California Independent System Operator Corporation

March 10, 2022

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

Re: California Independent System Operator Corporation
Docket No. ER22-____-000

Tariff Amendment to Increase Scheduling Parameter Values for Intertie Transmission Constraint Relaxation

Dear Secretary Bose:

The California Independent System Operator Corporation (CAISO) submits this tariff amendment to increase the existing scheduling parameter values associated with intertie transmission constraint relaxation in both the residual unit commitment (RUC) and real-time market (RTM).[1] These tariff revisions will help ensure the CAISO market optimization reaches a solution that more accurately reflects actual supply available to the system to meet demand and mitigates the reliability risk of overscheduling on the interties during tight supply conditions.

The CAISO is targeting an effective date for these tariff revisions of June 1, 2022. Therefore, the CAISO requests the Commission issue an order accepting its tariff revisions on or before May 15, 2022. However, out of an abundance of caution, the CAISO requests the Commission authorize an effective date for such tariff revisions on or before June 15, 2022, subject to the CAISO filing a notice with the Commission within 5 days of the actual effective date.

I. Executive Summary

The CAISO operates both day-ahead and real-time wholesale electricity markets. This tariff amendment relates to two market processes: the RUC, which occurs in the

[1] The CAISO submits this filing pursuant to section 205 of the Federal Power Act (FPA), 16 U.S.C. § 824d, and Part 35 of the Commission's Regulations, 18 C.F.R. Part 35. Capitalized terms not otherwise defined herein have the meanings set forth in appendix A to the CAISO tariff, and references herein to specific tariff sections are references to sections of the CAISO tariff unless otherwise specified.

day-ahead market, and the hour-ahead scheduling process (HASP), which occurs in the real-time market.

The CAISO uses software to optimize the day-ahead and real-time markets. The software uses configurable market scheduling and pricing parameters to reach a feasible solution and set appropriate prices for the market in instances where effective economic bids and self-schedules are insufficient to reach a feasible solution. The market parameters include penalty prices that apply when constraints enforced by the CAISO market, such as constraints to ensure that supply equals demand (the power balance constraint, also referred to as the system energy-balance constraint) or transmission constraints, are binding. The various constraints have different penalty price levels that represent the cost at which the software will relax a constraint if it cannot reach a feasible solution while enforcing the constraint. If this occurs, the market calculates locational marginal prices (LMPs) based on the penalty prices. The CAISO uses the penalty prices addressed in this filing and associated LMPs only in the scheduling runs of RUC and HASP to ensure constraints are respected; the CAISO does not utilize them directly in settlements.

The CAISO discovered that when the market software faces a condition that requires relaxation of both the power balance constraint and an intertie transmission constraint to reach a feasible market solution, the resulting LMPs for imports at an intertie can be too high in relation to penalty prices to avoid overscheduling imports on an intertie. The high LMPs can cause overscheduling on that intertie in both the RUC (which is conducted in the day-ahead market) and the real-time market.

Overscheduling creates issues for both reliability and market efficiency. When the market software clears intertie schedules that exceed the intertie scheduling limit, CAISO operators must then manually curtail those excess intertie schedules after the market clears. Overscheduling poses an especially large reliability risk during tight supply conditions. This is most likely to occur in the summer when high demand and extreme weather often coalesce. Further, when overscheduling occurs, the market clearing process accounts for import supply that is not actually available, resulting in inaccurate market signals and an inefficient market solution.

For example, this overscheduling problem occurred in the RUC at the Malin and Nevada-Oregon Border (NOB) interties on August 19, 2020, and at those same interties in the HASP (which is conducted in the real-time market) on July 9, 2021. Demand for electricity was high on both of those summer dates, and on the latter, the issue was exacerbated because the scheduling limits on both interties had to be significantly derated due to the Bootleg fire in southern Oregon.

To prevent overscheduling from occurring in similar future conditions, the CAISO proposes to revise the tariff to make the scheduling parameter values for intertie transmission constraint relaxation sufficiently high in both the RUC and the real-time market so that, even when the power balance constraint and the intertie transmission constraint are relaxed at the same time, they will produce an LMP that reflects the scarcity of available intertie capacity. Specifically, the CAISO proposes to increase the existing scheduling parameter for the intertie transmission constraint relaxation in the RUC from its current value of $1,250/MWh to $3,200/MWh.[2] The CAISO also proposes to increase the existing scheduling parameter for intertie transmission constraint relaxation in the real-time market from its current value of $1,500/MWh to $2,900/MWh when the soft energy bid cap (which equals $1,000/MWh) is in effect, and from its current value of $3,000/MWh to $5,800/MWh when the hard energy bid cap (which equals $2,000/MWh) is in effect. Table A below reflects these current and proposed scheduling parameter values (also referred to as penalty prices).

Table A – Intertie Transmission Constraint Penalty Prices

Market Process	Existing Value under $1,000/MWh Bid Cap	Existing Value under $2,000/MWh Bid Cap	Proposed change under $1,000/MWh Bid Cap	Proposed change under $2,000/MWh Bid Cap
RTM	$1,500/MWh	$3,000/MWh	$2,900/MWh	$5,800 MWh
RUC	$1,250/MWh	$1,250/MWh	$3,200/MWh	$3,200/MWh

The CAISO also proposes to reorganize the relevant tariff provisions so they track the chronological order in which the market processes take place. No participant in the stakeholder process specifically opposed increasing the scheduling parameter values as proposed in this filing.

The CAISO determined the revised scheduling parameter values for intertie transmission constraint relaxation considering the interplay between the power balance constraint relaxation price, the highest import penalty price for the applicable market, and a sufficient margin of difference among penalty prices. The CAISO also performed counterfactual market simulations to validate the correctness of the proposed changes; the simulation showed that if the revised scheduling parameter values had been in place when the overscheduling at the Malin and NOB interties occurred in 2020 and 2021, no overscheduling would have occurred.

[2] *See infra,* section II.B of this transmittal letter where the CAISO explains that RUC Availability Bids are not subject to the bid cap and thus maintaining a consistent penalty price under both the soft and hard energy bid caps is appropriate.

The tariff revisions proposed in this filing will prevent overscheduling from occurring at the interties. Thus, they will enhance reliability and market efficiency, especially during tight supply conditions that are most likely to happen in the summer. The tariff revisions are also consistent with the expectation, stated in the Commission's order accepting the original scheduling parameter provisions, that the CAISO will continually evaluate the scheduling parameter values in the tariff.

II. Background and Need for the Filing

A. The CAISO Market

The CAISO market processes include both day-ahead and real-time wholesale electricity markets.[3] The day-ahead market includes the integrated forward market (IFM) and the residual unit commitment (RUC) process.[4] The real-time market (RTM) includes the hour-ahead scheduling process (HASP) and other market processes.[5]

The CAISO's market optimization software schedules and prices resources in two successive runs. First, the scheduling run produces resource schedules. This involves clearing bids, enforcing the priorities of self-schedules, and potentially relaxing constraints. Second, the pricing run follows the scheduling run and produces the locational marginal prices (LMPs) utilized in settlements.[6] The LMP at each pricing node in the market – including the pricing nodes at the interties that connect the CAISO balancing authority area with other balancing authority areas – equals the sum of a system marginal energy component (SMEC), a marginal loss component (MLC), and a marginal congestion component (MCC) of the LMP calculation.[7]

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[3] Existing tariff sections 27, 31, *et seq.*, and 34, *et seq.*; tariff appendix A, existing definition of "CAISO Markets Process." For the sake of clarity, this transmittal letter distinguishes between existing tariff provisions (*i.e.*, provisions in the current CAISO tariff) and revised tariff provisions (*i.e.*, existing tariff provisions that the CAISO proposes to revise in this filing).

[4] Existing tariff section 31.

[5] Existing tariff section 34. The other real-time market processes are the real-time unit commitment (RTUC), the short-term unit commitment (STUC), the fifteen minute market (FMM), and the real-time dispatch (RTD). *Id.*

[6] Existing tariff sections 31.3 and 34.4.

[7] These are the three components of the LMP for the day-ahead market. Existing tariff, appendix C, section A. For the real-time market, the LMP for each pricing node comprises these same three components plus a component that represents marginal greenhouse gas cost. For each pricing node within a WEIM entity balancing authority area it also includes a WEIM bid adder component. Existing tariff, appendix C, section B. For the sake of simplicity, the marginal greenhouse gas cost component is not included in the calculations provided in this filing, and the WEIM bid adder component is not applicable because this filing solely concerns pricing nodes in the CAISO balancing authority area.

Market participants can submit economic bids and self-schedules for energy and ancillary services in the CAISO market.[8] The CAISO's security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) optimization, referred to herein as the market software, utilizes configurable market scheduling and pricing parameters to reach a feasible solution and set appropriate prices for the market in instances where effective economic bids are insufficient for a feasible solution, and the market must modify submitted self-schedules.[9]

The market parameters used throughout the day-ahead and real-time markets include penalty prices that apply when constraints enforced by the CAISO market are relaxed (or violated). The penalty prices applicable to the issue in this filing center on the power balance and intertie constraints.[10] The various types of constraints have different price values that represent the cost at which the software will relax a constraint if it cannot reach a feasible solution while enforcing the constraint. When the CAISO relaxes a constraint, the CAISO's market software calculates the scheduling run LMPs based on administratively determined relaxation prices, *i.e.*, the penalty prices.[11] Using penalty prices sets the priority level of the power balance constraint relative to other priorities within the market optimization.

The CAISO market clears economic bids and self-schedules for imports at interties in the CAISO market (*i.e.*, the market software accepts such bids and schedules) based on a supply curve. If the LMP in the scheduling run is lower than an economic import bid, the bid will not clear. The same principle applies to import self-schedules at an intertie: to be cut, the LMP has to be lower than an applicable penalty price used for adjusting the self-schedule. Because penalty prices for import self-

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8 Existing tariff section 30, *et seq.*

9 Existing tariff section 27.4.3, *et seq.*; business practice manual for market operations (Market Operations BPM), section 6.6.5 (listing market parameter values that are calibrated based on values set forth in the tariff). The SCUC and SCED software constitutes the real-time dispatch the CAISO uses to determine which resources to dispatch and to calculate LMPs. Tariff appendix A, existing definition of "Real-Time Dispatch."

10 The system energy-balance constraint ensures that the physical law of conservation of energy (*i.e*., the sum of generation and imports equals the sum of demand, including exports and transmission losses) is accounted for in the market solution. The shadow price of the system energy-balance constraint establishes the SMEC, which as explained above is a component of the calculation used to determine LMPs. Tariff appendix C, existing sections B-C; Market Operations BPM, section 6.6.5.4. The shadow price is defined as the marginal value of relieving a particular constraint. Tariff appendix A, existing definition of "Shadow Price."

11 *See* existing tariff sections 27.4.3.2.2 – 27.4.3.2.2.4 and 27.4.3.3.2 – 27.4.3.3.4. The penalty prices are set forth in separate tables for the IFM, the RUC, and the real-time market, and reflect the hierarchical priority order in which the constraint associated with each penalty price may be relaxed in the IFM, RUC, or real-time market by the SCUC and SCED software. Market Operations BPM, section 6.6.5. Self-schedules for existing transmission contracts (ETCs), transmission ownership rights (TORs), and converted CAISO transmission service rights are not subject to adjustment pursuant to price relaxation. Existing tariff section 27.4.3.4.

schedules are negative, the LMP must be more negative than the import penalty prices for the bid not to clear.[12]

The tariff includes a two-tier structure for capping energy offers: (1) a soft energy bid cap set at $1,000/MWh for non-validated energy offers for non-import resources, and (2) a hard energy bid cap set at $2,000/MWh.[13] The tariff likewise includes two sets of market parameters – one set related to the soft energy bid cap and the other set related to the hard energy bid cap.[14] The market uses one of these respective sets of market parameters depending on whether the ISO is accepting bids greater than $1,000. A floor of negative $150/MWh applies to all energy bids in the CAISO market.[15]

B. Tariff Provisions the CAISO Proposes to Revise in this Tariff Amendment

The two sets of market parameters related to the soft energy bid cap and hard energy bid cap include scheduling parameters for transmission constraints relaxation.[16] Under those tariff provisions, whenever the market software identifies congestion on an internal or intertie transmission constraint, the software will either: (1) redispatch resources to relieve the congestion if the cost to redispatch is equal to or less than any of the specified scheduling parameter values of the applicable constraint; or (2) relax the transmission constraint if the cost to redispatch is greater than any of those scheduling parameter values. Specifically, regarding the soft energy bid cap, the existing tariff provisions state as follows (with underlining added to indicate the RUC and real-time market values relevant to this tariff amendment):

> In the IFM, the enforced internal and Intertie Transmission Constraint scheduling parameter is set to $5,000 per MWh for the purpose of determining when the SCUC and SCED software in the IFM will relax an enforced Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.12 to relieve Congestion on the constrained facility. <u>This scheduling parameter is set to $1,500 per MWh for the RTM</u>. The effect of this scheduling parameter value is that if the optimization can re-dispatch

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12 Attachment E to this filing provides illustrative examples of how economic import bids and self-schedules on the supply curve may clear or be cut at an intertie.

13 Existing tariff sections 30.7.12, *et seq.*, 30.11, *et seq.*, and 39.6.1.1.1-39.6.1.1.2; tariff appendix A, existing definitions of "Soft Energy Bid Cap" and "Hard Energy Bid Cap."

14 Existing tariff sections 27.4.3.2, *et seq.* (market parameters related to soft energy bid cap) and 27.4.3.3, *et seq.* (market parameters related to hard energy bid cap). The market parameters related to the soft energy bid cap apply unless conditions specified in the tariff trigger the hard energy bid cap. Existing tariff sections 27.4.3.2 and 27.4.3.3.

15 Existing tariff section 39.6.1.4.

16 Existing tariff sections 27.4.3.2.1 and 27.4.3.3.1.

> resources to relieve Congestion on a Transmission Constraint at a cost of $5,000 per MWh or less for the IFM (<u>or $1,500 per MWh or less for the RTM</u>), the Market Clearing software will utilize such re-dispatch, but if the cost exceeds $5,000 per MWh in the IFM (<u>or $1,500 per MWh for the RTM</u>) the market software will relax the Transmission Constraint. <u>The corresponding scheduling parameter in RUC is set to $1,250 per MWh</u>.[17]

The tariff provisions regarding the hard energy bid cap read exactly the same as those quoted above, except that the scheduling parameter values for the IFM and the real-time market are doubled (from $5,000/MWh to $10,000/MWh for the IFM and from $1,500/MWh to $3,000/MWh for the real-time market),[18] to reflect the fact that the hard energy bid cap is double the soft energy bid cap. The scheduling parameter value for the RUC is $1,250/MWh in both sets of tariff provisions (*i.e.*, it is not doubled as the scheduling parameter values for the IFM and real-time market are),[19] because RUC availability bids are not energy bids and thus are always limited to $250/MWh.[20] The listed scheduling parameter values are positive or negative based on whether they are applied to exports or imports, *e.g.*, when the soft energy bid cap is in place, the scheduling parameter value for exports in the real-time market is $5,000/MWh and for imports is negative $5,000/MWh.

The Commission has found it just and reasonable for the CAISO to adjust the scheduling parameter values quoted above as needed. The CAISO filed the original version of the above-quoted tariff provisions in 2008 as part of the implementation of the CAISO's new market design.[21] In that filing, the CAISO proposed a scheduling parameter value of $5,000/MWh for both the IFM and the real-time market and a scheduling parameter value of $1,250/MWh for the RUC.[22] The CAISO explained that it

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[17] Existing tariff section 27.4.3.2.1. These tariff provisions originally applied only to internal transmission constraints. In 2014, the Commission accepted a CAISO tariff amendment to apply the tariff provisions to both enforced internal and intertie transmission constraints. *See Cal. Indep. Sys. Operator Corp.*, 148 FERC ¶ 61,089, at P 65 (2014).

[18] Existing tariff section 27.4.3.3.1.

[19] *Id.*

[20] Existing tariff section 39.6.1.2.

[21] *I.e.*, the Market Redesign and Technology Upgrade (MRTU), which the CAISO implemented on February 1, 2009 and remains the CAISO market design today. At the time, the tariff did not include separate sets of market parameters for the soft energy bid cap and the hard energy bid cap, because the Commission order that prompted the CAISO to file tariff revisions to include those separate sets (Order No. 831) would not be issued until 2016. *See Cal. Indep. Sys. Operator Corp.*, 172 FERC ¶ 61,262 (2020) (accepting in relevant part CAISO filing of tariff revisions to comply with Order No. 831).

[22] *See* CAISO tariff amendment, Docket No. ER09-240-000, at attachment B (red-lined tariff section 27.4.3.1) (Nov. 4, 2008). These tariff provisions, as subsequently modified, were included in tariff section 27.4.3.1 until 2021, when the Commission accepted a CAISO tariff amendment that included a change in the section numbering of the provisions to section 27.4.3.2.1. *See Cal. Indep. Sys. Operator Corp.*, 175 FERC ¶ 61,076 at P 42 (2021).

established these scheduling parameter values to balance two competing objectives: (1) setting the values high enough to avoid overusing transmission constraint relaxation in the markets because a guiding principle of the market design is to produce feasible day-ahead schedules and real-time dispatch instructions, and (2) setting the values low enough to avoid extreme market outcomes that result from using a large volume of redispatch from ineffective resources to obtain a small amount of congestion relief on a geographically distant constraint.[23] The CAISO stated that after the new market design went into effect, it would continue to evaluate its market results and modify the scheduling parameter values as necessary.[24]

The Commission accepted the original version of the tariff provisions as filed.[25] However, the Commission also noted that it expected the CAISO to follow through on its commitment to monitor the effectiveness of the market parameters over time and work with stakeholders when changes may be warranted.[26]

The CAISO continued using those same scheduling parameter values until 2013, when it filed a tariff amendment to lower the scheduling parameter value for the RTM from $5,000/MWh to $1,500/MWh (*i.e.*, equal to the currently effective real-time market value related to the soft energy bid cap).[27] The purpose of the tariff amendment was to help mitigate extremely high costs to manage real-time congestion (congestion offset costs) that the CAISO market experienced in the summer and fall of 2012.[28] These transmission constraints, and associated higher costs, resulted from both specific events, such as the outage of the San Onofre Nuclear Station and the California wildfires, and a change in operational practices resulting from greater regional coordination.[29] The CAISO performed an analysis which showed using a $1,500/MWh value for the real-time market would provide similar amounts of congestion relief in the market model as the $5,000/MWh value and produce a significant reduction in real-time congestion offset costs. Further, when the CAISO lowered the real-time market value to

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[23] CAISO tariff amendment, Docket No. ER09-240-000, Exh. ISO-1 (Prepared Direct Testimony of Lorenzo Kristov), at 20-22 (Nov. 4, 2008).

[24] Transmittal letter for CAISO tariff amendment, Docket No. ER09-240-000, at 9.

[25] *Cal. Indep. Sys. Operator Corp.*, 126 FERC ¶ 61,147 at PP 13, 19-21, 43-45, 81-82 (2009).

[26] *Id.* at P 82.

[27] Transmittal letter for CAISO tariff amendment, Docket No. ER13-1060-000, at 1 (Mar. 8, 2013). The CAISO did not propose to revise the scheduling parameter values for the IFM or the RUC.

[28] *Id.* at 7-8.

[29] In response to the September 8, 2011 southwest power outage, the Western Electricity Coordinating Council and neighboring balancing authority areas identified additional contingency constraints that the CAISO must manage, but which derive from flows external to the CAISO balancing authority area. In some cases these flow conditions that are external to the CAISO balancing authority area were not easy to predict, or there was not information is available in the day-ahead market. These conditions created real-time constraints that increased real-time congestion costs.

$1,500/MWh, constraint relaxation would generally result in only minimally increased flows on a constrained transmission line in the market model.[30]

The Commission accepted the tariff amendment. After reiterating its 2008 finding that "the $5,000/MWh scheduling run transmission constraint relaxation parameter . . . was a flexible parameter and could be revised," the Commission found that lowering the scheduling parameter value to $1,500/MWh "is a just and reasonable measure for addressing real-time congestion uplift costs at this time."[31]

In 2016, the Commission issued Order No. 831 to require Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) to, among other things, increase their energy market bid caps from $1,000/MWh to $2,000/MWh. Order No. 831 also required suppliers to base energy bids above $1,000/MWh on verifiable actual or expected costs to be eligible to set market prices. As part of its compliance with Order No. 831, the CAISO revised penalty prices for intertie transmission constraints under a $2,000/MWh maximum energy price, as discussed above.[32] In developing these market enhancements, the CAISO recognized the need to utilize penalty prices in the market scheduling run for intertie transmission constraints that would apply when market conditions supported bids above the $1,000/MWh. The CAISO did not propose to double the existing $1,250/MWh scheduling parameter for RUC because RUC availability bids are not energy bids and are not subject to the energy bid cap. The maximum RUC availability bid price is $250/MW/h.[33]

In sum, the Commission has found it just and reasonable for the CAISO to revise the scheduling parameter values set forth in the aforementioned tariff provisions from time to time as needed. Indeed, the Commission expects the CAISO to evaluate those values to determine whether they should be revised.

C. Concerns that Resulted in This Tariff Amendment

The illustrative examples provided in attachment E to this filing show that when no constraints are relaxed at an intertie, no penalty prices are triggered. The examples in attachment E also show how the LMP applicable to economic bids and self-schedules for imports at an interties in the CAISO market will not result in overscheduling so long as the LMP is below, and therefore triggers, the relevant penalty price when necessary to reflect the scarcity of available intertie capacity.

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30 CAISO tariff amendment, Docket No. ER13-1060-000, Exh. ISO-1 (Direct Testimony of Mark Rothleder), at 45-64.

31 *Cal. Indep. Sys. Operator Corp.,* 143 FERC ¶ 61,110 at PP 22-27 (2013) (citing 126 FERC ¶ 61,147 at P 82).

32 *See* CAISO tariff amendment, Docket No. ER21-1192 (Feb 17, 2021); *see also* existing tariff section 27.4.3.3.1.

33 Existing tariff section 39.6.1.2.

However, as discussed below, the situation changes when the market software relaxes the system energy-balance constraint at the same time the software relaxes the intertie transmission constraint to reach a feasible market solution. When that happens, the resulting LMPs for imports at an intertie can be too high relative to penalty prices. The high LMPs can thus cause overscheduling on that intertie in both the RUC (*i.e.*, the day-ahead market) and the HASP (*i.e.*, the real-time market). The CAISO provides examples below to illustrate how this occurs. Such overscheduling is not merely hypothetical. It occurred in the RUC at the Malin intertie and the Nevada-Oregon Border (NOB) intertie on August 19, 2020, and at those same interties in the HASP on July 9, 2021.

As noted above,[34] the LMP at each pricing node equals the sum of a system marginal energy component (SMEC), a marginal loss component (MLC), and a marginal congestion component (MCC) – *i.e.*, LMP = SMEC + MLC + MCC. For the sake of simplicity, the MLC is considered to equal $0/MWh and is therefore omitted from the discussion below, which means only the SMEC and MCC are used to calculate the LMPs shown below.

1. Overscheduling in the RUC

The administratively determined penalty price associated with the power balance constraint for the scheduling run in the RUC is $1,600/MWh.[35] If the market software relaxes the power balance constraint, the SMEC will equal that penalty price value.[36] If the software cannot redispatch resources to relieve congestion on an intertie transmission constraint at a price at or below the scheduling parameter value of $1,250/MWh for the RUC, the software will relax the intertie transmission constraint based on a scheduling run penalty price value of negative $1,250/MWh for imports.[37] As a result, the MCC in the scheduling run will equal that penalty price value.[38] Therefore, if both the power balance constraint and the intertie transmission constraint are relaxed at the same time to reach a feasible market solution, the LMP for imports at the intertie will equal:

$1,600/MWh [SMEC] + -$1,250/MWh [MCC] = $350/MWh [LMP][39]

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34 *See supra* section II.A of this transmittal letter.

35 Market Operations BPM, section 6.6.5, at the second row of the "Residual Unit Commitment (RUC) Parameter Values" table. This does not result in the final market price.

36 Tariff appendix C, existing section C.

37 Existing tariff sections 27.4.3.2.1 and 27.4.3.3.1; Market Operations BPM, section 6.6.5, at the fourth row of the "Residual Unit Commitment (RUC) Parameter Values" table.

38 Tariff appendix C, existing section D.

39 The LMP is the same regardless of whether the soft energy bid cap or the hard energy bid cap is in place.

The resulting LMP of $350/MWh is higher than any bid price down to the floor of negative $150/MWh.[40] Thus, all economic import bids between $350/MWh and negative $150/MWh in the RUC will clear at the intertie. The LMP of $350/MWh is also higher than the highest penalty price applicable to any import in the RUC. That penalty price equals an IFM import price-taker self-schedule penalty price of negative $1,100/MWh plus a RUC adder for IFM cleared supply schedules of negative $250/MWh, which adds up to a penalty price of negative $1,350/MWh applicable to an import self-schedule in the RUC.[41] Therefore, relaxing both the system-energy balance constraint and the intertie transmission constraint at the same time means that the LMP at the intertie is not low enough to trigger that penalty price. Instead, the LMP allows economic import bids to clear at the intertie without reducing any import self-schedules. The end result is that imports on the intertie can be overscheduled in the RUC.

Overscheduling creates both reliability and market efficiency issues. The market software clears intertie schedules that exceed the intertie scheduling limit, which then requires CAISO operators to curtail those excess intertie schedules manually after the market clears. Overscheduling poses a significant reliability risk during tight supply condition. This is most likely to happen in summer when high demand and extreme weather often coalesce. Further, when overscheduling occurs, the market clearing process accounts for import supply that is not actually available, which results in inaccurate market signals and an inefficient market solution.

Simultaneous relaxation of the two constraints caused overscheduling to occur in the RUC at the Malin and NOB interties on August 19, 2020, when the CAISO experienced high electricity demand. By relaxing the intertie transmission constraint, the market software considered there to be more feasible imports than the transmission capacity available on the interties could actually accommodate. As a result, the day-ahead market overscheduled imports on the interties, which forced CAISO operators to take manual actions to curtail those intertie schedules.

Specifically, the overscheduling in the RUC occurred in HE 17 through 21 at the Malin intertie and in HE 17 through 21 at the NOB intertie. As shown in figures 1 and 2 below, the RUC process relaxed the power balance constraint and the intertie transmission constraint at the same time during some or all of each overscheduled hour listed above,[42] which caused the LMPs (depicted by the blue columns) to be too high to

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40 Existing tariff section 39.6.1.4. This bid floor applies to all energy bids in the CAISO market.

41 Market Operations BPM, section 6.6.5, at the ninth row from the bottom of the “Integrated Forward Market (IFM) Parameter Values” table, and at the sixth row from the bottom of the “Residual Unit Commitment (RUC) Parameter Values” table. The negative $1,350/MWh penalty price excludes ETCs and TORs.

42 The SMEC (depicted by the orange line) did not equal the $1,600/MWh penalty price value in each overscheduled hour because the system energy-balance constraint was not relaxed for the entirety

reach the negative $1,350/MWh penalty price applicable to an import self-schedule in the RUC and thereby to avoid overscheduling at the Malin and NOB interties.

Figure 1: RUC scheduling prices at Malin intertie on August 19, 2020

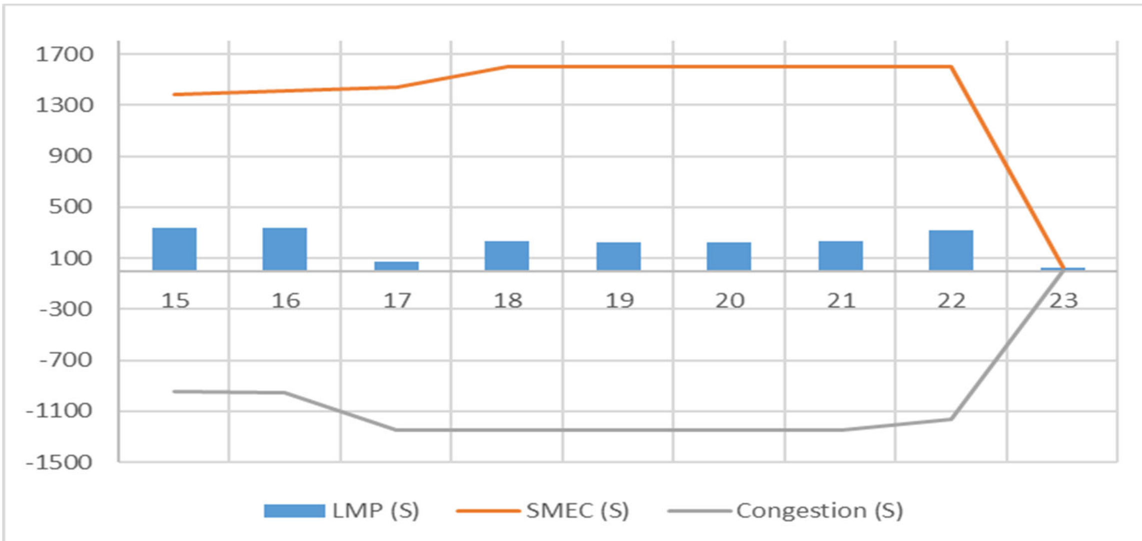
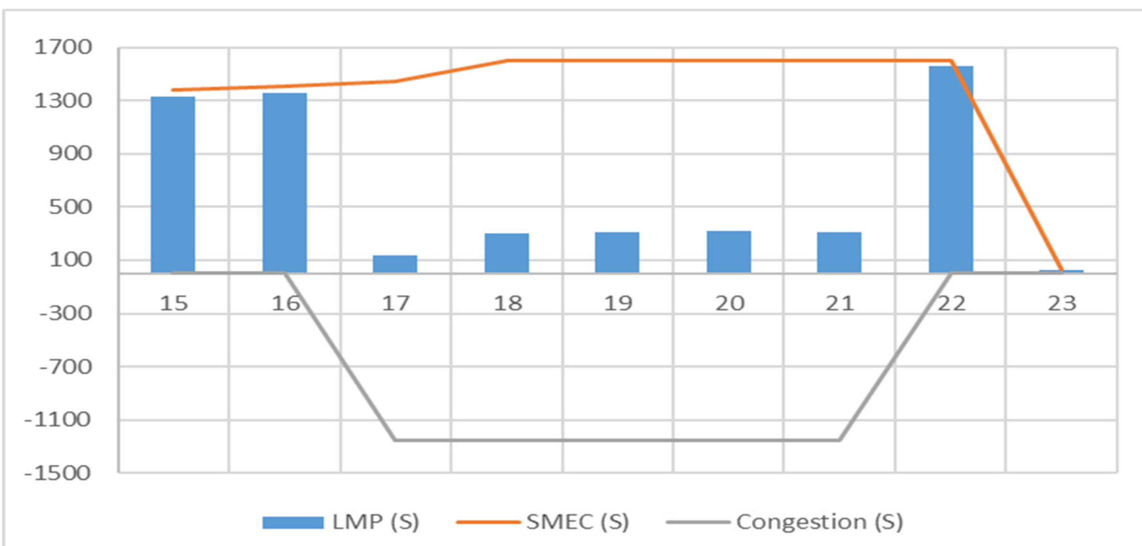


Figure 2: RUC scheduling prices at NOB intertie on August 19, 2020



If the scheduling parameter value (*i.e.*, the MCC depicted by the gray line) had been sufficiently lower than negative $1,250/MWh during those hours, the resulting LMPs

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of all the overscheduled hours, which meant the SMEC for an overscheduled hour could be high but average out to less than $1,600/MWh.

would have been low enough to reach the penalty price and thus avoid overscheduling during those hours.

2. Overscheduling in the HASP[43]

The administratively determined penalty price associated with the power balance constraint for the scheduling run in the HASP is $1,450/MWh.[44] If the market software relaxes the power balance constraint, the SMEC in the scheduling run will equal that penalty price value.[45] If the software cannot redispatch resources to relieve congestion on an intertie transmission constraint at a price at or below the scheduling parameter value of $1,500/MWh for the real-time market, the software will relax the intertie transmission constraint to a scheduling run penalty price value of negative $1,500/MWh for imports.[46] As a result, the MCC in the scheduling run will equal that penalty price value.[47] Therefore, if both the power balance constraint and the intertie transmission constraint are relaxed at the same time to reach a feasible market solution, the LMP for imports at the intertie will equal:

$1,450/MWh [SMEC] + -$1,500/MWh [MCC] = -$50/MWh [LMP][48]

The resulting LMP of negative $50/MWh is higher than any bid price down to the floor of negative $150/MWh that applies to all energy bids in the CAISO market.[49] Thus, all economic import bids between negative $150/MWh and negative $50/MWh in the HASP will clear at the intertie. The LMP of negative $50/MWh is also higher than both penalty prices applicable to an import self-schedule in the HASP – namely, (1) a penalty

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43 The example shown below is the same as the example shown on pages 14-15 of the Draft Final Proposal contained in attachment C to this filing. The example assumes the soft energy bid cap is in place rather than the hard energy bid cap. As explained in the footnotes below, however, the example is similar with the hard energy bid cap in place.

44 Market Operations BPM, section 6.6.5, at the first row of the "Real Time Market Parameters" table.

45 Tariff appendix C, existing section C. If the hard energy bid cap is in place, the SMEC penalty price value will equal $2,900/MWh (*i.e.*, double the $1,450/MWh value that applies with the soft energy bid cap in place). Market Operations BPM, section 6.6.5, at the first row of the "Real Time Market Parameters" table. These are not the final prices produced by the pricing run.

46 Existing tariff section 27.4.3.2.1; Market Operations BPM, section 6.6.5, at the second row of the "Real Time Market Parameters" table.

47 Tariff appendix C, existing section D. If the hard energy bid cap is in place, the MCC penalty price value will equal $3,000/MWh (*i.e.*, double the $1,500/MWh value that applies with the soft energy bid cap in place). Existing tariff, section 27.4.3.3.1; Market Operations BPM, section 6.6.5, at the second row of the "Real Time Market Parameters" table. These are not the final prices produced by the pricing run.

48 If the hard energy bid cap is in place, the LMP for imports at the intertie will equal: $2,900/MWh [SMEC] - $3,000/MWh [MCC] = -$100/MWh [LMP].

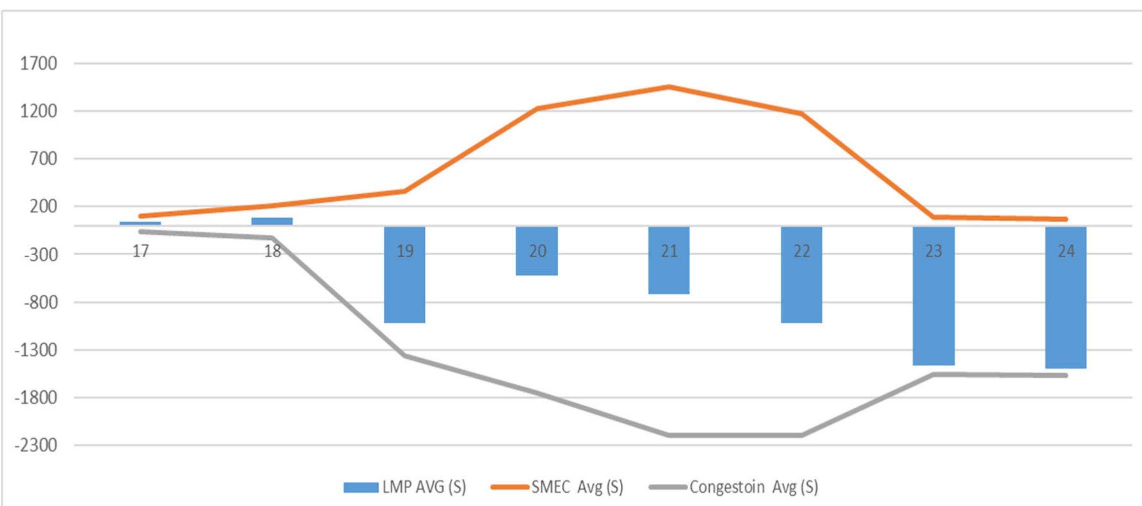
49 Existing tariff section 39.6.1.4.

price of negative $1,100/MWh for a real-time price-taker self-schedule without a RUC schedule, and (2) a penalty price of negative $1,200/MWh for a real-time price-taker self-schedule with a RUC schedule.[50] Therefore, relaxing both the system-energy balance constraint and the intertie transmission constraint at the same time means that the LMP at the intertie is not low enough to reach either of those penalty prices. Instead, the LMP allows import bids to clear at the intertie without reducing any self-schedules. Again, similar to the RUC example provided above, the end result is that the intertie can be overscheduled in the HASP, creating both reliability and market efficiency issues, especially in the summer months.

Simultaneous relaxation of the two constraints caused overscheduling to occur in the HASP at the Malin and NOB interties on July 9, 2021, when the CAISO experienced high electricity demand and the scheduling limits on both interties had to be significantly derated due to the Bootleg fire in southern Oregon. By relaxing the intertie transmission constraint, the market software considered there to be more feasible imports than the capacity available on the interties could actually accommodate. As a result, the real-time market overscheduled imports on the derated interties, which forced the CAISO operators to take manual actions to curtail those intertie schedules.

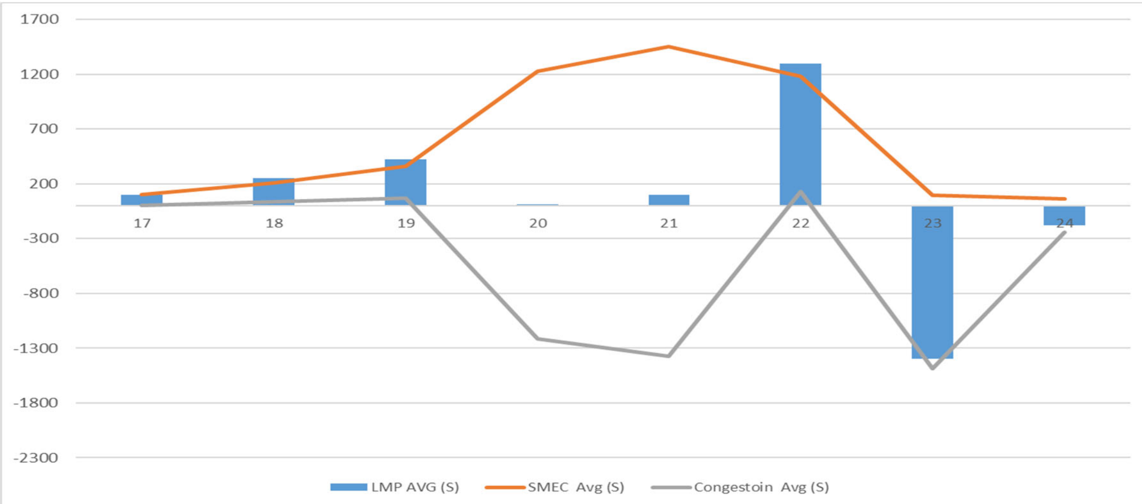
Specifically, the overscheduling in the HASP occurred in hours ending (HE) 19 through 22 at the Malin intertie and in HE 20 and 21 at the NOB intertie; the prices for these hours are depicted in figures 3 and 4 below:

Figure 3: HASP scheduling prices at Malin intertie on July 9, 2021



[50] Market Operations BPM, section 6.6.5, at the eighth and ninth rows from the bottom of the "Real Time Market Parameters" table.

Figure 4: HASP scheduling prices at NOB intertie on July 9, 2021



The power balance constraint and the intertie transmission constraint were both relaxed at the same time during some or all of each overscheduled hours listed above,[51] which caused the LMPs (depicted by the blue columns) to be too high to reach either the negative $1,000/MWh or the negative $2,000/MWh penalty price applicable to an import self-schedule in the HASP and thereby to avoid overscheduling at the Malin and NOB interties. If the scheduling parameter value (*i.e.*, the MCC depicted by the gray line) had been sufficiently lower than negative $1,500/MWh during those hours, the resulting LMPs would have been low enough to reach one or both of the penalty prices and thus avoid overscheduling during those hours.

D. Stakeholder Process for this Tariff Amendment and CAISO Response to Stakeholder Comments

As part of its review of summer 2021 operations, the CAISO published a paper reviewing market performance during the month of July 2021.[52] Among other issues, the report provided an overview of the operating conditions on July 9, 2021 discussed above and identified the need to re-assess the penalty prices for intertie transmission constraints. As part of ongoing discussion involving the resource sufficiency evaluation in the Western Energy Imbalance Market (WEIM), the CAISO presented an analysis

[51] The SMEC (depicted by the orange line) did not equal the $1,450/MWh penalty price value in each overscheduled hour because the system energy-balance constraint was not relaxed for the entirety of all the overscheduled hours, which meant the SMEC for an overscheduled hour could be high but average out to less than $1,450/MWh.

[52] Summer Market Performance Report July 2021 dated August 31, 2021: http://www.caiso.com/Documents/SummerMarketPerformanceReportforJuly2021.pdf.

regarding the July 9, 2021 conditions to its Market Surveillance Committee.[53] This analysis included the impact of the overscheduling on interties and the penalty prices and the consequences it had on intertie transactions.

In November 2021, the CAISO began a stakeholder initiative called "Adjustments to the Intertie Constraint Penalty Prices" to discuss the concerns raised by the aforementioned summer 2020 and 2021 events. The stakeholder process included publication of an Issue Paper/Straw Proposal and a Draft Final Proposal.[54] The CAISO also issued draft tariff revisions for stakeholder review, held two conference calls with stakeholders, and requested written stakeholder comments.[55]

During the stakeholder process, stakeholders requested the CAISO perform a scenario analysis with the proposed penalty prices for August 19, 2020 and July 9, 2021. In response to this request, the CAISO prepared an analysis to demonstrate how the tariff revisions proposed in this fling would have prevented over-scheduling at the CAISO interties on those trading days.[56]

In response to the Draft Final Proposal, one stakeholder expressed concern about the potential for unintended consequences that might result from the revising the scheduling parameters for intertie transmission constraint relaxation as proposed in this filing and suggested a holistic review of penalty pricing in the CAISO market. This concern ignores the extensive review the CAISO undertook to analyze the drivers for the overscheduling events and assess how the revised scheduling parameters will function in relation to other penalty prices in the market optimization. The CAISO's review identified no adverse impacts or unintended outcomes. The CAISO discussed with stakeholders how the relevant penalty prices interact with each other and described the overall synchronization of penalty prices to address the overscheduling issue that occurred on July 9, 2021 and August 19, 2020. In addition, as part of its ongoing operations, the CAISO monitors the overall market performance, including performance regarding market parameters, and it communicates with stakeholders on their performance. This can occur in the normal course of market assessment and stakeholder discussions as part of the CAISO's market performance and planning forum, or as part of more targeted analysis of certain market conditions such as the summer of 2021, as occurred here.

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[53] CASIO presentation to Market Surveillance Committee dated November 19, 2021: http://www.caiso.com/Documents/ResourceSufficiencyEvaluation-Presentation-Nov19-2021.pdf.

[54] The Draft Final Proposal is also provided in attachment C to this filing.

[55] Materials related to the stakeholder initiative are available on the CAISO website: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Adjustment-to-intertie-constraint-penalty-prices.

[56] *See* Draft Final Proposal at 22-31; CAISO stakeholder presentation on Adjustment to Inter-Tie Constraint Penalty Prices dated January 20, 2022, at slides 30-47: http://www.caiso.com/InitiativeDocuments/Presentation-Adjustment-IntertieConstraintPenaltyPrices-Jan20-2022.pdf.

The CAISO Board of Governors (Board) authorized, and the WEIM Governing Body advised on, the filing of this tariff amendment at their joint meeting on February 9, 2022.[57]

III. Proposed Tariff Revisions

As explained above,[58] overscheduling can occur, and has occurred, on the Malin and COB interties when the market software relaxes the power balance constraint and the intertie transmission constraint at the same time. This causes the scheduling run LMPs to be too high relative to the penalty price levels that prevent scheduling more imports than the interties' transmission capacity allows. As described below, to prevent overscheduling from occurring, the CAISO proposes to revise the tariff to make the scheduling parameter values for intertie transmission constraint relaxation sufficiently high in both the RUC and the real-time market so that, even when the power balance constraint and the intertie transmission constraint are relaxed at the same time, the markets will produce an LMP that reflects the scarcity of available intertie capacity. As noted above, the CAISO performed a series of analyses to determine the scheduling parameter values in the RUC and the real-time market that would be sufficiently high to produce LMPs that preserve expected scheduling priorities, *i.e.*, prevent overscheduling. The CAISO also proposes to reorganize the relevant tariff provisions so they track the chronological order in which the market processes take place.

These tariff revisions are just and reasonable. They will prevent overscheduling from occurring at the interties and will thus enhance reliability and market efficiency, especially during tight supply conditions that typically occur in the summer. As noted above,[59] the CAISO has performed counterfactual simulations showing that, if the tariff revisions had been in place when the overscheduling at the Malin and NOB interties occurred in the summers of 2020 and 2021, no overscheduling would have occurred. Thus, the tariff revisions will address the identified concerns at the interties. The tariff revisions are also consistent with the Commission's expectation that the CAISO will evaluate the scheduling parameter values in the tariff and adjust them if and when necessary.

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[57] Materials related to these actions are available on the California ISO's Board of Governors page at http://www.caiso.com/informed/Pages/BoardCommittees/Default.aspx. The materials include a memorandum from Anna McKenna, Vice President, Market Policy and Performance, to the Board and WEIM Governing Body dated February 2, 2022 (Memorandum). The Memorandum is also provided in attachment D to this filing.

[58] *See supra* section II.C of this transmittal letter.

[59] *See supra* section III.A of this transmittal letter.

A. Revisions to the Scheduling Parameters for Intertie Transmission Constraint Relaxation in the RUC

The CAISO proposes to increase the scheduling parameter for intertie transmission constraint relaxation in the RUC from its current value of $1,250/MWh to $3,200/MWh when the soft energy bid cap is in effect.[60] To determine that scheduling parameter value, the CAISO started by subtracting the power balance constraint relaxation price ($1,600/MWh),[61] from the highest penalty price applicable to any import in the RUC (negative $1,350/MWh).[62] That part of the calculation equals negative $2,950/MWh (*i.e.*, negative $1,350/MWh minus $1,600/MWh).

The CAISO performed sensitivity analyses to account for the interplay with other constraints and other components of the LMP, *e.g.*, the margin of difference needed to consider the marginal loss component (MLC) of the LMP calculation, because the losses at scheduling points can be either positive (for exports) or negative (for imports). These analyses showed that the largest MLC is in the range of plus or minus $150/MWh, and the CAISO determined it was appropriate to include an additional margin of negative $100/MWh for imports to account for the possibility of larger losses and to create sufficient separation in the priorities of the penalty prices. Therefore, the CAISO calculated a total margin of difference among penalty prices of negative $250/MWh (*i.e.*, negative $150/MWh plus negative $100/MWh) for imports.

The resulting scheduling parameter values for intertie transmission constraint relaxation equal negative $3,200/MWh (*i.e.*, negative $2,950/MWh plus negative $250/MWh) for imports and $3,200/MWh (*i.e.*, $2,950/MWh plus $250/MWh) for exports when the soft energy bid cap is in effect. These revised scheduling parameter values are just and reasonable because they are sufficiently high to prevent overscheduling from occurring when the market software relaxes both the power balance constraint and the intertie transmission constraint in the RUC. When both are relaxed, the resulting LMP for imports will be negative $1,600/MWh (*i.e.*, the power balance constraint relaxation price of $1,600/MWh plus the revised scheduling parameter value of negative $3,200/MWh), which is below the highest penalty price applicable to any import in the RUC (negative $1,350/MWh). Therefore, the resulting LMP will reach that penalty price level when necessary to reflect the scarcity of available intertie capacity.

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60 Revised tariff section 27.4.3.2.1. The CAISO does not propose to change the existing scheduling parameter value of $1,250/MWh for internal transmission constraint relaxation in the RUC that is set forth in the same tariff section.

61 Market Operations BPM, section 6.6.5, at the second row of the "Residual Unit Commitment (RUC) Parameter Values" table.

62 Market Operations BPM, section 6.6.5, at the ninth row from the bottom of the "Integrated Forward Market (IFM) Parameter Values" table, and at the sixth row from the bottom of the "Residual Unit Commitment (RUC) Parameter Values" table.

The CAISO also proposes to revise the scheduling parameter for intertie transmission constraint relaxation in the RUC from its current value of $1,250/MWh to $6,400/MWh when the hard energy bid cap is in effect.[63] This revised scheduling parameter value under the hard energy bid cap doubles the revised scheduling parameter value of $3,200/MWh under the soft energy bid cap. Currently, the scheduling parameter value for both internal and intertie transmission constraint relaxation in the RUC is $1,250/MWh, when either the soft energy bid cap or the hard energy bid cap is in effect.[64] In this filing, however, the CAISO proposes to distinguish between the scheduling parameter values for internal and intertie transmission constraint relaxation. Increasing the value for intertie transmission constraint relaxation to $6,400/MWh is consistent with that distinction.

In response to stakeholder requests, the CAISO simulated the impact at the Malin and NOB interties of having the tariff revisions in effect on August 19, 2020. This counterfactual market simulation indicated that, with the tariff revisions in effect, no overscheduling would have occurred in the RUC. The market simulation also showed that scheduling priorities would be maintained along with expected pricing outcomes.[65] Thus, the market simulation indicates that the tariff revisions will address the identified concerns at the interties.

B. Revisions to the Scheduling Parameters for Intertie Transmission Constraint Relaxation in the Real-Time Market

The CAISO proposes to increase the scheduling parameter for intertie transmission constraint relaxation in the real-time market (including the HASP) from its current value of $1,500/MWh to $2,900/MWh when the soft energy bid cap is in effect.[66] To determine that revised scheduling parameter value, the CAISO started by subtracting the highest import penalty price for the real-time market, which is the power balance constraint relaxation price ($1,450/MWh),[67] from the lowest penalty price applicable to an import self-schedule in the HASP (negative $1,200/MWh).[68] That part

[63] Revised tariff section 27.4.3.3.1. The CAISO does not propose to change the existing scheduling parameter value of $1,250/MWh for internal transmission constraint relaxation in the RUC that is set forth in the same tariff section.

[64] Existing tariff sections 27.4.3.2.1 and 27.4.3.3.1.

[65] Draft Final Proposal at 25-31.

[66] Revised tariff section 27.4.3.2.1. The CAISO does not propose to change the existing scheduling parameter value of $1,500/MWh for internal transmission constraint relaxation in the real-time market that is set forth in the same tariff section.

[67] Market Operations BPM, section 6.6.5, at the first row of the “Real Time Market Parameters” table.

[68] Market Operations BPM, section 6.6.5, at the ninth row from the bottom of the “Real Time Market Parameters” table.

of the calculation equals negative $2,650/MWh (*i.e.*, negative $1,200/MWh minus $1,450/MWh).

Again the CAISO performed sensitivity analyses to account for the interplay with other constraints and other components of the LMP, *e.g*., the margin of difference needed to consider the marginal loss component (MLC) of the LMP calculation because the losses at scheduling points can be either positive (for exports) or negative (for imports). These showed that the largest MLC is in the range of plus or minus $150/MWh, and the CAISO determined it was appropriate to include an additional margin of negative $100/MWh for imports to account for the possibility of larger losses and to create sufficient separation in the priorities of the penalty prices. Therefore, the CAISO calculated a total margin of difference among penalty prices of negative $250/MWh (*i.e.*, negative $150/MWh plus negative $100/MWh) for imports.

The resulting revised scheduling parameter values for intertie transmission constraint relaxation equal negative $2,900/MWh (*i.e.*, negative $2,650/MWh plus negative $250/MWh) for imports and $2,900/MWh (*i.e.*, $2,650/MWh plus $250/MWh) for exports when the soft energy bid cap is in effect. These revised scheduling parameter values are just and reasonable because they are sufficiently high to prevent overscheduling from occurring when the market software relaxes both the power balance constraint and the intertie transmission constraint in the real-time market. When both are relaxed, the resulting LMP for imports will be negative $1,450/MWh (*i.e.*, the power balance constraint relaxation price of $1,450/MWh plus the revised scheduling parameter value of negative $2,900/MWh), which is below the lowest penalty price applicable to an import self-schedule in the HASP (negative $1,200/MWh). Therefore, the resulting LMP will reach that penalty price level when necessary to reflect the scarcity of available intertie capacity.

The CAISO also proposes to revise the scheduling parameter for intertie transmission constraint relaxation for the real-time market from its current value of $3,000/MWh to $5,800/MWh when the hard energy bid cap is in effect.[69] The revised scheduling parameter value under the hard energy bid cap is just and reasonable because it doubles the revised scheduling parameter value under the soft energy bid cap (*i.e.*, $2,900), which matches the same ratio under the existing tariff.

In response to stakeholder requests, the CAISO simulated the impact at the Malin and NOB interties of having the tariff revisions in effect on July 9, 2021. This counterfactual market simulation indicated that, with the tariff revisions in effect, no overscheduling would have occurred in the real-time market. The market simulation also showed that scheduling priorities would be maintained along with expected pricing

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[69] Revised tariff section 27.4.3.3.1. The CAISO does not propose to change the existing scheduling parameter value of $3,000/MWh for internal transmission constraint relaxation in the real-time market that is set forth in the same tariff section.

outcomes.[70] Thus, the market simulation indicates that the tariff revisions will address the identified concerns at the interties.

C. Reorganization of the Tariff Provisions

The CAISO proposes to reorganize the tariff provisions regarding scheduling parameters for transmission constraint relaxation when the soft energy bid cap is in effect so that the order of the tariff provisions tracks the chronological order in which the CAISO market processes take place – *i.e.*, the revised tariff provisions list the day-ahead market (*i.e.*, IFM and RUC) provisions first, followed by the real-time market provisions.[71] The CAISO also proposes a corresponding reorganization of the tariff provisions regarding scheduling parameters for transmission constraint relaxation when the hard energy bid cap is in effect.[72]

IV. Effective Date and Request for Order

The CAISO is targeting an effective date for these tariff revisions of June 1, 2022, subject to the CAISO filing a notice with the Commission within 5 days of the actual effective date, and respectfully requests the Commission authorize the CAISO to issue a market notice of the actual effective date of the tariff revisions at least five calendar days before they are implemented.[73] To permit this effective date, the CAISO also requests that the Commission issue an order accepting the tariff revisions by May 15, 2022.

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[70] Draft Final Proposal at 22-24.

[71] Revised tariff section 27.4.3.2.1.

[72] Revised tariff section 27.4.3.3.1.

[73] The CAISO has included an effective date of 12/31/9998 as part of the tariff records submitted for the tariff revisions. The CAISO will file a notice with the Commission of the actual effective date of these tariff records within five business days after their implementation in an eTariff submittal using Type of Filing code 150 – Report. *See Cal. Indep. Sys. Operator Corp.*, 172 FERC ¶ 61,263, at Ordering Paragraphs (A) and (C) (2020) (authorizing a similar CAISO notification method).

V. Communications

Pursuant to Rule 203(b)(3) of the Commission's Rules of Practice and Procedure, the CAISO respectfully requests that all correspondence and other communications about this filing be served upon:

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VI. Service

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

VII. Contents of this filing

Besides this transmittal letter, this filing includes the following attachments:

Attachment A	Clean CAISO tariff sheets
Attachment B	Redlined CAISO tariff sheets
Attachment C	Draft Final Proposal
Attachment D	Board Memorandum
Attachment E	Illustrative examples of intertie scheduling

[74] 18 C.F.R. § 385.203(b)(3).

VIII. Conclusion

The CAISO respectfully requests that the Commission issue an order accepting the tariff revisions in this filing by May 15, 2022, effective as of a date the CAISO will specify in a market notice issued at least five calendar days before the actual implementation date.

Respectfully submitted,

/s/ Sarah Kozal

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Attachment A – Clean Tariff

Intertie Transmission Constraint Relaxation

California Independent System Operator Corporation

March 10, 2022

27.4.3.2.1 Scheduling Parameters for Transmission Constraint Relaxation

Scheduling parameters, or penalty prices, are used to determine when the SCUC and SCED software will relax an enforced Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.12 to relieve Congestion on the constrained facility. In the IFM, the enforced internal and Intertie Transmission Constraint scheduling parameter is set to $5,000 per MWh. The corresponding scheduling parameter in RUC is set to $1,250 per MWh for internal Transmission Constraints and $3,200 for Intertie Transmission Constraints. In the RTM, this scheduling parameter is set to $1,500 per MWh for internal Transmission Constraints and $2,900 MWh for Intertie Transmission Constraints. The effect of this scheduling parameter is that if the optimization can re-dispatch resources to relieve Congestion on a Transmission Constraint at or below the applicable price per MWh, the Market Clearing software will utilize such re-dispatch; but if the cost exceeds the applicable price per MWh, the market software will relax the Transmission Constraint.

* * * * *

27.4.3.3.1 Scheduling Parameters for Transmission Constraint Relaxation

Scheduling parameters or penalty prices, are used to determine when the SCUC and SCED software will relax an enforced Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.12 to relieve Congestion on the constrained facility. In the IFM, the enforced internal and Intertie Transmission Constraint scheduling parameter is set to $10,000 per MWh. The corresponding scheduling parameter in RUC is set to $1,250 for internal Transmission Constraints and $3,200 for Intertie Transmission Constraints. In the RTM, this scheduling parameter is set to $3,000 per MWh for internal Transmission Constraints and $5,800 for Intertie Transmission Constraints. The effect of this scheduling parameter is that if the optimization can re-dispatch resources to relieve Congestion on a Transmission Constraint at or below the applicable price per MWh, the Market Clearing software will utilize such re-dispatch; but if the cost exceeds the applicable price per MWh, the market software will relax the Transmission Constraint.

Attachment B – Marked Tariff

Intertie Transmission Constraint Relaxation

California Independent System Operator Corporation

March 10, 2022

27.4.3.2.1 Scheduling Parameters for Transmission Constraint Relaxation

~~In the IFM, the enforced internal and Intertie Transmission Constraint scheduling parameter is set to $5,000 per MWh for the purpose of determining~~ Scheduling parameters, or penalty prices, are used to determine when the SCUC and SCED software ~~in the IFM~~ will relax an enforced Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.12 to relieve Congestion on the constrained facility. In the IFM, the enforced internal and Intertie Transmission Constraint scheduling parameter is set to $5,000 per MWh. The corresponding scheduling parameter in RUC is set to $1,250 per MWh for internal Transmission Constraints and $3,200 for Intertie Transmission Constraints. In the RTM, ~~T~~this scheduling parameter is set to $1,500 per MWh for internal Transmission Constraints and $2,900 MWh for Intertie Transmission Constraints ~~for the RTM~~. The effect of this scheduling parameter ~~value~~ is that if the optimization can re-dispatch resources to relieve Congestion on a Transmission Constraint at or below the applicable price ~~a cost of $5,000~~ per MWh ~~or less for the IFM (or $1,500 per MWh or less for the RTM)~~, the Market Clearing software will utilize such re-dispatch;~~,~~ but if the cost exceeds ~~$5,000~~ the applicable price per MWh, ~~in the IFM (or $1,500 per MWh for the RTM)~~ the market software will relax the Transmission Constraint. ~~The corresponding scheduling parameter in RUC is set to $1,250 per MWh.~~

* * * * *

27.4.3.3.1 Scheduling Parameters for Transmission Constraint Relaxation

~~In the IFM, the enforced internal and Intertie Transmission Constraint scheduling parameter is set to $10,000 per MWh for the purpose of determining~~ Scheduling parameters or penalty prices, are used to determine when the SCUC and SCED software ~~in the IFM~~ will relax an enforced Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.12 to relieve Congestion on the constrained facility. In the IFM, the enforced internal and Intertie Transmission Constraint scheduling parameter is set to $10,000 per MWh. The corresponding scheduling parameter in RUC is set to $1,250 for internal Transmission Constraints and $3,200 for Intertie Transmission Constraints. In the RTM, ~~T~~this scheduling parameter is set to $3,000 per MWh for internal Transmission Constraints and $5,800 for Intertie Transmission Constraints. ~~for the RTM.~~ The effect of this scheduling parameter ~~value~~ is that if the optimization can re-dispatch resources to relieve Congestion on a Transmission Constraint at or below the applicable price~~a cost of $10,000~~ per MWh ~~or less for the IFM (or $3,000 per MWh or less for the RTM)~~, the Market Clearing software will utilize such re-dispatch;~~,~~ but if the cost exceeds the applicable price ~~$10,000~~ per MWh, ~~in the IFM (or $3,000 per MWh for the RTM)~~ the market software will relax the Transmission Constraint. ~~The corresponding scheduling parameter in RUC is set to $1,250 per MWh.~~

Attachment C – Draft Final Proposal

Intertie Transmission Constraint Relaxation

California Independent System Operator Corporation

March 10, 2022

Adjustment to Inter-Tie Constraint Penalty Prices

January 13, 2022

Draft Final Proposal

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Acronyms

BAA	Balancing Authority Area
CAISO	California Independent System Operator
ETC	Existing Transmission Contract
FMM	Fifteen-Minute Market
HASP	Hour Ahead Scheduling Process
HE	Hour Ending
IFM	Integrated Forward Market
ISL	Inter-Tie Scheduling Limit
ITC	Inter-Tie Constraint
LMP	Locational Marginal Price
LPT	Low priority Price Taker self-schedule
MCC	Marginal Congestion Component
MLC	Marginal Loss Component
NOB	Nevada/Oregon Border
PBC	Power Balance Constraint
PT	Price Taker self-schedule
RUC	Residual Unit Commitment
SCUC	Security Constrained Unit Commitment
SMEC	System Marginal Energy Component
TOR	Transmission Operating Rights

Introduction

The California ISO regularly reports on the performance of its markets to provide timely and relevant information. Recent monthly reports have focused on the CAISO's market performance and system conditions during the 2021 summer months, when system conditions in the CAISO and across the Western Interconnection were more constrained than other times of the year.

Through that effort, the CAISO identified instances where market schedules exceeded the de-rated limit of the MALIN500_ISL (Malin) and Nevada/Oregon Border (NOB_ITC "NOB") intertie in the real-time market. The overscheduling resulted because the intertie was largely de-rated due to transmission outages caused by the Bootleg fire, and because of the interplay of the scheduling priorities the CAISO uses in its market optimization. In real-time, the CAISO operators manually curtailed import schedules to comply with intertie limits. The CAISO also identified overscheduling on interties in the Residual Unit Commitment (RUC). The overscheduling of interties results in an overestimation of capacity actually available to the real-time market. To resolve this inconsistency between market results and actual conditions, the CAISO must manually curtail schedules to ensure flows are within operating limits.

The CAISO introduced the market issues paper and Straw proposal in November 11. With no concerns about the proposed changes, the CAISO is moving forward with the final proposal after addressing requests for additional market results.

This final proposal identifies the reasons why market overscheduling occurred, and proposes changes to specific penalty price parameters to ensure the market is able to resolve similar situations in the future consistent with observed conditions on the grid. The current hour ahead scheduling process (HASP) Inter-Tie Constraint (ITC) or Inter-Tie Scheduling Limit (ISL) relaxation parameter, which determines when the market optimization allows schedules to exceed stated limits, is $1,500/MWh. In this paper, the CAISO proposes to update this price to $2,900/MWh. The current RUC ITC/ISL relaxation penalty price is $1,250/MWh. In this paper, the CAISO proposes to similarly update this price to $3,200/MWh.

Changes to the Draft Final Proposal

Changes	Details
New sections adding simulated results	• Added metrics and description for simulated results with proposed penalty price change for July 9, 2021 HASP • Added metrics and description for simulated results with proposed penalty price change for August, 19, 2020 RUC

Stakeholder Comments

Stakeholders-submitted comments reflect stakeholder support for the HASP and RUC Inter-Tie Constraint (ITC) or Inter-Tie Scheduling Limit (ISL) relaxation parameter adjustments. Two stakeholders submitted comments.

Southern California Edison (SCE) requested additional data for the July 9, 2021 HASP and August 19, 2020 RUC in regards to the market results with the proposed penalty price changes. The CAISO has added the simulated results section to address this request.

Pacific Gas & Electric (PG&E) submitted a question about whether the penalty price adjustments would apply to other markets, including the Fifteen-Minute Market (FMM). The proposed penalty price adjustments will apply in each of the real time market processes. PG&E also submitted comments asking if there would be a market simulation for this initiative to assess the market outcomes under the proposed parameter changes. In response, the CAISO notes that this change is internal to the market applications and does not require any participant inputs. Therefore, a simulation for this change will not provide any additional insights to participants of how the market outcome is impacted by the proposed changes. In lieu of a market simulation, the CAISO is providing simulated results data for July 9, 2021 HASP and August 19, 2020 RUC to demonstrate how the adjusted penalty prices would function in the optimization. These simulated results are based on the actual production solution and reflect how the proposed changes will impact the market solution.

Background

There are four optimization elements that are foundational to the market clearing process and critical to understanding both the overscheduling issues and the analysis that informs the CAISO's proposal:

- **Market constraint relaxation parameter hierarchy:** As stated in the CAISO Business Practice Manual for Market Operations (referred to herein as "the BPM") Section 6.6.5:"Known in the jargon of mathematical optimization as 'penalty factors,' which are associated with constraints on the optimization and which govern the conditions under which constraints may be relaxed and the setting of market prices when any constraints are relaxed. Importantly, the magnitude of the penalty factor values in the tables for each market reflect the hierarchical priority order in which the associated constraint may be relaxed in that market by the market software."[1]

- **Locational Marginal Prices (LMP):** As stated in the CAISO Business Practice Manual for Market Operations Section 3.1, "The LMP is the marginal cost (expressed in $/MWh) of serving the next increment of demand at that PNode." The LMP consists of three main parts including System Marginal Energy Component (SMEC), Marginal Loss component (MLC), and Marginal Congestion Component (MCC).

- **Power Balance Constraint (PBC) relaxation:** The PBC ensures that the sum of the demand and transmission losses is equal to the supply. In order to assess the need to relax the PBC, its penalty price is included in the objective function of the optimization problem. The use of penalty prices sets the priority level of the PBC relative to other priorities within the optimization.[2] The penalty price, as stated in the BPM, for real-time and HASP is $1,450 and in RUC is $1,600.

- **Inter-Tie Constraint (ITC) or Inter-Tie Scheduling Limit (ISL) relaxation:** An ITC is a scheduling constraint that is modeled in the market. An ISL is a group comprised of multiple ITCs. ITC's have a bi-directional limits for cleared intertie or system resource bids. An ITC constraint ensures intertie schedules, considering the net direction of the import schedules and export schedules, do not violate either the physical limit for import or exports. The directional limits help ensure the accuracy of the power balance equation and scheduling within the CAISO, since the PBC includes net intertie schedules.[3] The penalty price, as stated in the BPM, for real-time and HASP is $1,500 and in RUC is $1,250.

HASP ITC and Under-generation Conditions

Issue description

On July 9, 2021[4] operating and market conditions dictated the simultaneous relaxation of both the PBC and the ITC constraints. These relaxations were driven by two key factors:

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[1] CAISO Business Practice Manual for Market Operations, Section 6.6.5.
[2] Id. at section 6.6.5.4.
[3] Id at Section 6.6.2.5.
[4] For more information on timelines and de-rates that occurred on July 9th, please see page 97 of the CAISO's Summer Market Performance Report for July 2021, http://www.caiso.com/Documents/SummerMarketPerformanceReportforJuly2021.pdf.

- High demand with an hourly average load of 42,924 MW.

- 3 out of 4 lines north of Malin on the Northwest AC intertie (NWACI) relayed due to the impact of the Bootleg fire, resulting in California Oregon Intertie (COI) de-rates from 2,967 MW to 1,800 MWs at Hour Ending (HE) 14 and later starting in HE 17 to 285 MWs. Pacific DC Intertie PDCI de-rates at the Nevada Oregon Border (NOB) started in HE 17 from 1,622 MWs to 785 MW.

Because of limitations of net imports into the CAISO balancing authority area, the high loads, and tight supply conditions, the CAISO market result relaxed ITC on the CAISO PACI_ITC constraint in HASP for HE 19. Figure 1 and Figure 2 below show the market schedules across the different markets at the Malin and NOB intertie scheduling points, respectively, compared to the ITC limits on July 9. The figures show the net intertie schedules for each market process, *i.e.* the day-ahead residual unit commitment (RUC), the hour-ahead scheduling process, the fifteen-minute market, and real-time dispatch compared to the import limit the market optimization used for each market process. The bar above the limit indicates the time periods where the CAISO market optimization relaxed the ITC. This resulted in the market overscheduling of the de-rated ITC limit.

Figure 1: July 9 2021 Malin schedules by market in comparison to the limit

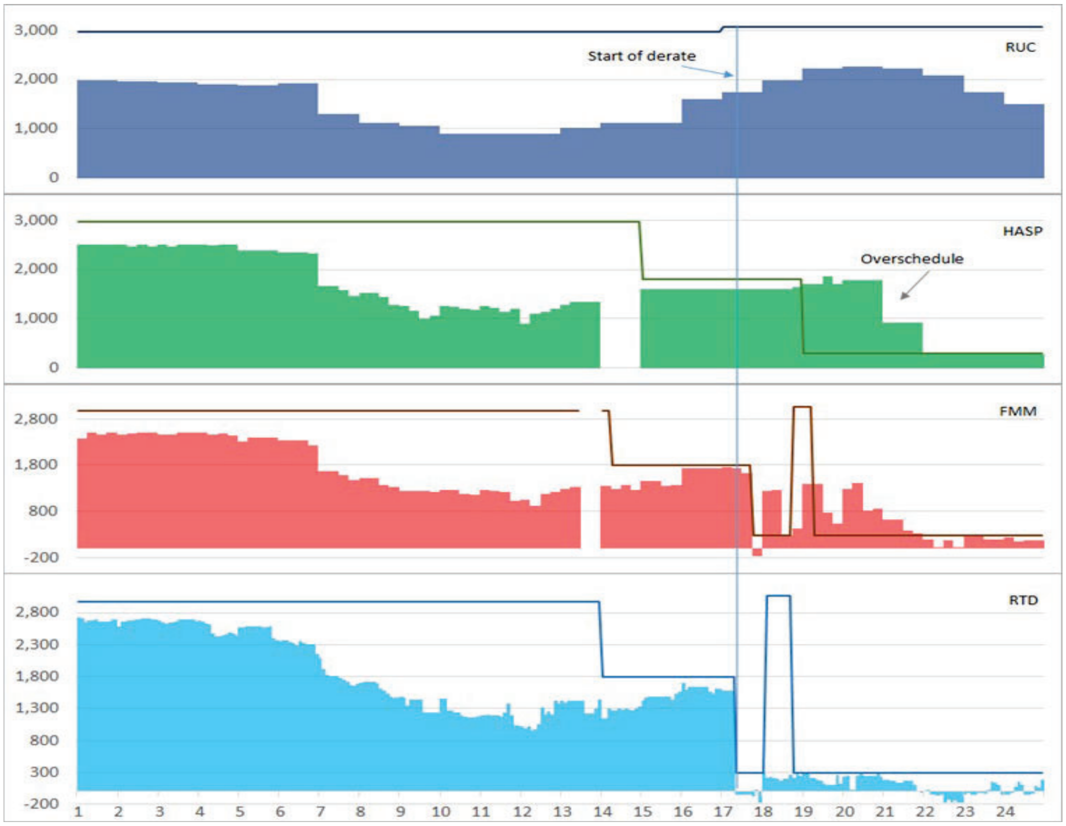
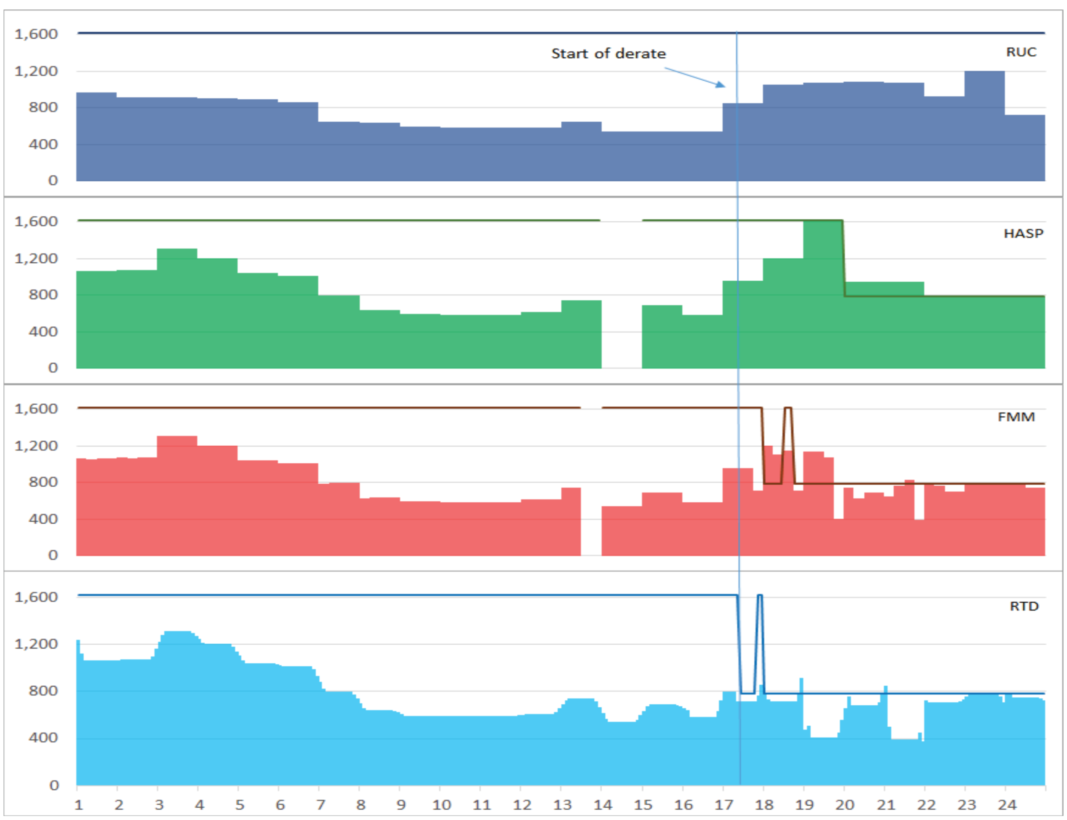


Figure 2: July 9th 2021 NOB schedules by market in comparison to the limit



To understand how the relaxation parameters worked together on July 9 there are several market design elements to consider. First, the bid floor and bid cap at -$150/MWh and $1,000/MWh, respectively, an import or export resource could bid into the market at any price point on that range. Alternatively, they could also self-schedule. The penalty prices for self-schedules for imports in HASP, as well as the other penalty price constraints relevant to this scenario, are listed below in Table 1.

Table 1: Applicable HASP Penalty Prices

Penalty Price Description	**Scheduling Run Value Based on $1000 Cap**	**Pricing Run Value Based on $1000 Cap**	**Scheduling Run Value Based on $2000 Cap**	**Pricing Run Value Based on $2000 Cap**	**Comment**
Real-time price-taker self-schedule import with RUC schedule and import leg of high priority wheel through self-schedule with RUC schedule	-1200	-150	-2400	-150	For hourly bids in HASP and fifteen- minute bids in FMM, a RUC scheduled import self-schedule Has a higher priority than over-generation energy slack
Real-time price-taker self-schedule import without RUC schedule and import leg of high priority wheel through self-schedule without RUC schedule	-1100	-150	-2200	-150	For hourly bids in HASP and fifteen-minute bid in FMM, a real time submitted self-schedule with no RUC schedule has a higher priority than over-generation energy slack
Energy balance/Load curtailment, RUC cleared self-scheduled export using identified non-RA capacity. RUC cleared export leg of a wheel through self-schedule. Real-time export leg of a wheel through self-schedule. Real-time market self-scheduled export using identified non-RA capacity.	1450	1000	2900	2000	Scheduling run penalty price is set high to achieve high priority in serving forecast load and exports that utilize non-RA capacity. Energy bid cap as pricing run parameter reflects energy supply shortage.
Transmission constraints: Intertie scheduling	1500	1000	3000	2000	The highest among all constraints in scheduling run, penalty price reflects its priority over load serving. Energy bid cap as pricing run parameter reflects energy supply shortage.

Imports are cleared based upon a supply curve. If the price goes below the bid in offer, the bid will not clear. This same principle applies to import self-schedules at a scheduling point: to be cut, the price at the scheduling point has to be more negative than the penalty price parameter used for adjusting the self-schedule.

On July 9, the reduction on the Malin and NOB scheduling limit occurred in the import direction. With the de-rate limit imposed, the market needed to reduce imports on these interties in the HASP to recognize the new limit. The order that this would be done in the optimization is as follows: First, the CAISO market clears economic imports and schedules in decreasing merit order (from most expensive to least) against the amount of import capacity. Should the market exhaust the bid stack, the next step is to reduce self-schedules. The market will first reduce real-time import self-schedules, followed by self-schedules that cleared RUC and have submitted self-schedules in real-time up to the RUC cleared level. In addition to these priorities, the formulation of the price at the scheduling point during each level of relaxation has to be considered to understand the impact on the market outcome.

The following series of examples highlight these issues, using the components of the Locational Marginal Price (LMP), including System Marginal Energy Component (SMEC), Marginal Loss component (MLC), and Marginal Congestion Component (MCC) through a series of decreasing import limits. For simplification, assume the loss component is $0/MWh. Assume the SMEC is $25/MWh. Four import resources bid at the tie location, each with 10 MW offers. There are two import economic bids, Bid A at $24/MWh and Bid B at -$10/MWh. Along with the two economic bids, there are two self-schedules: Bid C is a real-time self-schedule and Bid D is a self-schedule that cleared RUC.

- **Example 1:** This example demonstrate full availability at the scheduling point. Assuming a 50MW transfer limit on the scheduling point and SMEC being higher than all import bid offers. Assume the total imports bids at that scheduling point totals 40MW. Since all intertie bids are infra-marginal, all bid offers would be accepted and the total amount of schedules at the tie point would be 40 MW, which is lower than the ITC limit. Consequently, the ITC is not congested (is not binding).

- **Example 2:** This example shows a de-rated import limit. As a result, not all the economic bids are accepted due to reduced available transfer capability. It illustrates the impact of congestion on the priority of cleared economic bids, the determination of a shadow price, and the formulation of the LMP.

  Consider two scenarios with different import limits: 35 MW and 25 MW. For the larger transfer limit (35 MW) the marginal resource that clears at the limit is Bid A at 5 MW and the rest of the bids accepted at full capacity for a total schedule at the limits of 35 MWs. At the intertie location with Bid A is the marginal bid at a price of $24/MWh, this would result in a shadow price on the ITC of -$1/MWh. The MCC for the resource would also be -$1/MWh resulting in a LMP at the tie point of $24/MWh.

  If the intertie was de-rated further to 25 MW: Bid A would not clear, Bid B would clear at 5 MW, and the two self-schedules are cleared at full capacity of 10 MW each for a total schedule of 25 MW. Because Bid B is the marginal bid, the shadow price would be -$35/MWh resulting in a MCC at the point of -$35/MWh for a price of -$10/MWh.

- **Example 3:** The third example further reduces the scheduling limit of the intertie beyond economic bids to highlight how the cuts on the tie must be performed via scheduling priority, with cuts applied first to the lowest priority of self-schedules. The lowest priority of import self-schedule is the real-time self-schedules that did not clear in RUC, represented in these examples by Bid C. The penalty price for this type of self-schedule is -$1,100, as stated in Table 1. If the limit is now reduced to 15 MW, Bids A and B would not clear. Bid C would clear at 5 MW and Bid D would clear at full capacity of 10 MW, for a total schedule cleared of 15 MW. The partial quantity for Bid C clearing is due to its lower scheduling priority. In this example the shadow price at the ITC would be -$1,125/MWh and the MCC at that tie point would be -$1,125/MWh. With the SMEC of $25/MWh this results in a LMP at the intertie point of -$1,100/MWh.

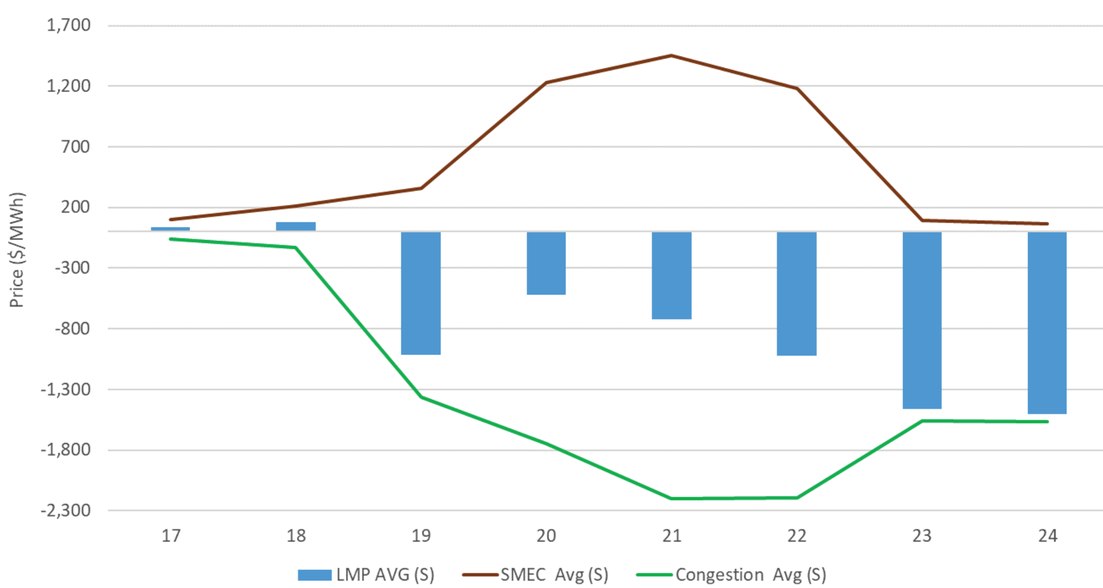
- **Example 4:** The fourth example highlights economic cuts that occur to a higher priority schedule scheduling on the intertie; specifically self-schedules that have cleared RUC. The penalty price for this type of self-schedule is -$1,200 MWh. For this example the import limit is now 5 MW. At this limit, Bid A, B, and C would not clear. Bid D would be the highest priority cleared at 5 MW for a total schedule cleared of 5 MW. The shadow price at the ITC would be -$1,225/MWh and the MCC at that tie point would be -$1,225/MWh. With the SMEC of $25/MWh this results in a LMP at the tie point of -$1,200/MWh.

These example demonstrate how self-schedule cuts work through the use of the LMPS and each component. This also demonstrates how when the PBC constraint and an ITC are at the level of price relaxation that overloads can occur on the ITC. In the examples above the SMEC was clearing at a price of $25/MWh. If the PBC was relaxed in the CAISO, this results in a SMEC of $1,450. The ITC penalty price is relaxed at -$1,500 penalty price. When these two constraints (ITC and PBC) bind, the price being set at that intertie scheduling point would be the SMEC plus the MCC, not considering loss, only the ITC congestion, the price at that location would be -$50/MW. As a result of both constraints being relaxed the net prices is not low enough to make the necessary cuts. This price will allow import bids to clear and will not reduce any self-schedules. This interaction is the result of the cleared price at the location being higher than any bid from -$50/MWh to the minimum bid price of -$150 MWh. All self-schedule would also clear because the penalty price is lower than the -$50/MWhs. This last example illustrates why the ITC is relaxed when the PBC binds when import limit cuts occur and also demonstrates the need for an updated ITC penalty price.

While these examples are illustrative, the overscheduling of the Malin and NOB intertie scheduling points that occurred on July 9 has additional complexities. Because the ITC penalty price was not high enough, there was still overscheduling. Figure 3 shows the scheduling run prices in the HASP hours of July 9 at the Malin scheduling point. The LMPs for this time frame were well below the -$50/MWh price. This was due to the fact that the SMEC did not reach PBC relaxation penalty for all the four of the intervals of HASP along with other system conditions that occurred.

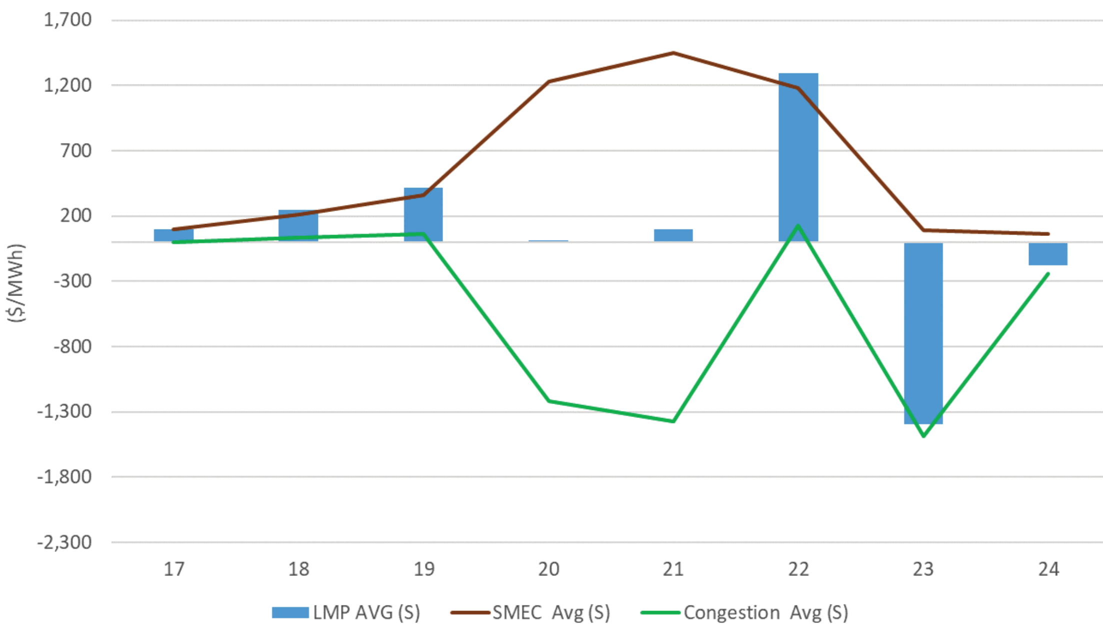
Similarly, the prices in hour ending HE 19 to HE 22 were well above the self-schedule penalty price of -$1,100 identified in Table 1. This was also due to the fact that SMEC did not reach PBC relaxation penalty price for all intervals of the hour. Further, in HE 23 and 24 prices decreased to approximately -$1,200/MWh, when the DA self-schedules are marginal. This is due to a combination of two factors: first, the SMEC decreases to a range of $100/MWh to $200/MWh. This indicates that the ITC and PBC constraints are no longer in conflict and binding at the same time. Second, there was additional congestion from relatively close transmission constraint for this time and contributed to the higher congestion component that is reflected in the LMP.

Figure 3: HASP scheduling prices at Malin on July 9, 2021



The NOB_ITC overloads occurred in HE 20 and 21 as indicated in Figure 4. For these two hours, the ITC and PBC relaxation penalties are closer to the -$50 /MWh. With the average LMP, which for these hours were $10.85/MWh and $98.38/MWh. This was due to an average SMEC being closer to PBC relaxation penalty price and the congestion component only being influenced by the ITC relaxation penalty price.

Figure 4: HASP scheduling prices at NOB on July 9, 2021



Proposed solution

In the BPM Section 6.6.5 and Tariff Section 27.4.3.2.1 the penalty price for the ITC in the real-time market is $1,500/MWh.

The CAISO proposes to increase the ITC penalty price from $1,500/MWh to $2,900/MWh for $1,000 bid cap and $5,800 for $2,000 bid cap (Tariff Section 27.4.3.3.1) so that under any conditions, the market does not overschedule interties. At this penalty price, the market will respect both the intertie scheduling limits and the PBC relaxation.

The methodology to set the price must consider other constraints binding in order to produce a price reflective of the necessary priorities. In this case, if there is a reduction in ITC limits and a PBC violation, the resultant penalty price must be lower than the highest priority self-schedule. When PBC is being relaxed and import limits have been reduced to the level of cutting import RUC cleared IFM schedules that penalty price in real-time needs to be less than -$1,200.

The new penalty price is determined as follows. Under the current self-schedule penalty price structure for imports and exports, the minimum penalty price on the import side would need to be the lowest ITC penalty price minus the highest import penalty price, excluding ETC or TORs. That would lead the minimum penalty price to be (-$1,200-$1,450 = -$2,650). Following sensitivity analysis performed by the CAISO we recommend there be a margin of difference among the penalty prices to account for interplay with other constraints and other components of the LMP. For instance, the CAISO needs to consider the loss component because the losses at scheduling points can vary in either direction. The testing showed the largest losses are in the range of plus or minus $150, so this is used a starting point. An additional $100 is added to provide additional margin for the possibility of larger losses and to create separation in the priorities. The CAISO determined that the proposed penalty price to addresses this interplay is at least $2,900/MWh for the export and -$2,900/MWh for the import direction.

As part of any penalty price change, the CAISO must coordinate such a change relative to other penalty prices in order to preserve the relative scheduling priority in the market optimization. Consequently, as part of this proposal for adjusting the ITC penalty price, there are other adjustments proposed, as listed in Table 2.

Table 2: Additional HASP Penalty Price for priority adjustment

Penalty Price Description	**Scheduling Run Value Based on $1000 Cap**	**Pricing Run Value Based on $1000 Cap**	**Scheduling Run Value Based on $2000 Cap**	**Pricing Run Value Based on $2000 Cap**	**Comment**
Exceptional Dispatch for Tie Generators	1600	1000	3200	2000	Priority to exceptional dispatches made by operators for Tie generators
EIM Base scheduled exports	1550	1000	3100	2000	EIM base scheduling priority for export when tagged schedules do not exist
Tagged Quantity for exports	1550	1000	3100	2000	After clearing in the real time market, Inter-tie tagged priority for exports. Higher priority than load in real time.
EIM Base scheduled imports	-1250	-150	-2500	-150	EIM base scheduling priority for import when tagged schedules do not exist
Tagged Quantity for imports	-1250	-150	-2500	-150	After clearing in the real time market, Inter-tie tagged priority for imports. Higher priority than over-generation energy slack
EIM Transfer Constraint	1500	1000	3000	2000	Penalty price and pricing parameter consistent with the transmission constraint;

These penalty prices are used to clear base schedules and tagged quantities in the energy imbalance market (EIM), exceptional dispatches on tie generators, and for internal CAISO tagged transactions that have already cleared the HASP or FMM markets. These scheduling priorities need to remain above the ITC relaxation penalty price in subsequent market runs because these become tagged (fixed) values that should not be cut in the markets. This is the responsibility of each Balancing Authority Area (BAA) to maintain through its scheduling process. Table 3 has the proposed adjustments to the additional penalty prices.

Table 3: Proposed additional HASP Penalty Price for priority adjustment

Penalty Price Description	Scheduling Run Value Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
Exceptional Dispatch for Tie Generators	3200	1000	6400	2000	Priority to exceptional dispatches made by operators for Tie generators
EIM Base scheduled exports	3100	1000	6200	2000	EIM base scheduling priority for export when tagged schedules do not exist
Tagged Quantity for exports	3100	1000	6200	2000	After clearing in the real time market, Inter-tie tagged priority for exports. Higher priority than load in real time.
EIM Base scheduled imports	-3100	-150	-6200	-150	EIM base scheduling priority for import when tagged schedules do not exist
Tagged Quantity for imports	-3100	-150	-6200	-150	After clearing in the real time market, Inter-tie tagged priority for imports. Higher priority than over-generation energy slack
EIM Transfer Constraint	2900	1000	5800	2000	Penalty price and pricing parameter consistent with the transmission constraint;

RUC ITC and Under-generation Conditions

Issue description

The RUC scheduling priority penalty price for ITC and PBC is very similar to the HASP, but is slightly different in scale due to the size of the scheduling run PBC. An example of the over-scheduling of the ITC in RUC occurred on August 19, 2020. The MALIN500_ISL was overscheduled in RUC by approximately 530 MW in HE 17 through 21. The NOB_ITC was overscheduled on this day by approximately 195 MW in HE 17 through 21.

In RUC the PBC relaxation penalty price is set to $1600 and the ITC penalty price is -$1250 for import, as described in Table 4.

Table 4: Applicable RUC Penalty Prices

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
Market energy balance - under procurement. IFM cleared self-scheduled exports using identified non-RA capacity. IFM cleared export leg of a wheel through self-schedule	1600	250	The RUC procurement may be less than the Demand forecast if the CAISO has committed all available generation and accepted intertie bids up to the intertie capacity.
Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	1250	250	These constraints affect the final dispatch in the Real-Time Market, when conditions may differ from Day-Ahead.
IFM cleared supply schedules	Min(energy bid price -$250, or $0)	0	These values preserve schedules established in IFM in both the RUC scheduling run and pricing run.
IFM cleared economical exports	IFM bid-in price +300	0	Export adder priority for IFM schedules

The supply that clears in the IFM is the base quantity of commitment and schedules determined in RUC, and is protected with a penalty price. For supply, this penalty price is a negative adder to the bid value used in IFM. For exports, it is a positive adder to the cleared IFM schedules. This is done to maintain the relative scheduling priority in RUC of schedules that cleared in the IFM.

Table 5: IFM intertie penalty prices

Penalty Price Description	Scheduling Run Value Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
Import price-taker self-schedule. Import leg of a high priority wheel through self-schedule.	-1100	-150	-2200	-150	Generic self-schedules for supply receive higher priority than Economic Bids at the bid floor.
Import leg of a low priority wheel through self-schedule	0	0	0	0	Import side of a low priority wheel self-schedule
Self-scheduled exports not using identified non-RA capacity, Exports leg of a low priority wheel through self-schedule	1050	1000	2100	2000	The scheduling parameter for self-scheduled exports not using identified non-RA capacity is set below the parameter for generic self-schedules for demand.

Exports supported by non-RA capacity do not have the adder applied due to these resources having the same priority as load. For example, if an import self-schedule clears

10 MW in the IFM at $0, that 10 MW would be protected in RUC at a -$250 penalty price. For self-schedules, the market uses the same adder on top of the import self-schedule penalty price used in the IFM. Those penalty prices are located in Table 5.

Based on these penalty prices, the highest import price that would occur in RUC would be -$1,350/MWh, this is the IFM -$1100 plus the -$250 adder. The largest export penalty price would be $1,600 at PBC and the lower priority penalty price would be $1,350. So when the PBC is relaxed in RUC the SMEC will be set to $1,600. At this point if an ITC or ISL is at the limit in IFM cuts to the exports schedule will be made at the lower priority first then PBC and higher priority. When these cuts occur this leads to ITC limits potentially binding or being overloaded due to lack of counter flow, if the penalty price is not set high enough, it's is less costly to overload that constraint. This is why a -$1,250 ITC penalty price in RUC results in the market optimization relaxing the PBC, ITC and reducing exports. A larger penalty price for the ITC would eliminate this undesired interaction. Figures 5 and 6 provide an example of this occurring; By looking at the scheduling run LMP prices that cleared at Malin and NOB on August 19, 2020 (Figure 5 and Figure 6), the -$1,250 ITC penalty price was not large enough to prevent the market optimization from relaxing it and allowing overscheduling of these interties.

Figure 5: RUC scheduling prices at Malin on August 19, 2020

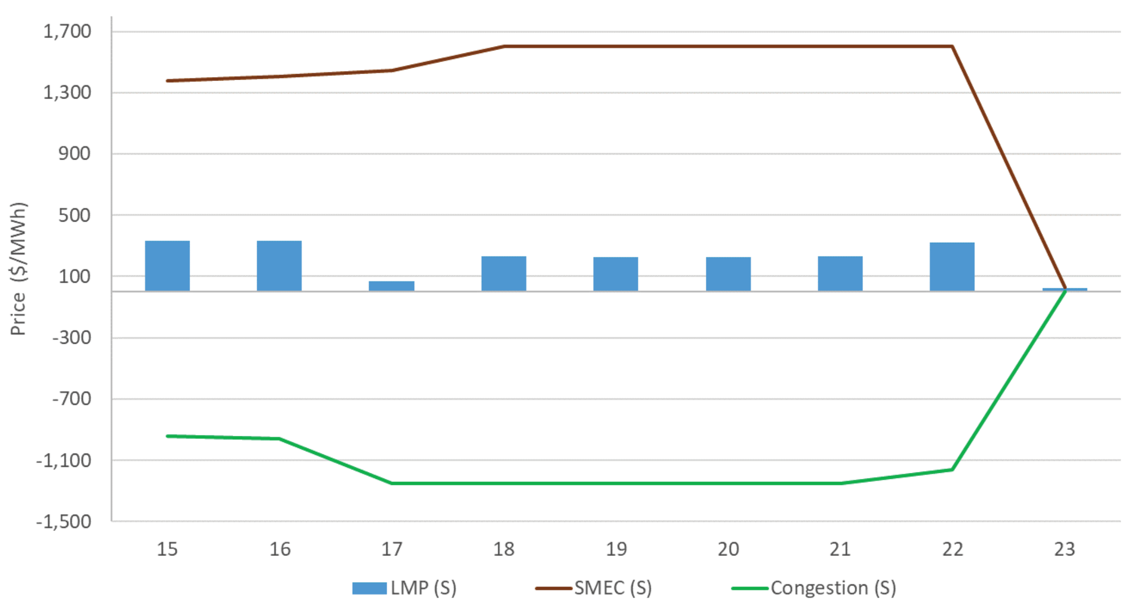
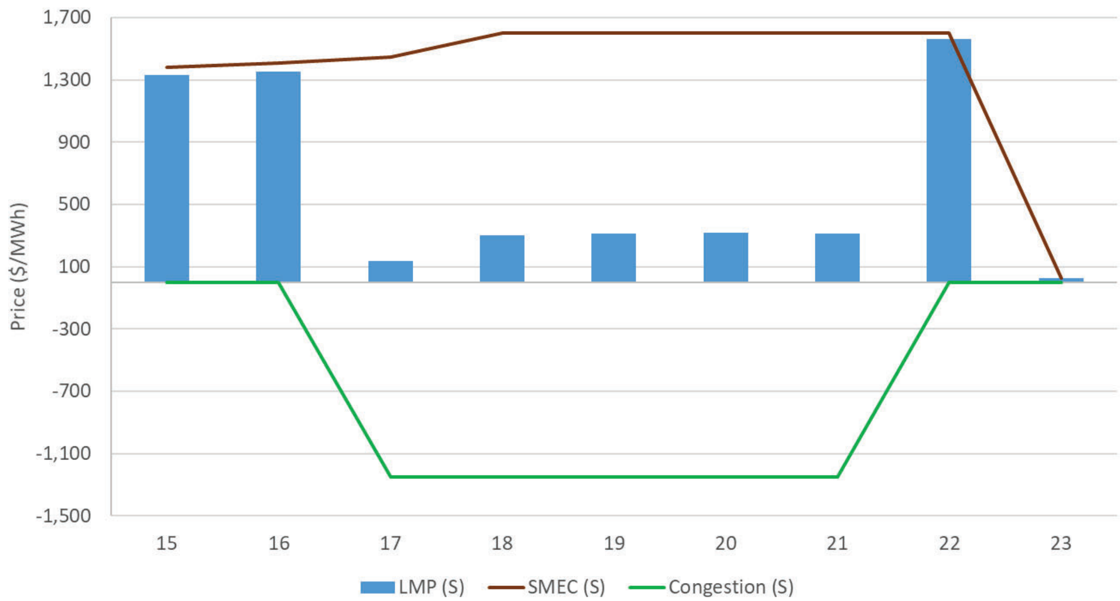


Figure 6: RUC scheduling prices at NOB on August 19, 2020



Proposed solution [revised 1/21/22 to correct error in proposed penalty price]

In the BPM Section 6.6.5 and Tariff Sections 27.4.3.2.1 and 27.4.3.3.1 the price for the ITC is $1,250/MWh. The CAISO proposes to adjust this amount to $3,200/MWh.

Similar to HASP, the penalty price adjustment for RUC ITC will be based on the highest import self-schedule, not including ETC/TOR, and the PBC relaxation penalty price. Therefore, the lower level for PT self-schedule price would be -$1,350 less the PBC relaxation or (-$1,350-$1,600) or -$2,950. Taking into consideration the loss component, which observations from testing indicate can range up to plus or minus $150 along with a $100 of margin the proposed price is -$3,200 for imports and $3,200 for exports. The CAISO identified that there are no other penalty price adjustments needed with the newly proposed ITC penalty price.

Simulated Results

In response to stakeholder requests, the CAISO has simulated the proposed changes using the markets of July 9, 2021 (HASP) and August 19, 2020 (RUC) with the proposed penalty price changes to produce a counterfactual solution. These are days when overscheduling on the interties was observed and are, therefore, a natural benchmark to simulate the proposed changes.

The counterfactual solution resulted in no overscheduling of the intertie constraints, which is the primary goal of this proposed change. The market simulation also shows scheduling priorities are maintained along with expected pricing outcomes. This section shows the comparison between original market results and counterfactual market results.

Simulated HASP solution

For the July 9, 2021 the simulation covers the HASP market for hours ending 19, 20, and 21 when overscheduling was observed on Malin and NOB constraints. Figure 7 and Figure 8 show the HASP prices at Malin and NOB broken out by energy, congestion and total LMP prices. For Malin, SMEC is over $1,000MWh while MCC is under -2,000MWh, this results in LMPs of about -$1,200MWh that with the increased ITC relaxation price run is low enough to maintain the scheduling priority due to the shadow price being more negative and the resulting LMP being low enough to cut the self-schedule when compared with Figure 3. As a result the ITC will not be relaxed. It can also be observed that the MALIN resultant LMP is at -$1,200 which is the correct priority for PT import.

Figure 7: HASP counterfactual scheduling prices at MALIN on July 9, 2021

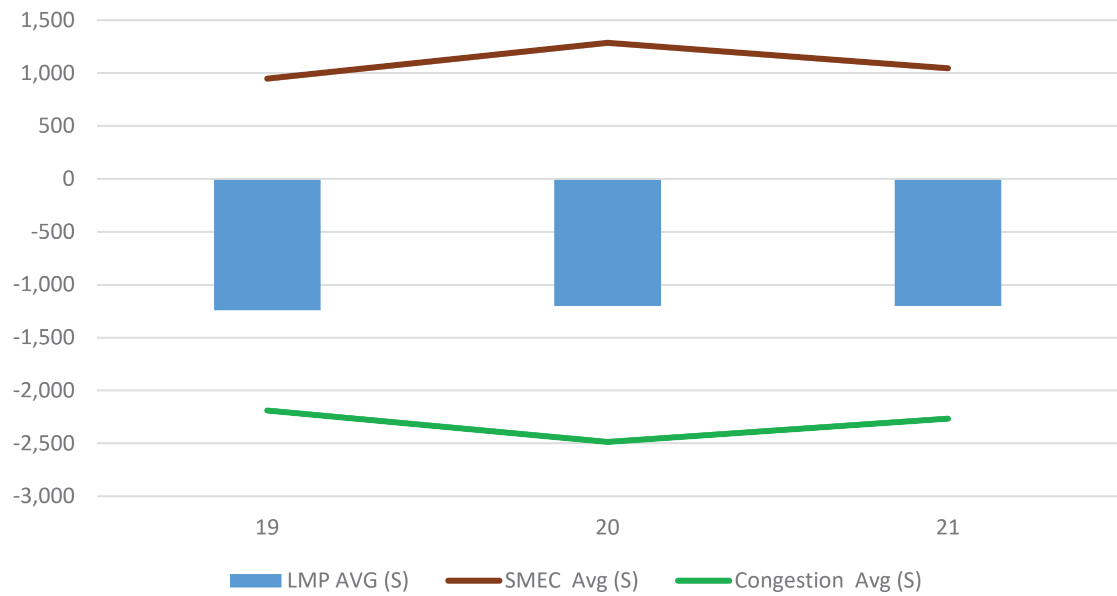
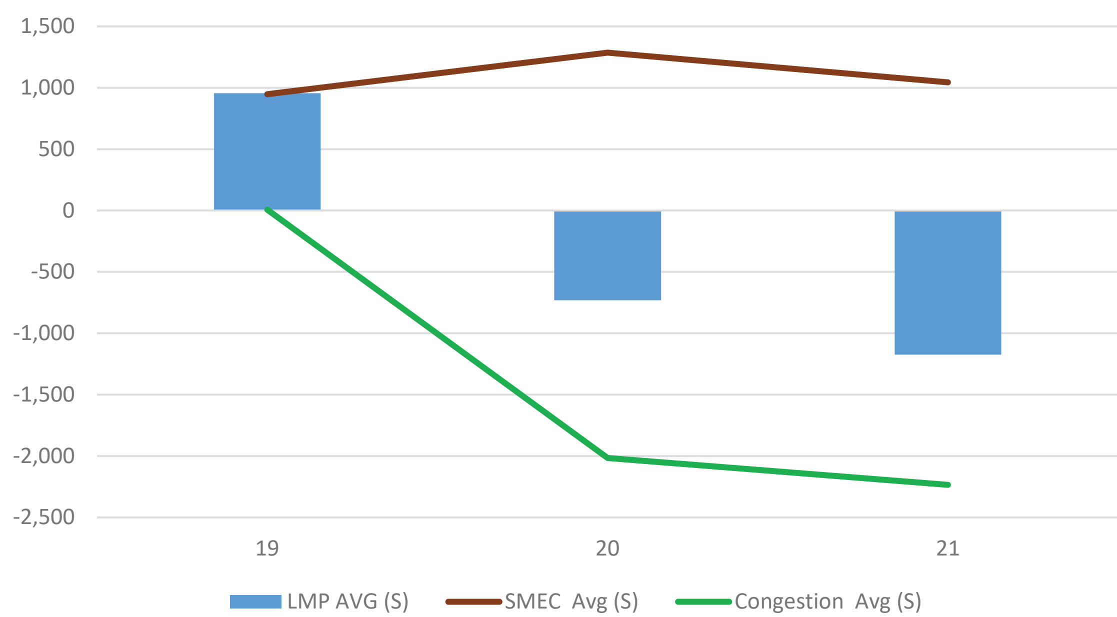


Figure 8: HASP counterfactual scheduling prices at NOB on July 9, 2021



With the proposed penalty price for intertie constraints being higher in the counterfactual, Figure 9 shows a breakdown by the type of imports and compares original and counterfactual schedules on all intertie resources. The largest reduction is for DA PT (high priority) imports. This is expected since the majority of schedules on NOB and Malin were made up DA PT imports and are next in priority after assessing economical bids. The imports with TOR/ETC priority will not be reduced since they have a higher scheduling priority reflected with higher penalty prices. With the counterfactual clearing less imports, there is no longer overscheduling on Malin and NOB; *i.e.,* the intertie limits are no longer relaxed.

As a result of reduced imports it can be observed in Figure 10 that the exports were cut further in the counterfactual run too. This is also as expected because the market has less supply due to the reduced imports and thus it can now support less exports. This is also expected based upon the priority of the export that were cut (real time LPT self-schedule export) having one of the lowest priority, below the high priority exports and below the power balance relaxation. Another observation is that not all economic export bids are cut because they are providing counter flow on congested ITC/ISL paths. Clearing exports enable additional clearing of imports. Additionally, there were still LPT and PT DA exports that were not cut in the counter factual results because of their relatively higher priority assigned for being cleared in the day-ahead market. The days under analysis have the old business rules and scheduling priorities prior to the implementation of the scheduling priority of the summer enhancements 2021.

Figure 9: All Import counterfactual on July 9, 2021

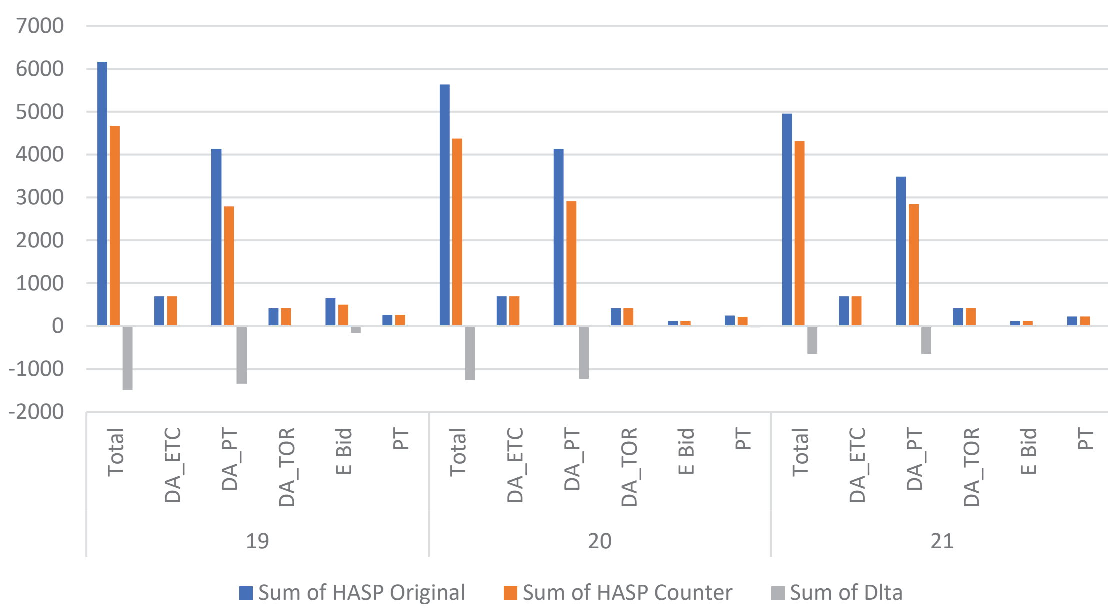
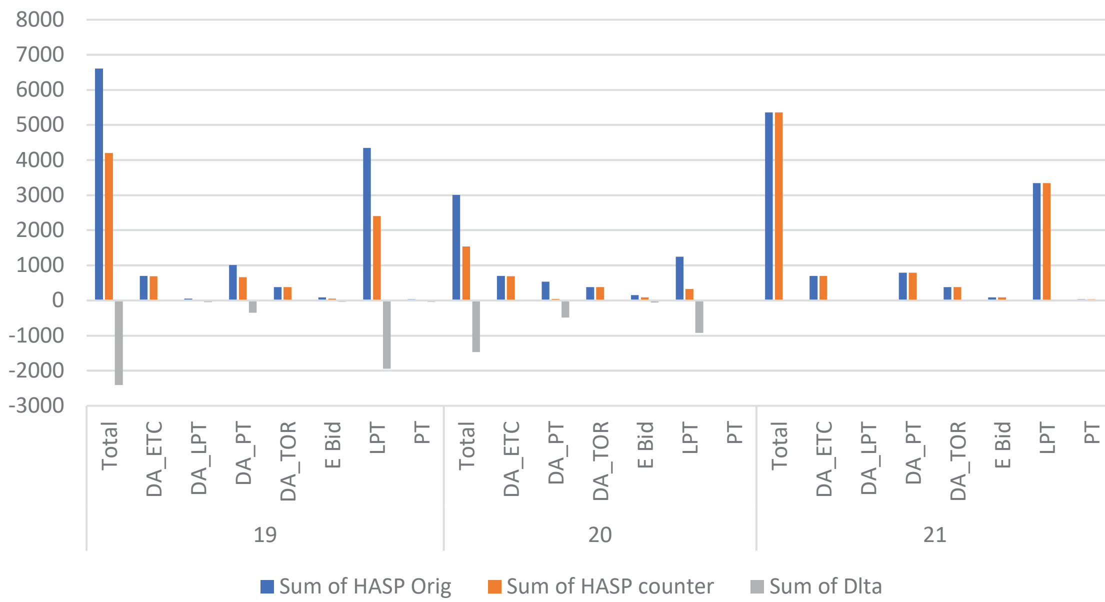


Figure 10: All Export counterfactual on July 9, 2021



Simulated RUC solution

For the RUC counterfactual results, Figure 11 and 12 show the LMP at the MALIN and NOB scheduling points. The increased ITC/ISL relaxation penalty price is reflected on the increasing magnitude of the intertie shadow prices when comparing with Figure 5 and Figure 6 that show the original prices. The resultant LMP is $0 because in the original run incremental imports were economic and overscheduled the ITC. When the penalty price was increased those imports were no longer scheduled but were marginal at the scheduling point and set the price.

Figure 13 compares the hourly volume of imports scheduled in RUC between the original and counterfactual solutions. The majority of the hours show no difference between the scenarios; it's only in peak hours under tight supply conditions when the counterfactual results in clearing less imports to comply with the intertie limit.

Figure 11: RUC counterfactual scheduling prices at MALIN on August 19, 2020

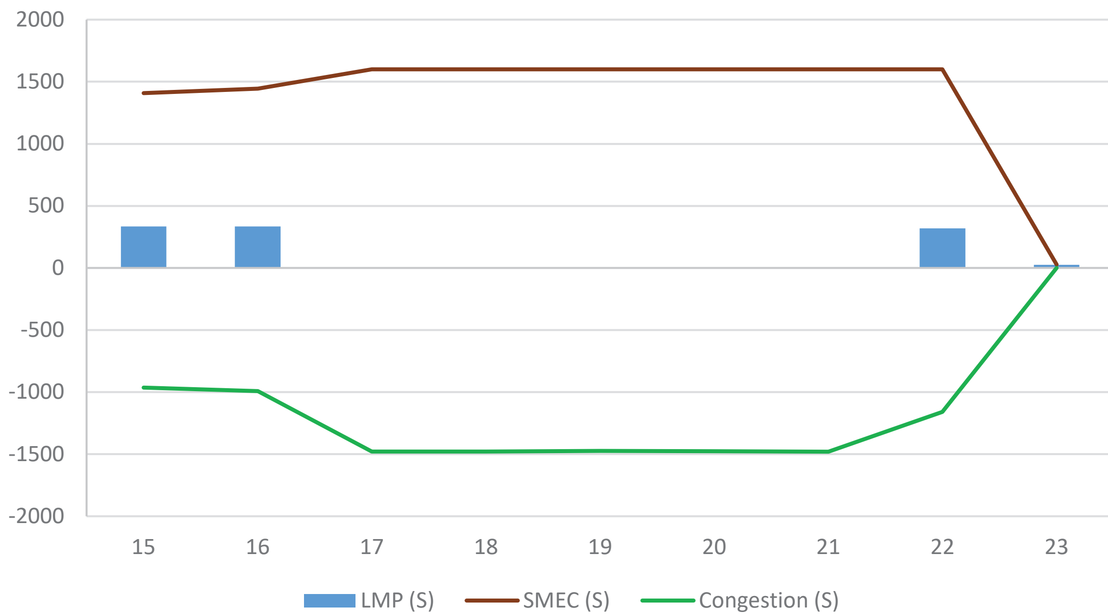


Figure 12: RUC counterfactual scheduling prices at NOB on August 19, 2020

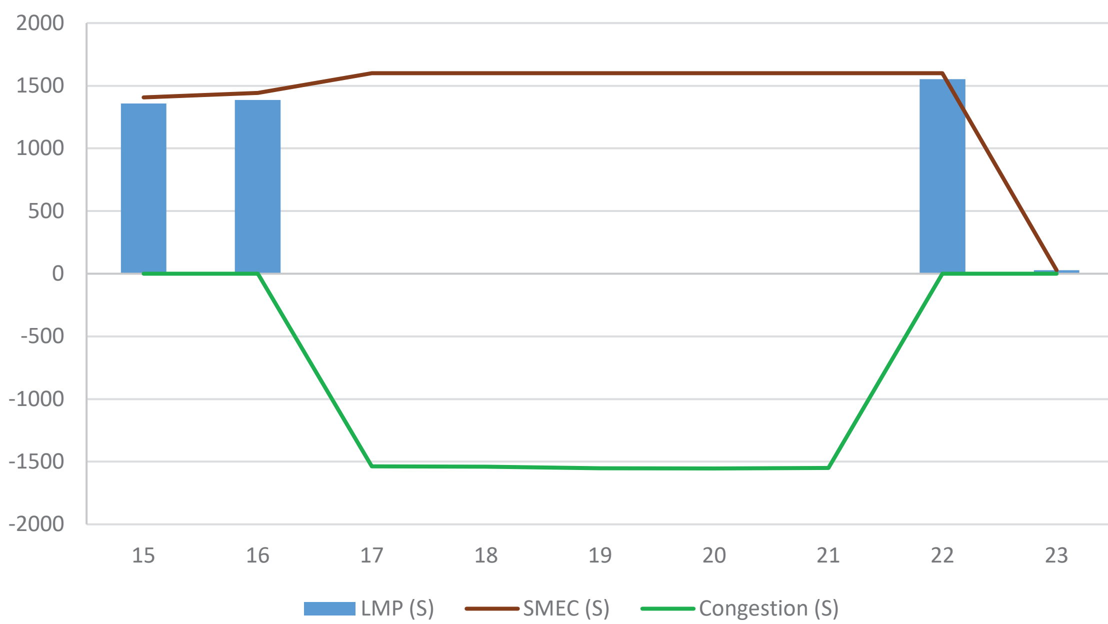
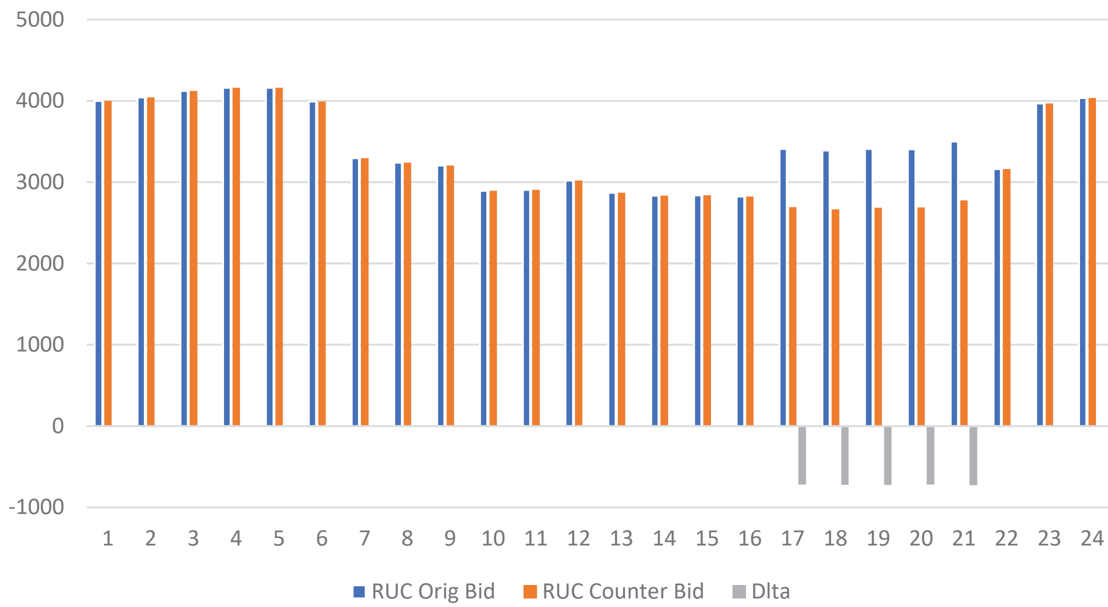


Figure 13: RUC Economic bid in import counterfactual on August 19, 2020



Figures 14 through 16 are import counterfactuals that show import self-schedules maintain correct priority and did not change between runs. This result is expected with the proposed changes.

Figure 14: RUC ETC import counterfactual on August 19, 2020

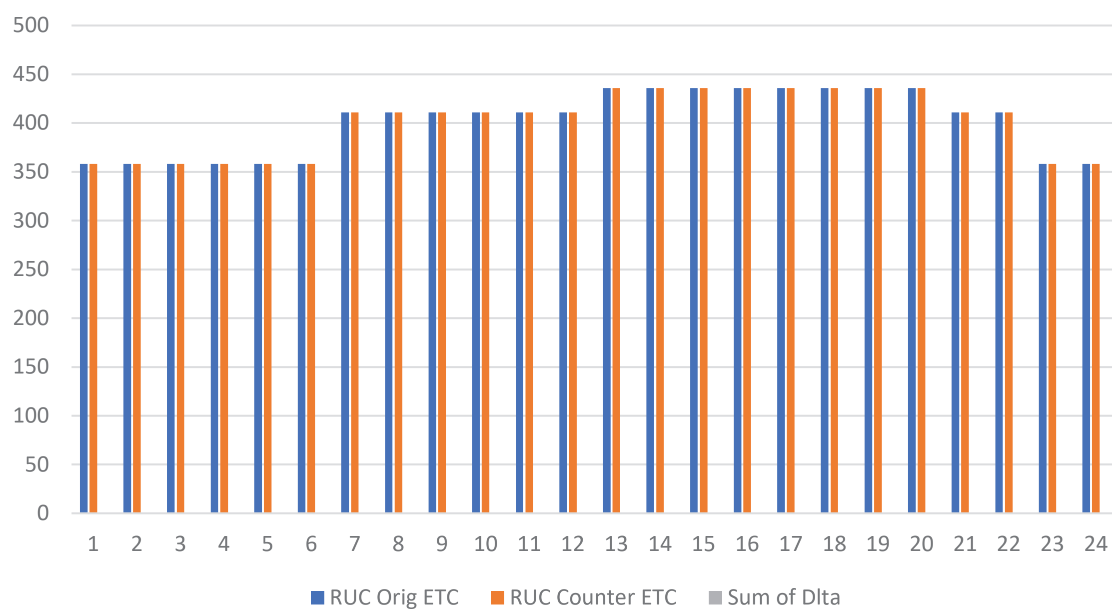


Figure 15: RUC PT import counterfactual on August 19, 2020

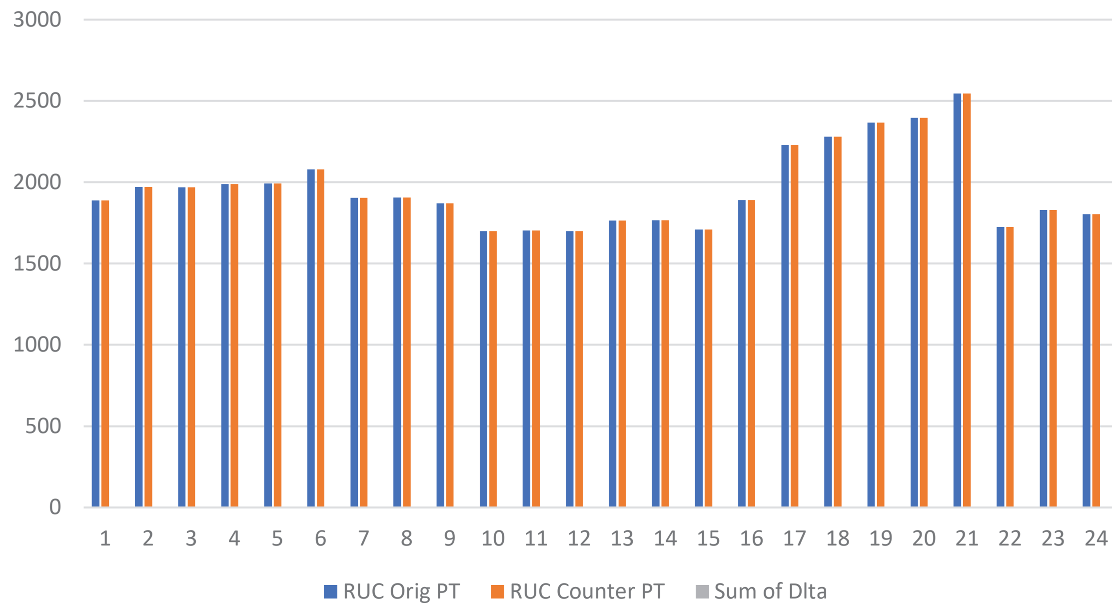


Figure 16: RUC TOR import counterfactual on August 19, 2020

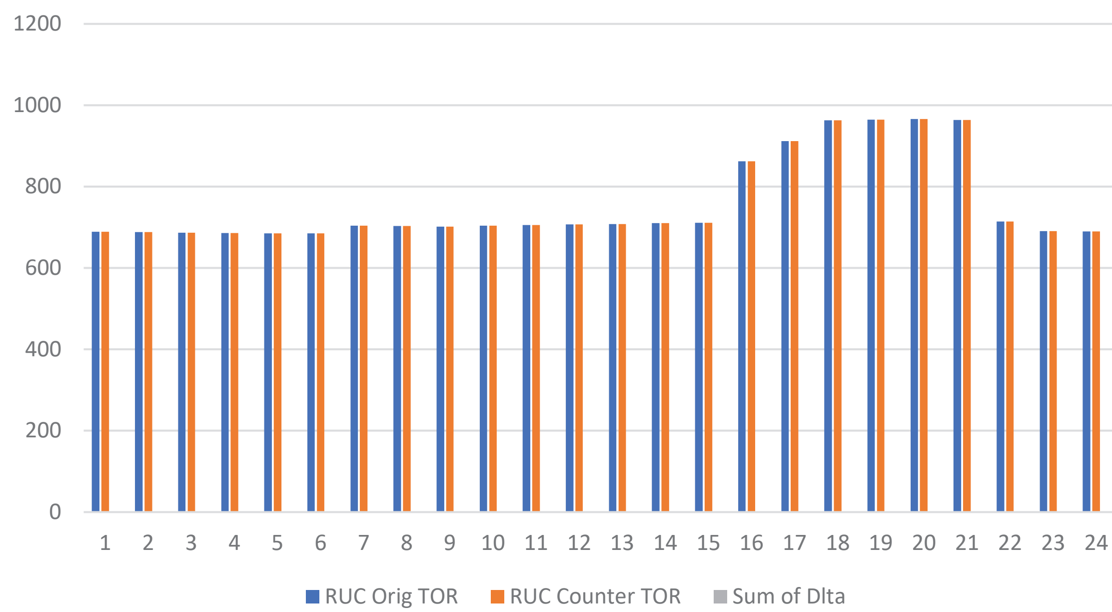
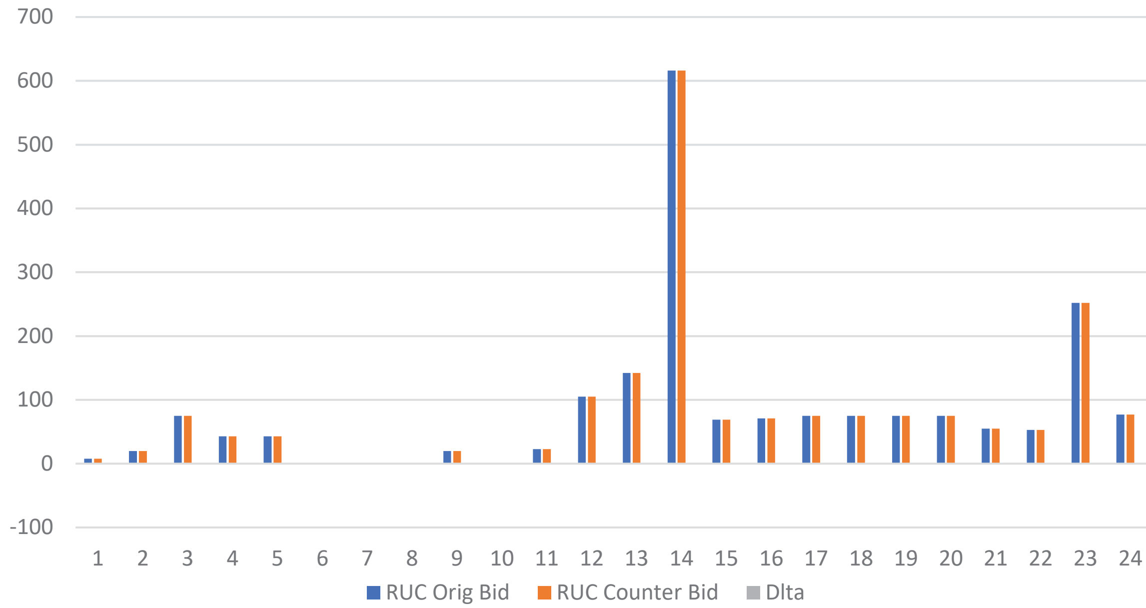


Figure 17: RUC Economic bid in export counterfactual on August 19, 2020



Figures 17 through 20 show the proposed changes to the export schedules between the original and counterfactual solutions. The ETC and TOR exports, as shown in Figures 18 and 20, maintain the same levels of exports, this result is expected. Schedules of economic exports as shown in Figure 17 also maintained the same levels. These economic bids cleared in both IFM and RUC during stressed system conditions in order to provide counter flow on ITC/ISL that were at the limit. This is also an expected outcome. Figure 19, has the change in the LPT export self-schedules. In the counterfactual results, there were additional LPT self-schedules that compensated for the loss of supply due to software differences between the original solution and the software run under the current version. It should be noted that these changes would occur with a pure re-run of the market solution with no penalty price change. Figure 20, results also show differences between the original results and the counterfactual. In the original market for August 19, 2020 there was a software defect that led to the PT exports having a lower priority than the power balance and consequently they were reduced in RUC. This issue was resolved and can be observed in the counterfactual results where more PT exports are scheduled in comparison to the original results. These results of more exports being scheduled in peak hours would have still occurred in the original market solution if it were not because of the software defect.

Figure 18: RUC ETC export counterfactual on August 19, 2020

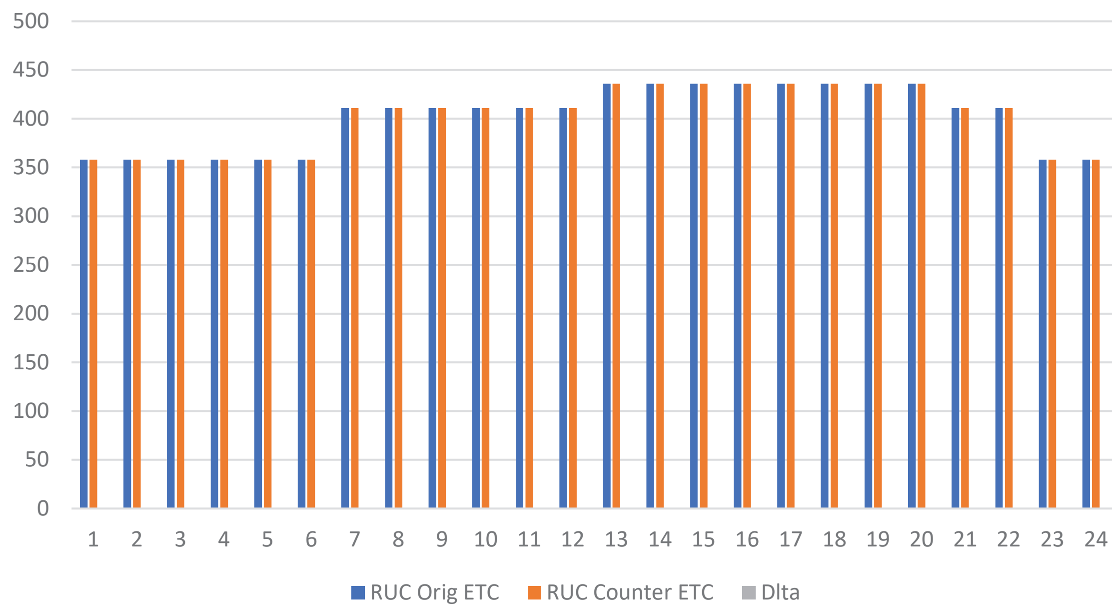


Figure 19: RUC LPT export counterfactual on August 19, 2020

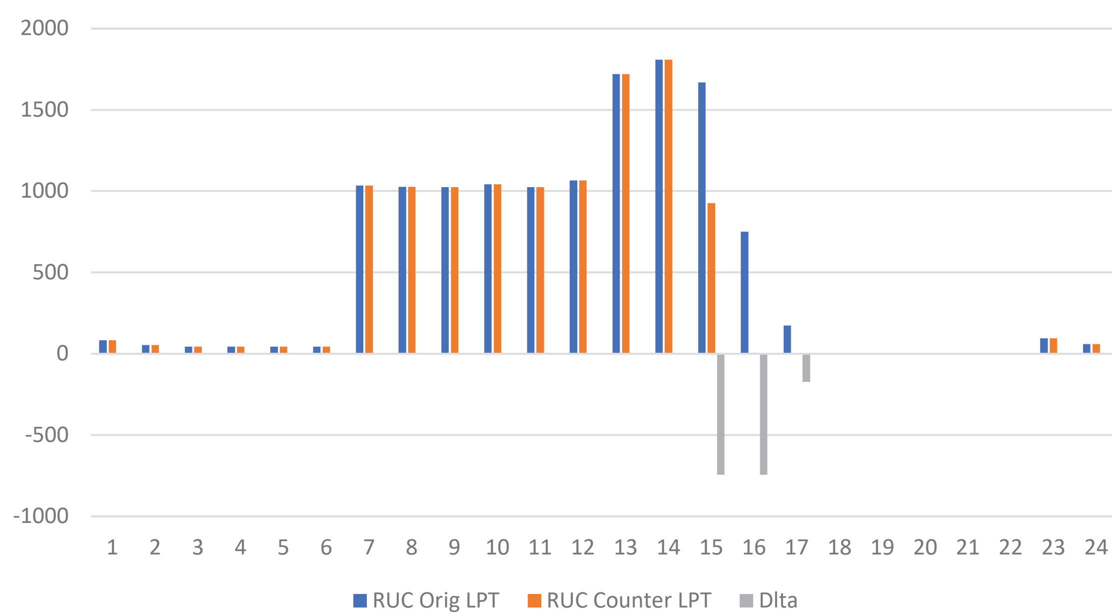


Figure 20: RUC PT export counterfactual on August 19, 2020

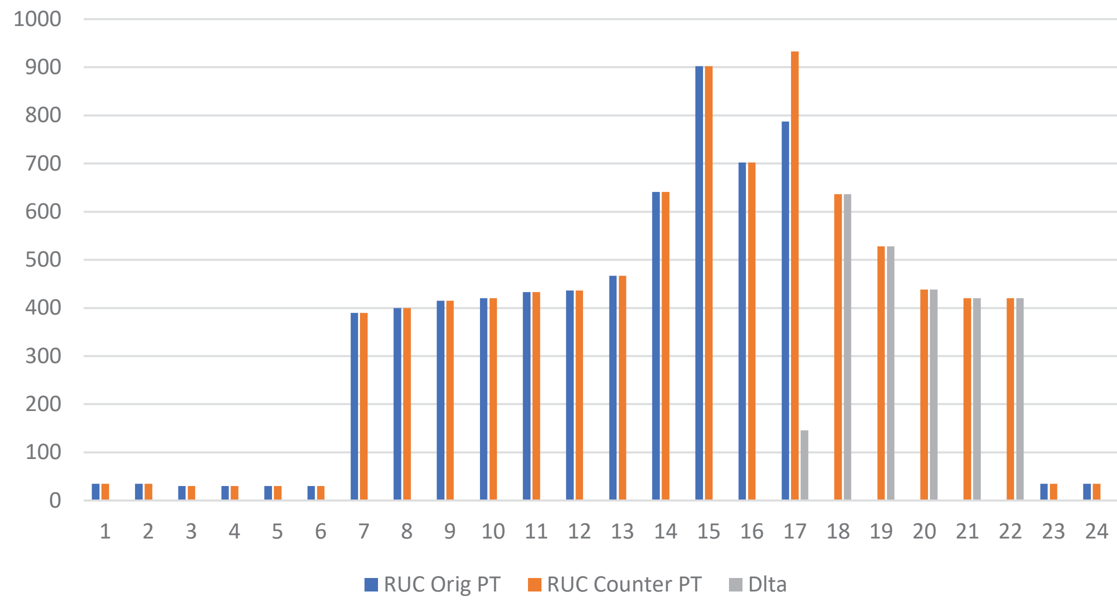
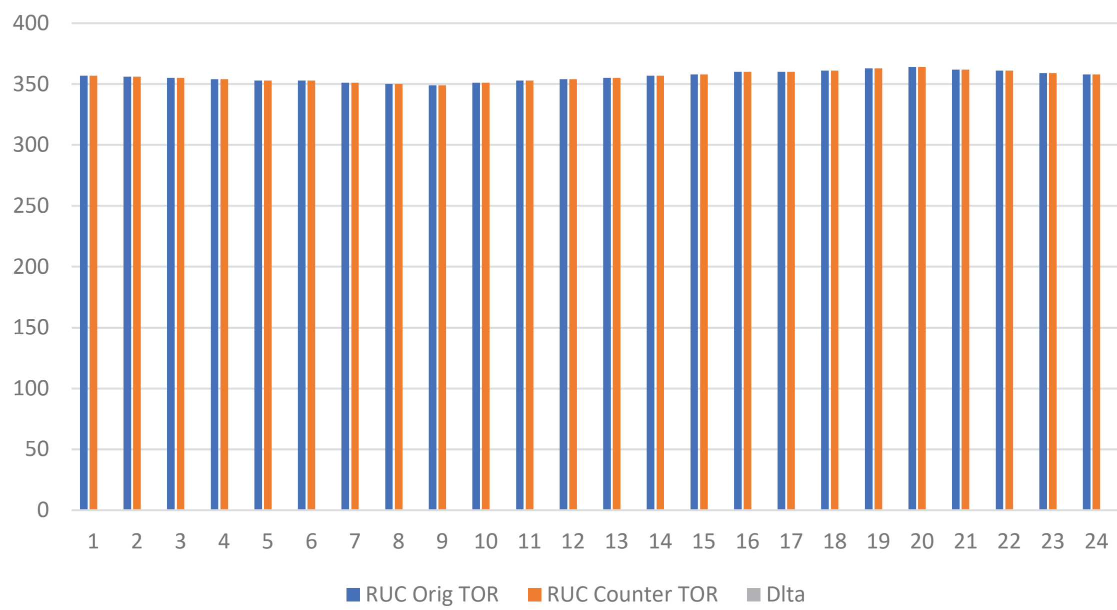


Figure 21: RUC TOR export counterfactual on August 19, 2020



EIM Governing Body Role

This initiative will consider changing the penalty price at the interties of the CAISO balancing authority area. CAISO staff believes that the EIM Governing Body would have an advisory role with respect to the proposed changes, which will go to the Board of Governors for decision in early 2022.

The role of the EIM Governing Body with respect to policy initiatives changed on September 23, 2021, when the Board of Governors adopted revisions to the corporate bylaws and the Charter for EIM Governance to implement the Governance Review Committee's Part Two Proposal. Under the new rules, the Board and the EIM Governing Body have joint authority over any proposal to change or establish any CAISO tariff rule(s) applicable to the EIM Entity balancing authority areas, EIM Entities, or other market participants within the EIM Entity balancing authority areas, in their capacity as participants in EIM. This scope excludes from joint authority, without limitation, any proposals to change or establish tariff rule(s) applicable only to the CAISO balancing authority area or to the CAISO-controlled grid.

Charter for EIM Governance § 2.2.1 The proposed changes to the penalty prices at the CAISO interties would not be "applicable to EIM Entity balancing authority areas, EIM Entities, or other market participants within EIM Entity balancing authority areas, in their capacity as participants in EIM." Instead, the proposed tariff rules apply to the day-ahead market (RUC process) and the hour-ahead scheduling process, both of which apply "only to the CAISO balancing authority area or to the CAISO-controlled grid." Moreover, the proposed penalty price adjustments are not rules of the EIM, but instead are used to ensure overscheduling does not occur on the CAISO's intertie scheduling points, which is a function the ISO would perform even in the absence of EIM. Accordingly, the proposed tariff changes fall outside the scope of joint authority.

The "EIM Governing Body may provide advisory input over proposals to change or establish tariff rules that would apply to the real-time market but are not within the scope of joint authority." Id. The proposed tariff revisions fall within this advisory role, because they would change rules that apply to the real-time market – specifically, the hour-ahead scheduling process.

Stakeholders are encouraged to submit a response to the EIM classification of this initiative as described above in their written comments, particularly if they have concerns or questions.

Next Steps

Milestone	Date

Draft Tariff / Final Proposal Stakeholder Call	January 20, 2022
Comments Due	January 27, 2022
Joint EIM Governing Body and ISO Board of Governors	February 9, 2022
FERC Filing	February/March 2022
Implementation	May 1, 2022

Attachment D – Board Memo

Intertie Transmission Constraint Relaxation

California Independent System Operator Corporation

March 10, 2022

Memorandum

To: ISO Board of Governors and EIM Governing Body

From: Anna McKenna, Vice President, Market Policy and Performance

Date: February 2, 2022

Re: Decision on adjustment to intertie constraint penalty prices

This memorandum requires Board of Governors and EIM Governing Body action.

EXECUTIVE SUMMARY

Management proposes to modify the parameters for intertie constraints used by the ISO's residual unit commitment process and real-time market so that the market optimization will not allow intertie schedules to exceed the applicable scheduling limit. This change will enhance the reliability of the market solution, especially during tight supply conditions, by ensuring the ISO's optimization observes the intertie transmission constraints in reaching a market solution.

The ISO's market optimization uses economic bids and supply offers to clear the market and produce feasible schedules and dispatches. In certain circumstances, however, the ISO's market optimization uses parameters or "penalty prices" that guide the market-clearing software to maintain expected scheduling priorities and comply with constraint limits. Under extreme conditions, the market optimization may encounter infeasibilities and thus may have to adjust certain inputs or constraints in order to reach a solution, including a constraint modeling the transmission scheduling import limits on an intertie.

One example occurred on July 9, 2021, when two ISO interties experienced significant derates due to the Bootleg fire in southern Oregon. With the derates in place, in order to reach a solution, the ISO real-time market had to simultaneously relax the constraint that balances supply and demand (the power balance constraint) and a transmission constraint that limits intertie schedules to the intertie's scheduling limit. By relaxing the transmission constraint, the market optimization essentially considered there to be more feasible imports than the system could actually accommodate because of the physical derate. As a result, the real-time market over-scheduled imports on the derated interties, which forced the ISO operators to have to take manual actions to curtail these intertie schedules. A similar phenomena occurred in the day-ahead market's residual unit commitment process for August 19, 2020. The changed proposed by Management in this memorandum will ensure the ISO market optimization does not overschedule imports at its interties under these conditions.

Management presents these proposed changes to the EIM Governing Body in its advisory role, and to the Board of Governors requesting its approval, at the February 9, 2022, joint meeting. Management proposes the following motion for the EIM Governing Body:

> ***Moved, that, as discussed at the February 9, 2022 meeting, the EIM Governing Body advises the ISO Board of Governors, that it [supports/opposes/takes no position on] Management's adjustment to intertie constraint penalty prices proposal described in the memorandum dated February 2, 2022.***

Management further recommends the following Board of Governors motion:

> ***Moved, that the ISO Board of Governors approves Management's adjustment to intertie constraint penalty prices proposal as described in the memorandum dated February 2, 2022; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposal described in the memorandum, including any filings that implement the overarching initiative policy but contain discrete revisions to incorporate Commission guidance in any initial ruling on the proposed tariff amendment.***

BACKGROUND

The ISO's market optimization determines optimal dispatches and prices based on bids and offers. The market uses a set of parameters, or "penalty prices," to determine the priorities of the various constraints it enforces and the priorities of submitted non-priced schedules when it reaches infeasibilities and must relax constraints to reach a solution. For example, the optimization enforces a power balance constraint designed to ensure that supply equals demand. The market optimization also enforces transmission constraints, including intertie transmission scheduling limits. The optimization will relax these constraints in extreme conditions in order to reach a solution.

On August 19, 2020, and July 9, 2021, the ISO experienced high electricity demand. In addition, there was a significant reduction in transmission capacity on the ISO's interties with the northwest on July 9, 2021, because of the Bootleg fire in southern Oregon.
On both days, the ISO's market optimization simultaneously relaxed the power balance constraint and intertie transmission constraints in order to reach a solution. Based on

existing penalty prices, the optimization determined that the least-cost solution was to relax the intertie scheduling limit and as a result it overscheduled the interties. Overscheduling creates issues for both reliability and market efficiency. Markets clear intertie schedules over the limit, which then requires operators to manually curtail after the fact. Additionally, when this happens, the market clearing process accounts for import supply that is not actually available, which results in inaccurate market signals.

PROPOSAL

Management proposes to change penalty prices related to intertie constraints to avoid these issues. Specifically, Management proposes to increase the penalty prices for intertie transmission constraints to $3,200/MWh in the residual unit commitment process and to $2,900/MWh in the real-time market when energy bids are limited to $1,000/MWh. The ISO proposes to increase the penalty prices for intertie transmission constraints to $3,200/MWh in the residual unit commitment process and to $5,800/MWh in the real-time market when energy bids are limited to $2,000/MWh.

These changes will ensure the market optimization does not overschedule imports even if it is necessary to relax the power balance constraint. These proposed changes ensure the existing scheduling priorities are maintained and will help ensure the market optimization more accurately reflects actual supply available to the system to meet demand.

STAKEHOLDER POSITIONS

ISO staff held a stakeholder process to explain the use of penalty prices in the market optimization and the interaction of those penalty prices. In response to stakeholder requests, ISO staff presented analysis that showed how the proposed penalty prices would have resolved overscheduling issues the ISO experienced on July 9, 2021, and August 19, 2020. No stakeholder opposes the proposed changes to the intertie transmission constraint penalty prices.

CONCLUSION

Management requests the EIM Governing Body exercise its advisory role to support this proposal, and that the Board of Governors approve the proposal. Management intends to implement these changes in the market optimization in advance of summer 2022 to help mitigate the risk of overscheduling that could occur during tight supply conditions.

Attachment E – Illustrative examples of intertie scheduling

Intertie Transmission Constraint Relaxation

California Independent System Operator Corporation

March 10, 2022

ATTACHMENT E

The following illustrative examples show how the LMP applicable to economic bids and self-schedules for imports at an interties in the CAISO market will not result in overscheduling so long as the LMP is below, and therefore triggers, the relevant penalty price when necessary to reflect the scarcity of available intertie capacity.

The LMP for each pricing node equals the sum of the system marginal energy component (SMEC), the marginal loss component (MLC), and the marginal congestion component (MCC) – *i.e.*, LMP = SMEC + MLC + MCC. For the sake of simplicity, the MLC equals $0/MWh and is therefore omitted from each of the examples, which means only the SMEC and MCC need to be calculated to determine the LMP.

In examples 1 through 4 below, the intertie scheduling limit is 50 MW absent any derate, and the value of the SMEC is set by economical bids at $25/MWh (*i.e.*, the SMEC when there is no power balance constraint relaxation). The examples involve four resources (labeled A, B, C, and D), with each resource offering 10 MW into the CAISO market:

- Resource A has an economic import bid for 10 MW at $24/MWh
- Resource B has an economic import bid for 10 MW at negative $10/MWh
- Resource C has a self-schedule for 10 MW in the real-time
- Resource D has a self-schedule for 10 MW that cleared the residual unit commitment (RUC)

Examples 1 through 4 show the effects on the LMP of successively more extreme derates of the intertie scheduling limit.

Example 1: Full availability of offers at the intertie[1]

In example 1, the intertie scheduling limit is 50 MW. Because the intertie scheduling limit is greater than the sum of the offers of resources A, B, C, and D (*i.e.*, 40 MW), all of those resources' offers at the intertie clear, *i.e.*, are accepted by the market software. This means there is no congestion at the intertie, so the MCC equals $0/MWh. As a result, the LMP at the intertie is set by the SMEC and equals:

$25/MWh [SMEC] + $0/MWh [MCC] = $25/MWh [LMP]

Example 2a: A derated import limit that requires a partial cut of the offer of

[1] This example 1 is the same as example 1 shown on page 13 of the Draft Final Proposal contained in attachment C to this filing.

resource A[2]

In example 2a, the intertie scheduling limit is derated from 50 MW to 35 MW. As a result, only 35 MW of the offers of resources A, B, C, and D clear the CAISO market. Specifically, due to the priority order in which the market software cuts schedules, all 10 MW self schedules of resource D and all 10MW of self schedules of resource C clear the market (because import self-schedules serving CAISO load are cut last in the priority order compared to bids), then all 10 MW in the economic bid of resource B clear the market (because the economic bid of resource B is negative $10/MWh, and is infra-marginal and less expensive than the $24/MWh economic bid of resource A), but then only 5 MW (not the full 10 MW) in the economic bid of resource A clear the market. Therefore, bid A is marginal and sets the prices at the intertie location.

The fact that the derated intertie scheduling limit (35 MW) is less than the sum of the offers (40 MW) of resources A, B, C, and D that can clear because all have bids below the SMEC price, indicates there is congestion at the intertie. The MCC represents the amount of congestion and equals the shadow price, which is the marginal value of relieving the constraint,[3] *i.e.*, the difference between the price of the offer that is being cut (the offer price of resource A) and the MLCC:

$24/MWh [offer price of resource A] - $25/MWh [MLCC] = -$1/MWh [MCC]

Therefore, the LMP at the intertie equals:

$25/MWh [SMEC] - $1/MWh [MCC] = $24/MWh [LMP]

Example 2b: A derated import limit that requires a full cut of the offer of resource A and a partial cut of the offer of resource B[4]

In example 2b, the intertie scheduling limit is derated to 25 MW. As a result, only 25 MW of the offers of resources A, B, C, and D can clear the CAISO market. Specifically, due to the priority order in which the market software cuts schedules, all 10 MW of self-schedule of resource D and all 10MW of self schedules of resource C clear the market (because import self-schedules serving CAISO load are cut last in the priority order), then only 5 MW (not the full 10 MW) of the economic bid of resource B clear the market. Therefore, bid B is marginal and sets the prices at the intertie location. No MW in the economic bid of resource A (which is more expensive than the economic bid of resource B) clear the market because there is no more capacity available on the intertie.

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2 This example 2a is the same as the first scenario under example 2 shown on page 13 of the Draft Final Proposal.

3 Tariff appendix A, existing definition of “Shadow Price.”

4 This example 2b is the same as the second scenario under example 2 shown on pages 13-14 of the Draft Final Proposal.

The fact that the derated intertie scheduling limit is less than the sum of the offers of resources A, B, C, and D that can clear because all have bids below the SMEC price results in congestion at the intertie. The MCC represents the amount of the congestion. The MCC equals the shadow price, *i.e.*, the difference between the price of the offer B, which is marginal and the first in the priority order to be cut (the offer price of resource B) and the MLCC:

-$10/MWh [offer price of resource B] - $25/MWh [SMEC] = -$35/MWh [MCC]

Therefore, the LMP at the intertie equals:

$25/MWh [SMEC] - $35/MWh [MLCC] = -$10/MWh [LMP]

Example 3: A derated import limit that requires full cuts of the offers of resources A and B and a partial cut of the offer of resource C[5]

In example 3, the intertie scheduling limit is derated to 15 MW. As a result, only 15 MW of the offers of resources A, B, C, and D can clear the CAISO market. Specifically, due to the priority order in which the market software cuts schedules, all 10 MW of the self-schedule of resource D clear the market (because self-schedules for imports cleared in RUC are cut last in the priority order), but then only 5 MW (not the full 10 MW) of the real-time self-schedule of resource C clear the market; this resource becomes marginal and sets the prices at the intertie location. No MW in the economic bids of resources A and B clear the market.

The fact that the derated intertie scheduling limit is less than the sum of the offers of resources A, B, C, and D that can clear because all have bids below the SMEC price results in congestion at the intertie. The MCC represents the amount of the congestion and equals the shadow price. Normally, the shadow price would be the difference between the price of the marginal offer that is the first in the priority order to be cut (*i.e.*, the offer price of resource C) and the MLCC. In example 3, however, it is the offer of resource C, which is a real-time self-schedule, that is being cut. Cutting resource C’s offer triggers the applicable penalty price of negative $1,100/MWh for a real-time price-taker self-schedule without a RUC schedule.[6] That penalty price substitutes for the offer price of resource C in the MCC calculation:

-$1,100/MWh [penalty price] - $25/MWh [SMEC] = -$1,125/MWh [MCC]

Therefore, the LMP at the intertie equals the penalty price of the real-time self-schedule being cut:

$25/MWh [SMEC] + -$1,125/MWh [MCC] = -$1,100/MWh [LMP]

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5 This example 3 is the same as example 3 shown on page 14 of the Draft Final Proposal.

6 Market Operations BPM, section 6.6.5, at the eighth row from the bottom of the “Real Time Market Parameters” table.

Example 4: A derated import limit that requires full cuts of the offers of resources A, B, C and a partial cut of the offer of resource D[7]

In example 4, the intertie scheduling limit is derated to 5 MW. As a result, only 5 MW of the offers of resources A, B, C, and D can clear the CAISO market. Specifically, due to the priority order in which the market software cuts schedules, only 5 MW (not the full 10 MW) of the self-schedule of resource D can clear. No MW in the real-time self-schedule of resource C clears the market because import self-schedule from a RUC schedule of resource D has a higher priority than the real-time import self-schedule of resource C, and no MW in the economic bids of resources A and B clears the market.

The fact that the derated intertie scheduling limit is less than the sum of the offers of resources A, B, C, and D that can clear since all have bids below the SMEC price results in congestion at the intertie. The MCC represents the amount of the congestion and equals the shadow price. Normally, the shadow price would be the difference between the price of the offer that is the first in the priority order to be cut (*i.e.*, the offer price of resource D) and the MLCC. In example 4, however, it is the offer of resource D, which is a day-ahead self-schedule, that is being cut and becomes marginal and sets the prices at the intertie location. Cutting resource D's offer triggers the applicable penalty price of negative $1,200/MWh for a day-ahead self-schedule.[8] That penalty price substitutes for the offer price of resource D in the MCC calculation:

-$1,200/MWh [penalty price] - $25/MWh [SMEC] = -$1,225/MWh [MCC]

Therefore, the LMP at the intertie is set by the day-ahead self schedule penalty price and equals:

$25/MWh [SMEC] + -$1,225/MWh [MCC] = -$1,200/MWh [LMP]

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7 This example 4 is the same as example 3 shown on page 14 of the Draft Final Proposal.

8 Market Operations BPM, section 6.6.5, at the ninth row from the bottom of the "Real Time Market Parameters" table.