1.

## Market Power Mitigation

The market power mitigation process is used to identify which scheduling coordinators can exercise local market power in circumstances where there are insufficient resources to rely on competition to mitigate constraints based on market bids. In the absence of sufficient resources to rely on competition, scheduling coordinators could potentially manipulate the energy price in their local area by economically withholding supply. Any scheduling coordinator that is identified through this process will be subject to bid mitigation.

The MPM process will consist of a single market optimization run in which all modeled transmission constraints are enforced. It will utilize the same market optimization engine as used in the CAISO’s IFM and RUC. Some characteristics of DAM LMPM are summarized as follows:

* The MPM process occurs in DAM immediately after the DAM close of bidding at 10:00 AM, by when all Bids and Self-Schedules are submitted by the SCs and validated by CAISO.
* The Time Horizon for MPM in DAM is 24 hours (23 and 25 respectively on Daylight Saving transition days).
* Each market interval for MPM in DAM is one hour.
* The time resolution of the CAISO Forecast of CAISO Demand in DAM is hourly.
* The Energy Bid mitigation in DAM is performed on an hourly basis.
* Virtual Bids and Bids from Demand Response Resources, Participating Load, Hybrid Resources, and non-storage Non-Generator Resources[[1]](#footnote-1) are considered in the MPM process as part of the power balance equation. However, these bids are not subject to mitigation. Bids from resources comprised of multiple technologies that include Non-Generator Resources will remain subject to mitigation.
* Multi-Stage Generating Resources will be subject to the market power mitigation procedures described in Section 31.2 of the CAISO Tariff at the MSG Configuration basis as opposed to the overall plant level.

### Decomposition method

The MPM method is referred to as the locational marginal price decomposition method (or LMP decomposition method). It consists of a single market optimization run in which all modeled transmission constraints are enforced. Then, each LMP in the market is be decomposed into four components: (1) the energy component; (2) the loss component; (3) the competitive congestion component; and (4) the non-competitive congestion component. For location i:

,

where

* EC stands for the energy component,
* LC stands for the loss component,
* CC stands for the competitive constraint congestion component (Competitive LMP), and;
* NC stands for the non-competitive constraint congestion component.

Under the LMP decomposition method, a positive non-competitive congestion component indicates the potential of local market power. The non-competitive congestion component of each LMP will be calculated as the sum over all non-competitive constraints of the product of the constraint shadow price and the corresponding shift factor.

In order for the non-competitive congestion component to be an accurate indicator of local market power, the reference bus that the shift factors relate to should be at a location that is least susceptible to the exercise of local market power. The CAISO selects as the reference bus the Midway 500kV bus when flow on Path 26 is north to south, and the Vincent 500kV bus when flow on Path 26 is south to north. The Midway and Vincent 500kV buses are excellent choices for LMPM purpose because they are located on the backbone of the CAISO’s transmission system near the center of the California transmission grid with sufficient generation and roughly half the system load on each side. Therefore, these buses are very competitive locations, and are least likely to be impacted by the exercise of local market power.

Every resource with the LMP non-competitive congestion component greater than the Mitigation Threshold Price (currently set at zero) is subject to mitigation. Bids from any such resources will be mitigated downward to the higher of the resource’s Default Energy Bid, or the “competitive LMP” at the resource’s location, which is the LMP established in the LMPM run minus the non-competitive congestion component thereof (Competitive LMP ). A small configurable adder, which in all cases will be less than $0.01, is be added to the Competitive LMP.

### Treatment of Legacy RMR Resources

All LRMR Resources are those with an RMR contract entered into prior to September 1, 2018, and remain under their LRMR contract. These contracts may have unique provisions for DA and RTM bidding, dispatch and settlements. All LRMR resources will be dispatched and settled according to the terms and conditions of their specific RMR contracts and Appendix H of the CAISO Tariff

#### Treatment of RMR Resources

RMR resources that are not LRMR are treated similarly to non-RMR resources in the LMPM process and have the same obligations and RA resources

### Competitive Path Criteria

This is based on CAISO Tariff Sections 39.7.2.2 and 39.7.3.

As part of each MPM run, an in-line dynamic competitive/non-competitive designation calculation (dynamic competitive path assessment or DCPA) determines whether a constraint is competiivte or non-competitive. A Transmission Constraint is competitive by default unless the Transmission Constraint is determined to be non-competitive as part of this calculation. This will occur when the maximum available supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow.

If, for some reason, the DCPA is unable to function, the MPM will rely on a default competitive path list that is compiled based on historical analysis of congestion and previous DCPA results on each Transmission Constraint.

The effect of enforcement of gas usage nomograms is not modeled in the DCPA. Therefore, the DCPA will not be able to account for the impact of reduced counter-flow from generators subject to nomogram constraints. When gas nomograms are enforced in the market, the CAISO will deem constraints as non-competitive when a gas nomogram is predicted to create conditions in which the maximum available supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow on that constraint.  First, the CAISO will identify the set of Transmission Constraints that can be relieved by counter-flow from potentially gas-limited resources. Then, the CAISO will estimate changes of the residual supply index (RSI) for each of those constraints resulting from gas nomograms of reflecting varying levels of restrictions on gas supply. Estimation of the RSI will involve identical calculations to the ones used in the market, but will use estimates of available capacity when a gas nomogram constraint is in place. The CAISO may designate a constraint or set of constraints non-competitive when the RSI is predicted to be non-competitive when a gas nomogram is imposed in the market.

Over time, the CAISO will develop a table that will identify the potentially non-competitive Transmission Constraints that CAISO operations may deem as non-competitive in the market based on imposition of a particular nomogram under various supply and demand conditions. For each constraint and nomogram combination, a limit or limits will be listed. If a gas nomogram is binding at a level listed on the table, it will be appropriate to declare the listed constraints non-competitive. The CAISO will continue to communicate data related to market power mitigation and the enforcement of gas usage constraints according to current procedures for both of these processes. A constraint deemed non-competitive through the manual override process based on the imposition of a gas supply nomogram will be included in the listings of constraints with competitive designation status provided on the CAISO OASIS site (<http://oasis.caiso.com>) in the reports MPM Nomogram/Branch Group Competitive Paths and MPM Intertie Constraint Competitive Paths.These reports are described in further detail in the BPM for Market Instruments, Section 12 Public Market Information.

*For a detailed process description for the competitive path criteria, Refer to Attachment B.*

### Default Energy Bids

This section is based on CAISO Tariff Section 39.7.1, Calculation of Default Energy Bids.

Default Energy Bids (DEBs) are calculated daily for both the Day-Ahead and Real-Time markets. With the exception of the LMP-based DEB, the DEB does not vary by peak/off-peak period. The CAISO offers various methodologies to calculate DEBs for resources. Please refer to the BPM for Market Instruments, Attachment D for more information on each DEB methodology and sample calculations.

### Bid Adder for Frequently Mitigated Units

This section is based on CAISO Tariff Section 39.8.1, Bid Adder Eligibility Criteria.

To receive a Bid Adder for Frequently Mitigated Units, a Generating Unit:

* Must have a Mitigation Frequency that is greater than 80% in the previous 12 months
* Must have run for more than 200 hours in the previous 12 months
* Must not have an contract to be a Resource Adequacy Resource for its entire Maximum Net Dependable Capacity or be subject to an obligation to make capacity available under the CAISO Tariff

Additionally, the SC for the Generating Unit must agree to be subject to the Frequently Mitigated Unit Option for a Default Energy Bid. Run hours are those hours during which a Generating Unit has positive metered output.

### Mitigation Exemptions for Small Storage Resources

Storage resources less than 5 MW are not subject to market power mitigation.

#### Enforcement of Constraints on the Interties

The CAISO enforces both scheduled and physical flows on the Interties through the use of a two-constraint approach. In the IFM, the ISO will continue to enforce a scheduling constraint and will include a physical flow constraint (based on the FNM expansion initiatives), each of which will consider both physical and Virtual Bids. To ensure uniqueness of prices, intertie constraints, similar to other transmission constraints, are formulated with additional slack variables. The scheduling constraint will continue to be based on the assessment of Intertie Bids submitted by the Scheduling Coordinators relative to the Available Transfer Capability of the specific Intertie location. This will ensure that contract paths are honored and will be used for E-Tagging intertie schedules. The physical flow constraint will be based on the modeled flows for the Intertie, taking into account the actual power flow contributions from all resource schedules in the Full Network Model against the Available Transfer Capability of the Intertie. Unlike the scheduling constraint, the contributions of intertie schedules towards the physical flow limit will be based on the shift factors calculated from the network model, which reflects the amount of flow contribution that change in output will impose on an identified transmission facility or flowgate. Each Intertie will have a single Total Transfer Capability and the scheduling limit and physical flow limit will be compared against the Intertie’s capacity. The scheduling limit and physical flow limit are not necessarily equal to each other.

In the Residual Unit Commitment, the CAISO will enforce two constraints that only consider physical awards with respect to contract path limits

(*i.e.*, Virtual Awards cannot provide counterflow to physical awards).

* + - 1. **Maximum Daily Run Time**

The maximum daily run time constraint enforces the maximum number of hours a resource can be committed on-line over the course of a calendar day. For resources that have this parameter, the IFM will limit commitment periods so that they do not exceed the hourly limitation. Commitment periods may or may not be consecutive. For resources that do not have this parameter set, the IFM may commit those resources for all hours in a day.

Market Participants may register this parameter in the Master File[[2]](#footnote-3).

## Differences from IFM

In general, the RTM applications are multi-interval optimization functions minimizing the cost of dispatching Imbalance Energy and procuring additional AS, when applicable, subject to resource and network constraints. In this respect, the RTM applications are not much different than the IFM application. The main differences are the following:

* The IFM application uses hourly time intervals, whereas the RTM applications use sub-hourly time intervals within their Time Horizon.
* The Time Horizon of the IFM application spans the next Trading Day, whereas the Time Horizon of the RTM applications is variable (due to submission timelines limiting the availability of real-time bids beyond the end of the next hour) and spans the current and next few Trading Hours at most. The RTM applications run at periodic intervals, every 5 or 15 minutes, with a Time Horizon that ends at or beyond the Time Horizon of the previous run. Results for time intervals other than the second (binding) one in the Time Horizon are advisory since they are recalculated the next time the application runs.
* The IFM application uses Demand Bids to clear against Supply Bids, whereas the RTM applications use CAISO Forecast of CAISO Demand and final scheduled exports. Demand Bids and Virtual Bids are not accepted in the RTM.
* The RTM applications use the latest available information about resource availability and network status; in fact, the optimal Dispatch is initialized by the SE solution that is provided by the Energy Management System (EMS).
* The IFM application commits resources optimally for the next Trading Day using three-part Energy Bids. Almost all resources can be considered for optimal commitment, except for resources with extremely long Start-Up, because the full cost impact of commitment decisions for these resources cannot be evaluated within the IFM Time Horizon. Similarly, the RTM applications that have Unit Commitment capabilities can commit resources optimally within their Time Horizon. However, because that Time Horizon is short (a few hours at most), only Fast-Start, Short-Start and Medium-Start Units can be committed. Consequently, any Long-Start Units that are not scheduled in the IFM or RUC, are effectively not participating in the RTM.
* Unlike the IFM application, the RTM applications need to interface with the Automated Dispatch System (ADS) to communicate financially binding commitment and Dispatch Instructions, and with the CAS for confirmation of System Resource Schedules and Dispatch.
* The RTM applications provide more control to the CAISO Operator with the capability to adjust the Imbalance Energy requirements (via adjustments to the Load forecast), block commitment or Dispatch Instructions, or issue Exceptional Dispatches. This CAISO Operator input is necessary to address any unexpected system conditions that may occur in Real-Time.
* The RTM applications also provide the functionality to the CAISO Operator to switch the system or individual resources into a Contingency state under which Contingency-Only Operating Reserves are dispatched optimally to address system contingencies. Contingency-Only Operating Reserves are otherwise reserved and not dispatched by the RTM applications.
* The CAISO Operator may augment or supplant the Dispatch Instructions generated by the RTM application with Exceptional Dispatches if necessary to address system conditions that are beyond the modeling capability of the RTM applications.
* The ISO market systems will validate Bids at transmission paths with zero rated TTC in both directions. The details of this procedure are provided in the BPM for Market Instruments. For System Resources that have registered a primary and alternate tie path in the Master File, and were awarded schedules in IFM/RUC on the primary tie, and the primary tie is rated zero in both directions in the real-time, the real-time systems will consider the award to be on the alternate tie for dispatch purposes.
* Unlike the IFM application, RDRR resources will not be selected for normal dispatch unless the CAISO Controlled Grid is in one or more of the following conditions as provided in the associated operating procedures (see CAISO public website):
* Under system emergencies, including Transmission emergencies; and
* Mitigating imminent or threatened operating reserve deficiencies; and
* Resolving local transmission and distribution system emergencies.

In the event these conditions exist, the CAISO operator may choose to activate a software flag that allows these resources to be dispatched. Likewise, after the condition has ended and conditions have stabilized, the operator will reset the flag which will prevent the resources from being dispatched, other than to their day-ahead awarded value. Day-ahead awarded values should be followed in either case.  RDRRs with day-ahead schedules will not receive any RT dispatches until operational conditions exist such that the software flag is activated per condition above. Once activated, the RT dispatch instructions generated will include both DA and RT MW components through ADS per section 7.2.3.5 .

* RDRR resources have the option of discrete dispatch capability in the RTM application. Similar to a COG unit, the RDRR resource selecting the discrete dispatch option will be dispatched either to zero or to a specified MW quantity, and will be allowed to set the LMP if a portion of energy from the resource is needed to serve demand. Unlike a COG unit, the MW quantity is specified via the hourly Energy Bid.
* NGR electing to use Regulation Energy Management can only provide regulation. The ability to provide regulation is dependent on their real-time state of charge. Thus their SOC energy constraint is managed in the Real-Time Economic Dispatch application in combination with EMS only, not IFM or Real-Time Unit Commitment.
* In the RTM application, startup time is included in the Outage time. After an outage has ended, a resource does not also have to have its startup time elapse prior to being considered for commitment, unlike the IFM.
* Startup time for PDRs that 1) registered for the 15-minute or 60-minute bid dispatchable option in the Master File and 2) submit bids into the Real-Time Market will be overridden. RTM will instead consider a 52.5 minute startup time for PDR resources registered for the 60-minute bid dispatchable option, and a 22.5 minute startup time for PDR resources registered for the 15-minute bid dispatchable option.
* For PDR-LSRs, 1) the bid dispatchable option must either be 15-minute or 5-minute. Since this is a single product under two resource IDs in the Master File, the bid dispatchable option must be the same for both PDR-LSR Curtailment Resource ID and PDR-LSR Consumption Resource ID. 2) bids submitted in the Real-Time Market will be overwritten, and instead consider a 22.5 minute startup time for 15-minute bid dispatchable option or 2.5 minute notification time for 5 minute bid dispatchable option.
* In RTM, for purposes of the maximum daily run time constraint, any commitments in IFM are considered binding regardless of whether the resource received a binding day-ahead commitment. RTM may commit resources for additional time periods, but the sum of any IFM commitments and RTM commitments shall not exceed the maximum daily run time constraint.
	1.

## MPM for Real-Time

This section is based on CAISO Tariff Sections 34.1.5 (Mitigating the Bid Sets Used in the RTM Optimization Processes). For a given Trading Hour, MPM is performed separately in FMM and RTD.

After the Market Close of RTM, after CAISO validates the Bids pursuant to CAISO Tariff Section 30.7, and prior to running FMM, the CAISO conducts the MPM process, the results of which are utilized in FMM.

Prior to FMM, the MPM process performs a DCPA for each interval of FMM (binding and advisories). For a given hour, a Bid that is not mitigated in a given 15min interval of one FMM run may be mitigated in a subsequent FMM run for the corresponding 15min interval. Once a Bid is mitigated in a FMM run for a given 15min interval, the mitigated Bid applies only to that 15min interval and only in that FMM run. The original unmitigated Bid will be evaluated again by the MPM process for the corresponding 15min interval of the next FMM run, if it lies within the market horizon.

For RTD, the MPM process is performed after the RTD solution for a configurable number (currently three) of 5min advisory intervals after the binding 5min interval. The MPM process performs a DCPA on these advisory intervals, the results of which are used to mitigate the Bids for these intervals, which will then be used for the corresponding 5min intervals of the following RTD run. Once a Bid is mitigated in a RTD run for a given 5min interval, the mitigated Bid applies only to that 5min interval and only for the following RTD runs. Bids cannot be unmitigated by subsequent RTD runs. However, a mitigated Bid may be further mitigated in a subsequent RTD run.

Bids from Demand Response Resources, Participating Load, Hybrid Resources, and non-storage Non-Generator Resources[[3]](#footnote-4) are considered in the MPM process as part of the power balance equation. However, these bids are not subject to mitigation. Bids from resources comprised of multiple technologies that include Non-Generator Resources will remain subject to mitigation.

For both Condition 1 and Condition 2 LRMR Units, when mitigation is triggered, an RMR Proxy Bid for each applicable interval is calculated using the same methodology described as for non-LRMR Units. The RMR Proxy Bid will be utilized for the corresponding 15min or 5min interval in FMM and RTD, respectively.

If a Condition 2 LRMR Unit is issued a Manual RMR Dispatch by the CAISO, then RMR Proxy Bids for all of the unit’s Maximum Net Dependable Capacity will be considered in the MPM process.

* For a Condition 1 LRMR Unit that has submitted Bids and has not been issued a Manual RMR Dispatch, to the extent that the non-competitive Congestion component of an LMP calculated in the MPM process is greater than zero, and that MPM process dispatches a Condition 1 LRMR Unit at a level such that some portion of its market Bid exceeds the Competitive LMP at the LRMR Unit’s Location, the resource will be flagged as an RMR dispatch if it is dispatched at a level higher than the dispatch level determined by the Competitive LMP.

Refer to section 6.5 for details on the MPM process.

#### Stored Energy Management for Non Generator Resources in Real-Time

For NGRs designated as Limited Energy Storage Resources (LESRs), state of charge (SOC) constraints are applied to both the binding and non-binding intervals in FMM and RTD based on their Master File parameters, Lower and Upper Charge Limit bids, End-of-Hour (EOH) SOC bids limits, and, if applicable, the reliability-induced Minimum SOC described in section 2.5.8 of this BPM.

**Real-Time Interval State-of-Charge Management**

To properly manage the SOC for each interval, RTED receives the latest SOC for each NGR via telemetry and uses this information to calculate an initial condition SOC for each NGR, similar to the way generator initial operating levels are calculated, by projecting the actual status toward the last dispatch.

The SOC of an LESR is calculated for each interval in FMM and RTD as follows:

Then, the ancillary service awards are constrained as follows:

In RTD, the SOC remaining at the end of the RTD time horizon is constrained to ensure the LESR is able to meet its self-schedules in intervals beyond the scope of the RTD time horizon. The end of horizon SOC will be constrained in RTD as follows:

Where:

|  |  |
| --- | --- |
| 1. *i*
 | is the resource index; |
| *t* | is the time interval index; |
| *te* | is the time interval in which the RTD case ends; |
|  | is the time interval duration (15min in FMM and 5min in RTD); |
|  | is the time unit, 60min; |
| *SOC* | is the State of Charge; |
|  | is the maximum State of Charge[[4]](#footnote-6); |
|  | is the minimum State of Charge5; |
|  | is the discharging schedule (positive); |
|  | is the charging schedule (negative); |
|  | is the optimal dispatch (algebraic); |
|  | is the maximum discharging capacity (positive); |
|  | is the minimum charging capacity (negative); |
| *η* | is the charging efficiency; |
| *u* | is the binary mode of operation, 1 for discharging and 0 for charging; |
| *RU* | is the Regulation Up award; |
| *RD* | is the Regulation Down award; |
| *SR* | is the Spinning Reserve award; |
| *NR* | is the Non-Spinning Reserve award; |
| *FRU* | is the Flex Ramp Up award;  |
| *FRD* | is the Flex Ramp Down award; |
| *SSEn* | is the Self-Scheduled Energy; |
| *SSRd* | is the Self-Scheduled Regulation Down; |
| *SSRu* | is the Self-Scheduled Regulation Up; |
| *SSSr* | is the Self-Scheduled Spinning Reserve; |
| *SSNr* | is the Self-Scheduled Non-Spinning Reserve; and |
| *RM* | is the number of minutes remaining from the end of the RTD case to the start of the next hour. |

CAISO tariff section 8.3.4 requires that resources scheduled to provide Spinning Reserve and Non-Spinning Reserve must be capable of maintaining that output or scheduled Interchange for at least 30 minutes from the point at which the resource reaches its award capacity. Resources offering Regulation in the real-time market must also have the capability to meet a continuous energy requirement for at least 30 minutes. *See* CASIO tariff section 8.4.1.1 and Appendix K, Part A.

Consistent with these requirements, when an NGR receives a Spinning Reserve or Non-Spinning reserve award, the CAISO will reserve its SOC to ensure the NGR can continuously deliver that capacity for 30 minutes. When an NGR receives a Regulation award or qualified self-provision, the CAISO will reserve its SOC to ensure it can continuously deliver that capacity for 30 minutes in the applicable fifteen-minute market and RTD interval.

Energy schedules and ancillary service awards are co-optimized in FMM subject to these SOC constraints. The ancillary service awards are fixed in RTD; however, the SOC constraints are still enforced in RTD to constrain the energy dispatch so that the sustained energy requirement is satisfied, and to ensure future awards and self-schedules can be met.

In Real-Time Contingency Dispatch (RTCD) and in Real-Time Disturbance Dispatch (RTDD) the market application will release the state of charge to deliver Spin and Non-Spin capacity for 10 minutes but continue to reserve the state of charge to ensure deliverability of Spin and Non-Spin capacity for future RTCD and RTDD. In subsequent RTCD and RTDD market runs, the application will release all state of charge to deliver Spin and Non-Spin capacity. In all RTCD and RTDD market runs, the market application will reserve the state of charge for 30 minutes to support deliverability of Regulation Up and Regulation Down capacity. In the event that a specific resource does not have sufficient state of charge prior to an ancillary service award or qualified self-provision in any fifteen-minute market interval, the CAISO may procure incremental ancillary services from another resource. In this event, the resource with an insufficient state of charge will be subject to the CAISO’s payment rescission rules.

For NGRs using Regulation Energy Management functionality, SOC is maintained by automatic generation control (AGC) with the following 50 percent rule:

* Maintains the SOC at 50% if system conditions are normal and it is not impacting the grid reliability by doing so.
* If SOC is below 50% and the system needs Regulation Down energy, AGC will calculate the MW charge level, and send a set point to NGRs for charging.
* If SOC is above 50% and system needs Regulation Up energy, AGC will calculate the MW charge level, and send a set point to the NGR for discharging.

RTD is mimicking what AGC is doing to bring SOC to 50 percent.

**End-of-Hour State-of-Charge Management**

Scheduling coordinators for LESRs may submit optional end-of-hour (EOH) state-of-charge (SOC) limits in the real-time market, as part of their energy bids, to manage the optimal use of their resources throughout the day. These EOH SOC limits are different from the minimum and maximum daily Lower and Upper Charge Limit bids, which ensure that resources receive dispatches that respect such daily Lower and Upper Charge Limit bids at the end of every market interval. Instead, the market may dispatch LESRs to meet imbalance energy needs within the hour, while ensuring the resource’s SOC satisfies the EOH limits only at the end of the corresponding hour, if submitted as part of the energy bids.

The scheduling coordinator submits a bid with minimum and maximum EOH SOC limits in MWh to reflect a target range. If the scheduling coordinator desires a single target EOH SOC, then the minimum and maximum EOH SOC limits may be set the same. The real-time market will respect an LESR’s minimum and maximum EOH SOC limits. The market will ignore EOH SOC limits if they conflict with the resource’s daily minimum and maximum SOC limits. However, there are bid validation rules that limit these occurrences in the market. See the *BPM for Market Instruments,* Appendix Attachment A, for more details.

The market prioritizes respecting ancillary services awards[[5]](#footnote-8) when a scheduling coordinator provides hourly EOH SOC limits that create conflicts. The market will maintain an SOC if the resource is providing ancillary services such that the resource can provide the full awarded MW amount over a 30-minute period. If a scheduling coordinator were to submit an EOH SOC target of 4 MWh, but the resource’s ancillary service awards require an 8 MWh SOC to ensure the ancillary service’s award can be met, the market will maintain the more limiting 8 MWh SOC. In addition, although the market will attempt to move the resource to the targeted EOH SOC, the actual state of charge could fluctuate above or below targets due to response from ancillary service instructions. Therefore, in hours where the resource receives simultaneous ancillary service and energy awards, there is no guarantee that the resource’s EOH SOC targets will be met. The market also respects Exceptional Dispatch instructions and cannot guarantee EOH SOC targets will be honored when EOH SOC limits and Exceptional Dispatch instructions simultaneously exist in the optimization time horizon.



Figure 1: Example of Ancillary Service award impact on an EOH SOC bid

While the Short-term Unit Commitment (STUC) market runs have no influence on energy storage resources, submitted EOH SOC limits can still influence the decision to commit (or not) additional medium-start units. Since real-time bids can be submitted and changed from the close of the day ahead market to 75 minutes prior to the start of the hour, to prevent any potential gaming opportunities, the CAISO will only use the binding limits in STUC, i.e., for hours for which the bidding market has closed.

*End-of-horizon management in RTED*

Although the RTUC time horizon always ends at the end of an hour, the RTED market may not, depending on the interval within the hour. There are several RTED runs that do not consider the same EOH SOC limits that an RTUC does, with the same binding interval start time. Thus, there may be sub-optimal situations where those RTED runs could undo what was planned by the RTUC/FMM, by not dispatching to charge or discharge the resource until it is too late to meet the EOH SOC targets.

End-of-horizon SOC constraints are implemented to align visibility of the EOH SOC limits to the same binding intervals for both RTED and RTUC/FMM. The end-of-horizon SOC constraint will enforce the EOH SOC limits, adjusted for the resource’s charging activity for intervals beyond the RTED time horizon until the EOH as determined by the latest RTUC advisory instructions for that period. For the purposes of the following two examples, consider the following: a 40 MWh resource with a -10 MW Pmin and 10 MW Pmax has a 25 MWh (62.5%) initial SOC for the RTUC 08:30 run, and must get to at least 30 MWh by the end of Hour Ending 10, thus an additional 5 MWh of charging is required[[6]](#footnote-9). In this same example, the initial SOC for the RTED 08:30 run is also 25 MWh. Suppose the resource is not economic to charge in the any of the binding or advisory intervals of the RTUC/FMM and RTED runs.

RTED end of horizon example 1:

For the RTUC, supposed the most economic prices to charge are for the last two intervals of the horizon, namely 09:30-09:45 and 09:45-10:00, so the resource will be scheduled at -10 MW for the 09:30 and 09:45 advisory intervals. When creating an end of horizon SOC constraint for the RTED 08:30 run, for which the horizon ends at 09:35, it is assumed that the RTED results will be following RTUC beyond 09:35. Thus, there will be 4.17 MWh of charging for the intervals covering 09:35-10:00 that are beyond the optimization time horizon[[7]](#footnote-10). The EOH SOC constraint for RTED thus becomes 30 MWh – 4.17 MWh, or 25.83 MWh of minimum SOC. Assuming prices between RTUC and RTED are converging, the incremental 0.83 MWh of charging will be dispatched in the interval 09:30-09:35.[[8]](#footnote-11)



Figure 2: RTED end-of-horizon example 1

RTED end of horizon example 2:

For the RTUC, suppose the most economic prices to meet the target are for the two intervals of the horizon 09:00-09:15 and 09:15-09:30, so the resource will be scheduled at -10 MW for the 09:00 and 09:15 advisory intervals. When creating an end-of-horizon SOC constraint for the RTED 08:30 run, for which the horizon ends at 09:35, it is assumed that the RTED results will follow RTUC. Thus, there will be no charging for the intervals 09:35- 10:00 that are beyond the optimization time horizon. The end of horizon SOC constraint for RTED thus becomes 30 MWh of minimum SOC. Assuming prices between RTUC and RTED are converging, the five MWh of charging will be picked up in the intervals 09:00-09:30[[9]](#footnote-12).



Figure 3: RTED end-of-horizon example 2

*Interaction between EOH SOC and MSOC constraints*

The Minimum State-of-Charge (MSOC) constraint described in section 2.5.8 of this BPM is a form of EOH SOC constraint. If the MSOC constraint is not active, the minimum and maximum EOH SOC limits submitted as part of bids will be used in the optimization. If MSOC requirements exist and are active, they will take priority over the bid EOH SOC and daily Lower and Upper Charge Limit bids during *critical[[10]](#footnote-13)* hours. During non-critical hours, the most restrictive between MSOC, minimum bid EOH SOC, and daily minimum SOC limits will be used. If necessary, the maximum bid EOH SOC and the daily maximum SOC limits shall be set to the MSOCwhen in conflict.

Example-1:

For a given RTM market interval (within critical hours) and a non-REM LESR with the following parameters:

* No Biddable Daily Lower Charge Limit
* No Biddable Daily Upper Charge Limit
* Biddable Min EOH SOC = 30 MWh
* Biddable Max EOH SOC = 70 MWh

If MSOC = 25 MWh, binding EOH SOC constraints used in RTM shall be:

* Min EOH SOC = 25 MWh (from MSOC)
* Max EOH SOC = 70 MWh (from Bid)

If MSOC = 50 MWh, binding EOH SOC constraints used in RTM shall be:

* Min EOH SOC = 50 MWh (from MSOC)
* Max EOH SOC = 70 MWh (from Bid)

If MSOC = 80 MWh, binding EOH SOC constraints used in the RTM shall be:

* Min EOH SOC = 80 MWh (from MSOC)
* Max EOH SOC = 80 MWh (Biddable Max EOH SOC conflicts with MSOC. Max value is set to MSOC)

Example-2:

For a given RTM market interval (within non-critical hours) and a non-REM LESR with the following parameters:

* No Biddable Daily Min ESL
* No Biddable Daily Max ESL
* Biddable Min EOH SOC = 30 MWh
* Biddable Max EOH SOC = 70 MWh

If MSOC = 25 MWh, binding EOH SOC constraints used in the RTM shall be:

* Min EOH SOC = 30 MWh (from Bid)
* Max EOH SOC = 70 MWh (from Bid)

If MSOC = 50 MWh, binding EOH SOC constraints used in the RTM shall be:

* Min EOH SOC = 50 MWh (from MSOC)
* Max EOH SOC = 70 MWh (from Bid)

If MSOC = 80 MWh, binding EOH SOC constraints used in the RTM shall be:

* Min EOH SOC = 80 MWh (from MSOC)
* Max EOH SOC = 80 MWh (Biddable Max EOH SOC conflicts with MSOC. Max value is set to MSOC.)
1. Some storage resources are also exempt from mitigation as described in section 6.5.6 of this BPM. [↑](#footnote-ref-1)
2. Eligibility to register the parameter may be limited to resources which meet specific criteria. See BPM for Market Instruments Appendix Attachment B for details. [↑](#footnote-ref-3)
3. Some storage resources are also exempt from mitigation as described in section 6.5.6 of this BPM. [↑](#footnote-ref-4)
4. The minimum and maximum State of Charge (SOC) enforced in the market will depend on the resource’s Master File parameters, bids, and system conditions as described in section 7.8.5.2 of this BPM. [↑](#footnote-ref-6)
5. However, satisfying the EOH SOC constraint will take precedence over procurement of ancillary services. [↑](#footnote-ref-8)
6. This requires two 15-minute intervals of full charging (-10 MW \* ½ hour = five MWh.) [↑](#footnote-ref-9)
7. 10 MW \* 25 minutes \* (1 hour / 60 minutes) = 4.17 MWh. [↑](#footnote-ref-10)
8. -10 MW \* 5 minutes \* (1 hour / 60 minutes) = 0.83 MWh. [↑](#footnote-ref-11)
9. Although the inputs to both real-time markets are the same, the two markets can lead to different results, and prices may not always converge. [↑](#footnote-ref-12)
10. Critical hours are defined by CAISO Operators based on Good Utility Practice. Critical hours are intended to represent the most critical load-serving hours of the day. All other hours of the day are deemed non-critical. [↑](#footnote-ref-13)