which BCR may be warranted in a future phase of this initiative.

Other stakeholders have taken a different position, noting that the proposed solution is overly punitive and fails to recognize the fact that storage assets do not have total control over their RT SOC given certain characteristics of the ISO's markets and optimization processes. Stakeholders such as the California Community Choice Association (CalCCA), California Energy Storage Alliance (CESA), Customized Energy Solutions (CES), and WPTF reflected these positions in their comments submitted on August 8th. In comments submitted August 26th, Vistra noted that the proposed solution is overly punitive and that other proposals put forth by stakeholders should be adopted in the interim.

In their September 23rd comments, San Diego Gas & Electric (SDG&E) noted that, while the ISO's proposed solution is not their preferred approach, SDG&E believes that adding additional logic to better identify what intervals should be flagged for this alternative treatment would be an improvement that would move the proposed solution to be more in line with the other stakeholder-suggested solutions. As such, SDG&E proposed to limit application of the proposed solution to intervals where: (1) the resource's SOC in the 5-min market is at the min or max SOC value going into that interval, (2) the resource has a day-ahead or base schedule that it cannot support due to the SOC value, and (3) the resource was not mitigated or exceptionally dispatched in a prior interval. This being said, SDG&E noted that they remain concerned that application of the ISO's proposed solution to eliminate all BCR when an SOC constraint binds, even with additional triggering conditions, may result in an unbalanced outcome for storage resources.

5.2. ~~CESA~~ Stakeholder-proposed~~Alternative S~~ solution

First Iteration

Several stakeholders stated that the timeline and schedule for Track 1 of this initiative may be insufficient to allow for the robust conversations needed to develop a durable and holistic solution to the issues in scope. In this context, CESA suggested implementing an alternative solution in the interim which would address Concern 2 (*Storage assets may have an incentive to bid strategically to maximize the combined BCR and market payment*). The first iteration of the alternative solution proposed by CESA would imply modifying the formula used to calculate BCR to use the day-ahead Locational Marginal Price (LMP) instead of the RT Bid, as follows:

- From: (RT dispatch – DA schedule) * (RT bid – RT LMP).

- To: (RT dispatch – DA schedule) * (***DA LMP*** – RT LMP).[10,11]

Stakeholders argue that this proposal would eliminate the impact of a resource's bid on BCR payments, alleviating the concerns regarding unduly inflated BCR payments. In addition, some stakeholders have noted that their software used -$150 bids in hours with day-ahead schedules to "firm them up", a practice that could yield unwarranted BCR under the status quo but would not contribute to unduly high BCR if RT Bids are not part of the BCR calculation.

This proposal's main advantage is that it would eliminate the impact of a resource's bid on BCR payments in the intervals it is applied, potentially addressing the concerns related to strategic bidding. On the other hand, this alternative also has some drawbacks, notably, this proposal would not address Concern 1, continuing the current insulation of storage resources from RT prices. Stakeholders have acknowledged that this alternative would not resolve Concern 1, but they argue it would allow more time to develop a holistic solution that addresses said concern appropriately. Moreover, this

[10] One stakeholder requested clarification on whether the BCR calculation only applies to hours in which there is a day-ahead schedule. BCR Shortfalls and Surpluses are calculated for all intervals, regardless of whether there is a day-ahead schedule or not. This stakeholder also asked why the formula does not breakout RT dispatch into fifteen-minute market (FMM) and five-minute real time dispatch (RTD) terms. For simplicity of explanation, this scenario assumes all buy- or sell-back occurs in the RTD. Unwarranted BCR from buy- or sell-back of day-ahead schedules may occur in between the 1) day-ahead schedule and the FMM; 2) day-ahead schedule and the RTD; and/or 3) FMM and the RTD. BCR resulting from the change between the day-ahead schedule and the FMM would be defined as: (FMM dispatch – DA schedule) * (RT bid – FMM LMP). BCR resulting from the change between the FMM and the RTD would be defined as: (RTD dispatch – FMM dispatch) * (FMM LMP –RTD LMP). BCR resulting from the change between the day-ahead schedule and the RTD dispatch remains defined as: (RT dispatch – DA schedule) * (RT bid – RTD LMP). Netted, these three formula would provide BCR.

[11] One stakeholder stressed the importance of clarifying the origination of this formula for BCR. This formula is a derivation from the formula found in the BPM Configuration Guide for RUC and RTM Bid Cost Recovery Settlement (CC6620). The ISO used the derivation to highlight the CESA alternative solution's change in simple, digestible terms. The ISO appreciates the stakeholder feedback that the derived formula caused confusion and shares the following proof as clarification:

CC6620 describes a RT interval as eligible for BCR when the following is true: BAARUCNetAmount + BAARTMNetAmount > 0. To simplify, all other bids and awards are assumed to be zero. Therefore, BAARUCNetAmount is zero because there are no awards from the RUC process.

BAARTMNetAmount is defined in CC6620 as: BAARTMNetAmount = RTM cost – RTM revenue. In this scenario, "cost" is MWh change multiplied by bid and "revenue" is MWh change multiplied by price. These terms are reflected as: RTM Cost = (RT dispatch – DA schedule) * RT bid; and RTM Revenue = (RT dispatch – DA schedule) * RT LMP. Therefore, BAARTMNetAmount is expressed as:

BAARTMNetAmount = (RT dispatch – DA schedule) * RT bid – ((RT dispatch – DA schedule) * RT LMP)

Rewritten: BAARTMNetAmount = (RT dispatch – DA schedule) * (RT bid – RT LMP) modification to the RT BCR formula would continue to pay BCR to resources that are not available in real-time, but it may limit its magnitude as the payment is now calculated by the price difference between day-ahead and RT as shown in the examples in Appendix A.

Second Iteration

In comments submitted August 26th, CESA offered a second iteration of ~~their~~ the proposal, as well as additional clarification stating that this alternative proposal should only apply in the intervals where the generic SOC constraint is binding. Specifically, CESA propose~~s~~d that the ~~ir~~ alternative solution should apply in 5-minute intervals where the buy-back or sell-back is caused by the generic SOC constraint binding.[12] Given the complexities of using the SOC as the trigger variable, CESA also offered an alternative set of trigger conditions that do not employ the SOC. For this alternative, CESA notes that if an interval fulfills three conditions it should trigger the alternative BCR calculation. In the case of a buy-back of a discharge schedule, the interval must have (1) a day-ahead schedule or base schedule to discharge, (2) a RT dispatch to discharge that is lower than the day-ahead or base schedule, and (3) a RT dispatch that does not charge the resource. In the case of a sell-back of a charge schedule, the interval must have (1) a day-ahead schedule or base schedule to charge, (2) a RT dispatch to charge that is lower than the day-ahead or base schedule, and (3) a RT dispatch that does not discharge the resource.

When a buy-back has occurred, CESA recommends using the higher of either the day-ahead LMP, the RT Default Energy Bid (DEB), or the RT Bid in the interval's BCR calculation. Conversely, when a sell-back has occurred, CESA recommends using the lower of the day-ahead LMP, the RT DEB, or the RT Bid. As such, CESA updated proposal would modify the aforementioned RT BCR calculation as follows:

- For a buy-back: (RT dispatch – DA schedule) * (***[Max(DA LMP, RT DEB, RT Bid)]*** – RT LMP).
- For a sell-back: (RT dispatch – DA schedule) * (***[Min(DA LMP, RT DEB, RT Bid)]*** – RT LMP).

Since ~~CESA'~~ this~~s~~ proposal would use the day-ahead LMP instead of the real-time bid, a particular rule for storage assets in the Western Energy Imbalance Market (WEIM) that are outside the ISO's footprint and not part of the Extended Day-Ahead Market (EDAM) is needed. In this paper, such resources are referred to as WEIM-only resources. Since there is no day-ahead LMP for WEIM storage assets, CESA recommended using a null value for those assets in the modified RT BCR calculation in lieu of the DA LMP.

Latest Iteration

In their September 23rd comments, CESA put forth a third iteration of the~~ir~~ proposal to modify the BCR calculation for intervals in which a buy- or sell-back may occur. CESA ~~has~~ maintained the trigger conditions described as part of the~~ir~~ second iteration; namely:

- For a buy-back of a discharge schedule

[12] In this context, the "generic SOC constraint" should be interpreted as the minimum and maximum limits of the resource, as opposed to other SOC constraints such as the ASSOC Constraint or the End-of-Hour (EOH) SOC constraint.

- (1) a day-ahead schedule or base schedule to discharge, and,
- (2) a RT dispatch to discharge that is lower than the day-ahead or base schedule, and,
- (3) a RT dispatch that does not charge the resource.

- For a sell-back of a charge schedule
  - (1) a day-ahead schedule or base schedule to charge, and,
  - (2) a RT dispatch to charge that is lower than the day-ahead or base schedule, and,
  - (3) a RT dispatch that does not discharge the resource.

For the latest iteration, CESA has slightly altered the proposed modified BCR calculation to:

- For a buy-back of a discharge schedule
  - (RT dispatch – DA schedule) * (**[Max(RT Bid, Min(DA LMP, Discharge Portion of RT DEB, RT LMP)]** – RT LMP)
- For a sell-back of a charge schedule
  - (RT dispatch – DA schedule) * (**[Min(RT Bid, Max(DA LMP, Charge Portion of RT DEB, RT LMP)]** – RT LMP)

CESA argues that this modification will ensure that if the RT bid would have resulted in a surplus in an interval, the surplus is maintained. On the other hand, if the RT bid would have resulted in a shortfall, the DA LMP or RT DEB could be used to minimize or eliminate that shortfall. Several stakeholders coalesced around this proposal in their September 23rd comments, including Pacific Gas & Electric (PG&E), Vistra, and the Western Power Trading Forum (WPTF). These stakeholders submitted minor variations of the latest iteration of this~~e CESA~~ proposal. These variations are discussed in subsequent subsections herein.

5.2.1. ~~Stakeholder~~ Feedback on stakeholder-proposed ~~CESA Alternative S~~solution

Stakeholders have noted the merits of this~~CESA's~~ proposal, highlighting that it warrants further development and consideration. In comments submitted August 26th, CalCCA underscored that, while they do not take a position on a preferred approach at this time, the ~~CESA and Vistra~~ proposal~~s~~ warrants further consideration, as it~~they~~ could offer improvements to the Proposed Solution's blunt mechanism for excluding storage resources from BCR. San Diego Gas & Electric (SDG&E) stated in their August 26th comments that alternative solutions proposed by stakeholders~~, such as CESA's Alternative Proposal,~~ offer creative temporary or short-term approaches to mitigating the quantity of BCR payments that result from bidding behavior or operator action and should be evaluated further in the Revised Straw Proposal. Other stakeholders have expressed support for the continued development of this ~~CESA's Alternative P~~proposal, submitting their own modified versions of it through written comments. These variations are detailed in the two subsequent subsections herein.

In their September 23rd comments, SDG&E stated that the second iteration of this ~~e CESA Alternative Solution~~ solution reduces their concerns with using the RT DEB within the RT BCR calculation since this formulation would use either the maximum or minimum of the DA LMP, RT DEB, and RT Bid. This being said, SDG&E noted that they remain unconvinced that it would be suitable to use the DEB prior to addressing the ongoing issues with its formulation. Additionally, SCE stated its support for a modification put forth by PG&E that would exclude the use of RT DEB as part of the modified calculation.

As part of their September 23rd comments, Vistra offered their support to the latest iteration of this ~~e CESA~~ proposal so that it can be applied as an interim solution. Vistra explicitly stated that such a modified calculation should only apply in identified intervals where there is a reasonable expectation of real-time buy-back or sell-back of schedules occurring due to constrained dispatch and not market economics or market design. Vistra notes that the modified BCR calculation should minimize the risk of inadvertently calculating a surplus that would offset warranted shortfalls in other intervals while minimizing shortfalls that may be potentially unwarranted. Given the complexities of using SOC as a trigger for modified BCR calculations, Vistra recommends to flag intervals where the SOC could not support its day-ahead award or base schedule. Vistra considers this would be a refinement to CESA's dispatch trigger conditions to identify intervals where the SOC levels constrained the market result and apply the modified BCR calculation.

In contrast, some stakeholders have expressed that this ~~CESA's A~~alternative ~~P~~proposal is not viable given the fact that it focuses solely on resolving Concern 2. In their August 26th comments, Cal Advocates noted that the ~~CESA's A~~alternative ~~P~~proposal would continue to compensate storage at the potentially high differential between day-ahead and RT prices, a factor that could be potentially exacerbated by the fact that RT prices under stressed grid conditions may increase further due to the elimination of the soft-offer cap for storage, leading to increased ratepayer exposure. In addition, Cal Advocates stated that the lack of clarity on how to apply the ~~CESA's A~~alternative ~~P~~proposal to storage assets in the WEIM should be sufficient to disqualify this proposal from consideration.

The DMM expressed that none of the alternative proposals presented by stakeholders would address the real-time bidding incentives created by the current BCR design, which can lead to inefficient dispatch based on bids below real-time marginal cost. In this context, the DMM noted that the ISO should not rush to implement interim measures that only address strategic bidding concerns or other limited scenarios created by the actions of scheduling coordinators.

Following the September 11th stakeholder meeting, Cal Advocates submitted comments indicating that they oppose the various proposals by CESA, Vistra, PG&E, and WPTF, because, under these proposals, storage would retain its eligibility for unwarranted BCR payments. Cal Advocates expressed concern over modifying the BCR calculation in a manner that would continue to allow large unwarranted BCR payments when there is a large difference between the RT LMP and the DA LMP or the DEB. Cal Advocates noted that a modified BCR calculation should not consider the DEB as it is a fixed value across all hours which could overestimate opportunity costs during and after the peak hours.

In those September 23rd comments, Cal Advocates also noted that the option of applying a modified BCR calculations across all intervals should not be pursued in principle, since while a modified formula may eliminate or mitigate the impact of the RT bid on the calculated BCR payment, storage would remain eligible for BCR payments when unable to meet DA schedules due to insufficient SOC, and these assets would remain shielded from RT prices, resulting in a cost-shift to ratepayers when unwarranted BCR is paid to storage assets that are unable to perform to meet DA schedules due to insufficient SOC. In this context, Cal Advocates argues that this ~~e CESA~~ proposal ~~s~~ and ~~thei~~its~~r~~ variations would incentivize storage resources to bid as close to the DEB or the DA LMP as possible to maximize BCR payments, rather than in a manner to fully represent their opportunity costs and to maintain sufficient SOC to meet their DA awards.

As such, Cal Advocates opposes the use of a modified BCR calculation across all intervals and instead recommends adopting the DMM's recommendation to eliminate most RT BCR payments to storage as an interim solution with a sunset provision. If the ISO moves forward with a modified BCR calculation as a means to resolve Concern 2, Cal Advocates urges the implementation of three key components to such an approach. First, CAISO should remove the RT Bid parameter in the modified bid formula and should apply the formula to all intervals. Second, CAISO should not use the DEB in the modified BCR formula since it does not represent hourly storage opportunity costs and may misrepresent opportunity costs leading up to peak demand hours. Third, CAISO should apply the minimum or maximum SOC trigger condition at the start of the binding interval.

Similarly, Salt River Project (SRP) noted in their September 23rd comments that this ~~e CESA~~ proposal and its variations focus solely on modifying the BCR formula by substituting different cost proxies without addressing Concern 1. SRP underscored that, while these proposals could serve as an interim solution, the dilution of the recovery of lost opportunity due to early deployment could incentivize participants to incorporate a risk premium in their bids or withhold bids during certain periods as a risk management strategy.

5.2.2. PG&E's ~~M~~modifications to the stakeholder-proposed solution ~~CESA's Proposal~~

In their August 26th comments PG&E recommended focusing the stakeholder-proposed ~~CESA's proposal~~ solution ~~to~~ on the hours with day-ahead schedules and removing the RT DEB from the modified BCR calculation. PG&E noted that its modified version of the stakeholder-proposed ~~CESA's Proposal~~ solution is more conservative, as it better limits the BCR recovery amounts.

In their September 23rd comments, PG&E expressed support for implementing an interim solution that would modify the BCR calculation to close potential loopholes for strategic bidding. In this context, PG&E supported the use of a modified version of the stakeholder-proposed solution~~CESA proposal~~:

- For a buy-back of a discharge schedule:
  - (RT dispatch – DA schedule) * (**Max[RT Bid, Min(DA LMP, discharging portion of RT DEB)]** – RT LMP)
- For a sell-back of a charge schedule:
  - (RT dispatch – DA schedule) * (**Min[RT Bid, Max(DA LMP, charging portion of RT DEB)]** - RT LMP)

Regarding when the modified BCR calculations should be applied, PG&E recommends using the same trigger criteria put forth by CESA; nevertheless, PG&E does support extending the modified BCR calculations to intervals with no DA schedules to charge/discharge if the ISO can provide additional information on if it can integrate logic to use a different RT BCR equation for intervals with no DA schedules.

Regarding the questions on how a proposal using the day-ahead LMP in the BCR calculation should apply to resources in the WEIM footprint, PG&E argues that WEIM-Only and CAISO/EDAM batteries should be handled differently for RT BCR given the fact that WEIM-Only Day-Ahead schedules are essentially self-scheduled while CAISO/EDAM day-ahead schedules are a product of the Integrated Forward Market. As a result, PG&E reasons that a WEIM-Only battery bidding in the RT markets should be presumed to have full control of its SOC in forming its bids relative to its base schedule. As such, given the fact that the base schedule of a WEIM-Only asset was not the product of any CAISO market process, these resources shouldn't be eligible for RT BCR due to buy-back of what can be deemed a self-schedule. These matters are further discussed in section 7.

5.2.3. WPTF's ~~M~~modifications to the stakeholder-proposed solution~~CESA's Proposal~~

In their August 26th comments, WPTF proposed modifications to the first iteration of the stakeholder-proposed ~~CESA's initial proposal~~solution. Specifically, WPTF proposed an interim solution that would first identify intervals where (1) the resource's SOC in the 5-minute market is at the min or max SOC value going into that interval, and (2) the resource has a day-ahead or base schedule that it cannot support due to the SOC value; then, replace the RT Bid component of the RT BCR calculation for those intervals with RT DEBs, day-ahead LMPs, and/or RT bids.

In their September 23rd comments WPTF indicated that they would support an interim solution that applies a modified BCR calculation in identified intervals where there is a reasonable expectation that buy- or sell-backs are occurring due to a constrained dispatch and not market economics or market design features. WPTF also noted that they would not support the expansion of the modified BCR calculation to advisory intervals in the MIO or applied to all intervals in the day since uneconomic dispatch in binding intervals can occur for several reasons, including factors such as advisory prices and awarded FRP. In this context, WPTF proposes to first identify intervals where insufficient SOC may not support the day-ahead schedule, although not necessarily at the minimum or maximum SOC value. In addition, WPTF recommends the ISO consider adding another condition to those specified by CESA; namely, to add a condition whereby an interval is not flagged to receive the modified BCR treatment if the resource had been mitigated (i.e., bid actually changed) in a prior market run. If this is too complex to implement for the purposes of an interim solution, WPTF notes that the added cost of this condition may not be worth the benefits.

5.3. Vistra's modifications to the stakeholder-proposed ~~Alternative S~~solution

In comments on the IPSP, Vistra noted that the ISO should improve its rules to ensure storage awards or dispatches due to outages or bid parameters should not be considered as optimal energy eligible for BCR, similarly to how use of the EOH SOC parameter makes intervals prior to and associated with this parameter ineligible for BCR.[13] In this context, Vistra proposed:

- **Component 1:** Classify energy associated with Instructed Imbalance Energy as non-optimal, thereby excluding it from the BCR calculation in intervals where there is an active:
    - Outage card that reduces its Pmax (Availability derate), Pmin (Load Max derate), Maximum Continuous Stored Energy (Maximum Energy derate), or Minimum Continuous Stored Energy (Minimum Energy rerate).
    - Bid parameter that reduces its Maximum Continuous Stored Energy (Maximum Energy derate) or Minimum Continuous Stored Energy (Minimum Energy rerate).
    - EOH SOC bid parameter constraining the solution to achieve a minimum SOC at the end-of-hour as requested by the SC.
- **Component 2:** If a given storage resource's SOC at the start of the binding interval is equal to its minimum or maximum SOC value, that binding interval bid cost recovery formula will use the DEB instead of the bid-in offers.
    - Include a sunset date for this element to ensure there is accountability for a future filing to provide a replacement make-whole payment framework.

Vistra argues that this proposal would appropriately classify energy associated with awards or instructions that are due to outages or due to SC action to drive the market outcome. In addition, Vistra argues that this proposal would mitigate Concern 2 by limiting bid cost assessments to the asset's DEB. In comments submitted August 26th, Vistra noted that only the portion unavailable would be classified as derated or rerated energy ineligible for BCR if an asset is not fully out of service. Vistra also noted that under their proposal, when any SOC bid parameter is used, the settlement interval would be considered ineligible for BCR such that all energy is reclassified as non-optimal.

In comments submitted September 23rd, Vistra underscored that they would not support applying a modified BCR calculation across all hours. Instead, Vistra supports adopting the conditions for applying a modified BCR solution based on CESA's dispatch trigger with an additional SOC-constrained dispatch trigger. If the ISO finds such an SOC trigger to be infeasible to implement, Vistra urges the ISO to consider another indicator for constrained dispatch, while also excluding intervals associated with real-time incremental Ancillary Services (AS) or Flexible Ramping Product (FRP) award. As a result, Vistra

[13] Per Tariff Section 11.6.6, where Scheduling Coordinators elect to submit end-of-hour state-of-charge targets, storage resources participating as Non-Generator Resources will be ineligible for RTM Bid Cost Shortfalls in the two hours preceding the scheduled Operating Hour.

recommends the following triggers to apply modified BCR calculations (sub-bullets in bold indicate a difference relative to the triggers put forth by CESA):

- Constrained dispatch buy-back flag
  - Day-ahead award or base schedule to discharge is associated with that interval; and,
  - **incremental upward AS or FRU is not associated with that interval; and,**
  - real-time discharge schedule is less than day-ahead or base schedule to discharge; and,
  - real-time schedule is not negative; and,
  - **real-time SOC is not sufficiently high enough to support day-ahead or base schedule to discharge (*i.e.,* SOC constrained dispatch trigger).**
    - If all those conditions are met, substitute the RT Bid component of the BCR calculation to:
      - Max(RT Bid, Min(DA LMP, RT DEB discharge, RT LMP))
- Constrained dispatch sell-back flag
  - Day-ahead award or base schedule to charge is associated with that interval; and,
  - **incremental downward AS or FRU is not associated with that interval; and,**
  - real-time discharge schedule is greater than day-ahead or base schedule to charge; and,
  - real-time schedule is not positive; and,
  - **real-time SOC is not sufficiently low enough to support day-ahead or base schedule to discharge (*i.e.,* SOC constrained dispatch trigger).**
    - If all those conditions are met, substitute the RT Bid component of the BCR calculation to:
      - Min(RT Bid, Max(DA LMP, RT DEB Discharge, RT LMP))

5.3.1. Stakeholder Feedback on Vistra's modifications to the stakeholder-proposed ~~Alternative S~~solution

Similarly to the stakeholder-proposed solution,~~CESA's Alternative Proposal,~~ some stakeholders have noted that Vistra's ~~alternative~~ proposal warrants further development and consideration. In comments submitted August 26th, CalCCA underscored that, while they do not take a position on a preferred approach at this time, the solutions put forth by stakeholders ~~CESA and Vistra proposals~~ warrant further consideration, as they could offer improvements to the Proposed Solution's blunt mechanism for excluding storage resources from BCR.

SDG&E also noted in their August 26th comments that alternative solutions proposed by stakeholders offer creative temporary or short-term approaches to mitigating the quantity of BCR payments that result from bidding behavior or operator action and should be evaluated further in the Revised Straw Proposal. SDG&E does however note that, while they do not endorse or oppose any alternative solution at this time, they are concerned that using the DEB in a modified BCR calculation is premature given the ISO's expressed intention to re-evaluate the formulation of the storage DEB in a later track of this initiative. As such, while SDG&E supports a comprehensive evaluation of the alternative proposals at this time, given the need for an expedited Track 1 solution, it would be premature to use the DEB for the purposes of a modified BCR calculation.

In contrast, some stakeholders have expressed that Vistra's p~~Alternative P~~roposal is not viable. In their August 26th comments, Cal Advocates argued that application of the DEB would be no more effective in mitigating unwarranted BCR than using the day-ahead LMP since DEBs tend to be lower than RT prices under stressed grid conditions. As such, large differentials between RT prices and the storage DEB would expose ratepayers to large BCR payments and shield storage resources from the same high RT prices. As a result, Cal Advocates states that Vistra's Alternative Proposal poses the same risks to ratepayers as other solutions put forth by stakeholders~~CESA's Alternative Proposal~~.

PG&E has also stated that Vistra's ~~Alternative P~~proposal is not viable since it relies on the DEB value for BCR, which they argue would only make sense in the RT intervals with no day-ahead schedule. Finally, the DMM expressed that none of the alternative proposals presented by stakeholders would address the real-time bidding incentives created by the current BCR design, which can lead to inefficient dispatch based on bids below real-time marginal cost. In this context, the DMM noted that the ISO should not rush to implement interim measures that only address strategic bidding concerns or other limited scenarios created by the actions of scheduling coordinators.

5.3.2. Responses to Vistra's Component 1 Questions

As noted previously, Vistra requested clarification on how the ISO currently classifies energy associated with intervals where SCs have submitted outage cards that reduce a resource's Pmax, Pmin, maximum continuous stored energy, or minimum continuous stored energy. In addition, Vistra also requested added clarity on how the ISO classifies energy associated with intervals where a bid parameter that reduces the resource's maximum continuous stored energy or minimum continuous stored energy has been submitted by the SC. This requests were echoed by other stakeholders such as WPTF.

Outages

When a scheduling coordinator submits an outage card that reduces a resource's Pmax, Pmin, that forces an uneconomic real-time dispatch contrary to day-ahead schedule. The market considers the resource's real-time energy as "derate energy". Per Tariff Section 11.8.4.1.5,[14] fifteen minute market and real time dispatch derate energy is ineligible for bid cost recovery. However, outages in the binding

[14] For any Settlement Interval, the RTM Energy Bid Cost for the Bid Cost Recovery Eligible Resource except Participating Loads shall be computed as the sum of the products of each RTD Instructed Imbalance Energy portion, except Standard Ramping Energy, Residual Imbalance Energy, FMM Exceptional Dispatch Energy or RTD Exceptional Dispatch Energy, FMM Derate Energy or RTD Derate Energy, MSS Load Following Energy, Ramping Energy Deviation and Regulating Energy, with the relevant Energy Bid prices, the Default Energy Bid price, or the Locational Marginal Price, if any, as further described in Section 11.17, for each Dispatch Interval in the Settlement Interval. For Settlement Intervals for which the Bid Cost Recovery Eligible Resource is ramping up to or down from a rerated Minimum Load that was increased pursuant to Section 9.3.3 for the Real-Time Market, the RTM Energy incurred by the ramping will be classified as FMM Derate Energy or RTD Derate Energy and will not be included in Bid Cost Recovery.

interval may also impact the storage resource's ability to meet future awards, which would not be covered under the binding interval's BCR exclusion due to derate energy.

A reduction in a resource's Pmax affects the maximum rate at which a storage resources can discharge. Reducing the maximum rate of discharge may lead to more than expected remaining charge from the day-ahead schedule. With the multi-interval optimization, the market may uneconomically dispatch the resource to meet future awards, whether for energy or ancillary services. In the current market design, this uneconomic dispatch results in BCR to make the resource whole. Similarly, an increase in a resource's Pmin affects the maximum rate at which a storage resources can charge. Reducing the maximum rate of charging may lead to less than expected remaining charge from the day-ahead schedule. The market may uneconomically dispatch the resource to charge meet future awards, whether energy or ancillary services. This uneconomic dispatch could qualify for BCR in the current market design.

Regarding maximum and minimum continuous stored energy, a reduction in a resource's maximum continuous stored energy value limits the maximum amount a storage resource can charge to. This reduction may limit day-ahead and ancillary service awards related to both charging and discharging. Day-ahead charging awards may be limited or even uneconomically reversed to prevent overcharging the resource past its maximum continuous stored energy value. With future discharges, the resource may be unable to meet its day ahead schedule without uneconomic charging awards. Any uneconomic dispatch in future intervals would be eligible for bid cost recovery. Correspondingly, an increase in a resource's minimum continuous stored energy value limits the maximum amount a storage resource can discharge to. This reduction may limit both day ahead and ancillary service awards related to both charging and discharging. Day-ahead charging awards may be limited or even uneconomically reversed to prevent going beyond the resource's minimum continuous stored energy value. With future charging, the resource may be unable to meet its day ahead schedule without uneconomic discharging awards. Currently, this uneconomic dispatch may result in bid cost recovery.

As noted above, uneconomic dispatch in intervals following the use of an outage could result in BCR shortfalls in future intervals despite the fact that it is the direct consequence of SC action. Given these circumstances, the ISO will seek to address these matters in future efforts related to the redesign of uplift for storage resources so as to ensure these circumstances do not delay the implementation of a near-term solution targeting the potential for strategic bidding that unduly inflates BCR.

Upper and Lower Charge Limits

Storage resources may submit upper and lower charge limits (also referred to as "energy storage limits") for each trading day. These bid parameters are separate from changes to the maximum and minimum continuous stored energy, which are fixed values stored in Master File. The upper and lower charge limits must remain within the bounds of the maximum and minimum continuous stored energy. The business requirements specification for Energy Storage and Distributed Energy Resources (ESDER) Phase 4 note that real time market bid cost recovery applies to "the entire operating range […] for nonregulation energy management limited energy storage resources."[15] As such, changes to bidding parameters which make the day ahead schedules infeasible due to limiting the "operating range" are not eligible for bid cost recovery. Like outage cards, changes to the upper and lower charge limits in the real time market may impact future advisory intervals for the day ahead schedule, leading to potentially unwarranted bid cost recovery payments.

In this context, a resource that reduces their upper charge limit does not qualify for bid cost recovery for values outside of the operating range. However, that resource may not be able to meet their day-ahead schedule or regulation awards later in the day due to its limited upper charge limit. To solve, the multi-interval optimization may dispatch the resource uneconomically in preparation. Even though this uneconomic dispatch is driven by the scheduling coordinator's upper charge limit bid parameter change, the resource may receive bid cost recovery associated with the hours of uneconomic dispatch. As a result, the ISO will seek to address these matters in future efforts related to the redesign of uplift for storage resources so as to ensure these circumstances do not delay the implementation of a near-term solution targeting the potential for strategic bidding that unduly inflates BCR.

6. Challenges related to the Potential Solutions

6.1. Issues Regarding Local Market Power Mitigation

Local Market Power Mitigation (LMPM) is the process by which the ISO seeks to mitigate non-competitive behavior and market power. Market power is having the ability to substantially distort competitive market outcomes. ISO market power mitigation measures intend to mitigate non-competitive behavior while avoiding unnecessary interference with competitive price signals. The measures identify conditions where scheduling coordinators can exercise market power and mitigate their bids to their DEB or the competitive LMP, whichever is greater.[16] Today, an asset's DEB cannot exceed $2,000. For storage resources participating as a non-generator resource, the DEB is calculated by adding 10% to the maximum of 1) the sum of the expected energy cost and the variable storage operation cost; and 2) the storage opportunity cost.

Local market power mitigation occurs when transmission constraints determine bids in a specific area as non-competitive. Here, the ISO conducts a three potential pivotal supplier test which seeks to determine if the largest three suppliers control too much counter-flow supply. Non-competitive areas are where available counter-flow capacity from internal resources not controlled by the identified potentially pivotal suppliers is less than the demand for the counter-flow capacity.[17] Once a bid is mitigated in a fifteen minute interval, the mitigated bid applies only in that run. The original unmitigated bid will be evaluated again for the corresponding fifteen minute interval of the next run, if it lies within the market

[15] ESDER Phase 4 BRS Section 6.6.1

[16] Methodology for bid mitigation can be found for the day-ahead market in Tariff Section 31.2.3 and for market power mitigation in the real-time market in Tariff Section 34.1.5 and Market Operations Business Practice Manual Section 7.4

[17] More information can be found in Tariff Section 39 and Market Operations Business Practice Manual Section 6.5

horizon. For the real-time dispatch, the market power mitigation process is conducted on three five minute advisory intervals after the binding five minute interval. Like the fifteen minute interval, the mitigated bid only applies to that five minute interval with the original unmitigated bid evaluated in future runs.

Stakeholders have noted that there are instances that would still warrant BCR, specifically underscoring mitigation. Some stakeholders have noted that instances in which resources were mitigated in intervals prior to a buy- or sell-back of a day-ahead schedule may merit specific BCR provisions. The Market Surveillance Committee (MSC) echoed this concern in the meeting held July 30th, noting that, depending on how material this impact would be in the short-run, the ISO should consider applying the same approach used for the Hold Exceptional Dispatch (ED).

Today, when the ISO issues a Hold ED to a storage asset, per Tariff Section 11.5.6.1.2, the ISO calculates the opportunity cost starting from the first Operating Interval when the resource met and followed the ED through the end of the operating day. The ISO calculates the difference between the resource's maximum potential RTM Energy revenues without the Hold ED and the resource's maximum potential RTM Energy revenues with the Hold ED. If the resource's maximum potential RTM Energy revenues without the Hold ED are higher than the resource's maximum potential RTM Energy revenues with the Hold ED, then the resource will receive the positive difference between these two values, which is its opportunity cost. The ISO calculates the resource's opportunity costs based on its Master File characteristics, bids, SOC, day-ahead schedules, and the applicable LMP. Given the similarities of this instances, where a given instruction may affect the potential revenues of an asset throughout the day, the MSC has noted that calculating a revenue counterfactual as the Hold ED could alleviate the issues of resources being mitigated.

In comments submitted August 8th, several stakeholders noted that the ISO should more thoroughly consider the potential impacts of LMPM in the Revised Straw Proposal. CES noted that under the current LMPM mechanism, a unit that is identified as possibly being able to exercise market power will have its bids adjusted downwards to the higher of its DEB or the next competitive bid price. CES further highlighted that for storage assets, this process may also result in downward price adjustments of charging bids as well as discharge bids. In this context, CES underscored that this application of LMPM may reduce the price at which the asset is willing to buy energy, potentially resulting in the resource not being able to achieve the necessary SOC to meet their day-ahead schedules later on. General recommendations to further consider the potential implications of LMPM were also voiced by SDG&E, Terra-Gen, Vistra, and WPTF as part of their respective August 8th comments.

In comments submitted August 26th, DMM noted that local market power mitigation could cause storage resources to be discharged or forgo charging at a price below their actual real-time opportunity cost as determined by expected real-time prices. DMM also referenced the data the ISO presented during the August 19th stakeholder meeting to attempt to assess the potential magnitude of the issue. DMM noted that the data the ISO referenced from previous DMM reports was estimated using the actual bids submitted to the market.

DMM underscored that current BCR rules imply that historical bids are not likely to include an accurate representation of real-time intra-day opportunity costs, and that if the ISO were to eliminate BCR associated with buying back or selling back day-ahead schedules due to binding state-of-charge constraints, that new policy would likely incentivize resources to increase bids in some hours to better reflect intraday opportunity costs. Such a modification and a change in bidding behavior could lead to a larger potential impact of mitigation than suggested by historical analysis, especially in hours with significant real-time intraday opportunity costs. In this context, during the September 11th stakeholder meeting, DMM presented analysis on the impact of mitigation on incremental dispatch and SOC to determine whether mitigation in hours preceding the peak and net peak has had a material impact on the ability of storage resources to meet their day-ahead schedules. As summarized in DMM's comments submitted September 23rd, DMM's analysis suggests that the overall financial impacts on individual resources resulting from mitigation under the ISO's proposed BCR changes are limited. DMM metrics show that in practice, mitigation has had a minimal impact on battery dispatch; and, when material, mitigation has had the greatest impact during the three peak net load hours, HE 19 to 21. As such, mitigation is unlikely to have affected the SOC of storage resources in a manner that would compromise their ability to meet day-ahead schedules.

Since the analysis referenced above is historical, DMM also conducted additional analysis to estimate the impact of mitigation under a circumstance where the ISO has eliminated BCR for storage assets buying and selling back day-ahead schedules. These conditions are materially distinct since such a rule would incent resources to submit higher priced bids during the mid-day and afternoon hours, prior to peak net load hours when they have been scheduled to discharge through the day-ahead market. To assess the potential impact of bid mitigation under this scenario, DMM used the same data used to assess the actual impact of mitigation, but assumed that all batteries bid at the $1,000/MWh bid cap during all hours and all batteries choose the storage DEB option, which includes an estimate of intraday opportunity cost based on day-ahead prices.

DMM's additional analysis shows that, even if batteries bid at $1,000/MWh in every hour, mitigation would likely have had minimal impact on dispatch prior to the peak net load hours on critical days. In this context, DMM does not believe that mitigation has or could have played a significant role in impacting the ability of resources supporting their day-ahead schedules. As such, DMM believes these analyses show that changes to BCR rules should not be deferred or delayed until enhancements related to mitigation, such as an enhanced storage DEB, are made.

While the current and future impact of mitigation on storage's ability to meet day-ahead schedules appears minimal given DMM's analyses, DMM underscored that some loss remains possible and, as a result, the ISO should consider additional settlement provision targeted at preventing revenue losses in this situation. As noted by the Market Surveillance Committee (MSC), such provisions could be based on current settlement provisions that were developed to compensate batteries for any lost revenues due to exceptional dispatches issued to hold state-of-charge.

In response to the analyses presented by DMM on September 11th, several stakeholders submitted comments regarding the interplay between mitigation and storage BCR modifications. Cal Advocates noted that DMM's analysis continues to indicate that incremental RT energy associated with bids that were lowered in the LMPM process was very low in 2022 and 2023. In addition, Cal Advocates underscored that the ISO's analysis of mitigation in 2023 and 2024 was consistent with DMM's conclusion. As such, Cal Advocates reasons that consideration of mitigation issues should not delay the implementation solutions to address the issues at hand and that issues related to mitigation should be considered as part of a long-term, durable, and fundamental reform of storage BCR.

In their September 23rd comments, Vistra indicated that they would be comfortable with the interim solution inadvertently capturing intervals affected by mitigation as long as in that interval BCR is modified to a reasonable calculation rather than being made ineligible. Given that any interim solution will capture intervals that are caused by CAISO market including mitigation, it is critical that the change to the BCR calculation is not overly punitive.

In order to assess and better understand the potential impacts of mitigation, the ISO conducted further analysis focused on the amount of SOC depletion associated with mitigated dispatch in the five-minute market (*i.e.,* Real-Time Dispatch or RTD) and the actual MW amount of day-ahead buy- and sell-back in RTD. RTD mitigation impacts the SOC which in turn has RTD dispatch implications for later in the day. This can have an impact of BCR for the revenue side in both the fifteen-minute market (FMM) and RTD. Since FMM results are financially binding but only operationally advisory, only RTD schedules have direct implications on future hours. Percentage impact of RTD mitigation on BCR is estimated as:

- $Percentage\ impact$ = $(Extra\ MW\ dispatch\ from\ RTD\ Mitigation\ in\ hours\ 12{-}17)$ / $(RTD\ MW\ short\ during\ peak\ hours\ 18{-}22)$

BCR impact is estimated as:

- $BCR\ impact$ \$ = $(Percentage\ impact)(RTM\ BCR)$

The extra MW dispatch is estimated as the difference between the original market dispatch (with mitigated bids) and a counterfactual dispatch using original resource bid (no mitigation). The counterfactual dispatch is calculated using the existing bids to determine the optimal dispatch under the original prices. For simplicity, the counterfactual dispatch does not consider the impact on SOC binding conditions.

The ISO's analysis found that percentage impact of RTD mitigation by MW volume is small: 3% annually and up to 6.6% in the month with the highest impact. The analysis also suggests that the overall distribution of percentage impact at the system level is low, with limited outliers as shown in Figure 1~~Figure 1~~ below. The analysis also indicates that the portion of real-time BCR impacted by mitigation was relatively low compared to the total real-time BCR paid to storage assets in the ISO, as shown in Figure 2~~Figure 2~~ below. According to the ISO's analysis, less than 25% of the resource-days were impact by mitigation, with only 8 resource-days having a BCR impact of \$10,000 or more. This estimates provides an upper bound on the real-time market power mitigation on BCR for storage resources.

Figure 1: Impact of RTD mitigation on dispatch volume (%)

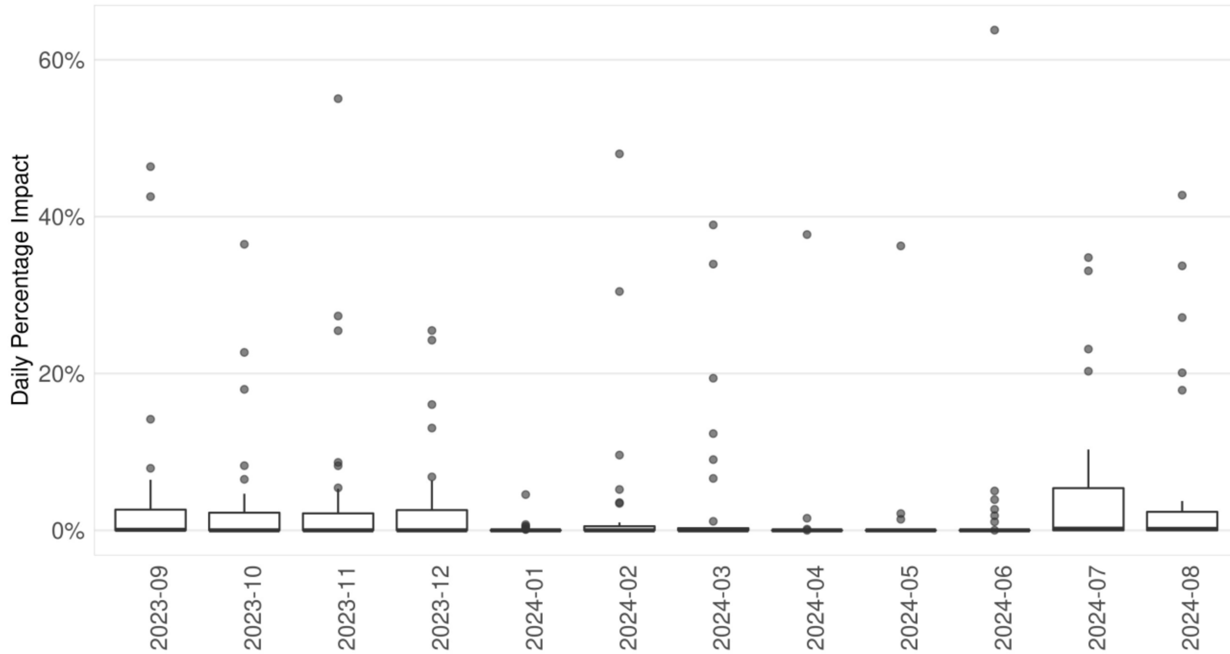
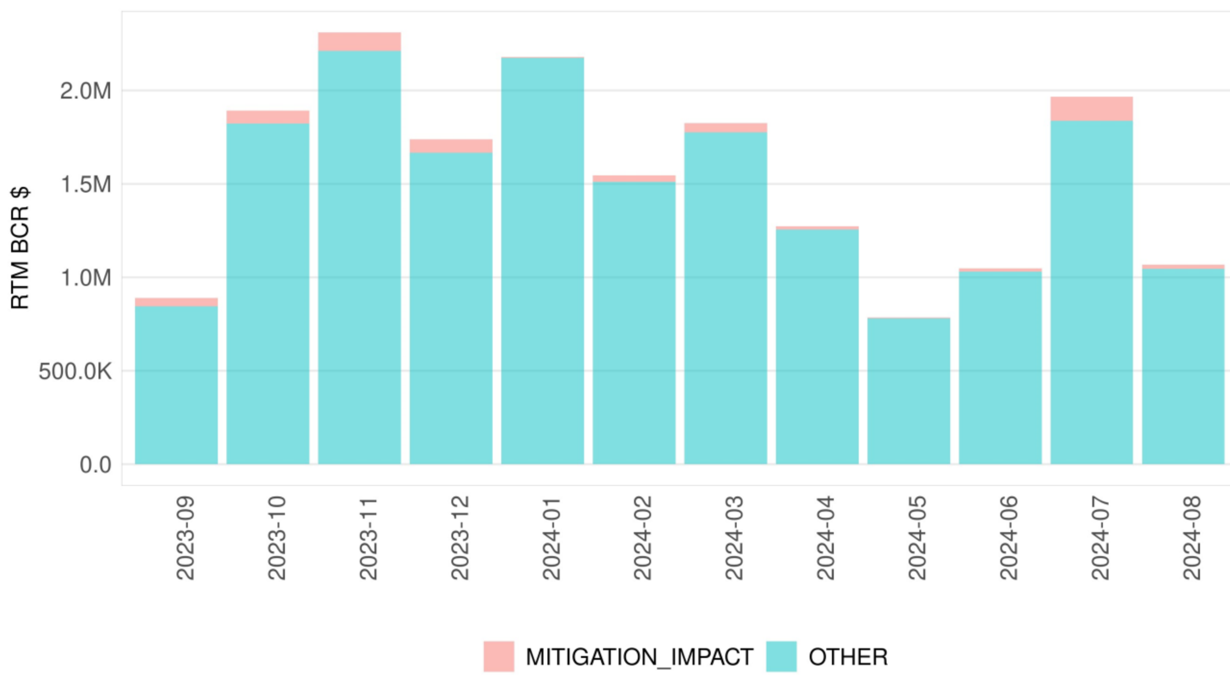


Figure 2: Relative impact of RTD mitigation on real-time BCR



Given the analyses presented by DMM and the ISO, it is apparent that the current and future impact of mitigation on SOC depletion remains minimal and should not delay or complicate the implementation of a near-term solution focused on closing the gap that would allow for strategic bidding behavior to unduly inflate BCR payments. This being said, given the fact that outlier impacts of mitigation exist, the

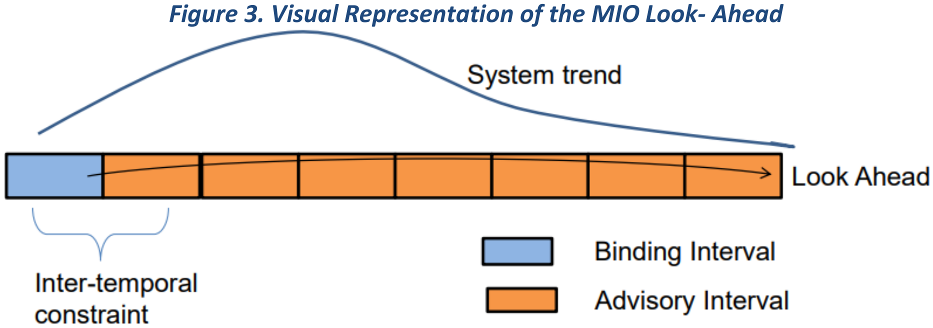
ISO agrees that consideration of a specific exception for instances of mitigation may be warranted as part of a holistic redesign of the uplift mechanism applicable to storage resources.

6.2. Issues Regarding Applicable Intervals and Multi-Interval Optimization

As noted in Section 5, all of the potential solutions described in this paper commence with the assumption that the ISO will be able to identify intervals where the SOC constraint is binding to later reclassify the energy associated with that interval, or to modify the BCR calculation applicable to that interval. As this initiative's efforts have progressed, the ISO has found that this condition is not met often in the binding interval, primarily due to the multi-interval optimization (MIO) process.

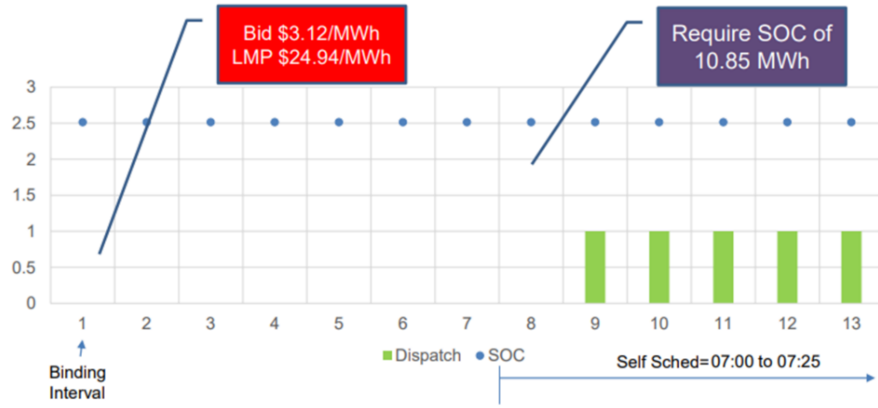
MIO allows the RTM to position resources to handle changes in the future horizon. For storage resources, the MIO charges or discharges a storage asset due to projected conditions in the future, linking solutions over intervals to ensure the asset's limited SOC is utilized when it is most valuable. As a result, the MIO may charge or discharge a storage resource to prepare for a future energy award, to avoid hitting the resource's maximum or minimum SOC constraint; to adjust for future interval economic conditions stemming from supply, demand or net interchange forecasts; or to rebalance an exceptional dispatch. Future intervals are considered "advisory intervals" while the current interval is the "binding interval." The 15-minute market can look ahead almost 2 hours past the binding interval, while the 5-minute market can look ahead up to thirteen 5-minute intervals past the binding interval.

Figure 3. Visual Representation of the MIO Look- Ahead



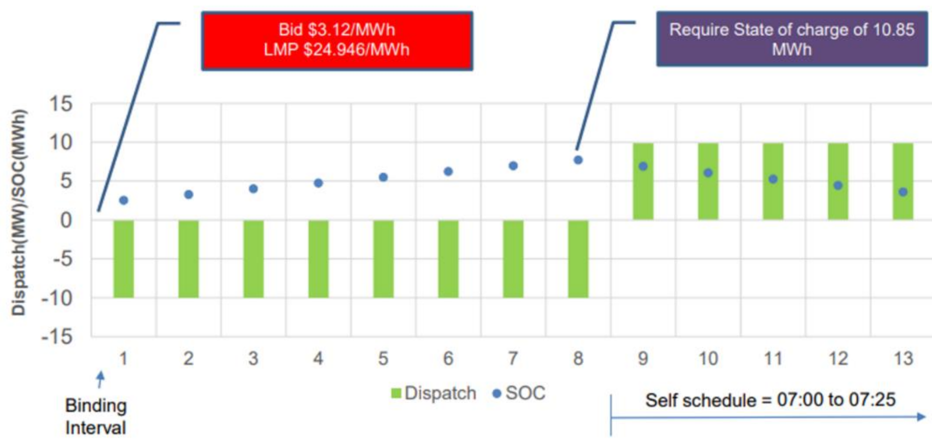
To exemplify how MIO works, consider the following hypothetical example. The MIO dispatch may be uneconomical (*i.e.,* out-of-merit) in the binding interval, in order to meet a future scheduled advisory interval. For example, the following resource has a future self-schedule that requires 10.85 MWh of state of charge. The resource needs to charge to meet that state of charge. However, the resource's bids to charge are below the LMP and are uneconomical. Without the multi-interval optimization, the resource does not charge and does not have the state of charge necessary to meet its self-schedule.

Figure 4. Example of MIO for a Storage Resource



With the MIO, the resource charges continuously from intervals 1 through 8 in order to meet the self-schedule discharge as best as possible. Looking at a single interval, this charge is uneconomic, as the resource has bid $3.12/MWh, much lower than the LMP of $24.946/MWh. Note, the resource does not reach a state of charge of 10.85 MWh, as the optimal solution accounts for the uneconomic charging bids during intervals 1 through 8. Instead, the MIO allows the resource to optimally fulfill its self-schedule, given current market conditions.[18]

Figure 5. Example of MIO for a Storage Resource



The example described above seeks to detail how MIO works. As stated during the September 11th stakeholder call, self-schedules are not the only instance in which MIO might drive uneconomic dispatch in the binding interval as a result of conditions in the advisory intervals. For example, consider a 5 MW four-hour resource with SOC at 25% (5 MWh). In this example, the resource has a bid to discharge at $100 and a bid to charge at $50 while the LMP in the binding interval is $120. The MIO look-ahead indicates that prices will remain at $120 for the binding interval and the next five advisory intervals, but then prices will be at $750 for the remaining six advisory intervals. Given these conditions, the MIO

[18] Further information regarding the MIO can be found in Tariff Section 34.5 and Market Operations Business Practice Manual Section 7.8.

determines that uneconomic dispatch to charge to capture future prices would be optimal. The following tables illustrate the logic behind MIO, as it seeks to dispatch the resource in a manner that would ensure the limited SOC is used in the intervals with the highest value.

Table 1. Example outcome if resource is dispatched economically in the binding interval (i.e., no MIO)

SOC (MWh)	Interval	Discharge Bid	Charge Bid	LMP	Dispatch (MWh)	Revenue	Profit
5.0	0	$ 100.0	$ 50.0	$ 120.0	0.4	$ 50.0	$ 8.3
4.6	1	$ 100.0	$ 50.0	$ 120.0	0.4	$ 50.0	$ 8.3
4.2	2	$ 100.0	$ 50.0	$ 120.0	0.4	$ 50.0	$ 8.3
3.8	3	$ 100.0	$ 50.0	$ 120.0	0.4	$ 50.0	$ 8.3
3.3	4	$ 100.0	$ 50.0	$ 120.0	0.4	$ 50.0	$ 8.3
2.9	5	$ 100.0	$ 50.0	$ 120.0	0.4	$ 50.0	$ 8.3
2.5	6	$ 100.0	$ 50.0	$ 750.0	0.4	$ 312.5	$ 270.8
2.1	7	$ 100.0	$ 50.0	$ 750.0	0.4	$ 312.5	$ 270.8
1.7	8	$ 100.0	$ 50.0	$ 750.0	0.4	$ 312.5	$ 270.8
1.3	9	$ 100.0	$ 50.0	$ 750.0	0.4	$ 312.5	$ 270.8
0.8	10	$ 100.0	$ 50.0	$ 750.0	0.4	$ 312.5	$ 270.8
0.4	11	$ 100.0	$ 50.0	$ 750.0	0.4	$ 312.5	$ 270.8
0.0	12	$ 100.0	$ 50.0	$ 750.0	0.0	$ -	$ -
Total					**5.0**	**$ 2,175.0**	**$ 1,675.0**

Table 2. Example outcome if resource is dispatched uneconomically in the binding interval (i.e., the effect of MIO)

SOC (MWh)	Interval	Discharge Bid	Charge Bid	LMP	Dispatch (MWh)	Revenue	Profit
5.0	0	$ 100.0	$ 50.0	$ 120.0	-0.4	$ (50.0)	$ (8.3)
5.4	1	$ 100.0	$ 50.0	$ 120.0	0.4	$ 50.0	$ 8.3
5.0	2	$ 100.0	$ 50.0	$ 120.0	0.4	$ 50.0	$ 8.3
4.6	3	$ 100.0	$ 50.0	$ 120.0	0.4	$ 50.0	$ 8.3
4.2	4	$ 100.0	$ 50.0	$ 120.0	0.4	$ 50.0	$ 8.3
3.8	5	$ 100.0	$ 50.0	$ 120.0	0.4	$ 50.0	$ 8.3
3.3	6	$ 100.0	$ 50.0	$ 750.0	0.4	$ 312.5	$ 270.8
2.9	7	$ 100.0	$ 50.0	$ 750.0	0.4	$ 312.5	$ 270.8
2.5	8	$ 100.0	$ 50.0	$ 750.0	0.4	$ 312.5	$ 270.8
2.1	9	$ 100.0	$ 50.0	$ 750.0	0.4	$ 312.5	$ 270.8
1.7	10	$ 100.0	$ 50.0	$ 750.0	0.4	$ 312.5	$ 270.8
1.3	11	$ 100.0	$ 50.0	$ 750.0	0.4	$ 312.5	$ 270.8
0.8	12	$ 100.0	$ 50.0	$ 750.0	0.4	$ 312.5	$ 270.8
Total					**4.6**	**$ 2,387.5**	**$ 1,929.2**

Given the MIO process, it is possible for a storage resource to reach a binding interval with an SOC that is close to either of its limits (0% or 100%) and have that remaining SOC preserved in that and several future intervals. This is because the MIO might find that the economic solution over the look ahead horizon is to conserve SOC with an uneconomic dispatch in the binding interval so that the asset can be dispatched later (in what is at that time an advisory interval) when the market revenue will exceed the loss in the binding interval. This outcome can theoretically happen to any resource, but given batteries' responsiveness, ramp rates, and limited fuel supply (*i.e.,* SOC), this is especially prevalent for storage assets. As a result, it is possible for a storage asset to be near having a binding SOC constraint in the binding interval but for it to not actually reach either of the SOC limits for several intervals.

This situation materially affects the feasibility of applying a solution that exclusively focuses on the binding interval and whether it has a binding SOC constraint. The Proposed Solution has a fundamental assumption that the dispatch is optimal for the binding interval, meaning that the SOC would be depleted to meet the day-ahead schedule and the storage asset would be at the SOC limit in the next interval, allowing for the Proposed Solution to be triggered. Nevertheless, if the optimal dispatch over the time horizon results in an uneconomic dispatch in the binding interval to preserve the SOC for a subsequent interval, this can be repeated over many RTD runs, thus preserving the SOC for one or several intervals before the Proposed Solution can kick in. Given the fact that the stakeholder-proposed solution and the ~~both the CESA and~~ Vistra ~~alternative~~proposal~~s~~, as well as the modifications proposed by PG&E and WPTF, would rely on first identifying intervals with a binding SOC constraint, these solutions may also run into the issue of being seldom triggered due to MIO. This materially erodes their effectiveness at resolving Concern 2.

In this context, the ISO noted in the Revised Straw Proposal and during the September 11th meeting that, if a solution akin to the stakeholder-proposed solution ~~CESA's proposal~~ is pursued (*i.e.,* one that focuses on modifying the RT Bid component of the RT BCR calculation), this issue could be circumvented by simply applying the modified formula for all intervals, not just intervals with a binding SOC constraint. This alternative may allow for a solution that addresses Concern 2 and is implementable in the near-term. The ISO believes that such a solution has significant merits since BCR is calculated over the course of the whole day and modifying the formulae for only a subset of intervals would not fully remove the impact a resource's bid has on BCR payments. If a solution akin to the stakeholder-proposed solution ~~CESA proposal~~ is applied only in a subset of intervals, BCR surplus calculated in other intervals, which impacts total BCR payout for the day, would still be derived using a resource's bid. Moreover, this solution could apply specifically in intervals where the resource's dispatch used SOC that directly implicated the resource not being able to deliver its day-ahead schedule. Overall, the ISO believes that a modification to the RT BCR formulae as proposed by CESA should be applied across all intervals so as to ensure consistency on the surplus and shortfall estimations throughout the day.

7. Draft Final Proposal

As illustrated in this paper, the issues related to storage BCR are complex and merit significant analysis and review. It is clear that the extension of the existing BCR construct to storage resources has resulted in complications and unintended outcomes that merit a holistic revision of the uplift mechanism applicable to this resources. This being said, it is also evident from the material discussed herein that the current design gap that could allow for strategic bidding behavior to unduly inflate BCR payments for storage assets must be closed in the near-term as it exposes market participants and ratepayers to adverse financial outcomes. In this context, the ISO proposes to move forward with a near-term, interim solution focused on modifying the real-time energy bid cost calculation in the real-time BCR settlement for energy storage resources participating under the non-generator resource pathway, between the fifteen-minute market and the day-ahead schedule as well as between the real-time dispatch (RTD) and the fifteen-minute schedule. This would be done by applying the formula put forth as part of the last iteration of the stakeholder-proposed solution ~~CESA proposed~~ for buy-backs for all intervals in which the difference in dispatch is less or equal to zero between the fifteen minute market and the day-ahead schedule as well as between the RTD and the fifteen-minute schedule. Conversely, the formula put forth as part of the last iteration of the stakeholder-proposed solution for ~~CESA proposed for~~ sell-backs would be applied for all intervals in which the difference in dispatch is greater than zero between the fifteen minute market and the day-ahead schedule as well as between the RTD and the fifteen-minute schedule. For intervals without a day-ahead schedule, the same formulas would be used with the exception that the DA LMP is not applicable in such intervals. This is also true for WEIM-only resources, for which a DA LMP is not applicable either.

The ISO considers that the latest iteration of the stakeholder-proposed solution ~~CESA's proposal~~ strikes a viable balance to modify the cost proxy used as part of the real-time BCR formula. Today, the BCR formula solely uses the RT bid as its cost proxy to determine surpluses and shortfalls despite the fact that the bids of storage resources have been found to not only express marginal costs, but opportunity costs and economic willingness to dispatch as well. In this context, a modified formula that takes into account other cost proxies such as the RT DEB and the day-ahead LMP presents a measured approach to ensure that the bidding behavior of market participants does not result, even inadvertently, in unduly inflated BCR calculations.

Given the complexities related to MIO and the fact that this solution would be sought as an interim modification, the ISO believes that this modified BCR calculation should be applied across all intervals of the day in real-time, as opposed to solely in the intervals that meet the conditions laid out by CESA and other stakeholders. An application across all intervals is necessary since the ability to unduly inflate BCR payments stems from the differences in the bid costs used across ~~interclass~~intervals in the BCR calculation. If the modified formula were applied to only a subset of intervals, resources would retain a significant ability to influence such difference. This is also true for intervals without a day-ahead schedule. As such, ~~T~~this implementation is desirable and viable for three reasons: it is feasible to develop in the near-term and resettle as needed, thus curing the current design gap as soon as possible; it is the only means to effectively eliminate the ability of resources to bid strategically in a manner that unduly inflates BCR across all intervals, not just a constrained subset of intervals; and, it is a measured approach to solve some of the concerns described herein while allowing for the continued development of a new uplift mechanism for storage assets.

This position is also consistent with the comments received by stakeholders representing load and ratepayers. SCE's comments submitted September 23rd illustrate this tradeoff succinctly. SCE stated that, while some market participants felt very strongly that the ~~CESA~~ stakeholder-proposed modified formula should only apply for hours of buyback or sellback, applying this modified formulation across all hours should be considered as a viable compromise. SCE reasons that such an application should result in less BCR than using the formula in only the buyback and sellback hours as these new method would incentivize market participants to bid accordingly, especially for hours that don't have a corresponding DA award. SCE noted that the current methodology could result in excess BCR, whereas completely removing RT BCR for storage assets would result in an opposite extreme outcome. In this context, SCE notes that using the ~~CESA~~ stakeholder-proposed modified formula for all hours would strike an implementable and a reasonable workaround to the complications related to MIO.

Regarding the applicability of these modified formulations to resources outside the CAISO BAA, the ISO currently favors near-term modifications that treat WEIM Only and CAISO/EDAM resources equally. As such, the ~~draft~~ final proposal would be applicable to WEIM-Only assets with the difference that the ~~. When the~~ DA LMP component in the formulas would not be applicable to WEIM-Only assets~~would be use in the modified BCR calculations, the ISO proposes to use a null value for WEIM-Only assets~~. The ISO appreciates the discussion regarding this matter put forth by stakeholders and welcomes consideration of whether circumstances may warrant differentiated treatment as part of the holistic uplift redesign for storage assets.

As a result, the ISO proposes to apply the stakeholder-proposed modified calculations, developed ~~put forth~~ by CESA, Vistra, WPTF, and PG&E, across all intervals of the real-time market on an interim basis. In comments submitted September 23rd, several parties noted that they would not oppose the application of modified BCR calculations for storage assets across all intervals, but requested additional details on the financial and operational implications of this change. As a response, the ISO has included several detailed 24-hour examples for different hypothetical units and conditions under all of the approaches detailed in the proposal herein in Appendix A. These examples are simplified scenarios based on dispatch observed in the market by ISO staff. These examples do not represent actual settlement outcomes for any existing resources. Given the focus of the draft final proposal on closing design gaps related to strategic bidding concerns, these examples are constructed to focus on scenarios where resources may bid in a manner that would capture unduly high BCR payments.

The examples illustrate that the application of different approaches results in differentiated outcomes per unit. This is driven by several variables, including the number of intervals that meet all of the conditions proposed by CESA as triggers. On this latter factor, it is important to note that the frequency of such intervals is largely determined by the fact that the trigger conditions are "and" statements, which for some units result in few intervals triggering an alternative calculation despite the fact that some of them meet one or two of the three conditions. In this context, the application of modified calculations across all intervals is necessary to eliminate the possibility of strategic bidding across the board.

Following the stakeholder call relative to the Draft Final Proposal several stakeholders requested additional clarity on the specific details of the modified energy bid cost formulas. In a good faith effort to ensure all stakeholders have adequate, sufficient, and transparent information to inform their written comments, ISO staff prepared a technical addendum and an example spreadsheet illustrating how the solution defined in the Draft Final Proposal would compare to the status quo in over 50 different scenarios. After these materials were posted, some stakeholders requested additional clarifications from the ISO. Stakeholders asked about the bid that would be used in instances of mitigation within the current and modified BCR calculations. Specifically, stakeholders requested clarity on whether the bid used is the one submitted by the SC or the mitigated bid. Today, the bid used in instances of mitigation is the mitigated bid. The solution described herein would not modify that. Stakeholders also asked for confirmation of whether the charging bid will be used when the real-time (FMM or RTD) schedule is charging and the discharge bid when the real-time (FMM or RTD) schedule is discharging. The appropriate bid to include in the Expected Energy Calculation is dependent on the market (FMM or RTD), the relative reference point (DA or FMM), and where the resource crosses that bid. For added clarity, please review the spreadsheet shared by the ISO.

In written comments submitted October 23, 2024, several stakeholders supported Management's proposal as a viable near-term compromise but urged the ISO to continue working on remaining issues immediately so as to close out Concern 1. On the other hand, some stakeholders opposed Management's proposal noting its application across all intervals could be overly conservative and may result in overly punitive outcomes. In general, all stakeholders have asked Management to continue working on a holistic redesign of uplift for storage resources immediately. In this context,

~~Finally,~~ the ISO wants to reiterate its commitment to continue working on an uplift redesign for storage assets. If the present near-term interim solution is approved by the joint Board of Governors and WEM Governing Body, the ISO will commence a storage initiative to holistically redesign uplift for storage assets in a manner aligned with the specific characteristics and complexities of these resources. These efforts will consider the interplay of storage BCR with other enhancements recommended by stakeholders to the ISO, such as modifications to the storage DEB formulation, consideration of the non-linearity of storage performance, and evaluation of the impacts of outages, bid parameters, and mitigation with relation to BCR.

8. Governance Classification: Joint Authority

This initiative proposes changes to "California ISO Settlements and Billing", "Bid and Self-Schedule Submission in California ISO", and "Market Power Mitigation Procedures" in the ISO tariff as they relate to bid cost recovery and default energy bid provisions for storage resources. The ISO believes that the WEM Governing Body has joint authority with the ISO Board of Governors over the proposed tariff rule changes.

The ISO Board of Governors and the WEM Governing Body have joint authority over any:

> Proposal to change or establish a tariff rule applicable to the WEIM/EDAM Entity balancing authority areas, WEIM/EDAM Entities, or other market participants within the WEIM/EDAM Entity balancing authority areas, in their capacity as participants in the WEIM/EDAM. The WEM Governing Body will also have joint authority with the Board of Governors to approve or reject a proposal to change or establish any tariff rule for the day-ahead or real-time markets that directly establishes or changes the formation of any locational marginal price(s) for a product that is common to the overall WEIM or EDAM markets. The scope of this joint authority excludes, without limitation, any other proposals to change or establish tariff rule(s) applicable only to the CAISO balancing authority area or to the CAISO-controlled grid. Note: For the

avoidance of any doubt, the joint authority definition is not intended to cover balancing authority-specific measures, such as any parameters or constraints, the CAISO may use to ensure reliable operation within its balancing authority area.[19]

All of the tariff rule changes proposed in this initiative would be "applicable to the WEIM/EDAM Entity balancing authority areas, WEIM/EDAM Entities, or other market participants within the WEIM/EDAM Entity balancing authority areas, in their capacity as participants in the WEIM/EDAM." None of the proposed tariff rules would be applicable "only to the CAISO balancing authority area or to the CAISO-controlled grid." Accordingly, this initiative falls entirely within the scope of joint authority.

~~9. Next Steps~~

~~The ISO will hold a stakeholder meeting on this Draft Final Proposal on October 9, 2024. Comments on the Draft Final Proposal, as well as the October 9, 2024 stakeholder meeting, will be due October 21, 2024.~~

[19] Charter for EIM Governance § 2.2.1

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~~10.~~1. Appendix A: Examples Using All Proposed Approaches

Table 1. Summary of BCR for all example units across all proposed approaches

Resource	Status Quo	BCR using DA LMP - All Intervals	BCR using RT DEB - All Intervals	BCR using First Min/Max Methodology - All Intervals	BCR using Latest Min/Max Methodology - All Intervals	BCR using DA LMP - Subset of Intervals	BCR using RT DEB - Subset of Intervals	BCR using First Min/Max Methodlogy - Subset of Intervals	BCR using Latest Min/Max Methodlogy - Subset of Intervals
Unit A	($36,010.00)	($2,941.00)	($9,465.00)	($1,449.00)	(5,813.00)	(23,683.00)	(25,827.00)	(23,593.00)	(25,447.00)
Unit B	($90,909.00)	($1,223.00)	($16,466.00)	($2,736.00)	(14,330.00)	(39,253.00)	(48,121.00)	(40,452.00)	(48,670.00)
Unit C	($24,490.00)	($960.00)	($4,989.00)	($880.00)	(5,209.00)	(22,518.00)	(22,860.00)	(22,439.00)	(22,553.00)
TOTAL	**($151,409.00)**	**($5,124.00)**	**($30,920.00)**	**($5,065.00)**	**($25,352.00)**	**($85,454.00)**	**($96,808.00)**	**($86,484.00)**	**($96,670.00)**

Real time energy bid price to calculate Real-Time Energy Bid Cost.

Replaced real-time energy bid with DA LMP to calculate Real-Time Energy Bid Cost.

Replaced real-time energy bid with real-time Default Energy bid to calculate Real-Time Energy Bid Cost.

Replaced real-time energy bid with the first Min/Max proposal for both buy-back and sell back to calculate Real-Time Energy Bid Cost.

Replaced real-time energy bid with the latest Min/Max proposal for both buy-back and sell back to calculate Real-Time Energy Bid Cost

Replaced real-time energy bid with DA LMP to calculate Real-Time Energy Bid Cost only in intervals that meet CESA triggers

Replaced real-time energy bid with real-time Default Energy bid to calculate Real-Time Energy Bid Cost only in intervals that meet CESA triggers

Replaced real-time energy bid with the first Min/Max proposal for both buy-back and sell back to calculate Real-Time Energy Bid Cost only in intervals that meet CESA triggers

Replaced real-time energy bid with the latest Min/Max proposal for both buy-back and sell back to calculate Real-Time Energy Bid Cost only in intervals that meet CESA triggers

Min and Max calculations are applied to both FMM IIE and RTD IIE. Checks for the CESA triggers are only applied for FMM for simplicty

Table 2. Frequency of intervals that meet all ~~CESA~~ trigger conditions proposed by CESA for each example unit

Resource	Buy-Back Intervals	Buy-Back Intervals (%)	Sell-Back Intervals	Sell-Back Intervals (%)	Total	Total (%)
Unit A	0	0%	19	7%	19	7%
Unit B	6	2%	33	11%	39	14%
Unit C	0	0%	6	2%	6	2%

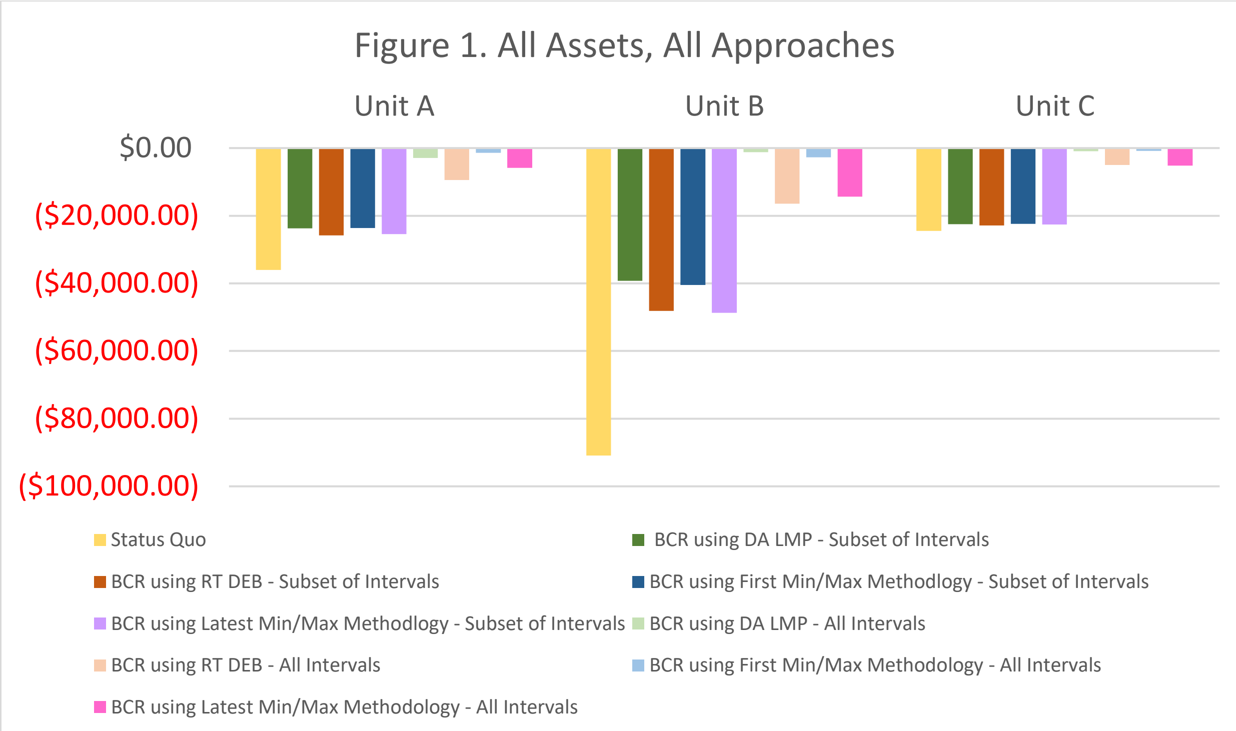


Figure 1. All Assets, All Approaches
Unit A
Unit B
Unit C
$0.00
($20,000.00)
($40,000.00)
($60,000.00)
($80,000.00)
($100,000.00)
Status Quo
BCR using DA LMP - Subset of Intervals
BCR using RT DEB - Subset of Intervals
BCR using First Min/Max Methodlogy - Subset of Intervals
BCR using Latest Min/Max Methodlogy - Subset of Intervals
BCR using DA LMP - All Intervals
BCR using RT DEB - All Intervals
BCR using First Min/Max Methodology - All Intervals
BCR using Latest Min/Max Methodology - All Intervals

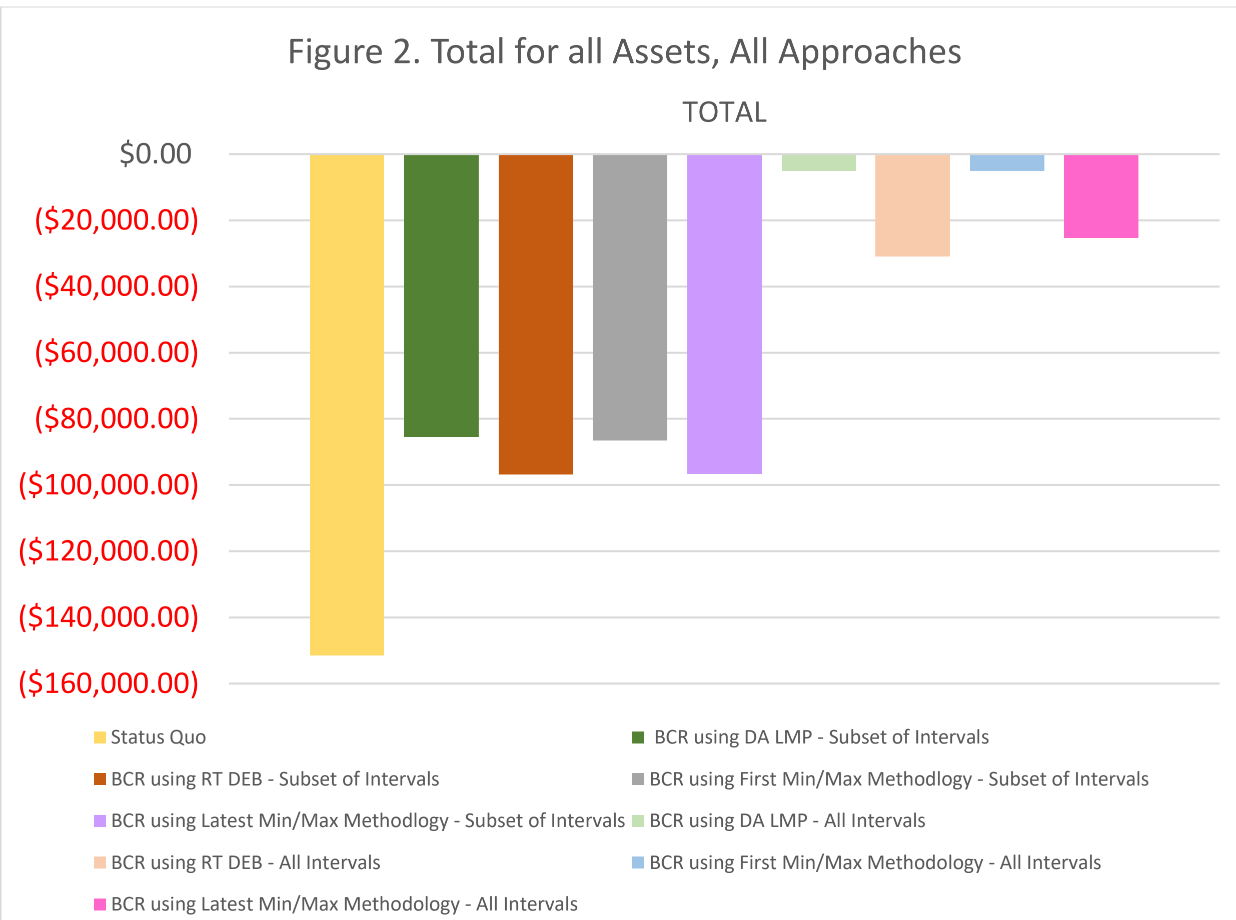


Figure 2. Total for all Assets, All Approaches
TOTAL
$0.00
($20,000.00)
($40,000.00)
($60,000.00)
($80,000.00)
($100,000.00)
($120,000.00)
($140,000.00)
($160,000.00)
Status Quo
BCR using DA LMP - Subset of Intervals
BCR using RT DEB - Subset of Intervals
BCR using First Min/Max Methodlogy - Subset of Intervals
BCR using Latest Min/Max Methodlogy - Subset of Intervals
BCR using DA LMP - All Intervals
BCR using RT DEB - All Intervals
BCR using First Min/Max Methodology - All Intervals
BCR using Latest Min/Max Methodology - All Intervals

Figure 3. All Assets, Approaches Applied to Intervals that meet all Triggers Proposed by CESA

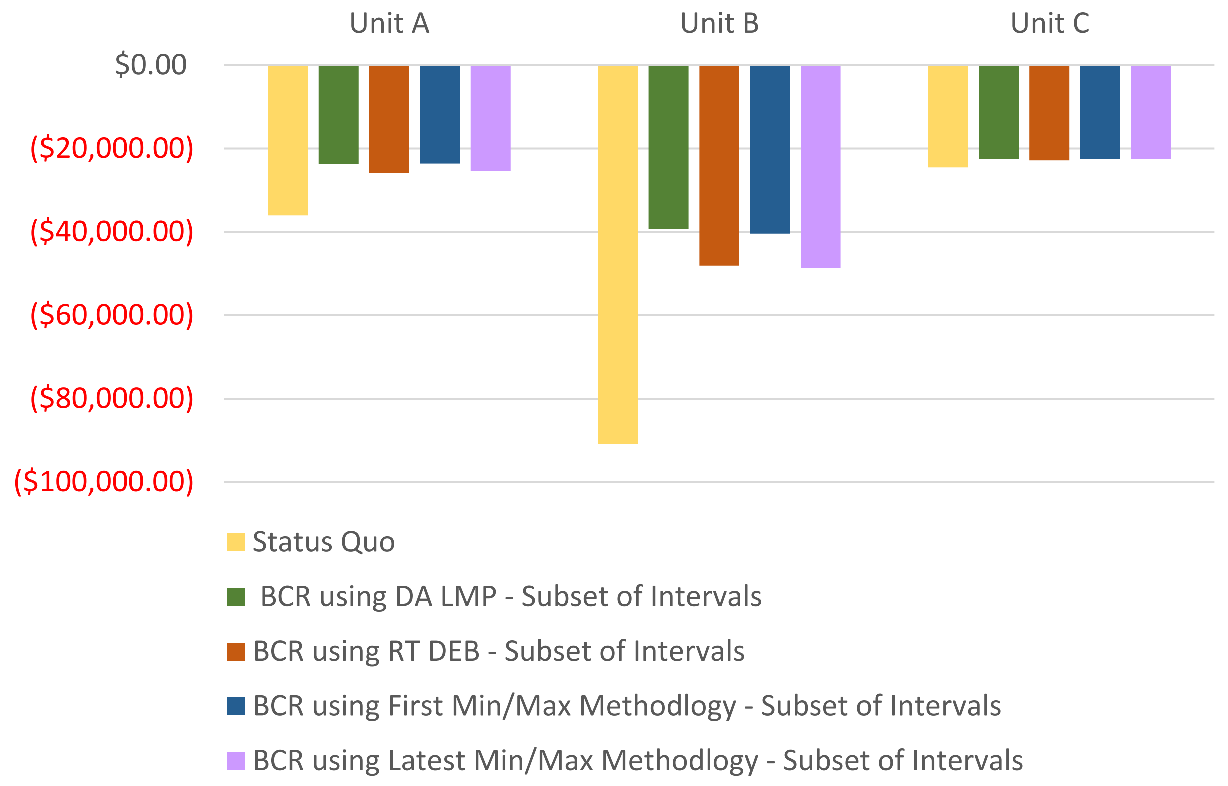


Figure 4. Total for all Assets, Approaches Applied to Intervals that meet all Triggers Proposed by CESA

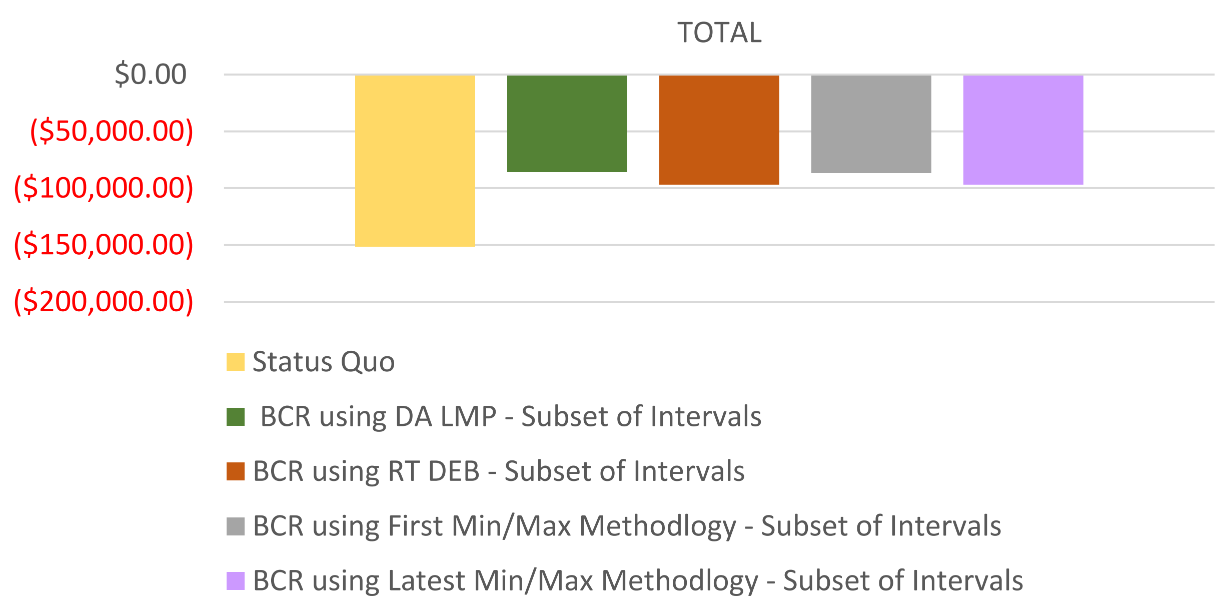


Figure 5. All Assets, Approaches Applied to All Intervals

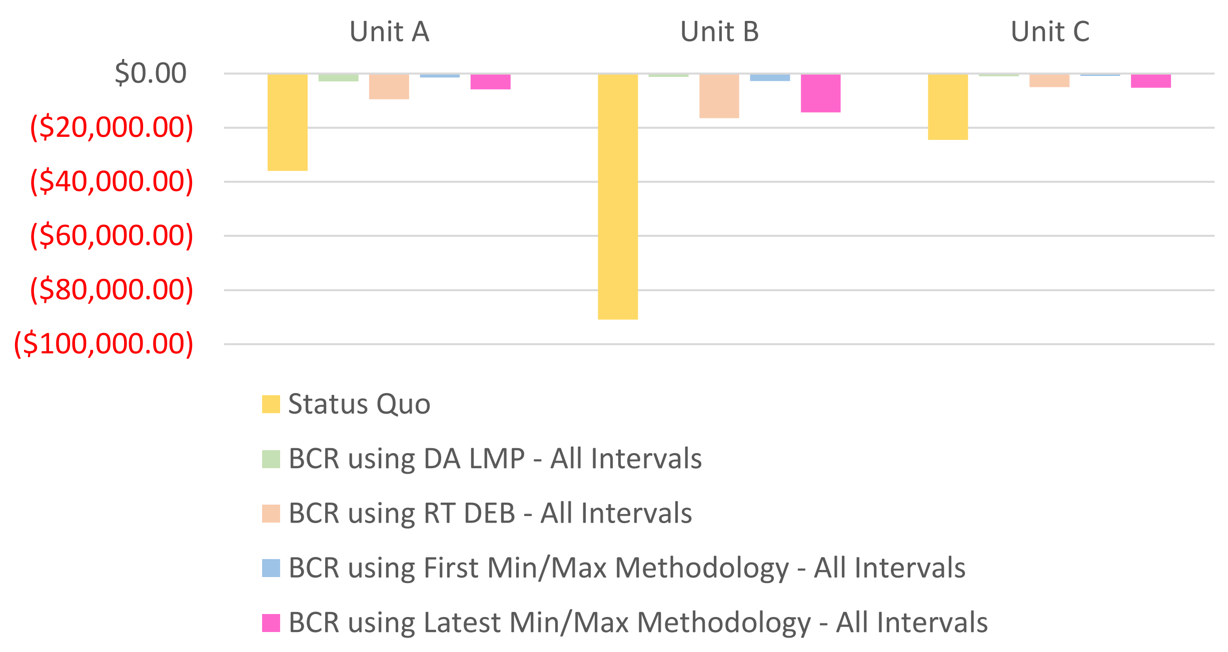
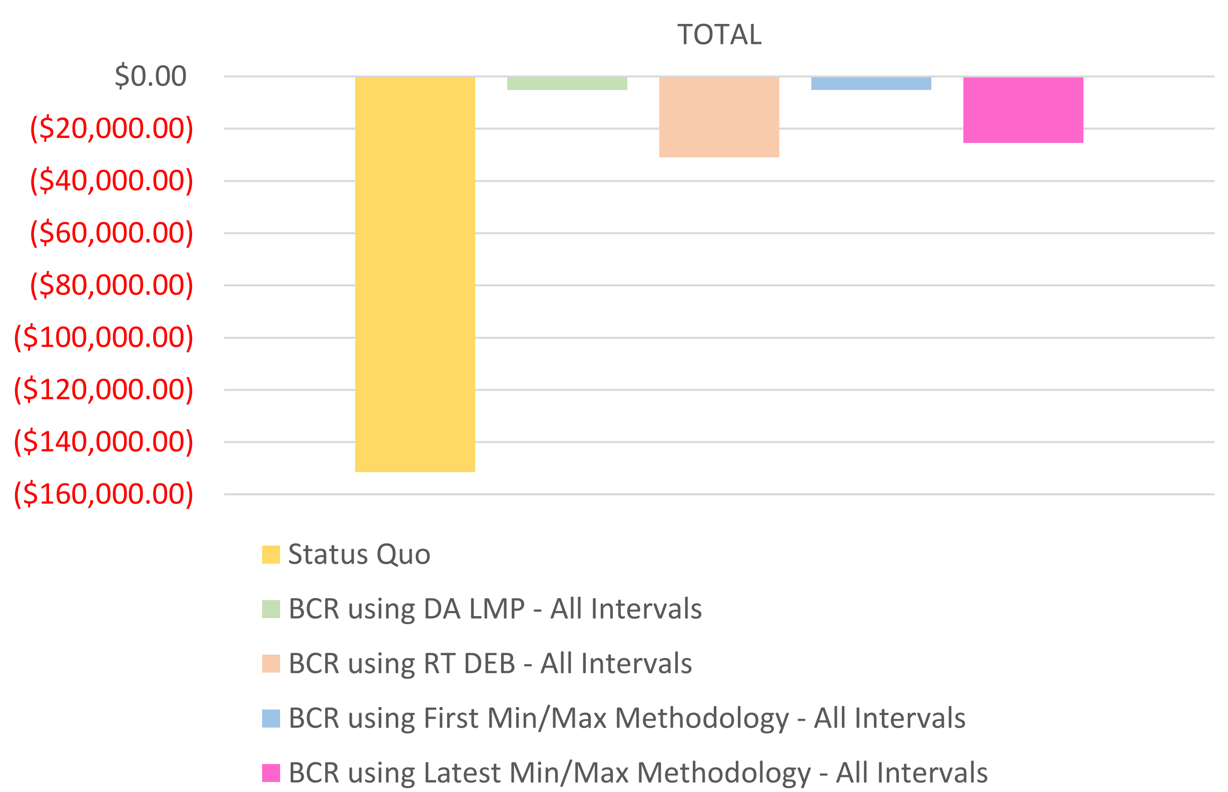


Figure 6. Total for all Assets, Approaches Applied to All Intervals



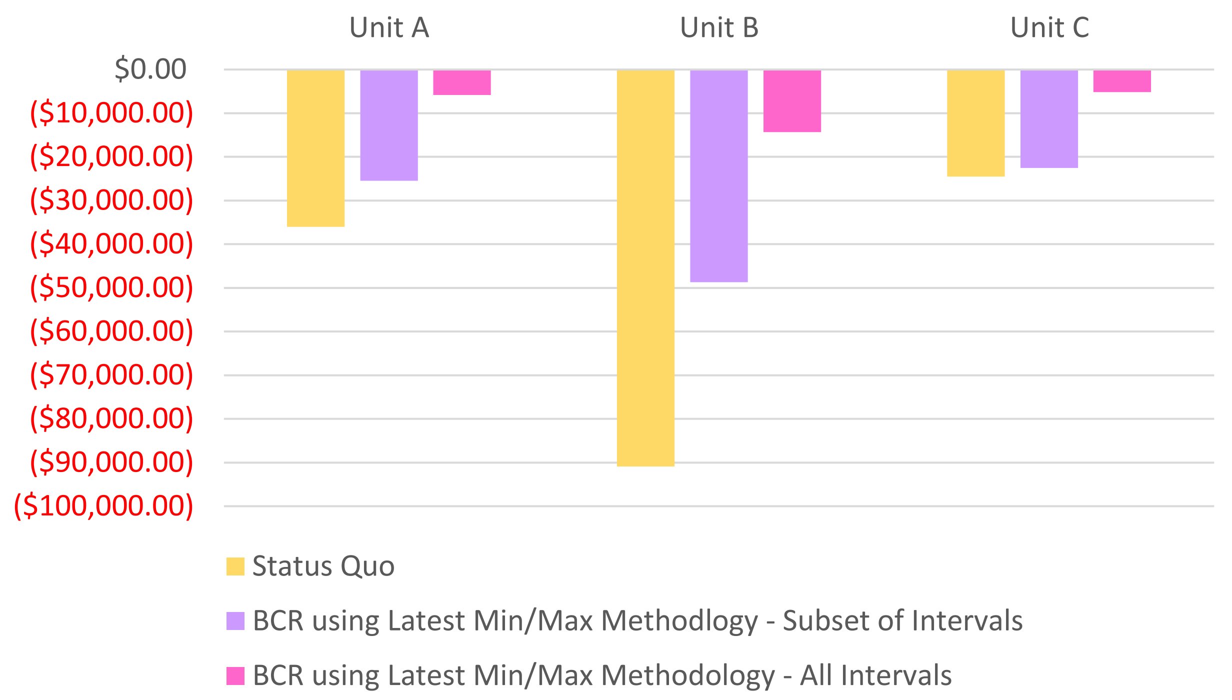


Figure 7. All Assets, Status Quo versus Latest Min/Max Proposals

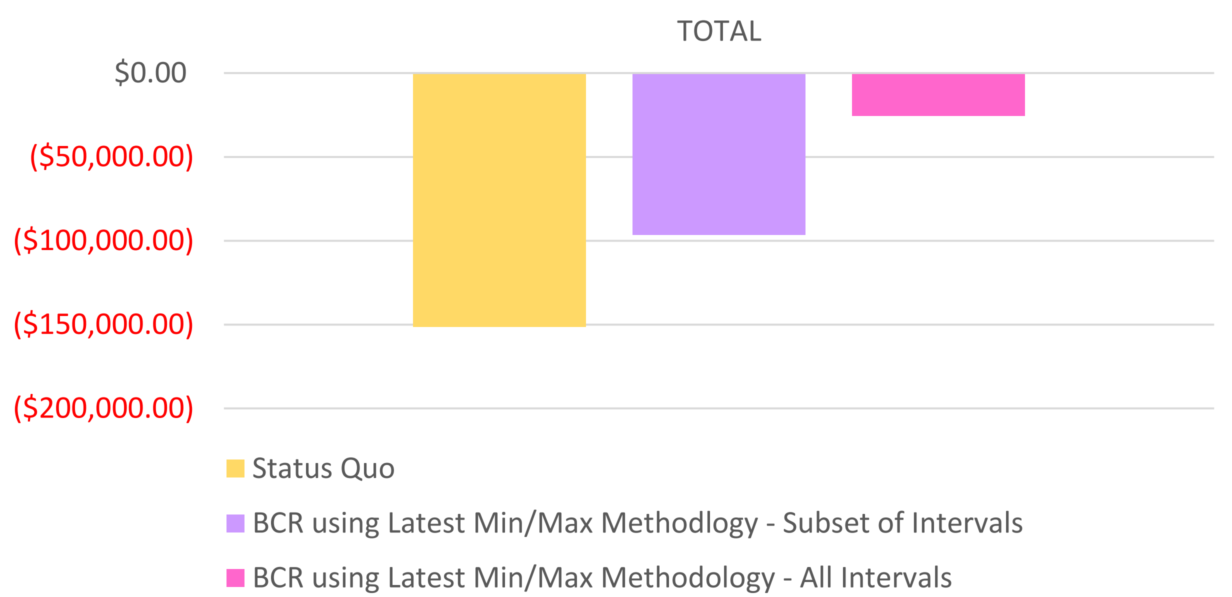


Figure 8. Total for all Assets, Status Quo versus Latest Min/Max Proposals

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Storage Bid Cost Recovery and Default Energy Bid Enhancements

Addendum to the Draft Final Proposal for Track 1

October 15, 2024

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1. Addendum on Modified Bid Cost Recovery Formulas

As illustrated in the Draft Final Proposal (DFP), the issues related to storage bid cost recovery (BCR) are complex and merit significant analysis and review. It is clear that the extension of the existing BCR construct to storage resources has resulted in complications and unintended outcomes that merit a holistic revision of the uplift mechanism applicable to this resources. This being said, it is also evident from the material discussed herein that the current design gap that could allow for strategic bidding behavior to unduly inflate BCR payments for storage assets must be closed in the near-term as it exposes market participants and ratepayers to adverse financial outcomes.

In this context, the ISO proposed to move forward with a near-term, interim solution focused on modifying the real-time energy bid cost calculation in the real-time BCR settlement for storage resources between the fifteen-minute market (FMM) and the day-ahead schedule as well as between the real-time dispatch (RTD) and the fifteen-minute schedule. This would be done by applying the stakeholder-proposed solution for buy-backs for all intervals in which the difference in dispatch is less or equal to zero between the fifteen minute market and the day-ahead schedule as well as between the RTD and the fifteen-minute schedule. Conversely, the stakeholder-proposed formula for sell-backs would be applied for all intervals in which the difference in dispatch is greater than zero between the fifteen minute market and the day-ahead schedule as well as between the RTD and the fifteen-minute schedule.

Since the publication of the DFP, the ISO held a stakeholder meeting on October 9th and went through the DFP and a series of examples contained therein. In response to the DFP and the aforementioned examples, several stakeholders requested added clarity on the formulas used to calculate Real-Time Energy Bid Costs across the different approaches included therein. This addendum seeks to offer such clarifications.

Status Quo

For the status quo examples, the BCR surpluses and shortfalls were calculated using the following formula:

- (FMM Dispatch – DA Schedule) * (FMM Bid – FMM LMP)
- (RTD Dispatch – FMM Schedule) * (RTD Bid – RTD LMP)

BCR using DA LMP

For the approach that uses the DA LMP instead of the RT bid to calculate the Real-Time Energy Bid Cost, the ISO used the following formulas across all intervals:

- (FMM Dispatch – DA Schedule) * (**DA LMP** – FMM LMP)
- (RTD Dispatch – FMM Schedule) * (**DA LMP** – RTD LMP)

For the version of this approach where the modified calculation is only utilized in the intervals that meet the trigger conditions established by the California Energy Storage Alliance (CESA), the ISO used the following formulas:

- To identify the intervals where the modified calculation should be applicable for:
  - For a buy-back:
    If(AND(DA Schedule > 0, DA Schedule > FMM Dispatch, FMM Dispatch >= 0))
  - For a sell-back:
    If(AND(DA Schedule < 0, DA Schedule < FMM Dispatch, FMM Dispatch <= 0))
- Modified formula applicable for said intervals (either buy- or sell-back):
  - (FMM Dispatch – DA Schedule) * (**DA LMP** – FMM LMP)
  - (RTD Dispatch – FMM Schedule) * (**DA LMP** – RTD LMP)
- Formula applied for the remainder of the intervals (*i.e.,* those that do not meet the trigger conditions):
  - (FMM Dispatch – DA Schedule) * (FMM Bid – FMM LMP)
  - (RTD Dispatch – FMM Schedule) * (RTD Bid – RTD LMP)

BCR using RT DEB

For the approach that uses the RT DEB instead of the RT bid to calculate the Real-Time Energy Bid Cost, the ISO used the following formula across all intervals:

- (FMM Dispatch – DA Schedule) * (**RT DEB** – FMM LMP)
- (RTD Dispatch – FMM Schedule) * (**RT DEB**– RTD LMP)

For the version of this approach where the modified calculation is only utilized in the intervals that meet the trigger conditions established by CESA. The ISO used the following formulas:

- To identify the intervals where the modified calculation should be applicable for:
  - For a buy-back:
    If(AND(DA Schedule > 0, DA Schedule > FMM Dispatch, FMM Dispatch >= 0))
  - For a sell-back:
    If(AND(DA Schedule < 0, DA Schedule < FMM Dispatch, FMM Dispatch <= 0))
- Modified formula applicable for said intervals (either buy- or sell-back):
  - (FMM Dispatch – DA Schedule) * (**RT DEB** – FMM LMP)
  - (RTD Dispatch – FMM Schedule) * (**RT DEB** – RTD LMP)
- Formula applied for the remainder of the intervals (*i.e.,* those that do not meet the trigger conditions):
  - (FMM Dispatch – DA Schedule) * (FMM Bid – FMM LMP)
  - (RTD Dispatch – FMM Schedule) * (RTD Bid – RTD LMP)

BCR using the First Min/Max Methodology

For the approach that uses the first version of the stakeholder-proposed Min/Max formulas, the ISO used the following formulas across all intervals:

- FMM Bid Costs:
  - If(Differential FMM Dispatch > 0, (FMM Dispatch – DA schedule) * (**[Min(DA LMP, RT DEB, FMM Bid)]** – FMM LMP), 0)
  - If(Differential FMM Dispatch <= 0, (FMM Dispatch – DA schedule) * (**[Max(DA LMP, RT DEB, FMM Bid)]** – FMM LMP), 0)
- RTD Bid Costs:
  - If(Differential RTD Dispatch > 0, (RTD Dispatch – FMM schedule) * (**[Min(DA LMP, RT DEB, RTD Bid)]** – RTD LMP), 0)
  - If(Differential RTD Dispatch <= 0, (RTD Dispatch – FMM schedule) * (**[Max(DA LMP, RT DEB, RTD Bid)]** – RTD LMP), 0)

For the version of this approach where the modified calculation is only utilized in the intervals that meet the trigger conditions established by CESA, the ISO used the following formulas:

- To identify the intervals where the modified calculation should be applicable for:
  - For a buy-back:
    If(AND(DA Schedule > 0, DA Schedule > FMM Dispatch, FMM Dispatch >= 0))
  - For a sell-back:
    If(AND(DA Schedule < 0, DA Schedule < FMM Dispatch, FMM Dispatch <= 0))
- Modified formula applicable for said intervals:
  - For intervals flagged as buy-back intervals based on the triggers above:
    (FMM Dispatch – DA schedule) * (**[Max(DA LMP, RT DEB, FMM Bid)]** – FMM LMP)
    (RTD Dispatch – FMM schedule) * (**[Max(DA LMP, RT DEB, RTD Bid)]** – RTD LMP)
  - For intervals flagged as sell-back intervals based on the triggers above:
    (FMM Dispatch – DA schedule) * (**[Min(DA LMP, RT DEB, FMM Bid)]** – FMM LMP)
    (RTD Dispatch – FMM schedule) * (**[Min(DA LMP, RT DEB, RTD Bid)]** – RTD LMP)
- Formula applied for the remainder of the intervals (*i.e.,* those that do not meet the trigger conditions):
  - (FMM Dispatch – DA Schedule) * (FMM Bid – FMM LMP)
  - (RTD Dispatch – FMM Schedule) * (RTD Bid – RTD LMP)

BCR using the Latest Min/Max Methodology [20]

For the approach that uses the latest version of the stakeholder-proposed Min/Max formulas across all intervals (the Draft Final Proposal), the ISO used the following formulas across all intervals:

- FMM Bid Costs:
  - If(Differential FMM Dispatch > 0, (FMM Dispatch – DA Schedule) * (**[Min(FMM Bid, Max(DA LMP, Charge Portion of RT DEB, FMM LMP))]** – FMM LMP), 0)
  - If(Differential FMM Dispatch <= 0, (FMM Dispatch – DA Schedule) * (**[Max(FMM Bid, Min(DA LMP, Discharge Portion of RT DEB, FMM LMP))]** – FMM LMP), 0)
- RTD Bid Costs:
  - If(Differential RTD Dispatch > 0, (RTD Dispatch – FMM schedule) * (**[Min(RTD Bid, Max(DA LMP, Charge Portion of RT DEB, RTD LMP))]** – RTD LMP), 0)
  - If(Differential RTD Dispatch <= 0, (RTD dispatch – FMM schedule) * (**[Max(RTD Bid, Min(DA LMP, Discharge Portion of RT DEB, RTD LMP))]** – RTD LMP), 0)

For the version of this approach where the modified calculation is only utilized in the intervals that meet the trigger conditions established by CESA, the ISO used the following formulas:

- To identify the intervals where the modified calculation should be applicable for:
  - For a buy-back:
    If(AND(DA Schedule > 0, DA Schedule > FMM Dispatch, FMM Dispatch >= 0))
  - For a sell-back:
    If(AND(DA Schedule < 0, DA Schedule < FMM Dispatch, FMM Dispatch <= 0))
- Modified formula applicable for said intervals:
  - For intervals flagged as buy-back intervals based on the triggers above:
    (FMM Dispatch – DA Schedule) * ((**[Max(FMM Bid, Min(DA LMP, Discharge Portion of RT DEB, FMM LMP))]** – FMM LMP)
    (RTD Dispatch – FMM Schedule) * ((**[Max(RTD Bid, Min(DA LMP, Discharge Portion of RT DEB, RTD LMP))]** – RTD LMP)
  - For intervals flagged as sell-back intervals based on the triggers above:
    (FMM Dispatch – DA Schedule) * (**[Min(FMM Bid, Max(DA LMP, Charge Portion of RT DEB, FMM LMP))]** – FMM LMP)
    (RTD Dispatch – FMM Schedule) * (**[Min(RTD Bid, Max(DA LMP, Charge Portion of RT DEB, RTD LMP))]** – RTD LMP)

[20] Please note that the formulas described in this section refer to the Charge and Discharge portions of the RT DEB. The calculation for these portions of the DEB may vary slightly since the Charging portion does not include the Variable Storage Operation Cost. In practice, this rarely results in different values for each of the portion since they are defined as:

- Charging Portion = Max(Energy Cost, Nth Highest DA LMP)*1.1
- Discharging Portion = Max (Energy Cost + Variable Storage Operation Cost, Nth Highest DA LMP)*1.1

As such, it is often the case that both the Charging and Discharging portions of the DEB are calculated at equivalent values resulting in the DEB being collapsed into a single segment that covers the whole operating range. As such, for simplicity, the Excel that accompanies this Addendum uses a single DEB for the purposes of this approach.

- Formula applied for the remainder of the intervals (*i.e.*, those that do not meet the trigger conditions):
  - (FMM Dispatch – DA Schedule) * (FMM Bid – FMM LMP)
  - (RTD Dispatch – FMM Schedule) * (RTD Bid – RTD LMP)

Regarding intervals with no DA Schedule

During the stakeholder meeting held October 9th, some stakeholders suggested that, for the intervals in which a resource does not have a DA schedule, the ISO should modify the latest Min/Max methodology to exclude the DA LMP. This approach was not taken in the examples included in the DFP, but it is included in the Excel spreadsheet that accompanies this Addendum. As such, in the accompanying Excel spreadsheet, the ISO used the following formulas for instances in which the resource does not have a DA schedule:

- FMM Bid Costs:
  - If(Differential FMM Dispatch > 0, (FMM Dispatch – DA schedule) * (**[Min(FMM Bid, Max(Charge Portion of RT DEB, FMM LMP))]** – FMM LMP), 0)
  - If(Differential FMM Dispatch <= 0, (FMM dispatch – DA schedule) * (**[Max(FMM Bid, Min(Discharge Portion of RT DEB, FMM LMP))]** – FMM LMP), 0)
- RTD Bid Costs:
  - If(Differential RTD Dispatch > 0, (RTD Dispatch – FMM schedule) * (**[Min(RTD Bid, Max(Charge Portion of RT DEB, RTD LMP))]** – RTD LMP), 0)
  - If(Differential RTD Dispatch <= 0, (RTD dispatch – FMM schedule) * (**[Max(RTD Bid, Min(Discharge Portion of RT DEB, RTD LMP))]** – RTD LMP), 0)