November 16, 2018

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. ER19- ___-000

Tariff Amendment to Implement Generator Contingency and Remedial Action Scheme Modeling

Dear Secretary Bose:

The California Independent System Operator Corporation ("CAISO") submits this tariff amendment to account for the unexpected loss of generation and the use of remedial action schemes in its markets.[1] Remedial action schemes—also known as special protection systems or direct transfer trips—are designed to automatically disconnect generators or load in the event of a contingency that would otherwise cause system overloads.[2] These schemes generally consist of circuit breakers and telecommunications equipment that can detect grid events and trip generators offline to protect grid equipment.[3] Currently the CAISO markets only account for the potential loss of transmission elements, but do not account for remedial action schemes and other *generator* contingencies. Moreover, the CAISO's existing locational marginal price ("LMP") calculations do not account for generator contingencies, thereby treating congestion from each generator equally even if a remedial action scheme would trip some generation offline in the event of a contingency.

Because remedial action schemes continue to be added in the West, the CAISO proposes to account for remedial action schemes and other generator contingencies in its markets. Based on engineering analysis and outage history, the CAISO will select specific generator contingencies and remedial action schemes to incorporate in its market models. LMPs will then account for whether a generator's output will require

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1 The CAISO submits this filing pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d. Capitalized terms not otherwise defined herein have the meanings set forth in the CAISO tariff, and references to specific sections, articles, and appendices are references to sections, articles, and appendices in the current CAISO tariff and revised or proposed in this filing, unless otherwise indicated.

2 The CAISO uses special protection systems as a subset of remedial action schemes, but notes that the two terms are used somewhat interchangeably within the industry.

3 Some remedial action schemes also can trip load offline, but these are relatively rare.

more or less transmission capacity in the event of generation loss, thereby improving market dispatch, decreasing out-of-market actions, and appropriately pricing each generator's contribution to congestion in the markets.

The CAISO respectfully requests that the Commission approve the proposed tariff revisions with an effective date of March 1, 2019.

I. Issue

A. Contingency Modeling

A secure transmission system must be able to withstand credible transmission contingencies at a minimum "N-1" contingency level under North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and local reliability requirements.[4] N-1 contingency planning means that the dispatch must not overload any transmission lines given the loss of any one element (N-1) or combination of elements that are simultaneously removed from service.

One way the CAISO protects against contingencies is by establishing and operating within system operating limits.[5] These pre-established energy flow limits account for transmission facilities' voltage limits, transient stability limits, and voltage stability limits, *inter alia*, any of which can be the most restrictive limit.[6] Facilities' limits are variable depending on the contingencies that may affect them. The same facility can have different sets of limits for each type of facility limit: normal and emergency limits, pre-contingency and post-contingency limits, etc. Transmission lines, for example, generally have "normal" and "emergency" thermal limits that determine how

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[4] "Credible" is an industry term that generally means a contingency is likely or plausible (independent of how critical or harmful the contingency may be, which is determined separately). The CAISO's determination of credibility takes a holistic view that includes engineering studies and operator experience based on system conditions at the time of a contingency. *See generally* NERC Reliability Concepts, available at: http://www.nerc.com/files/concepts_v1.0.2.pdf, and Peak Reliability System Operating Limits (SOL) Methodology for the Operations Horizon, available at: https://www.peakrc.com/SOLDocs/Peak%20RC%20SOL%20Methodology%20for%20the%20Operations%20Horizon%20v7.0.pdf.

The CAISO notes that this proposal is distinct from its Contingency Modeling Enhancements ("CME") initiative, which proposes to optimize both preventive and corrective actions in response to certain transmission contingencies. The corrective actions involve the search for a feasible system redispatch that satisfies generator ramp and network constraints in order to return the system to a secure operating point within a required length of time. The CAISO intends to file its tariff revisions for CME at a later date. *See* http://www.caiso.com/informed/Pages/StakeholderProcesses/ContingencyModelingEnhancements.aspx.

[5] NERC Reliability Standard TOP-002-2.1b (R6).

[6] *See* Peak Reliability, SOL Methodology for the Operations Horizon; *Version One Regional Reliability Standard for Transmission Operations*, 133 FERC ¶ 61,227 (2010).

much energy can flow on the lines without overheating them and damaging equipment.[7] Emergency thermal limits can be higher because heating occurs over time.[8] On the other hand, stability limits are determined by a system-wide voltage or frequency stability constraint, and loading the line above this limit for any amount of time could cause instability and cascading outages.[9] Nearly all limits have pre-contingency limits and post-contingency limits. Pre-contingency limits prevent potential negative impacts on reliability associated with a contingency.[10] Post-contingency limits are effective after the contingency occurs to bring the system back within normal operating limits.

The CAISO must obey particular sets of limits depending on the facilities, current system conditions, and credible contingencies. These contingencies generally account for the most probable unplanned transmission outages. For example, if an area of the bulk electric system is at no risk of encroaching upon stability or voltage limitations in the pre- or post-contingency state, and the most restrictive limitations in that area are pre- or post-contingency exceedance of facility ratings, then the thermal facility ratings are the most limiting limits.[11] If an area is not at risk of instability and no facilities are approaching their thermal facility ratings, but is prone to pre- or post-contingency low voltage conditions, then the system voltage limits are the most limiting in that area.

When contingencies cause a normal limit to be exceeded, the CAISO must obey corrective time requirements.[12] This means that after a contingency occurs, the CAISO must return line flows below normal ratings within the emergency rating time duration. For many transmission elements, this time duration ranges from 30 minutes up to four hours.[13] As such, the CAISO market optimization process always must ensure that (1) energy flows do not violate systems limits, and (2) the CAISO has sufficient available capacity to transition from the post-contingency system to the next secure state within established timeframes. In other words, the CAISO market optimization must dispatch resources to respect both pre-contingency and post-contingency limits. When the CAISO market optimization fails to create a dispatch pattern that respects reliability limits—because of multiple contingencies, unplanned outages, or differences in forecasts, for example—CAISO operators must use their experience and judgment to manually dispatch resources out of the market to restore the grid to stable conditions.[14]

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7 *Version One Regional Reliability Standard for Transmission Operations*, 133 FERC ¶ 61,227 at P 27.

8 *Id*.

9 *Id*.

10 Peak Reliability, SOL Methodology for the Operations Horizon at p. 14.

11 *Id*. at p. 11.

12 *Id*. at p. 32 *et seq.*

13 *Id*.

14 Generally through exceptional dispatch.

This process is called an "exceptional dispatch," and can include forced shutdowns, start-ups, ramp-downs, and ramp-ups of generators.[15] Exceptional dispatch ensures that the operators have sufficient capacity, energy, or ramping capability, but the units the operators select may not be the optimal solution that would have been procured in the market. Manual operations are prone to both under- and over-procurement, but the average procurement is conservative to protect the grid.

Transmission outages have the most immediate and fundamental impact on the transmission system because line or substation outages generally increase flows on other transmission lines.[16] This can lead to congestion and even reliability issues as flows approach system operating limits. Importantly, generator outages also can overload transmission lines. For example, consider a load of 1,000 MW that relies on a nearby 1,000 MW generator. If the transmission lines from other generators to this load cannot adequately support 1,000 MW of generation, and the nearby 1,000 MW generator suddenly trips offline, the energy flows from other generators trying to suddenly serve this load would overload the transmission lines absent operator intervention.

Most system operating limits are straightforward and, once derived, can be directly modeled in the market system. These include transmission line capacity and single outages that would overload transmission lines. The market optimization process uses these system operating limits to price and dispatch resources.[17] Some system operating limits, however, are more complex and require engineering studies of near-term system conditions to ensure that a reasonable mix of available generation and transmission in certain areas are sufficient to ensure N-1 security. For these complex system operating limits, the CAISO relies on sophisticated nomograms that account for multiple variables simultaneously. Operators must then watch real-time conditions to make generation dispatch adjustments out-of-market to ensure N-1 security through real-time.

B. Remedial Action Schemes

Remedial action schemes frequently are a cost effective and reliable method to use the transfer capability of transmission systems efficiently.[18] Without remedial action

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15 The causes and process for using exceptional dispatch is set forth in the CAISO's Real-Time Exceptional Dispatch Operating Procedure, #2330, *available at* https://www.caiso.com/Documents/2330.pdf; *see also* Section 34.11 of the CAISO tariff.

16 This also applies to transmission line deratings.

17 Among other factors.

18 Appendix A to the CAISO tariff defines a Remedial Action Scheme, or RAS, as "Protective systems that typically utilize a combination of conventional protective relays, computer-based processors, and telecommunications to accomplish rapid, automated response to unplanned power system events. Also, details of RAS logic and any special requirements for arming of RAS schemes, or changes in RAS

schemes, the interconnection of new generators would require costly new transmission lines, substation upgrades, and/or reconductoring of existing transmission lines. Instead, remedial action schemes generally consist of circuit breakers and software systems integrated into the transmission system that detect predetermined system conditions and automatically take corrective actions—such as automatically tripping generation—if a transmission line unexpectedly trips offline. Historically, transmission operators used remedial action schemes to increase a transmission system's capability to transmit remotely located hydroelectric generation long distances from load centers. Transmission planners now rely on remedial action schemes to transmit variable generation located far from load centers safely and reliably.

Determining whether to rely on a new remedial action scheme or a larger transmission upgrade is part of the generator interconnection study process.[19] It is an infrastructure development decision based on system reliability, deliverability, and infrastructure cost. Expected energy prices are not considered. When a new generator is connected to the grid, the CAISO and participating transmission owners conduct power flow and transient stability studies to determine if the new generator will contribute to any reliability violation in operating the bulk electric system. For any potential violation, the CAISO provides potential mitigation solutions such as building new lines, adding capacitors, installing new remedial action schemes, or curtailing generation in the area. Similarly, the CAISO evaluates and determines the transmission upgrades needed for generation deliverability. If an existing remedial action scheme in the area is the most cost-effective solution to mitigate a potential overload, the new generator will be required to finance and then use that remedial action scheme. Remedial action schemes are nearly always the most cost-effective solution to avoid potential overloads because the alternatives generally would require new transmission lines, substation upgrades, and/or reconductoring existing transmission lines to allow for higher flows in the event of a contingency.

Once a generator has financed the network upgrades required to interconnect reliably to the CAISO controlled grid, the transmission owner will reimburse the

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programming, that may be required. Remedial Action Schemes are also referred to as Special Protection Systems." Appendix A defines a Special Protection System, or SPS, as "An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain System Reliability. Such action may include changes in Demand, Generation (MW and MVar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) Underfrequency Load Shedding or undervoltage Load Shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). An SPS is also sometimes called a Remedial Action Scheme."

19 The CAISO's generator interconnection study process is integrated with its transmission planning process as well.

generator and then include those costs in its transmission revenue requirement.[20] All new or modified remedial action scheme upgrades are considered Reliability Network Upgrades, and the interconnection customer is reimbursed up to $60,000/MW for all its assigned costs within five years of the commercial operation date. The CAISO implemented the $60,000/MW cap to ensure that interconnection customers select cost-effective locations to interconnect. In other words, the cap ensures that a generator's costs of interconnection are proportionate to the benefits provided by the generator's new capacity.

The CAISO currently has approximately 19,800 MW of generation subject to remedial action schemes—known as "armable"—on its system. This represents 31% of total participating generating capacity.[21] To be sure, remedial action schemes only "arm" under certain system conditions. It is highly unlikely that most or all would be armed at any one time, and if they were, it would only be because multiple contingencies have already occurred.

C. Market Results

Failing to account for generator contingencies and generators' tripping offline due to remedial action schemes generally results in two suboptimal market results:[22] higher dispatch costs and the misallocation of congestion charges. The following examples demonstrate how dispatch costs can be higher when contingency modeling does not account for generators' tripping offline due to remedial action schemes.

Example 1: Dispatch that <u>does not account</u> for generator outage due to a remedial action scheme

The following examples assume there are three generators (G1, G2, and G3) serving a system load. Two of the generators (G1 and G2) are located on side A of the grid. The third generator (G3) and the load are located on side B. Because generators G1 and G2 are on side A, they both depend on two transmission lines (T1 and T2) to transmit their power to the load. T1 and T2 run from A to B.

Assume a remedial action scheme will trip offline Generator G1 if transmission line T2 is forced offline, causing the loss of generation to be made up from the system at B. Because the CAISO market software currently does not account for the remedial action scheme, they are not represented in the figure.

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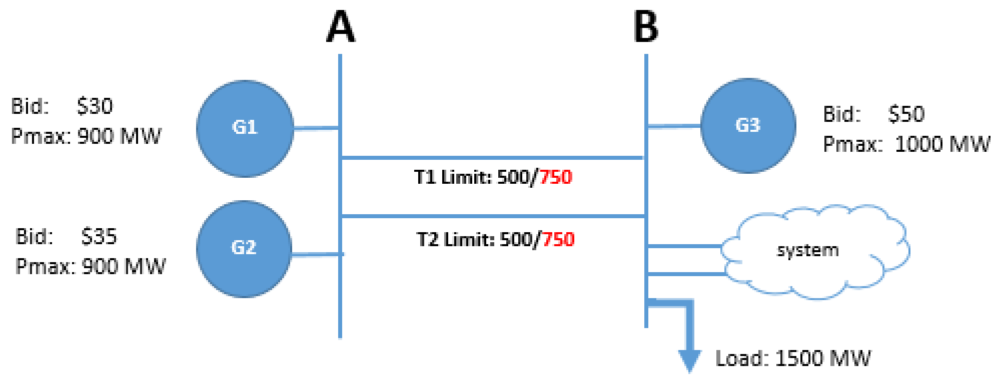
20 *See* Article 11.4.1 of Appendix EE to the CAISO tariff.

21 The CAISO's load peaked in 2017 at 50,116 MW.

22 As mentioned above, some remedial action schemes can trip load offline, but these remedial action schemes are relatively rare. In any case, the same principles apply and the CAISO proposes to model both types of remedial action schemes as discussed herein.



The CAISO market optimization process enforces two sets of limits from A to B. Pre-contingency, the total normal transfer limit from A to B is 1,000 MW (500 MW on T1 plus 500 MW on T2). The CAISO must account for the potential loss of T1 or T2 to be N-1 secure. As such, the CAISO enforces a post-contingency limit of 750 MW from A to B, which is the emergency limit of the remaining line. This means that the effective limit enforced in the market from A to B is 750 MW because the CAISO must secure the system for the N-1 contingency (which here, will be the loss of T2).

Assuming generators G1, G2, and G3 submit the following bids, the CAISO market would give the following awards given the existing market design:

Generator	Energy Bid ($/MWh)	Energy Award (MWh)
G1	$30	750
G2	$35	0
G3	$50	750

Given the system setup and bidding behavior, the market dispatches 750 MW of the cheapest energy on G1. The emergency transfer limit of 750 MW enforced from A to B for the loss of T2 binds, and the market dispatches G3 for the remaining 750 MW necessary to serve 1,500 MW of load. 750 MW flow from A to B, which respects the emergency transfer limit and is below the normal limit of 1,000 MW. G2 receives no energy award because G1 used all the available transfer capacity from A to B, and the market enforces the emergency transfer limit without accounting for G1 going offline if T2 goes offline. The following table sets forth the assumed path flows if T2 is offline:

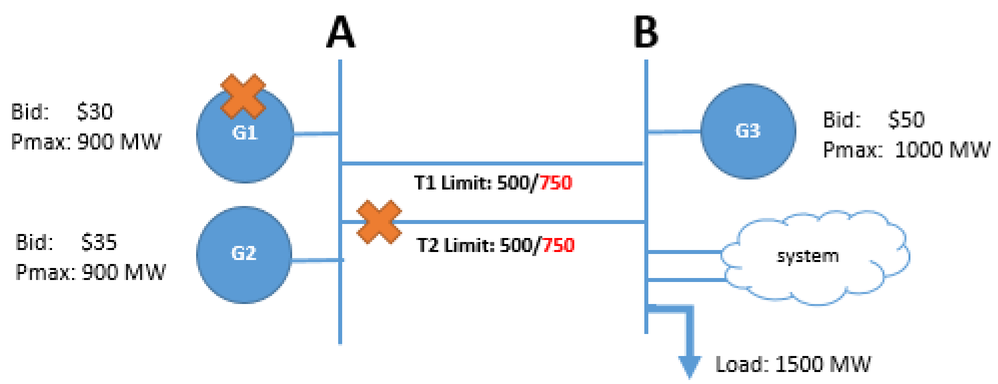
Path Flow		
Contingency	**Pre-Contingency Flow$_{BA}$ (MW)**	**Post-Contingency Flow$_{BA}$ (MW)**
Loss of T2	750	750
Loss of T2 & RAS loss	750	0

Although this dispatch is secure for the loss of transmission line T2, there is a remedial action scheme associated with the loss of T2 that is unaccounted for in the market dispatch. A remedial action scheme is defined such that for the loss of transmission line T2, generator G1 will trip offline.

As shown in the path flow table above, the loss of transmission line T2 and subsequent remedial action scheme loss of generator G1 would result in transmission line T1 to be loaded under its emergency rating (0 MW). The market could have dispatched the cheaper generator G2 higher if the RAS was modeled in the market. Instead, it yields a total dispatch cost of $60,000 ($22,500 + $37,500). As shown in the next example, this is more expensive than modeling the remedial action scheme contingency in the market.

Example 2: Dispatch that <u>accounts</u> for generator outage due to a remedial action scheme

Now consider market dispatch that accounts for the generator loss due to a remedial action scheme (represented below by the orange X on G1). Instead of only modeling a contingency as the loss of transmission line T2, the CAISO proposes also to include the corresponding remedial action scheme that will trip generator G1. Because generator G1 will trip in the event of the loss of transmission line T2, the market can dispatch it to a higher output without having to keep flows resulting from G1's output below transmission line T1's emergency rating in the event of the loss of transmission line T2.



As shown using orange X's above, the CAISO will now account for a remedial action that will trip G1 offline if line T2 is lost. The total pre-contingency limit between A and B is still 1,000 MW,[23] and the total post-contingency limit is still 750 MW, which the CAISO enforces to be N-1 secure. The key difference is that the CAISO market optimization process now includes the loss of G1 in securing for the loss of T2.

Assume generators G1, G2, and G3 submit the following bids and receive the following energy awards given the proposed market design. Although the bid are the same as the example above, the energy awards now are different.

[23] The normal limit of T1 plus the normal limit of T2.

Generator	Energy Bid ($/MWh)	Energy Award (MWh)
G1	$30	900
G2	$35	100
G3	$50	500

The market dispatches the cheapest energy on G1 up to its Pmax of 900 MW followed by the next cheapest energy from G2. The normal transfer limit between A and B of 1,000 MW binds, and the market dispatches G3 for the remaining 500 MW to serve 1,500 MW of load. 1,000 MW would flow between A and B absent the contingency, but only 100 MW flows between A and B in the remedial action scheme contingency case. The remedial action scheme constraint does not bind at 750 MW because only 100 MW (from G2) would flow between A and B after the loss of T2 and the remedial action scheme operation that trips G1. In the simplest terms, the CAISO market optimization process now accounts for the fact that G1 will be offline post-contingency, and the system is still N-1 secure pre-contingency even where G1 and G2 are dispatched above the emergency transfer limit of T1 or T2. The CAISO can thus rely on the normal transfer limits of T1 and T2 pre-contingency instead of the emergency transfer limit of only one line.

Path Flow		
Contingency	**Pre-Contingency Flow$_{BA}$ (MW)**	**Post-Contingency Flow$_{BA}$ (MW)**
Loss of T2 & RAS loss of G1	1000	100
Note: Loss of T2 alone no longer enforced because it does not reflect the actual system operation.		

As shown in the Path Flow table above, the loss of transmission line T2 and subsequent remedial action scheme loss of generator G1 would result in transmission line T1 to be loaded under its emergency rating (100 MW). The market dispatched the cheaper generator G2 higher because the remedial action scheme was correctly modeled in the market. This dispatch yields a total cost for generator of $27,000 + $3,500 + $25,000 = $55,500, which is lower than today's dispatch cost of $60,000.

C. Congestion Pricing

Congestion costs signal to the market that energy flows on transmission facilities are approaching or beyond their limits.[24] The marginal cost of congestion will be higher at nodes that require using congested transmission lines and lower in less congested areas.[25] The marginal cost of congestion thus gives market participants incentives to avoid congestion-causing transactions, and scarce transmission capacity is allocated to those who value it most.[26] As a simplified example, consider a load area that connects to the rest of the transmission system with only one transmission line. Based on bids and schedules, and before considering congestion, the CAISO's market selects generation outside of the area to serve the load in its area. The capacity of the transmission line connecting the area with the rest of the system, however, is constrained by certain factors, and cannot deliver all of the selected energy to the area. Accordingly, the CAISO's market software will revise the mix of generation, dispatching higher-priced generation within the load area to replace the generation outside the area that cannot be delivered due to transmission capacity limitations. The additional cost of this generation reflects the cost of the transmission constraint, namely, congestion.[27]

Currently, congestion pricing does not account for potential transmission overloads that would occur in the event of generator contingencies or generators' tripping offline due to remedial action schemes. This can lead to congestion charges where there would not be congestion.[28] The following examples demonstrate how accounting for remedial action schemes accurately allocate congestion costs.

Example 3: Dispatch that <u>does not account</u> for generator outage due to a remedial action scheme

In this example, assume again that a remedial action scheme will trip G1 offline if transmission line T2 trips offline, but that the CAISO market optimization process does

[24] Appendix A to the CAISO tariff defines "congestion" as "a characteristic of the transmission system produced by a binding Transmission Constraint to the optimum economic dispatch to meet Demand such that the LMP, exclusive of Marginal Cost of Losses, at different Locations of the transmission system is not equal." The marginal cost of congestion formula is set forth in Section 27.1.1.3 of the CAISO tariff and Section D of Appendix C to the CAISO tariff.

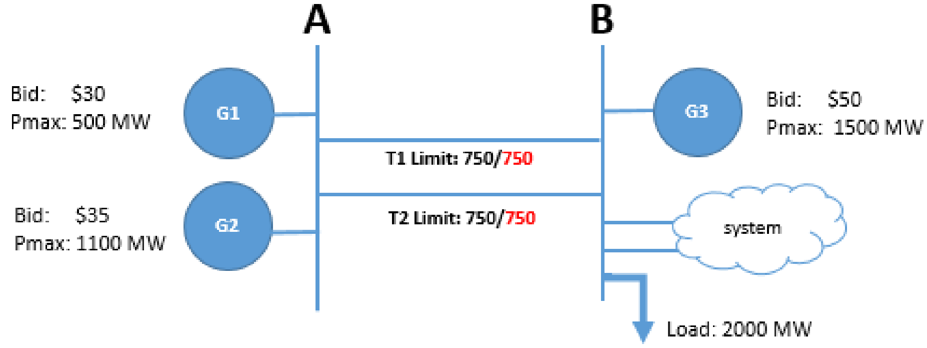
[25] For settlement/pricing purposes congestion actually is a negative number, so mathematically congestion costs are "lower" in more congested areas and "higher" in less congested areas.

[26] *See Sacramento Mun. Utility Dist. v. FERC*, 616 F.3d 520, 523-26 (D.C. Cir. 2010) (quoting *Wis. Pub. Power, Inc. v. FERC*, 493 F.3d 239, 250-51 (D.C.Cir.2007)).

[27] This is a simplified example. CAISO market software selects the most economic generation while respecting transmission constraints. The software calculates the incremental cost of dispatching generation to respect transmission constraints, and reflects this in the marginal cost of congestion.

[28] For generator contingencies that do not involve remedial action schemes, the opposite can be true: the market may not calculate congestion where there actually would be. Both issues are solved by the instant proposal.

not account for this. As such, the remedial action scheme is not represented in the following figure. This example will demonstrate that congestion charges for both G1 and G2 are equal, where example four will demonstrate that they should not be.



In this example, the transmission system is designed such that there is no additional transfer capability on T1 or T2 above normal limits. In other words, the distinction between normal and emergency limits is irrelevant for these lines in both pre- and post-contingency scenarios. To be N-1 secure, the CAISO market optimization process again accounts for the loss of T1 or T2, and enforces a 750 MW transfer limit from A to B.

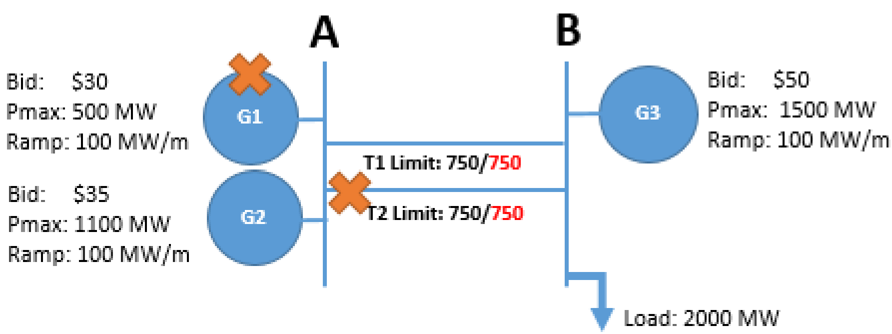
Generators G1, G2, and G3 submit the following bids and receive the following energy awards at the following energy prices given the existing market design.

Generator	Energy Bid ($/MWh)	Energy Award (MWh)	LMP ($/MWh)
G1	$30	500	$35
G2	$35	250	$35
G3	$50	1250	$50

The market dispatches the cheapest energy on G1 up to its Pmax of 500 MW followed by 250 MW of the next cheapest energy from G2. The transmission constraint of 750 MW for the loss of T2 binds, and the market dispatches G3 for the remaining 1,250 MW necessary to serve 2,000 MW of load. In this example the preventive constraint for the loss of T2 binds with a shadow cost of $15. As such, the marginal cost of congestion for G1 and G2 is $15, and both generators receive a $35 energy price. As demonstrated in the next example, this results in a misallocation of congestion charges and an under-representation of the actual available transfer capability from A to B.

Example 4: Dispatch that <u>accounts</u> for generator outage due to a remedial action scheme

The following example demonstrates that accounting for a remedial action scheme tripping a generator offline in the event of a contingency—as the CAISO proposes to do here—results in more accurate congestion pricing. The remedial action scheme is represented by the orange X on G1 below, which will trip generator G1 for the loss of transmission line T2. Now the CAISO market optimization process accounts for the fact that generator G1 will not contribute to congestion post-contingency, so the marginal cost of congestion for G1 is zero.



The CAISO market optimization process enforces the same limits pre- and post-contingency to be N-1 secure; however, it now accounts for the fact that G1 will trip offline in the post-contingency scenario. This allows for G2 to produce up to the 750 MW post-limit pre-contingency, because it will be the only generator still online post-contingency.

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the proposed market design.

Generator	Energy Bid ($/MWh)	Energy Award (MWh)	LMP ($/MWh)
G1	$30	500	$50
G2	$35	750	$35
G3	$50	750	$50

The market now dispatches the cheapest energy on G1 to its Pmax of 500 MW, followed by 750 MW of the next cheapest energy from G2, and 750 MW from G3 to serve the 2,000 MW load. Now that the market optimization process accounts for the remedial action scheme's tripping G1 offline if T2 goes offline, is also accounts for the fact that all of the generation from A to B will come from G2 post-contingency. As such, only G2's production above 750 MW would be congestion post-contingency, contributes so only G2 has a marginal cost of congestion (again, assume $15). G1 would not contribute to congestion post-contingency, and therefore has a marginal cost of congestion of zero (like G3).

Including the remedial action scheme in the CAISO's contingency modeling thus results in accurate congestion pricing. If the market does not consider the remedial action scheme, G1 is "charged" for congestion that it actually does not produce if T2 is lost.

II. Proposed Tariff Revisions

The CAISO proposes to account for remedial action schemes and generator contingencies in its market models. Doing so will make the CAISO's preventive modeling reflect existing grid realities, thus making the CAISO's economic dispatches more accurate and efficient while decreasing out-of-market actions. The CAISO has included two types of tariff revisions to implement this proposal: (A) tariff clarifications regarding contingencies and outages include those involving generators and remedial action schemes; and (B) new components to the CAISO's marginal cost of congestion formula that account for generator contingencies and remedial action schemes.[29] The CAISO explains each, below.

A. Outage Clarifications

To a large extent the CAISO's existing tariff language on modeling and operating the grid already includes generator contingencies and remedial action schemes.[30] Nevertheless, the CAISO believes that tariff clarifications will improve transparency. The CAISO tariff currently defines a "Contingency" as "a potential Outage that is unplanned, viewed as possible or eventually probable, which is taken into account when considering approval of other requested Outages or while operating the CAISO Balancing Authority Area or EIM Balancing Authority." Although this definition tacitly includes remedial action schemes, the CAISO proposes to add a clarifying sentence stating that "Contingencies include potential Outages due to Remedial Action Schemes." This clarification removes any potential ambiguity regarding whether generator outages are contingencies even where the remedial action scheme expressly contemplates the outage if an unplanned contingency occurs.

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[29] Because the CAISO's proposal affects contingency modeling and therefore congestion pricing, market participants will see settlement results reflecting those changes in the energy markets and for their congestion revenue rights (because the congestion revenue rights model is based on the most up-to-date direct current full network model, as explained below). The CAISO analyzed the potential impact of its proposal, and included its results in the Draft Final Proposal, attached here as Attachment C. The CAISO notes that this proposal does *not* include any modifications to the mechanics or rates, terms, and conditions of service for congestion revenue rights.

[30] To wit, Appendix A to the CAISO tariff defines "Transmission Constraints" as "Physical and operational limitations on the transfer of electric power through transmission facilities, which include *Contingencies* and Nomograms." "Contingency" is defined as "A potential *Outage* that is unplanned, viewed as possible or eventually probable, which is taken into account when considering approval of other requested Outages or while operating the CAISO Balancing Authority Area or EIM Balancing Authority." And "Outage" is defined as "Disconnection, separation or reduction in capacity, planned or forced, of one or more elements of an electric system." In other words, Transmission Constraints include Contingencies, which are potential Outages, which include the disconnection or reduction in capacity—planned or forced—of an element of an electric system.

This clarification is important because a large number of the CAISO tariff's modeling and operating provisions address "Transmission Constraints," which the CAISO tariff defines as "Physical and operational limitations on the transfer of electric power through transmission facilities, which include Contingencies and Nomograms." Although the plain reading of contingencies and outages reasonably would include generator and remedial-action-scheme-related outages, the CAISO's proposed tariff revision makes it express. The proposed tariff revision enhances transparency and therefore is just and reasonable.

The CAISO also proposes similar clarifications in Section 27 of the tariff, which addresses CAISO markets and processes. These clarifications consist of parentheticals that Remedial Action Schemes are included in the CAISO's modeling of Transmission Contingencies. The CAISO also proposes to clarify that it will include the impact of disconnected pricing nodes on any modeled remedial action in determining the LMP.[31] The CAISO's process and rationale for determining the LMP in the event of a disconnected pricing node remains unchanged.[32]

B. Marginal Cost of Congestion Formulae

A detailed mathematical explanation of the CAISO's marginal cost of congestion formula and the CAISO's proposed tariff revisions are explained in the CAISO's Draft Final Proposal, included here as Attachment C.[33] In simpler terms, the CAISO's current marginal cost of congestion formula for the day-ahead and real-time markets calculates the marginal cost of congestion based on the economic effect of additional power at a specific point flowing across a given *transmission* constraint.[34] To do so, the CAISO multiplies the relevant Transmission Constraint coefficient by the Power Transfer Distribution Factor ("PTDF") and its Shadow Price.[35] The PTDF is the percentage of a power transfer that flows on a transmission facility as a result of the injection of power at

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[31] Proposed Section 27.1.1 of the CAISO tariff.

[32] Section 27.1.1 states that "The CAISO uses the FMM or RTD LMPs for Settlements of the Real-Time Market. In the event that a Pricing Node becomes electrically disconnected from the market model during a CAISO Market run, the LMP, including the SMEC, MCC and MCL, at the closest electrically connected Pricing Node will be used as the LMP at the affected location." The CAISO proposes no change to this language or methodology. The CAISO merely proposes to clarify that this methodology will continue to be used for disconnected pricing nodes now that it LMP will also account for generator contingencies and remedial action schemes. As such, the process is unchanged, though affected.

[33] The CAISO notes that the Draft Final Proposal uses slightly different mathematical notation than the CAISO's proposed tariff revisions, though the substance is the same. The CAISO modified the notation to better match the CAISO's existing formulae.

[34] Section D of Appendix C to the CAISO tariff.

[35] The Transmission Constraint coefficient is 1 unless the constraint is a nomogram accounting for multiple constraints (*e.g.,* the potential loss of more than one transmission line), in which case the coefficient reflects the nomogram.

the relevant bus and the withdrawal of power at the reference bus. The Shadow Price is the marginal value ($/MWh) of relieving the constraint.[36]

The CAISO proposes to add a new component to this formula so that transmission constraints may include potential generator outages as well.[37] Such outages can be due either to contingencies or remedial action schemes triggered by contingencies. Under the CAISO's revised formula, the CAISO will thus calculate the marginal cost of congestion by multiplying the relevant Transmission Constraint coefficient by the PTDF for the relevant transmission components and its shadow price (*i.e.*, the existing formula), and then subtracting the product of the PTDF for the relevant generator contingencies and its shadow price as well.[38] The CAISO proposes to make similar enhancements[39] to the formula to calculate the marginal cost of congestion for pricing nodes in the energy imbalance market areas in the real-time market.[40]

Because the CAISO will account for significant generator contingencies and remedial action schemes as part of its transmission constraint modeling, the CAISO plans to include modeled generator contingencies and remedial action schemes with its published transmission contingencies and nomograms. These models are available in the CAISO's Customer Market Results Interface ("CMRI") under Transmission Constraints. Because of the sensitive nature of this information, the CAISO requires market participants to execute a non-disclosure agreement to access the CMRI. The CAISO does not propose to change this requirement, but will not require any separate process or agreement to access generator contingency and remedial action scheme models because these contingencies are comparable to modeled transmission contingencies.

Accounting for generator contingencies in the marginal cost of congestion is just and reasonable. Doing so will ensure the CAISO's preventive modeling and market prices reflect existing grid realities. It will also help to decrease out-of-market actions and the need for operators to manually monitor remedial action schemes and critical

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36 The shadow price is equivalent to the reduction in cost resulting from a marginal increase of capacity on the constraint.

37 Proposed Section D of Appendix C to the CAISO tariff.

38 Expressing generator contingencies mathematically is somewhat more complex than expressing transmission contingencies. This expression requires more notation and a longer formula, principally to capture (1) the binary parameter that identifies the pricing node with a potential generator outage, and (2) a generator *loss* distribution factor for all generators in that contingency case. The latter is expressed as a frequency response capable generator's output divided by the sum of the output from all committed frequency response capable generators (*i.e.,* the generators that will respond to the drop in generation). These components allow the CAISO to account for the loss of generation due to an outage, and the subsequent response of remaining online generators.

39 The only changes are notational to account for the different areas.

40 Proposed Section D to Appendix C to the CAISO tariff. Energy imbalance market balancing authority areas do not participate in the CAISO's day-ahead market.

generator contingencies. Accounting for generator contingencies in the marginal cost of congestion also will appropriately price each generator's contribution to congestion in the markets.

III. Stakeholder Process

The stakeholder process that resulted in this filing included:

- Five policy papers issued by the CAISO;
- Developing draft tariff provisions;
- Four stakeholder meetings and conference calls to discuss the CAISO papers and the draft tariff provisions; and
- Five opportunities to submit written comments on the CAISO papers and the draft tariff provisions.[41]

Stakeholders generally supported the CAISO's proposed enhancements. The CAISO's Department of Market Monitoring noted the CAISO's proposal presents "clear reliability and market efficiency benefits," and "will allow the day-ahead and real-time market models to more efficiently manage generator contingency and RAS constraints and is consistent with standard LMP market design and congestion pricing."[42] Likewise, the CAISO's Market Surveillance Committee—an independent body of economists and experts providing recommendations to the CAISO Board[43]—concluded:

> [M]odeling of generator contingencies and remedial action schemes in the CAISO market models will contribute to increasing the security and efficiency of the CAISO's day-ahead and real-time markets. The replacement of *ad hoc* operator actions and constraints with explicit modeling of the system's response to transmission and generation contingencies, including approximations of corrective actions, will likely lead to lower cost schedules that meet security requirements and pricing

41 Materials regarding the stakeholder process are available on the CAISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/GeneratorContingency_RemedialActionSchemeModeling.aspx. A list of key dates in the stakeholder process that are relevant to this tariff amendment is provided in attachment E to this filing.

42 http://www.caiso.com/Documents/DMMComments-GeneratorContingencyandRemedialActionSchemeModeling-DraftFinalProposal.pdf.

43 *See* http://www.caiso.com/informed/Pages/BoardCommittees/MarketSurveillanceCommittee/Default.aspx.

that more accurately reflects the value of resources to the system.[44]

Southern California Edison Company ("SCE") was the only stakeholder that did not support the CAISO's proposal. SCE expressed concern that the CAISO's proposal will further the use of remedial action schemes, which allow for generators to interconnect to congested areas more economically. SCE argued this "will only cause or exacerbate congestion."[45] SCE further stated that the CAISO's proposed pricing will result in a generator with a remedial action scheme potentially receiving a higher LMP than a generator that is not on a remedial action scheme. SCE argued that this is inappropriate because the generator on the remedial action scheme "has [already] effectively been compensated by the resource not being obligated to fund physical transmission system upgrades."[46]

SCE's arguments suffer from several flaws. First and foremost, SCE fails to recognize that the CAISO's proposed enhancements will align its market optimization process with actual grid realities—the loss of generation post-contingency. The enhancements also better align congestion pricing with actual contributions to congestion in the event of a contingency. The CAISO's markets are designed to determine the most efficient scheduling and dispatch of resources. CAISO market prices are a mechanism for incentivizing the resources that currently exist to participate in the market and to perform in the way that maximizes consumer and supplier (total) surplus while maintaining grid reliability. Ignoring grid realities like remedial action schemes and other generator contingencies only interferes with proper incentives.

Second, SCE overlooks the fact that remedial action schemes are merely a subset of the generator contingencies the CAISO believes it is appropriate to account for in the market. In other words, SCE focuses its arguments solely on the selection of remedial action schemes while ignoring that the issues and solutions discussed here apply to a broad set of generator contingencies, a significant portion of which do not involve remedial action schemes. Without the proposed reforms, the CAISO will continue to face the inefficiencies described above.

Third, the CAISO's proposed methodology does not inappropriately provide incentives for certain network upgrades. As SCE recognizes, the CAISO and the transmission owner select the appropriate network upgrades—whether they be remedial action schemes, line upgrades, or substation upgrades— based on interconnection reliability studies only. Generators do not receive a menu of options for interconnection.

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44 http://www.caiso.com/Documents/MSCFinalOpinionGeneratorContingencies_RemedialActionSchemes-Aug28_2017.pdf.

45 http://www.caiso.com/Documents/SCEComments_GeneratorContingencyRemedialActionSchemeModeling_RevisedStrawProposal.pdf.

46 *Id*.

The CAISO and the transmission owner require all new generators to interconnect reliably and with the least cost to ratepayers, which the CAISO and the transmission owner determine. The CAISO sees no distortions to the interconnection process because it will continue to base its interconnection decisions on the results of reliability studies and fixed infrastructure costs. When studies indicate that the system can no longer support generation participating in remedial action schemes, it will require the development of other transmission upgrades. The CAISO does not believe it is prudent to account for energy revenues, which are market-based, in selecting the most cost-efficient cost-based transmission upgrades for resources that will participate only in the energy markets.

Fourth, SCE's argument ignores that a generator on a remedial action scheme will turn off if the modeled contingency occurs. Thus, even if a generator on a remedial action scheme receives a slightly higher LMP (because it will not contribute to congestion), such additional revenues would be counterbalanced when the contingency occurs and the generator is tripped off and foregoes any energy payment. Generators that are not on remedial action schemes will remain online and do not face this risk. In any case, selecting remedial action schemes in the interconnection process and the CAISO's instant proposal are completely separate and unrelated. As a stakeholder and a transmission owner, SCE has other venues if it believes that using remedial action schemes to interconnect new generation has become inappropriate.[47]

The proposal was presented to the CAISO Governing Board during its public meetings on September 19, 2017. The Board approved the proposal and authorized management to many any necessary filings.[48]

IV. Effective Date and Request for Order

The CAISO proposes an effective date of March 1, 2019. The CAISO also respectfully requests that the Commission issue an order by January 17, 2019. The instant proposal will result in enhancements to a number of modeled contingencies in the CAISO's market optimization system. The CAISO must model these revised contingencies in the congestion revenue rights ("CRR") model in February to allocate and auction monthly CRRs for March.[49] Additionally, this proposal has required

[47] For example, the CAISO's public transmission planning process.

[48] Materials related to the Board's authorization to prepare and submit this filing are available on the CAISO website at http://www.caiso.com/informed/Pages/BoardCommittees/BoardGovernorsMeetings.aspx.

[49] *See* Section 36.4 of the CAISO tariff; *California Independent System Operator Corp.*, 163 FERC ¶ 61,237 at P 5 (2018) ("for the annual and monthly CRR allocations and auctions, CAISO maintains a CRR model that is based on the most up-to-date direct current full network model. In determining the available capacity to include in the CRR model used in each allocation and auction process, CAISO considers information regarding maintenance outages of transmission facilities that may significantly affect the CRR auction model").

significant software development, simulation, and testing. A Commission order by January 17, 2019 will provide the CAISO and its market participants with regulatory certainty sufficiently in advance of the proposed effective date to ensure readiness before the revised contingencies are modeled in the CRR monthly auction on February 1, and before the tariff revisions go into effect on March 1.

V. Communications

Correspondence and other communications regarding this filing should be directed to:

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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 this filing on the CAISO website.

VII. Contents of Filing

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

Attachment A	Clean CAISO tariff sheets incorporating this tariff amendment;
Attachment B	Red-lined document showing the revisions in this tariff amendment;
Attachment C	Revised draft final proposal;
Attachment D	Board memoranda; and

Attachment E List of key dates in the stakeholder process.

VIII. Conclusion

For the reasons set forth in this filing, the CAISO respectfully requests that the Commission accept the tariff revisions proposed in this filing.

Respectfully submitted,

/s/ William H. Weaver
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Attachment A – Clean Tariff

Generator Contingency and Remedial Action Scheme

California Independent System Operator Corporation

27.1.1 Locational Marginal Prices for Energy

As further described in Appendix C, the LMP for Energy at any PNode is the marginal cost of serving the next increment of Demand at that PNode calculated by the CAISO through the operations of the CAISO Markets considering, as described further in the CAISO Tariff, among other things, modeled Transmission Constraints (including Remedial Action Schemes), transmission losses, the performance characteristics of resources, and Bids submitted by Scheduling Coordinators and as modified through the Locational Market Power Mitigation process. The LMP at any given PNode is comprised of three marginal cost components: the System Marginal Energy Cost (SMEC); Marginal Cost of Losses (MCL); and Marginal Cost of Congestion (MCC). Through the IFM the CAISO calculates LMPs for each Trading Hour of the next Trading Day. Through the FMM the CAISO calculates distinct financially binding fifteen-minute LMPs for each of the four fifteen-minute intervals within a Trading Hour. Through the Real-Time Dispatch, the CAISO calculates five-minute LMPs for each of the twelve (12) five (5) minute Dispatch Intervals of each Trading Hour. The CAISO uses the FMM or RTD LMPs for Settlements of the Real-Time Market. In the event that a Pricing Node becomes electrically disconnected from the market model during a CAISO Market run, the LMP, including the SMEC, MCC and MCL, at the closest electrically connected Pricing Node will be used as the LMP at the affected location. The CAISO will include the impact of the disconnected Pricing Node on any modeled Remedial Action Scheme in determining the LMP.

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27.1.1.3 Marginal Cost of Congestion

The Marginal Cost of Congestion at a PNode reflects a linear combination of the Shadow Prices of the binding Transmission Constraints (including Remedial Action Schemes) in the network, multiplied by the corresponding Power Transfer Distribution Factor (PTDF) and coefficient relevant to the transmission segment within that constraint, which is described in Appendix C. The Marginal Cost of Congestion for a Transmission Constraint may be positive or negative depending on whether a power injection at that Location marginally increases or decreases Congestion.

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27.5.6 Management and Enforcement of Constraints in the CAISO Markets

The CAISO operates the CAISO Markets through the use of a market software system that utilizes various information including the Base Market Model, the State Estimator, submitted Bids including Self-Schedules, Generated Bids, Transmission Constraints, and transmission and generation Outages, including due to Remedial Action Schemes. The market model used in each of the CAISO Markets is derived from the most current Base Market Model available at that time. To create a more relevant time-specific network model for use in each of the CAISO Markets, the CAISO will adjust the Base Market Model to reflect Outages and derates that are known and applicable when the respective CAISO Market will operate, and to compensate for observed discrepancies between actual real-time power flows and flows calculated by the market software. Through this process the CAISO creates the market model to be used in each Day-Ahead Market and each process of the Real-Time Market. The CAISO will manage the enforcement of Transmission Constraints, consistent with good utility practice, to ensure, to the extent possible, that the market model used in each market accurately reflects all the factors that contribute to actual Real-Time flows on the CAISO Controlled Grid and that the CAISO Market results are better aligned with actual physical conditions on the CAISO Controlled Grid. In operating the CAISO Markets, the CAISO may take the following actions so that, to the extent possible, the CAISO Market solutions are feasible, accurate, and consistent with good utility practice:

(a) The CAISO may enforce, not enforce, or adjust flow-based Transmission Constraints if the CAISO observes that the CAISO Markets produce or may produce results that are inconsistent with observed or reasonably anticipated conditions or infeasible market solutions either because (a) the CAISO reasonably anticipates that the CAISO Market run will identify Congestion that is unlikely to materialize in Real-Time even if the Transmission Constraint were to be ignored in all the markets leading to Real-Time, or (b) the CAISO reasonably anticipates that the CAISO Market will fail to identify Congestion that is likely to appear in the Real-Time. The CAISO does not make such adjustments to intertie Scheduling Limits.

(b) The CAISO may enforce or not enforce Transmission Constraints if the CAISO has determined that non-enforcement or enforcement, respectively, of such Transmission Constraints may result in the unnecessary pre-commitment and scheduling of use-limited resources.

(c) The CAISO may not enforce Transmission Constraints if it has determined it lacks sufficient visibility to conditions on transmission facilities necessary to reliably ascertain constraint flows required for a feasible, accurate and reliable market solution.

(d) For the duration of a planned or unplanned Outage, the CAISO may create and apply alternative Transmission Constraints that may add to or replace certain originally defined constraints.

(e) The CAISO may adjust Transmission Constraints for the purpose of setting prudent operating margins consistent with good utility practice to ensure reliable operation under anticipated conditions of unpredictable and uncontrollable flow volatility consistent with the requirements of Section 7.

To the extent that particular Transmission Constraints are not enforced in the operations of the CAISO Markets, the CAISO will operate the CAISO Controlled Grid and manage any Congestion based on available information including the State Estimator solutions and available telemetry to Dispatch resources through Exceptional Dispatch to ensure the CAISO is operating the CAISO Controlled Grid consistent with the requirements of Section 7.

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Appendix A

Master Definition Supplement

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- Contingency

A potential Outage that is unplanned, viewed as possible or eventually probable, which is taken into account when considering approval of other requested Outages or while operating the CAISO Balancing Authority Area or EIM Entity Balancing Authority Area. Contingencies include potential Outages due to Remedial Action Schemes.

* * * * *

- Remedial Action Scheme (RAS)

Protective systems that typically utilize a combination of conventional protective relays, computer-based processors, and telecommunications to accomplish rapid, automated response (including Outages) to unplanned power system events. Also, details of RAS logic and any special requirements for arming of RAS schemes, or changes in RAS programming, that may be required. Remedial Action Schemes are also referred to as Special Protection Systems.

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Appendix C

Locational Marginal Price

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D. Marginal Congestion Component Calculations (Day-Ahead and Real-Time)

The CAISO calculates the Marginal Costs of Congestion at each bus as a component of the bus-level LMP. The Marginal Cost of Congestion (*MCCi*) component of the LMP at bus i is calculated in the Day-Ahead Market using the equation:

$$MCC_i = -\sum_{m=1}^{M}\sum_{j=1}^{J_m} c_{j,m}\, PTDF_{i,j}\, \mu_m - \sum_{k=1}^{K}\sum_{m=1}^{M} PTDF_{i,m}^{k}\, \mu_m^{k}$$
$$-\sum_{g=1}^{K_g}\sum_{m=1}^{M}\left(PTDF_{i,m}^{g} + \delta_{O_g,i}\sum_{n=1}^{N} PTDF_{n,m}^{g}\, GLDF_{O_g,n}\right)\mu_m^{g}$$

where:

- i is a node index.
- n is a node index.
- m is the constraint or monitored element index.
- k is the preventive contingency case.
- g is the generation contingency case.
- Og is the node index associated with the generator contingency case g.
- j is the transmission component index of Transmission Constraint m. When Transmission Constraint m is a Nomogram, there can be more than one transmission component. When Transmission Constraint m is any other Transmission Constraint, there shall be only one transmission component.
- N is the number of preventive contingencies.

- K is the number of preventive transmission contingencies.
- Kg is the number of preventive generation contingencies.
- M is the number of monitored elements.
- Jm is the number of transmission components for constraint m.
- $PTDF_{i,j}$ the Power Transfer Distribution Factor for the bus i on transmission component j of the Transmission Constraint *k* which represents the flow across that transmission component j when an increment of power is injected at bus i and an equivalent amount of power is withdrawn at the Reference Bus. The CAISO does not consider the effect of losses in the determination of PTDFs.
- $C_{j,m}$ is the constraint coefficient for the transmission component j in constraint m. When constraint m is a Nomogram, this represents the relevant coefficient for that component. When constraint m is any other Transmission Constraint, this coefficient will always be one.
- μm is the constraint Shadow Price on constraint m and is equivalent to the reduction in system cost expressed in $/MWh that results from a marginal increase of the capacity on constraint m. If the market-clearing problem is limited by any Transmission Constraint including Interties, branch groups, flowgates, nomograms, and Energy Imbalance Market-related transmission constraints (EIM Transfer constraints and power balance constraint for a Balancing Authority Area), the market clearing process would create a Shadow Price for the Transmission Constraint, only when the relaxation of the constraint would result in a reduction in the total cost to operate the system.
- μ_m^k is the constraint Shadow Price on constraint m in the preventive transmission contingency case k and is equivalent to the reduction in system cost expressed in $/MWh that results from a marginal increase of the capacity on constraint m in the preventive transmission contingency case k. If the market-clearing problem is limited by any Transmission Constraint including Interties, branch groups, flowgates, nomograms, and Energy Imbalance Market-related transmission constraints (EIM Transfer constraints and

power balance constraint for a Balancing Authority Area), the market clearing process would create a Shadow Price for the Transmission Constraint, only when the relaxation of the constraint would result in a reduction in total cost to operate the system.

- μ_m^g is the constraint Shadow Price on constraint m in the preventive generator contingency case g and is equivalent to the reduction in system cost expressed in $/MWh that results from a marginal increase of the capacity on constraint m in the preventive generator contingency case g. If the market-clearing problem is limited by any Transmission Constraint including Interties, branch groups, flowgates, nomograms, and Energy Imbalance Market-related transmission constraints (EIM Transfer constraints and power balance constraint for a Balancing Authority Area), the market clearing process would create a Shadow Price for the Transmission Constraint, only when the relaxation of the constraint would result in a reduction in the total cost to operate the system.
- $\delta_{O_g,i}$ is the binary parameter that identifies the node with a generator outage under generator contingency case g. This parameter is one for all nodes in index i when i is the outage node Og associated with a generator contingency case g. This parameter is zero for all nodes in index i when i is not the outage node Og associated with the generator contingency case g.
- $PTDF_{i,m}^k$ is the Power Transfer Distribution Factor for the bus i on transmission component m under the preventive contingency case k, which represents the flow across that transmission component m when an increment of power is injected at bus i and an equivalent amount of power is withdrawn at the Reference Bus. The CAISO does not consider the effect of losses in the determination of PTDFs.
- $PTDF_{i,m}^g$ is the Power Transfer Distribution Factor for the bus i on transmission component m under the generator contingency case g, which represents the flow across that transmission component m when an increment of power is injected at bus i and an equivalent amount of power is withdrawn at the Reference Bus. The CAISO does not consider the effect of losses in the determination of PTDFs.
- $PTDF_{n,m}^g$ is the Power Transfer Distribution Factor for the bus n on transmission

component m under the generator contingency case g, which represents the flow across that transmission component m when an increment of power is injected at bus n and an equivalent amount of power is withdrawn at the Reference Bus. The CAISO does not consider the effect of losses in the determination of PTDFs.

- $GLDF_{Og,n}$ is the generation of loss distribution factor in the preventive generator contingency case g. The value is negative one when n is Og. This value is zero when n is not *Og*, and when n is not associated with a frequency response capable generator. This value is the committed generator output at n divided by the sum of the output from all committed frequency response capable generators when n is not Og and n is associated with a frequency response capable generator.

The MCC at PNodes in an EIM Entity Balancing Authority Area j in the Real Time Market includes an additional contribution from the shadow price of the power balance constraint for that Balancing Authority Area, λ_j, as follows:

$$MCC_i = \lambda_j - \sum_{m=1}^{M} PTDF_{ij} \cdot \mu_m - \sum_{k=1}^{K} \sum_{m=1}^{M} PTDF_{i,m}^{k}\, \mu_m^{k} - \sum_{g=1}^{K_g} \sum_{m=1}^{M} \left(PTDF_{i,m}^{g} + \delta_{O_g,i} \sum_{n=1}^{N} PTDF_{n,m}^{g}\, GLDF_{O_g,n} \right) \mu_m^{g}$$

A power balance constraint is not formulated for the CAISO Balancing Authority Area alone in the RTM. The shadow price of the power balance constraint for EIM Entity Balancing Authority Area j (λ_j) has the following contributions:

a) the shadow price of the EIM Transfer distribution constraint (φ_j), which distributes the EIM Transfer for Balancing Authority Area j to Energy transfers on interties with other Balancing Authority Areas in the EIM Area; and

b) the shadow price of the EIM Transfer scheduling limit for Balancing Authority Area j, upper (ν_j) or lower (ξ_j):

$$\lambda_j = \varphi_j - \nu_j + \xi_j$$

Where λ_j is zero for the CAISO Balancing Authority Area since the power balance constraint is not formulated for it.

The difference between the shadow prices of the EIM Transfer distribution constraints for two Balancing Authority Areas j and k in the EIM Area has the following contributions from any intertie l used for energy transfers between these two Balancing Authority Areas:

a) the EIM Transfer schedule cost that applies to that intertie l (c_l);

b) the shadow price of the Energy transfer schedule limit from Balancing Authority Area j to Balancing Authority Area k that applies to that intertie l, upper limit (ρ_l) or lower limit (σ_l); and

c) the shadow price of the scheduling limit that constrains both Energy transfers and additional schedules to Balancing Authority Area j on that intertie l, upper limit (ζ_l) or lower limit (η_l):

Attachment B – Marked Tariff

Generator Contingency and Remedial Action Scheme

California Independent System Operator Corporation

27.1.1 Locational Marginal Prices f~~F~~or Energy

As further described in Appendix C, the LMP for Energy at any PNode is the marginal cost of serving the next increment of Demand at that PNode calculated by the CAISO through the operations of the CAISO Markets considering, as described further in the CAISO Tariff, among other things, modeled Transmission Constraints (including Remedial Action Schemes), transmission losses, the performance characteristics of resources, and Bids submitted by Scheduling Coordinators and as modified through the Locational Market Power Mitigation process. The LMP at any given PNode is comprised of three marginal cost components: the System Marginal Energy Cost (SMEC); Marginal Cost of Losses (MCL); and Marginal Cost of Congestion (MCC). Through the IFM the CAISO calculates LMPs for each Trading Hour of the next Trading Day. Through the FMM the CAISO calculates distinct financially binding fifteen-minute LMPs for each of the four fifteen-minute intervals within a Trading Hour. Through the Real-Time Dispatch, the CAISO calculates five-minute LMPs for each of the twelve (12) five (5) minute~~t~~ Dispatch Intervals of each Trading Hour. The CAISO uses the FMM or RTD LMPs for Settlements of the Real-Time Market. In the event that a Pricing Node becomes electrically disconnected from the market model during a CAISO Market run, the LMP, including the SMEC, MCC and MCL, at the closest electrically connected Pricing Node will be used as the LMP at the affected location. The CAISO will include the impact of the disconnected Pricing Node on any modeled Remedial Action Scheme in determining the LMP.

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27.1.1.3 Marginal Cost of Congestion

The Marginal Cost of Congestion at a PNode reflects a linear combination of the Shadow Prices of the binding Transmission Constraints (including Remedial Action Schemes) in the network, multiplied by the corresponding Power Transfer Distribution Factor (PTDF) and coefficient relevant to the transmission segment within that constraint, which is described in Appendix C. The Marginal Cost of Congestion for a Transmission Constraint may be positive or negative depending on whether a power injection at that Location marginally increases or decreases Congestion.

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27.5.6 Management and Enforcement of Constraints in the CAISO Markets

The CAISO operates the CAISO Markets through the use of a market software system that utilizes various information including the Base Market Model, the State Estimator, submitted Bids including Self-Schedules, Generated Bids, Transmission Constraints, and transmission and generation Outages, including due to Remedial Action Schemes. The market model used in each of the CAISO Markets is derived from the most current Base Market Model available at that time. To create a more relevant time-specific network model for use in each of the CAISO Markets, the CAISO will adjust the Base Market Model to reflect Outages and derates that are known and applicable when the respective CAISO Market will operate, and to compensate for observed discrepancies between actual real-time power flows and flows calculated by the market software. Through this process the CAISO creates the market model to be used in each Day-Ahead Market and each process of the Real-Time Market. The CAISO will manage the enforcement of Transmission Constraints, consistent with good utility practice, to ensure, to the extent possible, that the market model used in each market accurately reflects all the factors that contribute to actual Real-Time flows on the CAISO Controlled Grid and that the CAISO Market results are better aligned with actual physical conditions on the CAISO Controlled Grid. In operating the CAISO Markets, the CAISO may take the following actions so that, to the extent possible, the CAISO Market solutions are feasible, accurate, and consistent with good utility practice:

(a) The CAISO may enforce, not enforce, or adjust flow-based Transmission Constraints if the CAISO observes that the CAISO Markets produce or may produce results that are inconsistent with observed or reasonably anticipated conditions or infeasible market solutions either because (a) the CAISO reasonably anticipates that the CAISO Market run will identify Congestion that is unlikely to materialize in Real-Time even if the Transmission Constraint were to be ignored in all the markets leading to Real-Time, or (b) the CAISO reasonably anticipates that the CAISO Market will fail to identify Congestion that is likely to appear in the Real-Time. The CAISO does not make such adjustments to intertie Scheduling Limits.

(b) The CAISO may enforce or not enforce Transmission Constraints if the CAISO has determined that non-enforcement or enforcement, respectively, of such Transmission Constraints may result in the unnecessary pre-commitment and scheduling of use-limited resources.

(c) The CAISO may not enforce Transmission Constraints if it has determined it lacks sufficient visibility to conditions on transmission facilities necessary to reliably ascertain constraint flows required for a feasible, accurate and reliable market solution.

(d) For the duration of a planned or unplanned Outage, the CAISO may create and apply alternative Transmission Constraints that may add to or replace certain originally defined constraints.

(e) The CAISO may adjust Transmission Constraints for the purpose of setting prudent operating margins consistent with good utility practice to ensure reliable operation under anticipated conditions of unpredictable and uncontrollable flow volatility consistent with the requirements of Section 7.

To the extent that particular Transmission Constraints are not enforced in the operations of the CAISO Markets, the CAISO will operate the CAISO Controlled Grid and manage any Congestion based on available information including the State Estimator solutions and available telemetry to Dispatch resources through Exceptional Dispatch to ensure the CAISO is operating the CAISO Controlled Grid consistent with the requirements of Section 7.

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Appendix A

Master Definition Supplement

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- Contingency

A potential Outage that is unplanned, viewed as possible or eventually probable, which is taken into account when considering approval of other requested Outages or while operating the CAISO Balancing Authority Area or EIM Entity Balancing Authority Area. Contingencies include potential Outages due to Remedial Action Schemes.

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- Remedial Action Scheme (RAS)

Protective systems that typically utilize a combination of conventional protective relays, computer-based processors, and telecommunications to accomplish rapid, automated response (including Outages) to unplanned power system events. Also, details of RAS logic and any special requirements for arming of RAS schemes, or changes in RAS programming, that may be required. Remedial Action Schemes are also referred to as Special Protection Systems.

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Appendix C

Locational Marginal Price

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D. Marginal Congestion Component Calculations (Day-Ahead and Real-Time)

The CAISO calculates the Marginal Costs of Congestion at each bus as a component of the bus-level LMP. The Marginal Cost of Congestion ($MCCi$) component of the LMP at bus i is calculated in the Day-Ahead Market using the equation:

$$MCC_i = -\sum_k \sum_j C_{j,k}\, PTDF_{i,j}\, FSP_k$$

$$MCC_i = -\sum_{m=1}^{M} \sum_{j=1}^{Jm} c_{j,m}\, PTDF_{i,j}\, \mu_m - \sum_{k=1}^{K} \sum_{m=1}^{M} PTDF_{i,m}^{k}\, \mu_m^{k}$$

$$-\sum_{g=1}^{K_g} \sum_{m=1}^{M} \left(PTDF_{i,m}^{g} + \delta_{O_g,i} \sum_{n=1}^{N} PTDF_{n,m}^{g}\, GLDF_{O_g,n} \right) \mu_m^{g}$$

where:

- i is a node index~~K is the Transmission Constraint index~~.
- n is a node index.
- m is the constraint or monitored element index.
- k is the preventive contingency case.
- g is the generation contingency case.
- Og is the node index associated with the generator contingency case g.
- j is the transmission component index of Transmission Constraint m~~k~~. When Transmission Constraint m~~k~~ is a Nomogram, there can be more than one transmission component. When Transmission Constraint m~~k~~ is any other Transmission Constraint, there shall be only one transmission component.

- N is the number of preventive contingencies.
- K is the number of preventive transmission contingencies.
- Kg is the number of preventive generation contingencies.
- M is the number of monitored elements.
- Jm is the number of transmission components for constraint m.
- $PTDF_{i,j}$ the Power Transfer Distribution Factor for the bus i on transmission component j of the Transmission Constraint *k* which represents the flow across that transmission component j when an increment of power is injected at bus i and an equivalent amount of power is withdrawn at the Reference Bus. The CAISO does not consider the effect of losses in the determination of PTDFs.
- $C_{j,m\cancel{k}}$ is the constraint coefficient for the transmission component j in constraint ~~k~~m. When constraint ~~k~~ m is a Nomogram, this represents the relevant coefficient for that component. When constraint ~~k~~ m is any other Transmission Constraint, this coefficient will always be one~~1~~.
- ~~FSP_k~~ μm is the constraint Shadow Price on constraint ~~k~~m and is equivalent to the reduction in system cost expressed in $/MWh that results from a marginal increase of the capacity on constraint m~~k~~. If the market-clearing problem is limited by any Transmission Constraint including Interties, branch groups, flowgates, nomograms, and Energy Imbalance Market-related transmission constraints (EIM Transfer constraints and power balance constraint for a Balancing Authority Area), the market clearing process would create a Shadow Price for the Transmission Constraint, only when the relaxation of the constraint would result in a reduction in the total cost to operate the system.
- μ_m^k is the constraint Shadow Price on constraint m in the preventive transmission contingency case k and is equivalent to the reduction in system cost expressed in $/MWh that results from a marginal increase of the capacity on constraint m in the preventive transmission contingency case k. If the market-clearing problem is limited by any Transmission Constraint including Interties, branch groups, flowgates, nomograms, and

Energy Imbalance Market-related transmission constraints (EIM Transfer constraints and power balance constraint for a Balancing Authority Area), the market clearing process would create a Shadow Price for the Transmission Constraint, only when the relaxation of the constraint would result in a reduction in total cost to operate the system.

- μ_m^g is the constraint Shadow Price on constraint m in the preventive generator contingency case g and is equivalent to the reduction in system cost expressed in $/MWh that results from a marginal increase of the capacity on constraint m in the preventive generator contingency case g. If the market-clearing problem is limited by any Transmission Constraint including Interties, branch groups, flowgates, nomograms, and Energy Imbalance Market-related transmission constraints (EIM Transfer constraints and power balance constraint for a Balancing Authority Area), the market clearing process would create a Shadow Price for the Transmission Constraint, only when the relaxation of the constraint would result in a reduction in the total cost to operate the system.
- $\delta_{O_g,i}$ is the binary parameter that identifies the node with a generator outage under generator contingency case g. This parameter is one for all nodes in index i when i is the outage node Og associated with a generator contingency case g. This parameter is zero for all nodes in index i when i is not the outage node Og associated with the generator contingency case g.
- $PTDF_{i,m}^k$ is the Power Transfer Distribution Factor for the bus i on transmission component m under the preventive contingency case k, which represents the flow across that transmission component m when an increment of power is injected at bus i and an equivalent amount of power is withdrawn at the Reference Bus. The CAISO does not consider the effect of losses in the determination of PTDFs.
- $PTDF_{i,m}^g$ is the Power Transfer Distribution Factor for the bus i on transmission component m under the generator contingency case g, which represents the flow across that transmission component m when an increment of power is injected at bus i and an equivalent amount of power is withdrawn at the Reference Bus. The CAISO does not consider the effect of losses in the determination of PTDFs.

- $PTDF_{n,m}^{g}$ is the Power Transfer Distribution Factor for the bus n on transmission component m under the generator contingency case g, which represents the flow across that transmission component m when an increment of power is injected at bus n and an equivalent amount of power is withdrawn at the Reference Bus. The CAISO does not consider the effect of losses in the determination of PTDFs.
- $GLDF_{Og,n}$ is the generation of loss distribution factor in the preventive generator contingency case g. The value is negative one when n is Og. This value is zero when n is not Og, and when n is not associated with a frequency response capable generator. This value is the committed generator output at n divided by the sum of the output from all committed frequency response capable generators when n is not Og and n is associated with a frequency response capable generator.

The MCC at PNodes in an EIM Entity Balancing Authority Area j in the Real Time Market includes an additional contribution from the shadow price of the power balance constraint for that Balancing Authority Area, λ_j, as follows:

$$MCC_i = \lambda_j - \sum_{k=1}^{K} PTDF_{jk}\ FSP_k$$

$$MCC_i = \lambda_j - \sum_{m=1}^{M} PTDF_{ij} \cdot \mu_m - \sum_{k=1}^{K}\sum_{m=1}^{M} PTDF_{i,m}^{k}\ \mu_m^{k} - \sum_{g=1}^{K_g}\sum_{m=1}^{M} \left(PTDF_{i,m}^{g} + \delta_{O_g,i} \sum_{n=1}^{N} PTDF_{n,m}^{g}\ GLDF_{O_g,n} \right) \mu_m^{g}$$

A power balance constraint is not formulated for the CAISO Balancing Authority Area alone in the RTM. The shadow price of the power balance constraint for EIM Entity Balancing Authority Area j (λ_j) has the following contributions:

a) the shadow price of the EIM Transfer distribution constraint (φ_j), which distributes the EIM Transfer for Balancing Authority Area j to Energy transfers on interties with other Balancing Authority Areas in the EIM Area; and

b) the shadow price of the EIM Transfer scheduling limit for Balancing Authority Area j, upper (ν_j) or lower (ξ_j):

$$\lambda_j = \varphi_j - \nu_j + \xi_j$$

Where λ_j is zero for the CAISO Balancing Authority Area since the power balance constraint is not formulated for it.

The difference between the shadow prices of the EIM Transfer distribution constraints for two Balancing Authority Areas j and k in the EIM Area has the following contributions from any intertie l used for energy transfers between these two Balancing Authority Areas:

a) the EIM Transfer schedule cost that applies to that intertie l (c_l);

b) the shadow price of the Energy transfer schedule limit from Balancing Authority Area j to Balancing Authority Area k that applies to that intertie l, upper limit (ρ_l) or lower limit (σ_l); and

c) the shadow price of the scheduling limit that constrains both Energy transfers and additional schedules to Balancing Authority Area j on that intertie l, upper limit (ζ_l) or lower limit (η_l):

Attachment C – Draft Final Proposal and Revised Draft Final Proposal

Generator Contingency and Remedial Action Scheme

California Independent System Operator Corporation

Generator Contingency & RAS Modeling

Draft Final Proposal

July 25, 2017

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Table of contents

Revision History

Date	Revision
06/30/2017	Initial Release
07/25/2017	Updated Section 4, revising the Energy Imbalance Market Governing Body's authority to include providing advisory input on those aspects of the proposal relating to the real-time market.

1. Executive summary

The ISO operators currently manage constraints impacted by generator contingencies and remedial action scheme operation outside the market through manual intervention or in the market using static nomograms which approximately represent the constraint. Neither approach is optimal because each relies on human judgement and untimely operating condition assumptions. The proposed market design changes to recognize the impact of generator contingencies and remedial action scheme operation in the market will result in the most efficient and reliable generation dispatch by using the latest available information in the security constrained economic dispatch and not relying on manual intervention or operating condition assumptions.

Currently, the security constrained economic dispatch only considers loss of transmission elements in its contingency modeling. However, the transmission system may be constrained due to the loss of generation alone or due to remedial action scheme operation. The transmission system relies on an already large and increasing amount of remedial action scheme armed generation because these schemes are a cost effective and reliable method of increasing the transfer capability of transmission systems. The ISO intends to update the security constrained economic dispatch to:

(1) model generation loss in the dispatch, and

(2) model transmission loss along with subsequent generation/load loss due to remedial action scheme (RAS) operation in the dispatch.

The proposed changes result in an update to the congestion component of the locational marginal price so that it considers the cost of positioning the system to account for generator contingencies and remedial action scheme operations. A remedial action scheme connected generator will potentially receive higher energy prices than generators not connected to a remedial action scheme at the same bus because a remedial action scheme connected generator does not contribute to binding emergency limits.[1] While under certain scenarios the generator may receive a higher price for its energy, the constraint allows the dispatch to potentially use less expensive generation reducing overall production cost.

This initiative proposes market design changes that will impact generation dispatch in the market. The proposed changes can be used to model the loss of generation, a reliability issue that can require generation dispatched in certain locations in order to protect transmission elements for the loss of another generator.[2] The same functionality can be used to model generation loss due to remedial action scheme operation, which can increase the dispatch of lower cost generation efficiently through the market.[3]

[1] This behavior is shown in Section 6.4.1.2.
[2] This behavior is shown in Section 6.4.2.1.
[3] This behavior is shown in Section 6.4.1.1.

2. Scope of initiative

This initiative is focused on required enhancements to the day ahead market, real time market, and energy imbalance market to support generator contingencies. The final proposal should result in an economic dispatch that will respect all emergency limits after the loss of a generating unit or after remedial action scheme operation without the need for out-of-market intervention.

This initiative will not focus on the system response and state after the loss of a generating unit and subsequent deployment of contingency reserves.

The initiative’s objectives are to:

(1) Allow for the benefits of increased transmission capability while protecting the transmission system for remedial action scheme events;

(2) Pre-dispatch generation such that transmission lines will not overload if a generator event or remedial action scheme event were to occur; and

(3) Price the contribution to congestion for generators on remedial action schemes versus generators not on remedial action schemes.

3. Stakeholder Comments and changes to this proposal

In this initiative, the ISO has focused its efforts on ensuring transmission security immediately after generation loss (including due to remedial action scheme operation). This focus allowed the ISO to develop a methodology that realizes the benefits of remedial action schemes in the market, while also addressing issues that carry higher reliability risk. Stakeholders generally supported this approach because it will reduce out of market actions by modeling the cost of certain constraints in the market. DC Energy, Pacific Gas and Electric (PG&E), Powerex, Western Power Trading Forum (WPTF), and the Division of Market Monitoring (DMM) supported the proposed approach.

In its comments on the revised straw proposal, PG&E suggested that the ISO should also make its remedial action scheme modeling approach general enough to include dropping load or reconfiguring the transmission system by switching elements in addition to dropping generation. After reviewing remedial action scheme logic, the ISO agrees with PG&E that the ISO's proposed methodology should also be used to model remedial action schemes that drop load or reconfigure the transmission system. The functionality aligns with the ISO's goals of ensuring transmission security and reducing out-of-market actions.

Stakeholders also support the ISO's proposal to directly model the generator and remedial actions scheme contingencies in the congestion revenue rights market. PG&E suggested that the ISO update its congestion revenue rights market generation distribution factor calculation methodology to be based on the monthly average share of committed capacity. The ISO maintained its proposal to directly model the contingencies in the congestion revenue rights market, eliminated the previously discussed alternatives, and adjusted its generation distribution factor calculation methodology to align with PG&E's suggestion.

The Division of Market Monitoring demonstrated a potential consequence of the congestion revenue rights market granularity difference from the day-ahead market. It explains, however, that this is not caused by the ISO's proposed design of generator contingency and remedial action scheme modeling, but rather caused by the ISO's current congestion revenue rights market design. It shows the potential opportunity for market participants to receive higher payments on congestion revenue rights that would be valued lower in auction when a generator contingency or remedial action scheme is only modeled for a portion of the month in the day-ahead market. The ISO reviewed potential remedial action schemes and only found a few that may not be enabled, and therefore not enforced, for the entirety of a month; the rest will be enabled and enforced all month.

PacifiCorp submitted comments principally targeted at the implementation of the policy discussed in the revised straw proposal. The ISO will work with stakeholders on these items in the implementation stage of the initiative. PacifiCorp also questioned how the initiative would interact with ancillary services. As discussed in the revised straw proposal, the purpose of the initiative is to reserve transmission capacity for the loss of generation; the formulation does not procure generation capacity and therefore is not intended to ensure performance of generation reserves.

The Six Cities asked the ISO to clarify why the proposed revisions in the modeling would be optional for energy imbalance market entities. The ISO applies the same algorithm for dispatch optimization in all balancing authority areas participating in the energy imbalance market. As proposed, energy imbalance market entities could choose which generator or remedial action scheme contingencies, or any at all, they wish to enforce in that optimization. This follows the existing practice of allowing energy imbalance market entity operations engineers to interact with ISO operations engineers in determining constraints to enforce in their areas.

In response to the revised straw proposal, Southern California Edison (SCE) reiterated that it does not support using the proposed methodology to model remedial action schemes in the market. SCE states that it could lead to (1) unjustified revenue for remedial action scheme resources, (2) false incentives for network upgrades, and (3) distortions in the interconnection process. SCE does find merit in the approach for modeling generator contingencies, but seeks more information about the impact on congestion revenue rights and the impact of virtual bidding.

As discussed previously,[4] the ISO maintains that the price formation for the remedial action scheme generator is justified because it appropriately values the generator's contribution to congestion on the system and results in the most efficient dispatch of the resource. The ISO's markets are designed to determine the most efficient scheduling and dispatch of resources. CAISO market prices are a mechanism for incentivizing the resources that currently exist to participate in the market and to perform in the way that maximizes consumer and supplier (total) surplus while maintaining grid reliability. The methodology does not provide false incentives for network upgrades because it is the ISO and the transmission owner that decide the appropriate network upgrades, whether they be remedial action schemes or conventional transmission infrastructure, based on interconnection reliability studies. Finally, the ISO sees no distortions to the interconnection process because it will continue to base its interconnection decisions on the results of reliability studies and fixed infrastructure costs. When studies indicate that the system can no longer support generation participating in remedial action schemes, it will require the development of other transmission upgrades.

The ISO made the following changes to address stakeholder comments:

(1) In **_Section 6.5_**, the ISO proposed to use its methodology to also model remedial action schemes that drop load or reconfigure the transmission system.
(2) In **_Section 6.9_**, the ISO expanded its discussion on virtual bidding considerations to clarify the real-time settlement of day-ahead positions.
(3) In **_Section 6.11.3_**, the ISO proposed to track the generator and remedial action scheme contingency impact on real-time congestion imbalance offset going forward after implementation.
(4) In **_Section 6.12.3_**, the ISO proposed to directly model the generator and remedial action scheme contingencies in the congestion revenue rights market.
(5) In **_Section 6.12.3_**, the ISO proposed a methodology for calculating congestion revenue rights market generation distribution factors based on historical unit commitments.

[4] Section 6.5, Generator Contingency & RAS Modeling Revised Straw Proposal

(6) In ***Section 6.12.3***, the ISO analyzed the potential impact that granularity differences between the congestion revenue rights market and the day-ahead market may have on the proposed congestion revenue rights market generation distribution factor.
(7) In ***Section 6.12.3***, the ISO clarified that it will follow existing practices for enforcing generation contingencies in the congestion revenue rights market.

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4. Stakeholder engagement

As described in more detail below, this CAISO has revised its proposed plan for seeking approval and input on this initiative from the EIM Governing Body. The policy issues that this initiative addresses are within the scope of and will affect the ISO's Energy Imbalance Market where a participating EIM entity wishes to enforce generator or remedial action scheme contingencies within its EIM entity area.

Accordingly, Management plans to seek approval under the EIM Governing Body's primary authority for the element of this initiative that proposes to allow an EIM Entity the option to enforce generator or remedial action scheme contingencies within its EIM balancing authority area. The approach of dividing the initiative into separate components is consistent with the guidance in section II.B. of the *Guidance for Handling Policy Initiatives within the Decisional Authority or Advisory Role of the EIM Governing Body.* That document addresses how to proceed when an initiative contains a severable component that CAISO management would plan to file for approval whether or not another components or components are approved. In such a case, it states that "…any severable EIM-specific element should be separated after the conclusion of stakeholder review and directed to the EIM Governing Body for decision. The severable EIM-specific element (alone) should be directed to the EIM Governing Body as part of primary authority. The remainder of the initiative should be classified according to the applicable rules.

In the version of the draft final proposal issued on June 30, 2017, the CAISO stated that the EIM Governing Body would not have any role, however, in connection with the remainder of the proposal, because the remainder does not govern participation in the entire real-time market, but only the ISO balancing authority area portion of the real-time market. Upon further consideration, the CAISO has concluded that it would be appropriate for the EIM Governing Body to have the opportunity to provide advisory input on those aspects of the proposal relating to the real-time market, given that the resulting changes to the real-time market needed to accommodate this functionality would ultimately apply to any EIM Entities that may choose to adopt this functionality for their balancing authority area. For this reason, the CAISO has updated the draft final proposal issued on June 30, 2017, with changes only to this Section 4. As revised, Management plans to present to the EIM Governing Body for any potential advisory input those aspects of this proposal relating to the real-time market that are not already within the EIM Governing Body's primary approval authority. This advisory input is in addition to the EIM Governing Body's primary approval authority as described in June 30, 2017 draft final proposal. This is the only change that has been made to the June 20, 2017 draft final proposal.

The schedule for stakeholder engagement is provided below and targets the September 2017 Board of Governors meeting.

Date	Event
Wed 04/19/2016	Issue paper
Mon 04/25/2016	Stakeholder conference call
Fri 05/13/2016	Stakeholder comments due on issue paper
Mon 11/07/2016	Revised Issue Paper & Straw proposal posted
Tue 11/15/2016	Stakeholder conference call
Fri 12/02/2016	Stakeholder comments due on revised issue paper & straw proposal
Wed 03/15/2017	Revised straw proposal posted
Wed 03/22/2017	Stakeholder conference call
Wed 04/05/2017	Stakeholder comments due on revised straw proposal
Fri 06/30/2017	Draft final proposal posted
Fri 07/07/2017	Stakeholder conference call
Fri 07/14/2017	Stakeholder comments due on draft final proposal
September 2017	Energy Imbalance Market Governing Body
September 2017	Board of Governors

5. Background & issues

The ISO must ensure feasible dispatches. To do so, the ISO has two mandates when faced with generation and/or load loss:

> (1) The system must be secure after the loss of a generation/load element alone or in combination with a transmission element due to remedial action scheme operation, and
>
> (2) The system must be secure after the loss of a generation/load element alone or in combination with a transmission element due to remedial action scheme operation and the subsequent deployment of contingency reserves.

This proposal focuses on system security immediately after the loss of a generation/load element alone or in combination with a transmission element due to remedial action scheme operation.

5.1. Discussion

Among its many reliability requirements, the ISO must ensure a secure dispatch that considers the system condition immediately after a generator contingency. This section discusses the appropriate system condition immediately after any single contingency.

Evaluations for transmission security include planning for the potential loss of generation. The market enforces transmission security today, but it does not consider generator contingencies (i.e., loss of generation). Currently, the ISO evaluates and ensures transmission security for loss of generation outside of the market. As discussed below, by not modeling generator contingencies, the market could produce a transmission insecure dispatch considering the impact of the loss of a generating unit. In ***Section 5.1.2***, we evaluate what the market does today, the resulting issue, and what a desirable dispatch would achieve.

Remedial action schemes are a cost effective and reliable method of increasing the transfer capability of transmission systems. Remedial action schemes are physical/software systems integrated into the transmission system that detect predetermined system conditions and automatically take corrective actions such as automatically tripping generation if a transmission line is forced out. The ISO currently has more than 19,800 MW of remedial action scheme arm-able generation on its system. Evaluations for transmission security include planning for the loss of transmission along with immediate loss of associated generation such as could occur due to remedial action scheme operation.

Currently, the ISO evaluates and ensures transmission security for remedial action scheme operation outside of the market. As discussed below, by not explicitly modeling remedial action schemes in its security constrained economic dispatch, the market may be pricing in congestion where no congestion really exists and may be inaccurately reflecting the locational cost of supply. In ***Section 5.1.5***, we evaluate what the market does today, why that may be leaving room for more production cost savings, and what a desirable dispatch would achieve. In ***Section 5.1.6***, we evaluate another example of what the market does today, why that may not be accurately reflecting the locational cost of supply, and what a desirable dispatch would achieve.

5.1.1. N-1 security including potential loss of generation

All transmission operators, including the ISO, must plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 contingency planning) in accordance with North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and local reliability requirements. N-1 contingency planning means that the dispatch must not overload any transmission lines given the loss of any one element (N-1) or combination of elements that are simultaneously removed from service. The ISO accomplishes this by establishing and operating within system operating limits.[5]

Most system operating limits are straightforward and, once derived, can be directly modeled in the market system; the market uses these limits to produce a security constrained economic dispatch. Others are more complex and the ISO relies on operations engineering studies of near term system conditions to ensure that a reasonable mix of available generation and transmission in certain areas are sufficient to ensure N-1 security. For these complex system operating limits, operators additionally watch the real-time conditions and make generation dispatch adjustments out-of-market to ensure N-1 security through real-time.

A secure transmission system must be able to withstand credible transmission contingencies as well as credible generation contingencies.[6]

Transmission security for transmission contingencies

Transmission loss obviously has an immediate impact on the transmission system.

The ISO market system currently ensures that for the loss of a transmission element, all elements of the remaining system will be below emergency transmission ratings.

With the addition of the market changes resulting from the *Contingency Modeling Enhancements* initiative, the ISO market system will ensure that for the loss of a transmission element, no element of the remaining system will be over its emergency rating and that there is enough ramping capability to return transmission elements below a dynamic post-contingency system operating limit within 30 minutes.

[5] NERC Reliability Standard TOP-002-2.1b (R6)

[6] Credibility is an industry term that generally means a contingency is likely or plausible (independent of how critical or harmful the contingency may be, which is determined separately). The ISO's determination of credibility is not based solely on regulatory standards, but takes a holistic view of credibility that includes engineering studies and operator experience based on system conditions at the time of a contingency. *See generally* NERC Reliability Concepts and Peak Reliability SOL Methodology for the Operations Horizon.

Transmission security for generator contingencies

Generation loss also has an immediate impact on transmission system flows. While generation loss does not change the network topology of the system, it could dramatically impact flows and even cause operating limit exceedances and violations.

The ISO has not yet added the functionality to model generation loss within its security constrained economic dispatch because until recently, remedial action schemes were not as prevalent in the system. The loss of a generating unit in certain areas could result in flows over transmission elements above emergency ratings as the system responds.

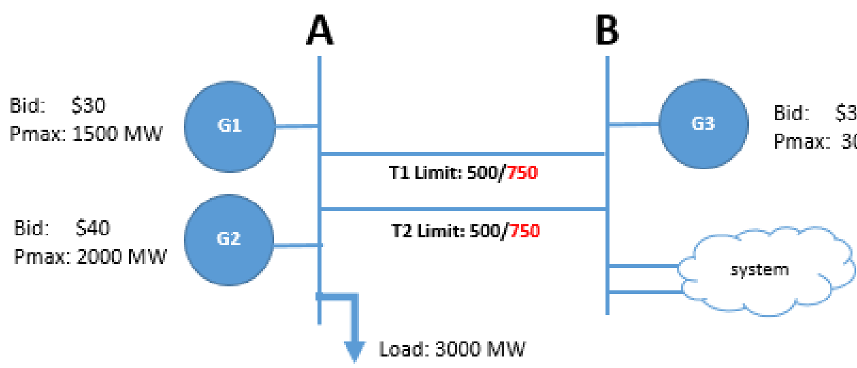
5.1.2. Insecure transmission given the potential loss of generation

The following example illustrates how the market could produce an insecure dispatch if it does not consider the loss of generation.

Market dispatch that does not consider generation loss

A market that does not consider generation loss produces a transmission insecure dispatch that requires operator intervention to maintain reliability.

We show a transmission path overload above its emergency rating after the loss of a generator if the system operator does not engage in out-of-market corrections to the dispatch.



Currently, the market will only schedule generation that results in a transfer of 750 MW between A and B because security constraints require the dispatch to account for the loss of T1 or T2. The market enforces a 750 MW emergency limit on transmission line T1 for the loss of transmission line T2.[7] The total normal transfer limit from B to A is 1000 MW (500 MW on T1 plus 500 MW on T2). The total emergency transfer limit from B to A is 1500 MW (750 MW on T1 plus 750 MW on T2); however, to protect for the loss of T2, a post-contingency emergency transfer limit from B to A of 750 MW is enforced today.

[7] In this particular scenario, enforcing the emergency rating on T1 for the loss of T2 yields the same dispatch as additionally enforcing the emergency rating on T2 for the loss of T1. In these scenarios, the ISO may only model one of the two contingencies because it yields the same dispatch and congestion.

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the current market dispatch.

Generator	Energy Bid	Energy Award
G1	$30	1500
G2	$40	750
G3	$35	750

Given the system setup and bidding behavior, the market dispatches the cheapest energy on G1 up to its pmax of 1500 MW followed by the next cheapest energy from G3. The emergency transfer limit 750 MW enforced from B to A for the loss of T2 binds, and the market dispatches G2 for the remaining 750 MW necessary to serve 3,000 MW of load.

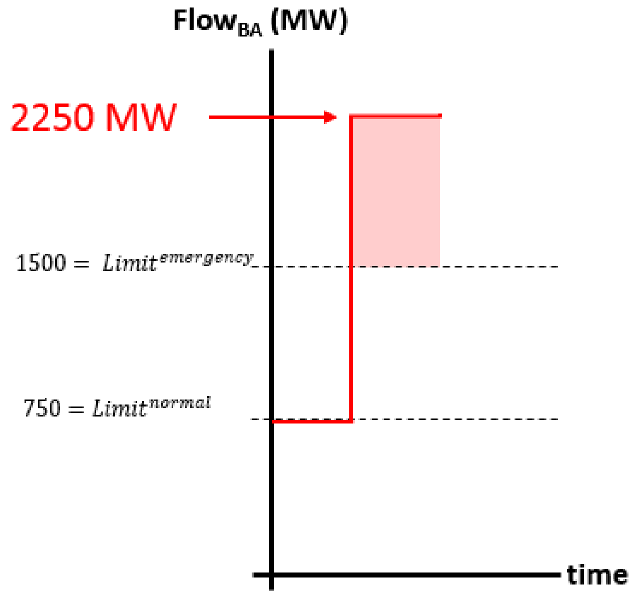
750 megawatts flow from B to A which respects the 1000 MW normal transfer limit and the 750 MW emergency transfer limit.

Path Flow		
Contingency	**Pre-Contingency Flow$_{BA}$ (MW)**	**Post-Contingency Flow$_{BA}$ (MW)**
Loss of T2	750	750
Loss of G1	750	**2250**

While this dispatch is secure for the loss of transmission line T2, it is not secure for the loss of generator G1. Assuming the total generation loss is made up from the rest of the system, if the system were to lose generator G1, an additional ~1500 MW would flow from B to A. This brings the total flow on the path to 2250 MW (750 MW pre-contingency flow plus the additional 1500 MW of generation required to meet load at A). The path from B to A would be well above its emergency rating given the potential loss of generator G1, which is not an N-1 secure dispatch and would therefore require manual intervention.

The image below shows the flow from B to A for the loss of G1 given the current market dispatch.

Figure 1: Flow on path B to A for loss of G1 given current market dispatch



Given the loss of the generator G1 at A, path AB would be loaded above its emergency rating of 1500 MW. A secure dispatch would ensure that path AB does not load above its emergency rating given a single contingency event. The dispatch that achieves this goal is shown below.

Market dispatch that <u>does</u> consider generation loss

A market that does consider generation loss produces a transmission secure dispatch that does not require operator intervention to maintain reliability.

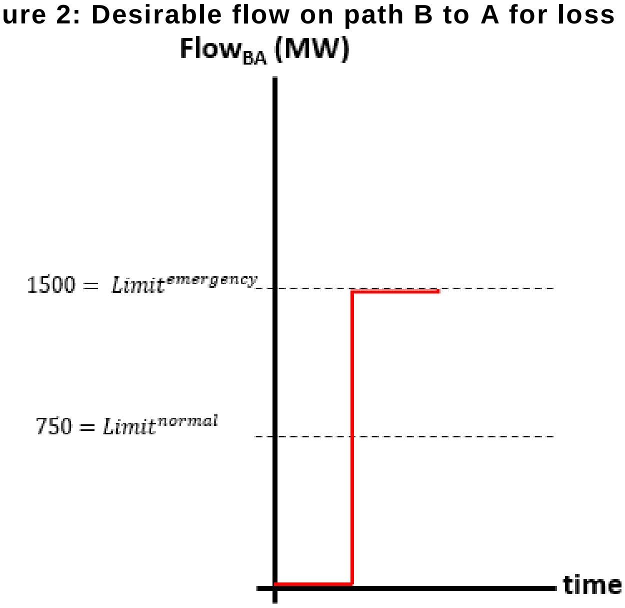
We now add the generator contingency into the set of contingencies.

Generator	Energy Bid	Energy Award
G1	$30	1500
G2	$40	1500
G3	$35	0

The secure dispatch places generator G2 at 1500 MW to ensure that post contingency flows from B to A do not exceed 1500 MW after the loss of generator G1. Assuming the total generation loss is made up from the rest of the system, the 1500 MW emergency rating on path AB does not bind for the generator contingency, but ensures post contingency flows would be less than or equal to 1500 MW. The 750 MW emergency rating on T1 does not bind for the loss of T2. The normal rating on Path AB does not bind.

The acceptable dispatch does not allow the flow from B to A for the loss of G1 to be greater than the emergency rating on the path. The image below shows the flow from B to A for the loss of G1 with an acceptable market dispatch. Note that flows stay below the emergency rating on the path.

Figure 2: Desirable flow on path B to A for loss of G1



5.1.3. Background on generator interconnection and remedial action scheme installations

The process to include a generator on a remedial action scheme is determined during the generation interconnection process. It is an infrastructure development decision based on system reliability, deliverability, and infrastructure cost. Expected energy prices are not considered.

When a new generator is connected to the grid, the ISO and participating transmission owners conduct power flow and transient stability studies to determine if the new generator will contribute to any reliability violation in operating the bulk electric system. If any potential violation is found, the ISO provides potential mitigation solutions such as building new lines, adding capacitors, installing new remedial action schemes, or curtailing generation in the area. Similarly, the ISO evaluates and determines the transmission upgrades needed for generation deliverability. If an existing remedial action scheme in the area is the most cost effective solution to mitigate a potential overload, the new generator will be required to finance and then use that remedial action scheme. In performing its generator interconnection studies, the ISO only considers the fixed infrastructure costs and not expected energy market prices.

Currently, all new or modified remedial action scheme upgrades are considered Reliability Network Upgrades (RNUs) and the interconnection customer is reimbursed up to $60,000/MW for all its assigned RNU costs within five years of the commercial operation date. Generators are reimbursed for network upgrades by the participating transmission owner. This means that the interconnection customer does not pay for transmission needed to mitigate the potential congestion. The ISO bases the decision on which transmission solution to require on system reliability, deliverability, and fixed infrastructure cost.

5.1.4. Prevalence of remedial action schemes on the system

Transmission systems in the western interconnection rely on an already large and increasing amount of arm-able remedial action scheme generation. Where remedial action schemes are not reflected in the market, price signals for the actual locational cost of supply can be muted.

Remedial action schemes are a cost effective and reliable method of increasing the transfer capability of transmission systems. Remedial action schemes have been historically utilized to increase a transmission system's capability to transmit remotely located hydroelectric generation long distances from load centers. They are now also being utilized to increase the grid's ability to transmit renewable generation that is remotely located long distances from load centers. Unfortunately, it is often the case that the realized benefits of the remedial action schemes are managed outside the market through operator intervention. This is not optimal.

Total generation-drop-related remedial action scheme installations have the capability to arm up to approximately 19,800 MW of generation. Northern California installations have the capability to arm up to 8,600 MW with a maximum single contingency loss of approximately 1,450 MW. Southern California installations have the capability to arm up to 11,200 MW with a maximum single contingency loss of approximately 2,300 MW. While remedial action schemes only arm the maximum capacity under certain system conditions (and it is highly unlikely that most or all arm-able remedial action scheme capacity is armed at one time), these numbers indicate the prevalence of remedial action schemes on the system. The term “arm-able” here means that the generation to be dropped at a given time is dependent on transmission system flows. Generally, when transmission flows in an area of the system are highest, the maximum amount of generation will be armed in that area. These conditions are the conditions that the ISO proposes to protect for in this initiative. If conditions on the system are not such that generation would be armed, it is unlikely that the generator and remedial action scheme constraints would bind. At some point during the day, one area of the system may have fully armed generation while another area of the system will not have generation armed at all. When conditions are such that no generation would be armed, it is unlikely that the generator and remedial action scheme constraints would bind. As such, the largest potential generation that could be dropped due to a remedial action scheme would present a significant impact on the system and is therefore important regardless of the aggregate level armed in the system at a given time.

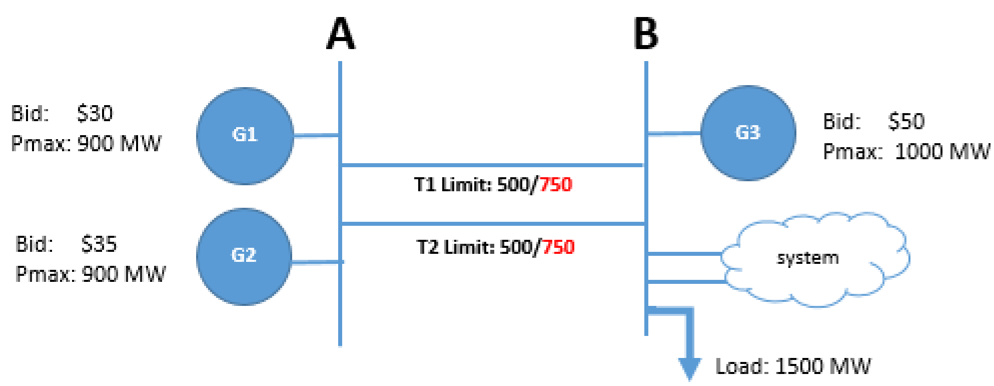
5.1.5. Production cost savings realized when modeling RAS generation loss

Many of the remedial action schemes in the system involve the loss of a transmission element along with the subsequent loss of all or a portion of generation. If not explicitly modeled in the market, the ISO may be producing a higher production cost dispatch due to certain constraints. If the ISO gains the capability to model the loss of generation, it could explicitly model remedial action schemes in the market, which would be optimal.

Market dispatch that does <u>not</u> consider RAS generation loss

Let us start with how the market behaves today. The market does not consider RAS generation loss, determines a dispatch yielding a higher production cost, and requires operator intervention to achieve the benefits from the remedial action scheme.

In this example, the market does not produce the lowest production cost dispatch without operator intervention, because it is inaccurately modeling congestion. Assume a remedial action scheme is defined such that for the loss of transmission line T2, generator G1 will trip offline with the loss of generation made up from the system at B.



Currently, the market enforces a 750 MW emergency limit on transmission line T1 for the loss of transmission line T2. The total normal transfer limit from A to B is 1000 MW (500 MW on T1 plus 500 MW on T2). The total emergency transfer limit from A to B is 1500 MW (750 MW on T1 plus 750 MW on T2); however, given the loss of T2, an emergency transfer limit from A to B of 750 MW is enforced today.

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the current market dispatch.

Generator	Energy Bid	Energy Award
G1	$30	750
G2	$35	0
G3	$50	750

Given the system setup and bidding behavior, the market dispatches 750 MW of the cheapest energy on G1. The emergency transfer limit of 750 MW enforced from A to B for the loss of T2 binds, and the market dispatches G3 for the remaining 750 MW necessary to serve 1,500 MW of load.

750 megawatts flow from A to B which respects the 1000 MW normal transfer limit and the 750 MW emergency transfer limit.

Path Flow		
Contingency	**Pre-Contingency Flow$_{BA}$ (MW)**	**Post-Contingency Flow$_{BA}$ (MW)**
Loss of T2	750	750
Loss of T2 & RAS loss of G1	750	0

While this dispatch is secure for the loss of transmission line T2, there is a RAS associated with the loss of T2 that is unaccounted for in the market dispatch. A remedial action scheme is defined such that for the loss of transmission line T2, generator G1 will trip offline.

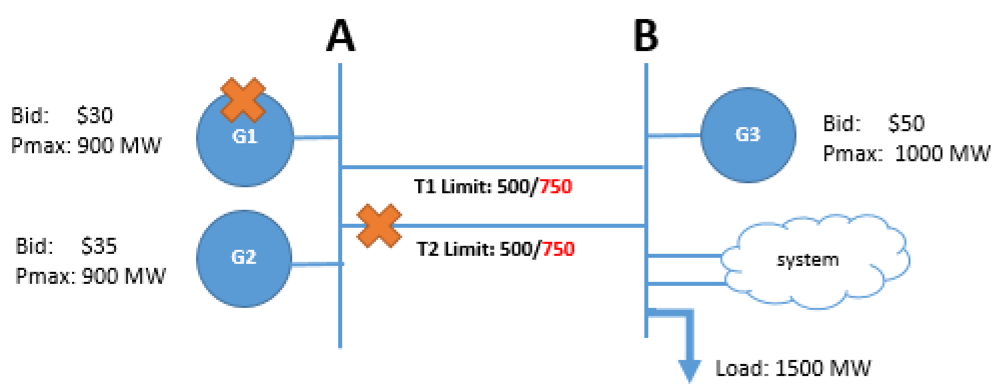
As shown in the Path Flow table above, the loss of transmission line T2 and subsequent remedial action scheme loss of generator G1 would result in transmission line T1 to be loaded under its emergency rating (0 MW). The market could have dispatched the cheaper generator G2 higher in the base case if the RAS was modeled in the market.

This dispatch yields a production cost of $22,500 + $37,500 = $60,000.

Market dispatch that <u>does</u> consider RAS generation loss

A market that does consider RAS generation loss determines the optimal dispatch yielding a lower production cost without the need for operator intervention.

Below, a contingency is defined as the loss of T2 along with the loss of generator G1. With this capability, the ISO does not enforce the loss of T2 alone because the contingency does not reflect the actual system operation.



As shown using orange X's above, a remedial action scheme is defined such that if T2 is lost, G1 will be tripped offline. The total normal transfer limit between A and B is 1000 MW (500 MW on T1 plus 500 MW on T2). The total emergency transfer limit between A and B is 1500 MW (750 MW on T1 plus 750 MW on T2); however, given the preventive loss of T2+G1, an emergency transfer limit between A and B of 750 MW will be enforced.

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the desired market dispatch.

Generator	Energy Bid	Energy Award
G1	$30	900
G2	$35	100
G3	$50	500

The market dispatches the cheapest energy on G1 up to its pmax of 900 MW followed by the next cheapest energy from G2. The normal transfer limit between A and B of 1000 MW binds, and the market dispatches G3 for the remaining 500 MW necessary to serve 1,500 MW of load.

1,000 MW flows between A and B in the base case, and only 100 MW flows between A and B in the remedial action scheme preventive case. Note that the remedial action scheme constraint does not bind at 750 MW because only 100 MW would flow between A and B after the potential loss of T2 and remedial action scheme operation that removes G1 from service.

Path Flow		
Contingency	**Pre-Contingency Flow$_{BA}$ (MW)**	**Post-Contingency Flow$_{BA}$ (MW)**
Loss of T2 & RAS loss of G1	1000	100
Note: Loss of T2 alone no longer enforced because it does not reflect the actual system operation.		

As shown in the Path Flow table above, the loss of transmission line T2 and subsequent remedial action scheme loss of generator G1 would result in transmission line T1 to be loaded under its emergency rating (100 MW). The market dispatched the cheaper generator G2 higher in the base case since the remedial action scheme was correctly modeled in the market.

This dispatch yields a production cost of $27,000 + $3,500 + $25,000 = $55,500, which is lower than today's dispatch production cost of $60,000.

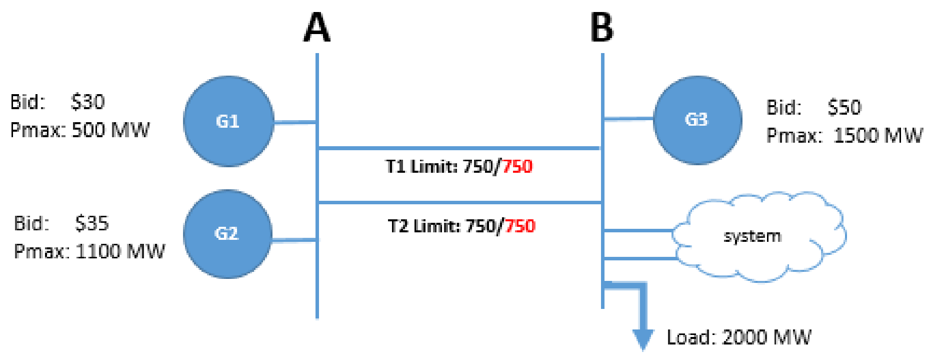
5.1.6. Accurate pricing of generation associated with remedial action schemes

Many of the remedial action schemes in the system involve the loss of a transmission element along with the subsequent loss of all or a portion of generation. If not explicitly modeled in the market, the resulting costs may not be accurately reflected in the locational marginal price. If the ISO market gains the capability to model the loss of generation, it could accurately price generation associated with remedial action schemes in the market.

Market dispatch that does not consider RAS generation loss

A market that does not consider remedial action scheme generation loss may suppress energy prices.

For example, here we show the emergency limit binding, but because the remedial action scheme is not modeled in the market, congestion charges for both G1 and G2 are equal.



The total normal transfer limit between A and B is 1,500 MW (750 MW on T1 plus 750 MW on T2). The total emergency transfer limit between A and B is 1,500 MW (750 MW on T1 plus 750 MW on T2); however, given the loss of T2, an emergency transfer limit between A and B of 750 MW will be enforced. In this example, the transmission system is designed such that there is no additional transfer capability on T1 or T2 above normal limits.

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the desired market dispatch.

Generator	Energy Bid	Energy Award	LMP
G1	$30	500	$35
G2	$35	250	$35
G3	$50	1250	$50

The market dispatches the cheapest energy on G1 up to its pmax of 500 MW followed by 250 MW of the next cheapest energy from G2. The transmission constraint of 750 MW for the loss of T2 binds, and the market dispatches G3 for the remaining 1250 MW necessary to serve

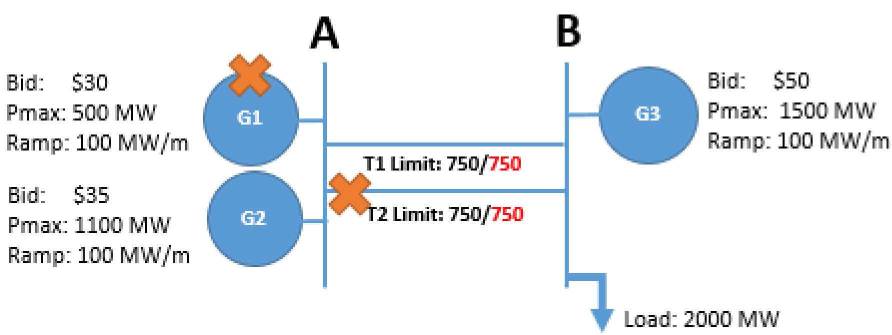
2,000 MW of load. In this example, the preventive constraint for the loss of T2 binds with a shadow cost of $15.

Both G1 and G2 are charged $15 of congestion associated with the binding transmission constraint, and both generators receive a $35 energy price.

Market dispatch that <u>does</u> consider RAS generation loss

A market that does consider remedial action scheme generation loss allows for accurate pricing of generation associated with remedial action schemes.

In this example, we show the emergency limit binding, but because the remedial action scheme generator is not contributing to preventive case congestion, it is not charged for that congestion.



As shown using orange X's above, a remedial action scheme is defined such that if T2 is lost, G1 will be tripped offline. The total normal transfer limit between A and B is 1,500 MW (750 MW on T1 plus 750 MW on T2). The total emergency transfer limit between A and B is 1,500 MW (750 MW on T1 plus 750 MW on T2); however, given the loss of T2+G1, an emergency transfer limit between A and B of 750 MW will be enforced. In this example, the transmission system is designed such that there is no additional transfer capability on T1 or T2 above normal limits.

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the desired market dispatch.

Generator	Energy Bid	Energy Award	LMP
G1	$30	500	$50
G2	$35	750	$35
G3	$50	750	$50

The market now dispatches the cheapest energy on G1 to its pmax of 500 MW followed by 750 MW of the next cheapest energy from G2. The remedial action scheme constraint limit from A to B of 750 MW binds, and the market dispatches G3 for the remaining 750 MW necessary to serve 2,000 MW of load.

1,250 MW flow between A and B in the base case, and 750 MW flow between A and B in the RAS preventive case. Note that the remedial action scheme constraint binds at 750 MW because a full 750 MW would flow from A to B after the potential loss of T2 and remedial action scheme operation that removes G1 from service, all of which is being produced by G2.

Only G2 contributes to the remedial action scheme constraint congestion, therefore, only G2 is charged the $15 in congestion from A to B. G1 is charged the same amount in congestion as any other generator that is not contributing to the congestion (G1 and G3 are charged $0 in congestion from A to B).

5.2. Existing strategies for reliable operations

The following rules are not modeled in the market leading to a less efficient and less reliable dispatch:

(1) Given a generator loss, all transmission facilities must be below emergency ratings.

(2) Given a transmission line loss, plus a generation loss due to remedial action scheme operation, all transmission facilities must be below emergency ratings.

The ISO achieves N-1 transmission security for the loss of generation today; however it often achieves this through manual intervention.

ISO operators rely on real-time contingency analysis tools and custom displays to constantly monitor the potential for generator contingencies that may push the system outside of operating limits and take manual action if necessary to keep the system within applicable limits. Assessing and ensuring N-1 security for generation contingencies requires a mix of offline studies, manual review, analysis, and out-of-market intervention.

ISO operations engineers also use remedial action scheme nomograms in limited areas of the system where it is possible to model for the loss of generation due to remedial action scheme operation. This method can only be used in certain areas of the system, requires full network model changes, relies on stale shift factors that may not be reflective of current system conditions, and can only monitor a limited portion of the system as opposed to ensuring all transmission elements do not overload for the operation of the remedial action scheme. In other areas of the system, operators de-activate single transmission contingencies related to the remedial action scheme, adjust path ratings, and manually monitor and adjust flows on the particular path throughout the day.

All strategies the ISO currently uses to achieve N-1 transmission security for the loss of generation suffer from the inefficiencies associated with manual review, analysis, and out-of-market intervention. The market will gain efficiency and pricing accuracy by implementing market design changes that produce an economic dispatch that respects all emergency limits after the loss of a generating unit alone or due to remedial action scheme operation without the need for out-of-market intervention. These market design changes will reduce inefficiencies associated with manual review, analysis, and out-of-market intervention.

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6. Proposal

This section describes a preventive constraint used to enable the market to model and price for the immediate impact of remedial action scheme operation on the transmission system. The purpose of this methodology is to ensure that the transmission system is below emergency ratings immediately after the loss of transmission and associated remedial action scheme generation loss; because reliability standards do not allow for any corrective timeframe in which to resolve these potential overloads, this methodology also allows for no corrective timeframe.

The N-1 preventive contingency model also can be expanded to enforce generation contingencies or simultaneous transmission and generation contingencies in preventive mode. The generation contingency is a G-1 contingency event and the simultaneous transmission and generation contingency is an N-1 transmission contingency with a remedial action scheme that trips one or more generating resources. The differences between the two types of contingency models are as follows:

	Preventive (G-1 or N-1+RAS)	**Preventive-Corrective (N-1-1)**
Contingency element	▪ Transmission Line ▪ Generation ▪ Transmission+Generation	▪ Transmission Line
Corrective action	Generation loss distribution	Re-dispatch
Corrective time period	Immediate	20-30mins
Post-corrective transmission limits	Emergency limits on all transmission elements	N-1-1 limit (lower than base case limit) on affected transmission corridor; emergency limits on other transmission elements
Contingency reserve dispatch	No	No

The base case is solved simultaneously with all contingencies in preventive mode and all contingencies in corrective mode, co-optimizing all commodities such as energy and ancillary services.

6.1. Modeling power flow for loss of generation

Before describing how to model for the loss of generation in the security constrained economic dispatch, it is helpful to first look to how planning and operations engineers study for the loss of generation in power flow studies today.

All analyses related to generator contingencies and remedial action scheme contingencies examine the resulting transmission system flows compared to emergency ratings of transmission facilities. The goal of the analyses is to determine the appropriate amount of transmission capacity to reserve on transmission lines to account for the change in flows caused by the loss of generation.

The ISO regional transmission planning engineers perform long-term studies where they analyze the potential for overloads given generator and remedial action scheme contingencies in stressed system conditions. In these studies the planning engineers model generation loss by removing a generator from service and spreading its generation to other frequency response capable generators on the system in accordance with applicable study criteria. The studies spread the generation to simulate the response of the system and observe the resulting flows on transmission lines. These studies utilize a generation distribution factor based on governor status, maximum generator output, and the units committed on the system.

The ISO operations planning engineers perform short-term studies where they analyze the potential for overloads given generator and remedial action scheme contingencies based on upcoming system conditions, outages, and assumptions of generator commitment status and output. In these studies, the operations engineers account for generation loss by removing a generator from service and spreading its generation to other frequency response enabled generators on the system in accordance with applicable study criteria. The studies spread the generation to simulate the response of the system and observe the resulting flows on transmission lines. These studies utilize a generation distribution factor based on governor status, maximum generator output, assumptions of the units committed on the system, and assumptions of the generator output.

The ISO real-time operations engineers also perform ad-hoc real-time studies where they analyze the potential for overloads given generator and remedial action scheme contingencies based on real-time system conditions, outages, generator commitment status, and generator output. They use the Real-Time Contingency Analysis (RTCA) tool to perform this study. The RTCA spreads the generation to simulate the response of the system and observe the resulting flows on transmission lines. These studies utilize a generation distribution factor based on governor status, maximum generator output, units committed on the system, and generator output.

The RTCA tool alerts operators when it detects an overload condition and operators take out-of-market action. The RTCA is a reactionary mechanism: it detects the real-time condition based on the current dispatch produced by the market, and operators react to potential problems.

All of these studies assume a generation distribution factor to simulate the system response to the loss of generation. This factor is the vehicle to distribute the lost generation across the system so one can determine the amount of power flowing on transmission elements after the loss of generation.

As discussed further below, we intend to utilize this same technique in modeling for the loss of generation in the security constrained economic dispatch. This will ensure that the pre-contingency dispatch pattern produced by the market will not violate operating criteria and ISO operations will no longer need to take reactionary out-of-market actions to meet reliability criteria.

6.2. Reserving transmission capacity for potential loss of generation

The generator contingency and remedial action scheme modeling proposal discussed below for the day-ahead and real-time markets reserves *transmission capacity* to account for the change in flows caused by the loss of generation. When generation is lost, the system has an immediate response whereby all frequency response enabled resources on the system automatically increase their output to compensate for the load and supply imbalance. The loss of the generator and the system response to the loss of the generator creates dramatically different flows on the system in the post-contingency state. The purpose of this initiative is to ensure that if the contingency were to happen, the resulting flows would not be greater than the emergency ratings on any transmission elements in the system. The proposal seeks to reserve enough *transmission capacity* in the right places to ensure that no transmission element would be loaded above its emergency rating if the contingency were to occur. This proposal does not reserve generation capacity.

6.3. Proposal Formulation

6.3.1. Notation

The following notation will be used throughout:

i	node index
m	transmission constraint index
k	preventive contingency index
g	generation contingency index
o_g	node index for generator outage under generation contingency g
N	total number of nodes
M	total number of transmission constraints
K	total number of preventive contingencies
K_g	total number of generation contingencies
S_{FR}	set of supply resources with frequency response capability
^{k}	superscript denoting preventive post-contingency values
^{g}	superscript denoting generation post-contingency values
$\tilde{}$	superscript denoting initial values from a power flow solution
$\forall$	for all…
Δ	denotes incremental values
u_i	commitment status of generating resource i (0: offline, 1: online)
G_i	generation schedule at node i
$G_{i,\min}$	minimum generation schedule at node i
$G_{i,\max}$	maximum generation schedule at node i
L_i	load schedule at node i
C_i	energy bid from generation at node i
$\mathbf{G}$	generation schedule vector
$g(\mathbf{G})$	power balance equation
$h_m(\mathbf{G})$	power flow for transmission constraint m
F_m	power flow limit for transmission constraint m
$Loss$	power system loss

LPF_i	loss penalty factor for power injection at node *i*
$SF_{i,m}$	shift factor of power injection at node *i* on transmission constraint *m*
$GDF_{o_g,i}$	generation loss distribution factor of generation contingency *g*
LMP_i	locational marginal price at node *i*
λ	system marginal energy cost (shadow price of power balance constraint)
μ_m	shadow price of transmission constraint *m*
$\delta_{o_g,i}$	Binary parameter (0 or 1) that identifies the generator node with generator outage under generation contingency *g*

6.3.2. Simplifying assumptions

To simplify the mathematical formulation solely for the purpose of presentation, the following assumptions are made:

- There is a single interval in the time horizon, thus inter-temporal constraints are ignored.
- There is a single Balancing Authority Area, thus Energy Imbalance Market Entities and Energy Transfers are ignored.
- Imports and exports are ignored.
- Unit commitment costs and variables are ignored, thus it is assumed that all generating resources are online and all Multi-State Generators are fixed in a given state.
- Load bids are ignored, thus load is scheduled as a price-taker at the load forecast.
- The energy bids cover the entire generating resource capacity from minimum to maximum.
- There is a single energy bid segment for each generating resource.
- Ancillary services are ignored.

6.3.3. Mathematical formulation

The mathematical formulation of the complete preventive contingency optimization problem is as follows:

$$\min \sum_{i=1}^{N} C_i \left(G_i - G_{i,\min}\right) \qquad (a)$$

subject to:

$$g(\boldsymbol{G}) = 0 \qquad (b)$$

$$h_m(\boldsymbol{G}) \le F_m, \quad m = 1,2,\dots,M \qquad (c)$$

$$h_m^k(\boldsymbol{G}) \le F_m^k, \quad \begin{cases} m = 1,2,\dots,M \\ k = 1,2,\dots,K \end{cases} \qquad (d)$$

$$G_i^g = G_i + GDF_{o_g,i} \cdot G_{o_g}, \quad \begin{cases} i = 1,2,\dots,N \\ g = 1,2,\dots,K_g \end{cases} \qquad (e)$$

$$h_m^g(\boldsymbol{G}^g) \le F_m^g, \quad \begin{cases} m = 1,2,\dots,M \\ g = 1,2,\dots,K_g \end{cases} \qquad (f)$$

$$G_{i,\min} \le G_i \le G_{i,\max}, \quad i = 1,2,\dots,N \qquad (g)$$

Where:

(a) is the objective function comprised of the bid cost for energy.

(b) is the power balance constraint in the base case, which can be linearized around the base case power flow solution as follows:

$$g(\boldsymbol{G}) \equiv \sum_{i=1}^{N} (G_i - L_i) - Loss \cong \sum_{i=1}^{N} \frac{\left(G_i - \tilde{G}_i\right)}{LPF_i} = 0$$

(c) is the set of transmission constraints in the base case, which can be linearized around the base case power flow solution as follows:

$$h_m(\boldsymbol{G}) \cong \tilde{h}_m\left(\widetilde{\boldsymbol{G}}\right) + \sum_{i=1}^{N} SF_{i,m} \left(G_i - \tilde{G}_i\right) \leq F_m, \qquad m = 1,2,\ldots,M$$

(d) is the set of transmission constraints in each preventive contingency case, which can be linearized around the base case power flow solution as follows:

$$h_m^k(\boldsymbol{G}) \cong \tilde{h}_m\left(\widetilde{\boldsymbol{G}}\right) + \sum_{i=1}^{N} SF_{i,m}^k \left(G_i - \tilde{G}_i\right) \leq F_m^k, \qquad \begin{cases} m = 1,2,\ldots,M \\ k = 1,2,\ldots,K \end{cases}$$

where the shift factors reflect the post-contingency network topology and the transmission power flow limits are the applicable emergency limits.

(e) is the generation loss distribution in the generation contingency state, which is assumed lossless and pro rata on the maximum online generation capacity from supply resources with frequency response capability, ignoring associated capacity and ramp rate limits. This value approximates the system response to loss of generation closely to how the system will actually behave. This value is used only to model flows placed on transmission in the contingency case, and is aligned with current operations engineering study practices:

$$GDF_{o_g,i} = \begin{Bmatrix} -1 & i = o_g \\ 0 & i \notin S_{FR} \wedge i \neq o_g \\ \dfrac{u_i\, G_{i,\max}}{\sum_{\substack{i \in S_{FR} \\ i \neq o_g}} u_i\, G_{i,\max}} & i \in S_{FR} \wedge i \neq o_g \end{Bmatrix}, \quad \begin{cases} i = 1,2,\ldots,N \\ g = 1,2,\ldots,K_g \end{cases}$$

(f) is the set of transmission constraints in each generation contingency case, which can be linearized around the base case power flow solution as follows:

$$h_m^g(\boldsymbol{G}^g) \cong \tilde{h}_m\left(\widetilde{\boldsymbol{G}}\right) + \sum_{i=1}^{N} SF_{i,m}^g \left(G_i^g - \tilde{G}_i\right) = \tilde{h}_m\left(\widetilde{\boldsymbol{G}}\right) + \sum_{i=1}^{N} SF_{i,m}^g \left(G_i + GDF_{o_g,i}\, G_{o_g} - \tilde{G}_i\right)$$
$$\leq F_m^g, \qquad \begin{cases} m = 1,2,\ldots,M \\ g = 1,2,\ldots,K_g \end{cases}$$

where the shift factors reflect the post-contingency network topology, which can be different than the base case if the contingency definition includes a transmission outage, and the transmission power flow limits are the applicable emergency limits.

(g) is the set of the resource capacity constraints in the base case.

Locational marginal prices

The locational marginal prices are as follows:

$$LMP_i = \frac{\lambda}{LPF_i} - \sum_{m=1}^{M} SF_{i,m}\,\mu_m - \sum_{k=1}^{K}\sum_{m=1}^{M} SF_{i,m}^{k}\,\mu_m^{k} - \sum_{g=1}^{K_g}\sum_{m=1}^{M}\left(SF_{i,m}^{g} + \delta_{o_g,i}\sum_{i=1}^{N} SF_{i,m}^{g}\,GDF_{o_g,i}\right)\mu_m^{g}\,,$$
$$i = 1,2,\dots,N$$

Where:

$$\delta_{o_g,i} = \begin{cases} 1 & i = o_g \\ 0 & i \neq o_g \end{cases},\ \begin{cases} i = 1,2,\dots,N \\ g = 1,2,\dots,K_g \end{cases}$$

Therefore, the marginal congestion contribution from a binding transmission constraint in a generator contingency to the locational marginal price at the node of the generator outage includes the impact of the assumed generation loss distribution.

A generator modeled in a generator contingency receives appropriate compensation taking into account its contribution to total production cost. The transmission constraint shadow prices are zero for constraints that are not binding in the base case or the relevant contingency case.

Generator flow factors

Similar to how a traditional "shift factor" represents the control variable's contribution to a particular constraint ($SF_{i,m}$ and $SF_{i,m}^{k}$), we can summarize a generator's contribution to the generator preventive constraint cost for a particular monitored element as a "generator flow factor" (GFF) in order to simplify the locational marginal price calculation in the examples presented in this paper.

The GFF, or contribution to the generator contingency preventive constraint, is:

$$GFF_{i,m}^{g} = SF_{i,m}^{g} + \delta_{o_g,i}\sum_{i=1}^{N} SF_{i,m}^{g}\,GDF_{o_g,i}$$

The GFF for the all generators that are not the contingency generator ($i \neq o_g$) simplifies to the network topology shift factor because each generator's $\delta_{o_g,i} = 0$:

$$GFF_{i,m}^{g} = SF_{i,m}^{g} + \delta_{o_g,i}\sum_{i=1}^{N} SF_{i,m}^{g}\,GDF_{o_g,i} = SF_{i,m}^{g} + (0)\sum_{i=1}^{N} SF_{i,m}^{g}\,GDF_{o_g,i}$$

$$GFF_{i,m}^{g} = SF_{i,m}^{g} \qquad \forall i \neq o_g$$

The GFF for the generator that is the contingency generator ($i = o_g$) simplifies as follows:

$$GFF^{g}_{o_g,m} = SF^{g}_{o_g,m} + \delta_{o_g,i} \sum_{i=1}^{N} SF^{g}_{i,m}\, GDF_{o_g,i}$$

$$GFF^{g}_{o_g,m} = SF^{g}_{o_g,m} + (1) \sum_{i=1}^{N} SF^{g}_{i,m}\, GDF_{o_g,i} = SF^{g}_{o_g,m} + SF^{g}_{o_g,m} \cdot GDF_{o_g,i} + \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF^{g}_{i,m}\, GDF_{o_g,i}$$

$$GFF^{g}_{o_g,m} = SF^{g}_{o_g,m} + SF^{g}_{o_g,m} \cdot (-1) + \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF^{g}_{i,m}\, GDF_{o_g,i}$$

$$GFF^{g}_{o_g,m} = \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF^{g}_{i,m}\, GDF_{o_g,i}$$

This generator flow factor simplifies the locational marginal price calculation in the examples below. All generators not part of the generator contingency definition ($i \neq o_g$) are charged $GFF^{g}_{i,m}$ (simplified above to the network topology shift factor $SF^{g}_{i,m}$) multiplied by the shadow cost of the generator contingency constraint (μ^{g}_{m}).The generator on contingency ($i = o_g$) is charged $GFF^{g}_{o_g,m}$ multiplied by the shadow cost of the generator contingency constraint (μ^{g}_{m}). It represents the total impact on the monitored element from all of the locations on the system to where the optimization distributes the lost generation.

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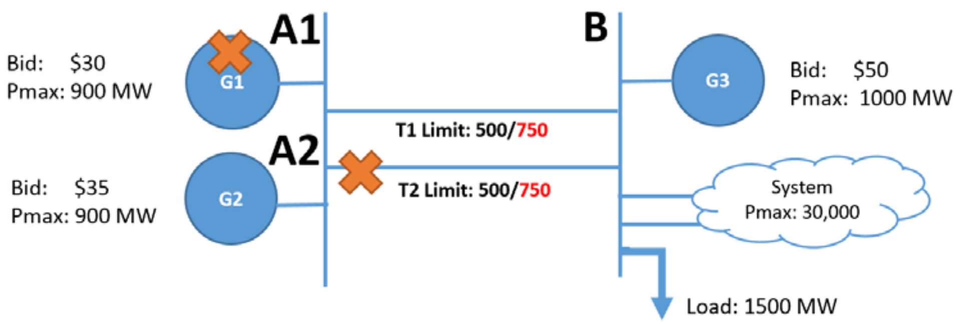
6.4. Examples

6.4.1. Secure transmission after remedial action scheme operation

The three examples below illustrate how the remedial action scheme preventive constraint solution methodology impacts market dispatch, price formation, and settlement while ensuring the system is within its emergency limits immediately after a transmission loss and associated remedial action scheme generation loss. Each example has slightly different resource definitions and/or bidding behaviors.

6.4.1.1. Example 1 (normal limit binds)

In this example, we show the normal limit binding while the remedial action scheme preventive constraint does not bind, thereby showing that the remedial action scheme generator that still contributes to base case congestion is charged for base case congestion.



As shown using orange X's above, a remedial action scheme is defined such that if T2 is lost, G1 will be tripped offline. The total normal transfer limit between A and B is 1000 MW (500 MW on T1 plus 500 MW on T2). The total emergency transfer limit between A and B is 1500 MW (750 MW on T1 plus 750 MW on T2); however, given the simultaneous preventive loss of T2 and G1, an emergency transfer limit between A and B of 750 MW will be enforced.

Bids & Awards

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the enhanced market dispatch.

Generator	Energy Bid	Energy Award	LMP
G1	$30	900	$35
G2	$35	100	$35
G3	$50	500	$50

The market dispatches the cheapest energy on G1 up to its pmax of 900 MW followed by the next cheapest energy from G2. The normal transfer limit between A and B of 1000 MW binds, and the market dispatches G3 for the remaining 500 MW necessary to serve 1,500 MW of load.

Modeled Flows

1,000 MW flow from A to B in the base case and the normal constraint binds. Only 125 MW flow from A to B in the remedial action scheme preventive case, which does not bind. Note that the remedial action scheme preventive constraint does not bind because only 125 MW would flow from A to B after the loss of T2 and remedial action scheme operation that removes G1 from service; all of which is modeled as being produced from bus A.

Base case flows from A to B are calculated:

$$Flow^0_{AB} = \text{G1 Energy Award} \cdot (SF^0_{A1,AB}) + \text{G2 Energy Award} \cdot (SF^0_{A2,AB}) + \text{G3 Energy Award} \cdot (SF^0_{B,AB})$$

$$1{,}000 \text{ MW} = 900 \cdot (1) + 100 \cdot (1) + 500 \cdot (0)$$

Base case flows of 1,000 MW are less than or equal to the normal transfer capability on the path and the constraint binds at a shadow cost (μ^0_{AB}) of $15.

As discussed in Section 6.3.3, the system's response to G1's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G1's contribution to flows on the path from A to B and consequently its contribution to this constraint's cost is calculated as a Generation Flow Factor ("GFF"):

$$GFF^{RAS}_{A1,AB} = \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF^g_{i,m}\, GDF_{o_g,i} = \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF^g_{i,m} \frac{G_{i,max}}{\sum_{i \neq o_g} G_{i,max}} = (1) \cdot \frac{900}{31{,}900} + (0) \cdot \frac{1{,}000}{31{,}900} + (0) \cdot \frac{30{,}000}{31{,}900} = 0.028213$$

Remedial action scheme preventive case flows from A to B are calculated:

$$Flow^{RAS}_{AB} = \text{G1 Energy Award} \cdot (GFF^{RAS}_{A1,AB}) + \text{G2 Energy Award} \cdot (GFF^{RAS}_{A2,AB}) + \text{G3 Energy Award} \cdot (GFF^{RAS}_{B,AB})$$

$$125 \text{ MW} = 900 \cdot (0.028213) + 100 \cdot (1) + 500 \cdot (0)$$

Remedial action scheme preventive case flows of 125 MW are less than the emergency transfer capability on the path, given the remedial action scheme operation, and the constraint does not bind. There is a shadow cost (μ^g_{AB}) of $0.

Price Formation

Generator G1 is charged for its contribution to the congestion from A to B ($SF^0_{A1,AB}$). In this example, it is charged congestion on the energy that flows on the binding normal constraint. Because bus A has a network topology shift factor of 1 ($SF^0_{A1,AB}$) to the constraint, all of the energy (G1 Energy Award· ($SF^0_{A1,AB}$) ≅ 900 MW) is charged μ^0_{AB} in congestion.

Generator G2 is charged the $15 in congestion from A to B because its full output has a network topology shift factor of 1 to the normal constraint ($SF^0_{A1,AB}$). Generator G1 is charged approximately the same amount in congestion as any other generator that is contributing to the congestion (G1 and G2 are charged $15 in congestion from A to B), while G3 which contributes nothing to the normal constraint ($SF^0_{B,AB}$) is not charged.

Note that the contribution factors to the remedial action scheme preventive constraint ($GFF^{RAS}_{i,AB}$) did not impact the energy prices because it had no shadow cost.

		Normal		Loss of G1+T2		
Generator (i)	**λ^0**	**$SF^0_{i,AB}$**	**μ^0_{AB}**	**$GFF^{RAS}_{i,AB}$**	**μ^{RAS}_{AB}**	**LMP**
G1	$50	1	$15	0.028213	$0	$35
G2	$50	1	$15	1	$0	$35
G3	$50	0	$15	0	$0	$50

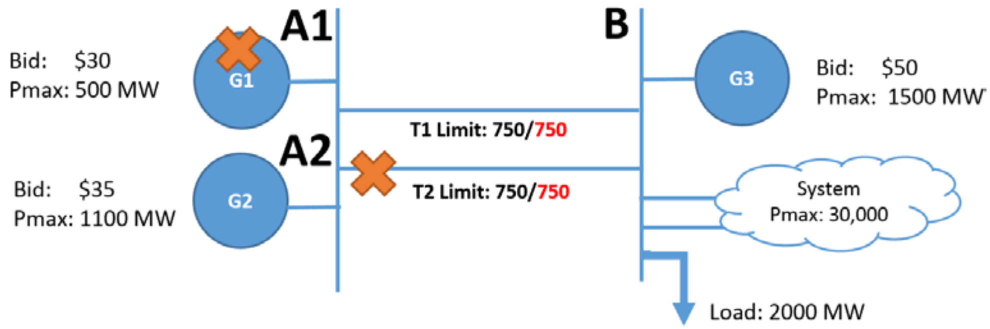
Both G1 and G2 contribute to the normal limit congestion, therefore, both are charged the $15 in congestion from A to B.

Settlement

Generator/ Load	LMP	Energy Award	Energy Payment	Total Revenue
G1	$35	900	$31,500	$31,500
G2	$35	100	$3,500	$3,500
G3	$50	500	$25,000	$25,000
Load B	$50	-1500	-$75,000	-$75,000
Energy & Capacity				-$15,000
CRR_{AB}	$15	750		$11,250
Market Net				-$3,750

6.4.1.2. Example 2 (Emergency limit binds)

In this example, we show the emergency limit binding, but because the remedial action scheme generator is minimally contributing to preventive case congestion, it is only charged a small amount for that congestion.



As shown using orange X's above, a remedial action scheme is defined such that if T2 is lost, G1 will be tripped offline. The total normal transfer limit between A and B is 1,500 MW (750 MW on T1 plus 750 MW on T2). The total emergency transfer limit between A and B is 1,500 MW (750 MW on T1 plus 750 MW on T2); however, given the simultaneous preventive loss of T2 and G1, an emergency transfer limit between A and B of 750 MW will be enforced. In this example, the transmission system is designed such that there is no additional transfer capability on T1 or T2 above normal limits.

Bids & Awards

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the enhanced market dispatch.

Generator	Energy Bid	Energy Award	LMP
G1	$30	500	$49.49
G2	$35	733	$35
G3	$50	767	$50

The market dispatches the cheapest energy on G1 up to its pmax of 500 MW followed by the next cheapest energy from G2. The remedial action scheme preventive constraint transfer limit from A to B of 750 MW binds because of a 733 MW contribution to flow from G2 plus the additional contribution from the portion of the lost generator that was distributed to node A2 of 17 MW (733+17=750). The market dispatches G3 for the remaining 750 MW necessary to serve 2,000 MW of load.

Modeled Flows

1,233 MW flow from A to B in the base case, and 750 MW flow from A to B in the remedial action scheme preventive case. Note that the remedial action scheme preventive constraint binds at 750 MW because a full 750 MW would flow from A to B after the loss of T2 and remedial action scheme operation that removes G1 from service; all of which is modeled as being produced from bus A.

Base case flows from A to B are calculated:

$$Flow^{0}_{AB} = \text{G1 Energy Award} \cdot (SF^{0}_{A1,AB}) + \text{G2 Energy Award} \cdot (SF^{0}_{A2,AB}) + \text{G3 Energy Award} \cdot (SF^{0}_{B,AB})$$

$$1{,}233 \text{ MW} = 500 \cdot (1) + 733 \cdot (1) + 767 \cdot (0)$$

Base case flows of 1,233 MW are less than the normal transfer capability on the path and the constraint does not bind.

As discussed in Section 6.3.3, the system's response to G1's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G1's contribution to flows on the path from A to B and consequently its contribution to this constraint's cost is calculated as:

$$GFF^{RAS}_{A1,AB} = \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF^{g}_{i,m}\, GDF_{o_g,i} = \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF^{g}_{i,m} \frac{G_{i,max}}{\sum_{i \neq o_g} G_{i,max}} = (1) \cdot \frac{1{,}100}{32{,}600} + (0) \cdot \frac{1{,}500}{32{,}600} + (0) \cdot \frac{30{,}000}{32{,}600} = 0.033742$$

Remedial action scheme preventive case flows from A to B are calculated:

$$Flow^{RAS}_{AB} = \text{G1 Energy Award} \cdot (GFF^{RAS}_{A1,AB}) + \text{G2 Energy Award} \cdot (GFF^{RAS}_{A2,AB}) + \text{G3 Energy Award} \cdot (GFF^{RAS}_{B,AB})$$

$$750 \text{ MW} = 500 \cdot (0.033742) + 733 \cdot (1) + 767 \cdot (0)$$

Remedial action scheme preventive case flows of 750 MW are less than or equal to the emergency transfer capability on the path, given the remedial action scheme operation, and the constraint binds at a shadow cost (μ^{RAS}_{AB}) of $15.

Price Formation

Generator G1 is charged for its contribution to the congestion from A to B. In this example, it is charged for the portion of its output that was distributed to bus A using the pro-rata distribution (the impact of the distributed generation is represented as the generator flow factor $GFF^{RAS}_{A1,AB}$). Because node A1 has a network topology shift factor of 1 ($SF^{g}_{A1,AB}$) to the constraint, all of the portion of energy distributed to bus A (G1 Energy Award· ($GFF^{RAS}_{A1,AB}$) ≅ 17 MW) is charged μ^{RAS}_{AB} in congestion.

Generator G2 is charged the $15 in congestion from A to B because its full output has a network topology shift factor of 1 ($SF^{g}_{A2,AB}$) to the constraint in the remedial action scheme preventive constraint. G1 is charged approximately the same amount in congestion as any other generator that is not contributing to the congestion (G1 and G3 are charged ~$0 in congestion from A to B), while G2 which contributes its full output to the remedial action scheme preventive case congestion is charged $15.

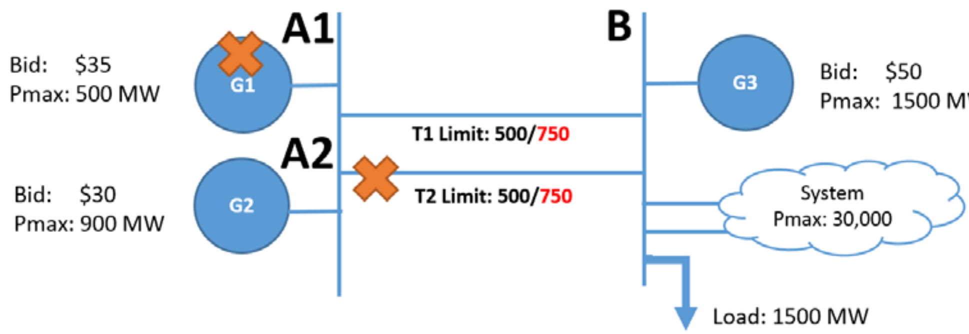
		Normal		Loss of G1+T2		
Generator (i)	**λ^0**	**$SF^0_{i,AB}$**	**μ^0_{AB}**	**$GFF^{RAS}_{i,AB}$**	**μ^{RAS}_{AB}**	**LMP**
G1	$50	1	$0	0.033742	$15	$49.49
G2	$50	1	$0	1	$15	$35
G3	$50	0	$0	0	$15	$50

Settlement

Generator/ Load	LMP	Energy Award	Energy Payment	Total Revenue
G1	$49.49	500	$24,745	$24,745
G2	$35	733	$25,655	$25,655
G3	$50	767	$38,350	$38,350
Load B	$50	-2000	-$100,000	-$100,000
Energy & Capacity				-$11,250
CRR_{AB}	$15	750		$11,250
Market Net				$0

6.4.1.3. Example 3 (Both normal and emergency limits bind)

In this example, we show the normal limit binding and the remedial action scheme preventive constraint binding, thereby showing that the remedial action scheme generator that still contributes to base case congestion is charged for base case congestion. However, because it is minimally contributing to preventive case congestion, it is minimally charged for that congestion.



As shown using orange X's above, a remedial action scheme is defined such that if transmission line T2 is lost, generator G1 will be tripped offline. The total normal transfer limit from A to B is 1,000 MW (500 MW on T1 plus 500 MW on T2). The total emergency transfer limit from A to B is 1,500 MW (750 MW on T1 plus 750 MW on T2); however, given the simultaneous preventive loss of T2 and G1, an emergency transfer limit between A and B of 750 MW will be enforced.

Bids & Awards

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the enhanced market dispatch.

Generator	Energy Bid	Energy Award	LMP
G1	$35	257	$35
G2	$30	743	$30
G3	$50	500	$50

The market dispatches 743 MW of the cheapest energy from G2. The RAS preventive constraint transfer limit from A to B of 750 MW binds, and the market dispatches 257 MW of the next cheapest generation from G1. The base case normal transfer limit between A and B of 1000 MW binds, and the market dispatches the remaining 500 MW necessary to serve 1,500 MW of load from G3.

1,000 MW flows from A to B in the base case, and 750 MW flows from A to B in the remedial action scheme preventive case. Note that the remedial action scheme preventive constraint binds at 750 MW because a full 750 MW would flow from A to B after the loss of T2 and remedial action scheme operation that removes G1 from service; all of which is modeled as being produced from bus A.

Modeled Flows

1,000 MW flow from A to B in the base case, and 750 MW flow from A to B in the remedial action scheme preventive case. Note that the remedial action scheme preventive constraint binds at 750 MW because a full 750 MW would flow from A to B after the loss of T2 and remedial action scheme operation that removes G1 from service; all of which is modeled as being produced from bus A.

Base case flows from A to B are calculated:

$$Flow^0_{AB} = \text{G1 Energy Award}\cdot (SF^0_{A1,AB}) + \text{G2 Energy Award}\cdot (SF^0_{A2,AB}) + \text{G3 Energy Award}\cdot (SF^0_{B,AB})$$

$$1{,}000 \text{ MW} = 257\cdot(1) + 743\cdot(1) + 500\cdot(0)$$

Base case flows of 1,000 MW are less than or equal to the normal transfer capability on the path and the constraint binds at a shadow cost (μ^0_{AB}) of $15.

As discussed in Section 6.3.3, the system's response to G1's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G1's contribution to flows on the path from A to B and consequently its contribution to this constraint's cost is calculated as:

$$GFF^{RAS}_{A1,AB} = \sum_{\substack{i=1 \\ i\neq o_g}}^{N} SF^g_{i,m}\, GDF_{o_g,i} = \sum_{\substack{i=1 \\ i\neq o_g}}^{N} SF^g_{i,m} \frac{G_{i,max}}{\sum_{i\neq o_g} G_{i,max}} = (1)\cdot\frac{900}{32{,}400} + (0)\cdot\frac{1{,}500}{32{,}400} + (0)\cdot\frac{30{,}000}{32{,}400} = 0.027778$$

Remedial action scheme preventive case flows from A to B are calculated:

$$Flow^{RAS}_{AB} = \text{G1 Energy Award}\cdot(GFF^{RAS}_{A1,AB}) + \text{G2 Energy Award}\cdot (GFF^{RAS}_{A2,AB}) + \text{G3 Energy Award}\cdot (GFF^{RAS}_{B,AB})$$

$$750 \text{ MW} = 257\cdot(0.027778) + 743\cdot(1) + 500\cdot(0)$$

Remedial action scheme preventive case flows of 750 MW are less than or equal to the emergency transfer capability on the path, given the remedial action scheme operation, and the constraint binds at a shadow cost (μ^{RAS}_{AB}) of $5.

Price Formation

Because both G1 and G2 contribute to the normal limit congestion, they are charged \$15 in congestion from A to B. G2 additionally contributes to the remedial action scheme preventive constraint congestion, and is therefore charged an additional \$5 in congestion from A to B. G1 is charged a total of \$15 in congestion while G2 is charged a total of \$20 in congestion from A to B. G3 does not contribute to congestion from A to B, so it does not receive a congestion charge.

Generator G1 is charged for its contribution to the congestion from A to B mostly due to the normal constraint, but also minimally due to the remedial action scheme preventive constraint. Generator G1's full output is charged μ^0_{AB} due to its contribution to the binding normal limit. It is also charged the congestion related to the remedial action scheme preventive constraint (μ^{RAS}_{AB}) for the portion of its output that was distributed to bus A using the pro-rata distribution (the impact of the distributed generation is represented as the generator flow factor $GFF^{RAS}_{A1,AB}$). Because bus A has a network topology shift factor of 1 ($SF^g_{A1,AB}$) to the constraint, all of the portion of energy distributed to bus A (G1 Energy Award· ($GFF^{RAS}_{A1,AB}$) ≅ 7 MW) is charged μ^{RAS}_{AB} in congestion.

Generator G2 is charged a total of \$20 for its contribution to the congestion from A to B due to the normal constraint (μ^0_{AB}=\$15) and the remedial action scheme preventive constraint (μ^{RAS}_{AB}=\$5). Generator G2's full output is charged μ^0_{AB} due to its contribution to the binding normal limit. Generator G2 is also charged μ^{RAS}_{AB} in congestion from A to B because its full output has a contribution factor of 1 ($GFF^g_{A2,AB}$) to the constraint in the remedial action scheme preventive constraint.

Generator G1 is charged for its total contribution to congestion, mostly through its contribution to the normal constraint, but also minimally due to the remedial action scheme preventive constraint. Generator G2 is charged for its total contribution to congestion through both the normal constraint and the remedial action scheme preventive constraint.

		Normal		**Loss of G1+T2**		
Generator (i)	**λ^0**	**$SF^0_{i,AB}$**	**μ^0_{AB}**	**$GFF^{RAS}_{i,AB}$**	**μ^{RAS}_{AB}**	**LMP**
G1	\$50	1	\$15	0.027778	\$5	\$35
G2	\$50	1	\$15	1	\$5	\$30
G3	\$50	0	\$15	0	\$5	\$50

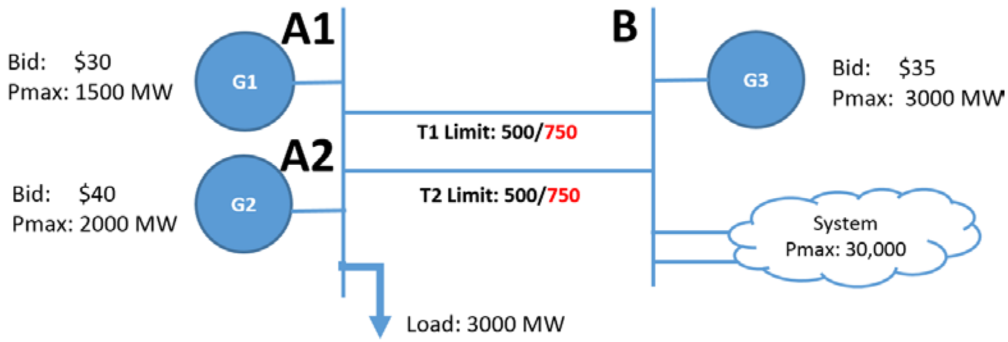
Settlement

Generator/ Load	LMP	Energy Award	Energy Payment	Total Revenue
G1	$35	257	$8,995	$8,995
G2	$30	743	$22,290	$22,290
G3	$50	500	$25,000	$25,000
Load B	$50	-1500	-$75,000	-$75,000
Energy & Capacity				-$18,715
CRR_{AB}	$20	750		$15,000
Market Net				-$3,715

6.4.2. Secure transmission after generator loss

6.4.2.1. Example 1 (Emergency limit binds for loss of generation)

In this example, we show the emergency limit binding for the loss of a generator. Here, we examine the interplay between today's transmission constraints and the proposed generator contingency constraints. This example shows that the loss of generation modeled as proposed may be more limiting than the loss of transmission in an area of the system by enforcing both types of contingencies in the market.



The total normal transfer limit from B to A is 1,000 MW (500 MW on T1 plus 500 MW on T2). The total emergency transfer limit from B to A is 1,500 MW (750 MW on T1 plus 750 MW on T2); however, given the preventive loss of T1, an emergency transfer limit from B to A of 750 MW will be enforced. We also enforce a generator contingency preventive constraint to protect the path from B to A for the potential loss of each generator (G1, G2, and G3); this constraint has a total emergency transfer limit of 1,500 MW (750 MW on T1 plus 750 MW on T2).

Bids & Awards

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the enhanced market dispatch.

Generator	Energy Bid	Energy Award	LMP
G1	$30	1500	$35.29
G2	$40	1414	$40
G3	$35	86	$35

The market dispatches the cheapest energy on G1 up to its pmax of 1,500 MW followed by the next cheapest energy from G3. To protect for the loss of G1, the generator contingency preventive constraint transfer limit from B to A of 1,500 MW binds, and the market dispatches G2 for the remaining 1,414 MW necessary to serve 3,000 MW of load.

Modeled Flows

Base case. 86 MW flow from B to A in the base case. Base case flows from B to A are calculated:

$$Flow^{0}_{BA} = \text{G1 Energy Award}\cdot(SF^{0}_{A1,BA}) + \text{G2 Energy Award}\cdot(SF^{0}_{A2,BA}) + \text{G3 Energy Award}\cdot(SF^{0}_{B,BA})$$

$$86\text{ MW} = 1500\cdot(0) + 1414\cdot(0) + 86\cdot(1)$$

Base case flows of 86 MW are less than the normal transfer capability of 1,000 MW on the path and the normal constraint does not bind.

Transmission line T1 contingency. 86 MW flow from B to A in the preventive case protecting for the loss of T1. Flows are calculated:

$$Flow^{T1}_{BA} = \text{G1 Energy Award}\cdot(SF^{T1}_{A1,BA}) + \text{G2 Energy Award}\cdot(SF^{T1}_{A2,BA}) + \text{G3 Energy Award}\cdot(SF^{T1}_{B,BA})$$

$$86\text{ MW} = 1500\cdot(0) + 1414\cdot(0) + 86\cdot(1)$$

Preventive case flows of 86 MW are less than the emergency rating on the path and the constraint does not bind.

Generator G1 contingency. 1,500 MW flow from B to A in the generator contingency preventive case protecting for the loss of G1. Flows are calculated:

$$Flow^{G1}_{BA} = \text{G1 Energy Award}\cdot(GFF^{G1}_{A1,BA}) + \text{G2 Energy Award}\cdot(GFF^{G1}_{A2,BA}) + \text{G3 Energy Award}\cdot(GFF^{G1}_{B,BA})$$

$$1{,}500\text{ MW} = 1500\cdot(0.942857) + 1414\cdot(0) + 86\cdot(1)$$

As discussed in Section 6.3.3, the system's response to G1's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G1's contribution to flows on the path from B to A and consequently its contribution to this constraint's cost is calculated as:

$$GFF^{G1}_{A1,BA} = \sum_{\substack{i=1\\ i\neq o_g}}^{N} SF^{g}_{i,m}\, GDF_{o_g,i} = \sum_{\substack{i=1\\ i\neq o_g}}^{N} SF^{g}_{i,m}\, \frac{G_{i,max}}{\sum_{i\neq o_g} G_{i,max}} = (0)\cdot\frac{2000}{35{,}000} + (1)\cdot\frac{3{,}000}{35{,}000} + (1)\cdot\frac{30{,}000}{35{,}000} = 0.942857$$

The other GFF's are equal to the network topology shift factors.

Generator contingency preventive case flows of 1,500 MW are less than or equal to the emergency rating on the path and the constraint binds at a shadow cost (μ^{G1}_{BA}) of \$5.

Generator G2 contingency. 1,439 MW flow from B to A in the generator contingency preventive case protecting for the loss of G2. Flows are calculated:

$Flow^{G2}_{BA}$ = G1 Energy Award· ($GFF^{G2}_{A1,BA}$) + G2 Energy Award· ($GFF^{G2}_{A2,BA}$) + G3 Energy Award· ($GFF^{G2}_{B,BA}$)

1,439 MW = 1500·(0) + 1414·(0.956522) +86·(1)

As shown in the formulation section above, the system's response to G2's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G2's contribution to flows on the path from B to A and consequently its contribution to this constraint's cost is calculated as:

$$GFF^{G2}_{A2,BA} = \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF^{g}_{i,m}\, GDF_{o_g,i} = \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF^{g}_{i,m}\, \frac{G_{i,max}}{\sum_{i \neq o_g} G_{i,max}} = (0) \cdot \frac{1500}{34{,}500} + (1) \cdot \frac{3{,}000}{34{,}500} + (1) \cdot \frac{30{,}000}{34{,}500} = 0.956522$$

The other GFF's are equal to the network topology shift factors.

Generator contingency preventive case flows of 1,439 MW are less than the emergency rating on the path and the constraint does not bind.

Generator G3 contingency. 77 MW flow from B to A in the generator contingency preventive case protecting for the loss of G3. Flows are calculated:

$Flow^{G3}_{BA}$ = G1 Energy Award· ($GFF^{G3}_{A1,BA}$) + G2 Energy Award· ($GFF^{G3}_{A2,BA}$) + G3 Energy Award· ($GFF^{G3}_{B,BA}$)

77 MW = 1500·(0) + 1414·(0) +86·(0.895522)

As shown in the formulation section above, the system's response to G3's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G3's contribution to flows on the path from B to A and consequently its contribution to this constraint's cost is calculated as:

$$GFF^{G3}_{B,BA} = \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF^{g}_{i,m}\, GDF_{o_g,i} = \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF^{g}_{i,m}\, \frac{G_{i,max}}{\sum_{i \neq o_g} G_{i,max}} = (0) \cdot \frac{1500}{33{,}500} + (0) \cdot \frac{2{,}000}{33{,}500} + (1) \cdot \frac{30{,}000}{33{,}500} = 0.895522$$

The other GFF's are equal to the network topology shift factors.

Generator contingency preventive case flows of 77 MW are less than the emergency rating on the path and the constraint does not bind.

Price Formation

Generator G1 is charged for its contribution to the congestion from B to A. In this example, it is charged for the portion of its output that was distributed to bus B using the pro-rata distribution. Because node B has a network topology shift factor of 1 ($SF^{G1}_{B,BA}$) to the constraint, all of the portion of energy distributed to bus B (G1 Energy Award· ($GFF^{G1}_{A1,BA}$) ≅ 1414 MW) is charged μ^{G1}_{BA} in congestion.

Generator G3 is charged for its contribution to the congestion from B to A because it has a contribution factor of 1 ($GFF^{G1}_{B,BA}$) to the path for the transmission preventive constraint that binds at a shadow cost (μ^{G1}_{BA}) of $5.

For generators G2 and G3, the generator flow factors representing the impact on the path of the portions of their output distributed to the various buses in the system were calculated ($GFF^{G2}_{A2,BA}$ and $GFF^{G3}_{B,BA}$) but not used because the constraints did not bind.

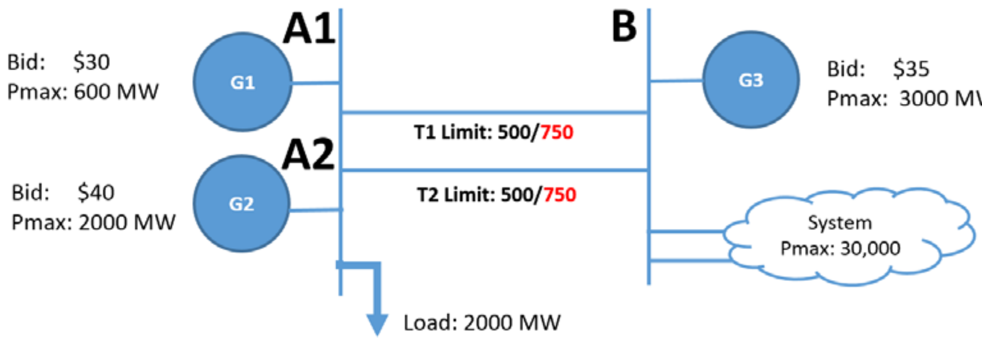
		Normal		Loss of T1		Loss of G1		Loss of G2		Loss of G3		
Generator (i)	**λ^0**	**$SF^0_{i,BA}$**	**μ^0_{BA}**	**$SF^{T1}_{i,BA}$**	**μ^{T1}_{BA}**	**$GFF^{G1}_{i,BA}$**	**μ^{G1}_{BA}**	**$GFF^{G2}_{i,BA}$**	**μ^{G2}_{BA}**	**$GFF^{G3}_{i,BA}$**	**μ^{G3}_{BA}**	**LMP**
G1	$40	0	$0	0	$0	0.942857	$5	0	$0	0	$0	$35.29
G2	$40	0	$0	0	$0	0	$5	0.956522	$0	0	$0	$40
G3	$40	1	$0	1	$0	1	$5	1	$0	0.895522	$0	$35

Settlement

Generator/ Load	LMP	Energy Award	Energy Payment	Total Revenue
G1	$35.29	1500	$52,935	$52,935
G2	$40	1414	$56,560	$56,560
G3	$35	86	$3,010	$3,010
Load A	$40	-3000	-$120,000	-$120,000
Energy & Capacity				-$7,495
CRR_{BA}	$5	750		$3,750
Market Net				-$3,745

6.4.2.2. Example 2 (Emergency limit binds for loss of transmission)

In this example, we show the emergency limit binding only for the loss of a transmission line even though we enforce a generator contingency for all three generators. Here, we examine the interplay between today's transmission constraints and the proposed generator contingency constraints. This example shows that the loss of transmission, as modeled today, may be more limiting than the loss of generation in an area of the system by enforcing both types of contingencies in the market.



The total normal transfer limit from B to A is 1,000 MW (500 MW on T1 plus 500 MW on T2). The total emergency transfer limit from B to A is 1,500 MW (750 MW on T1 plus 750 MW on T2); however, given the preventive loss of T1, an emergency transfer limit from B to A of 750 MW will be enforced. We also enforce a generator contingency preventive constraint to protect the path from B to A for the potential loss of each generator (G1, G2, and G3); this constraint has a total emergency transfer limit of 1,500 MW (750 MW on T1 plus 750 MW on T2).

Bids & Awards

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the enhanced market dispatch.

Generator	Energy Bid	Energy Award	LMP
G1	$30	600	$40
G2	$40	650	$40
G3	$35	750	$35

The market dispatches the cheapest energy on G1 up to its pmax of 600 MW followed by the next cheapest energy from G3. To protect for the loss of T1, the preventive constraint transfer limit from B to A of 750 MW binds, and the market dispatches G2 for the remaining 650 MW necessary to serve 2,000 MW of load.

Modeled Flows

Base case. 750 MW flow from B to A in the base case. Base case flows from B to A are calculated:

$$Flow^{0}_{BA} = \text{G1 Energy Award} \cdot (SF^{0}_{A1,BA}) + \text{G2 Energy Award} \cdot (SF^{0}_{A2,BA}) + \text{G3 Energy Award} \cdot (SF^{0}_{B,BA})$$

$$750\text{ MW} = 600 \cdot (0) + 650 \cdot (0) + 750 \cdot (1)$$

Base case flows of 750 MW are less than or equal to the normal transfer capability of 1,000 MW on the path and the normal constraint does not bind.

Transmission line T1 contingency. 750 MW flow from B to A in the preventive case protecting for the loss of T1. Flows are calculated:

$$Flow^{T1}_{BA} = \text{G1 Energy Award} \cdot (SF^{T1}_{A1,BA}) + \text{G2 Energy Award} \cdot (SF^{T1}_{A2,BA}) + \text{G3 Energy Award} \cdot (SF^{T1}_{B,BA})$$

$$750\text{ MW} = 600 \cdot (0) + 650 \cdot (0) + 750 \cdot (1)$$

Preventive case flows of 750 MW are less than or equal to the emergency rating on the path and the constraint binds at a shadow cost (μ^{T1}_{AB}) of $5.

Generator G1 contingency. 1,316 MW flow from B to A in the generator contingency preventive case protecting for the loss of G1. Flows are calculated:

$$Flow^{G1}_{BA} = \text{G1 Energy Award} \cdot (GFF^{G1}_{A1,BA}) + \text{G2 Energy Award} \cdot (GFF^{G1}_{A2,BA}) + \text{G3 Energy Award} \cdot (GFF^{G1}_{B,BA})$$

$$1{,}316\text{ MW} = 600 \cdot (0.942857) + 650 \cdot (0) + 750 \cdot (1)$$

As discussed in Section 6.3.3, the system's response to G1's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G1's contribution to flows on the path from B to A and consequently its contribution to this constraint's cost is calculated as:

$$GFF^{G1}_{A1,BA} = \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF^{g}_{i,m}\, GDF_{o_g,i} = \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF^{g}_{i,m} \frac{G_{i,max}}{\sum_{i \neq o_g} G_{i,max}} = (0) \cdot \frac{2000}{35{,}000} + (1) \cdot \frac{3{,}000}{35{,}000} + (1) \cdot \frac{30{,}000}{35{,}000} = 0.942857$$

The other GFF's are equal to the network topology shift factors.

Generator contingency preventive case flows of 1,316 MW are less than the emergency rating on the path and the constraint does not bind.

Generator G2 contingency. 1,388 MW flow from B to A in the generator contingency preventive case protecting for the loss of G2. Flows are calculated:

$$Flow^{G2}_{BA} = \text{G1 Energy Award}\cdot (GFF^{G2}_{A1,BA}) + \text{G2 Energy Award}\cdot (GFF^{G2}_{A2,BA}) + \text{G3 Energy Award}\cdot (GFF^{G2}_{B,BA})$$

$$1{,}388 \text{ MW} = 600\cdot(0) + 650\cdot(0.98214) + 750\cdot(1)$$

As discussed in Section 6.3.3, the system's response to G2's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G2's contribution to flows on the path from B to A and consequently its contribution to this constraint's cost is calculated as:

$$GFF^{G2}_{A2,BA} = \sum_{\substack{i=1 \\ i\neq o_g}}^{N} SF^{g}_{i,m}\, GDF_{o_g,i} = \sum_{\substack{i=1 \\ i\neq o_g}}^{N} SF^{g}_{i,m}\, \frac{G_{i,max}}{\sum_{i\neq o_g} G_{i,max}} = (0)\cdot\frac{600}{33{,}600} + (1)\cdot\frac{3{,}000}{33{,}600} + (1)\cdot\frac{30{,}000}{33{,}600} = 0.98214$$

The other GFF's are equal to the network topology shift factors.

Generator contingency preventive case flows of 1,388 MW are less than the emergency rating on the path and the constraint does not bind.

Generator G3 contingency. 690 MW flow from B to A in the generator contingency preventive case protecting for the loss of G3. Flows are calculated:

$$Flow^{G3}_{BA} = \text{G1 Energy Award}\cdot (GFF^{G3}_{A1,BA}) + \text{G2 Energy Award}\cdot (GFF^{G3}_{A2,BA}) + \text{G3 Energy Award}\cdot (GFF^{G3}_{B,BA})$$

$$690 \text{ MW} = 600\cdot(0) + 650\cdot(0) + 750\cdot(0.92025)$$

As discussed in Section 6.3.3, the system's response to G3's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G3's contribution to flows on the path from B to A and consequently its contribution to this constraint's cost is calculated as:

$$GFF^{G3}_{B,BA} = \sum_{\substack{i=1 \\ i\neq o_g}}^{N} SF^{g}_{i,m}\, GDF_{o_g,i} = \sum_{\substack{i=1 \\ i\neq o_g}}^{N} SF^{g}_{i,m}\, \frac{G_{i,max}}{\sum_{i\neq o_g} G_{i,max}} = (0)\cdot\frac{600}{32{,}600} + (0)\cdot\frac{2{,}000}{32{,}600} + (1)\cdot\frac{30{,}000}{32{,}600} = 0.92025$$

The other GFF's are equal to the network topology shift factors.

Generator contingency preventive case flows of 690 MW are less than the emergency rating on the path and the constraint does not bind.

Price Formation

Generator G3 is charged for its contribution to the congestion from B to A because it has a shift factor of 1 ($SF^{T1}_{B,BA}$) to the path for the transmission preventive constraint that binds at a shadow cost (μ^{T1}_{AB}) of $5.

For all generators in generator contingencies, while the generator flow factors representing the impact of the portions of their output of which were distributed to the various buses in the system were calculated ($GFF^{G1}_{i,BA}$, $GFF^{G2}_{i,BA}$, and $GFF^{G3}_{i,BA}$) the constraints did not bind.

		Normal		Loss of T1		Loss of G1		Loss of G2		Loss of G3		
Generator (i)	**λ^0**	**$SF^0_{i,BA}$**	**μ^0_{BA}**	**$SF^{T1}_{i,BA}$**	**μ^{T1}_{BA}**	**$GFF^{G1}_{i,BA}$**	**μ^{G1}_{BA}**	**$GFF^{G2}_{i,BA}$**	**μ^{G2}_{BA}**	**$GFF^{G3}_{i,BA}$**	**μ^{G3}_{BA}**	**LMP**
G1	$40	0	$0	0	$5	0.942857	$0	0	$0	0	$0	$40
G2	$40	0	$0	0	$5	0	$0	0.98214	$0	0	$0	$40
G3	$40	1	$0	1	$5	1	$0	1	$0	0.92025	$0	$35

Settlement

Generator/ Load	LMP	Energy Award	Energy Payment	Total Revenue
G1	$40	600	$24,000	$24,000
G2	$40	650	$26,000	$26,000
G3	$35	750	$26,250	$26,250
Load A	$40	-2000	-$80,000	-$80,000
Energy & Capacity				-$3,750
CRR_{BA}	$5	750		$3,750
Market Net				$0

6.5. Methodology not limited to only generation-drop based remedial action schemes

In its comments on the revised straw proposal, PG&E suggested that the ISO should make its remedial action scheme modeling approach general enough to include load drops or reconfiguring the transmission system by switching elements (in addition to generation drops). After reviewing remedial action scheme logic, the ISO is convinced that its methodology should also be used to model remedial action schemes that drop load or reconfigure the transmission system. The functionality is aligned with the ISO's proposed design.

To model for the loss of load due to remedial action scheme operation, the methodology will spread the net energy lost or gained in the contingency using the generation distribution factors. A remedial action scheme that trips 1,000 MW of generation and 500 MW of load will result in the spread of only 500 MW to each node on the system according to its generation distribution factor. A remedial action scheme that trips 1,000 MW of generation and 1,500 MW of load will result in the spread of 500 MW of load to each node on the system according to its generation distribution factor. This functionality aligns with the operational characteristics of remedial action schemes, and the proposed methodology handles the scenarios using the appropriate modeling of the elements lost and the net energy lost or gained.

To model for reconfiguration of the transmission system by switching elements in addition to dropping generation and/or load, the ISO's proposed methodology will use the post-contingency shift factors to show the impact on the system. These reconfigurations can be defined as part of the contingency definition itself. This functionality aligns with the operational characteristics of remedial action schemes and the proposed methodology handles the scenarios using the appropriate modeling of the elements lost or gained on the system to derive the correct shift factors to be used in the optimization.

6.6. Price formation and economic signals

The proposed approach provides the appropriate locational marginal price for each generator on the system. On any path in the system, there are two constraints to protect for: (1) normal operating limits and, (2) in the event of a contingency, emergency limits. The approach described above simply models the transmission system as it will electrically behave. In the examples above, all generation will place flows on the path under normal conditions while only the non-remedial action scheme generator will place flows on the line in the contingency condition. A generator that would not contribute to an emergency limit binding on a particular path (because it would not be online after the contingency) does not contribute to the emergency limit congestion. As such, the generator should not be charged for this congestion. While the two generators are at the same physical location, they are in two very different electrical locations based on electric system characteristics.

Stakeholders point to the potential higher locational marginal price for a generator on a remedial action scheme and interpret it as valuing the participation in remedial action schemes higher than normal participation. While the outcome is true, it should rather be thought of as *appropriately valuing each generator's contribution to congestion* on the system. A generator that would not contribute to congestion should not be charged for that congestion. A generator on a remedial action scheme simply would not contribute congestion toward the emergency limit on the nearby path;[8] and because of this, the security constrained economic dispatch can increase its use of cheaper generation behind the constraint, lowering overall production cost. While two generators at the same physical location may receive two different locational marginal prices, each price represents each generator's actual contribution to congestion, and each price is aligned with each generator's dispatch.

Stakeholders also express concern that this pricing enhancement could lead to an unnecessary incentive for new remedial action schemes. But the locational marginal price is not providing a signal for generators to invest in remedial action scheme additions. As discussed in ***Section 5.1.3***, the grid operator and participating transmission owner decide to require a remedial action scheme based on system reliability, deliverability, and fixed infrastructure cost and not expected energy market prices. The proposed changes to the day-ahead and real-time markets merely allow the market to reflect the electrical characteristics of the installed system.

6.7. Constraint selection criteria

Similar to how preventive transmission constraints are enforced in the market as needed to reliably manage the system based on engineering analysis and outage studies today, the ISO will enforce preventive generator and remedial action scheme constraints in the market as needed to reliably manage the system based on engineering analysis and outage studies.

6.8. Enforce constraints in all markets

The ISO proposes to enforce these contingencies in the integrated forward market for the financial outcome where virtual bids are used just like physical bids, in the residual unit commitment for the operational outcome, and finally in the real-time market.

6.9. Virtual bidding considerations

Virtual bids in the integrated forward market will have the same impact on the generator and remedial action scheme preventive constraints as on other constraints and products in the integrated forward market today. Virtual demand and supply at a generator or remedial action scheme contingency node will be treated as an injection or withdrawal where the net injection or withdrawal at the node is reflected in generation vector G^g. This treatment is consistent with the current treatment of a virtual bid's impact on transmission constraints today.

In its comments on the revised straw proposal, SCE asked for clarity on whether generator contingency constraints would apply to virtual bids. Specifically, if there are only virtual bids, and no physical bids, at the location of the physical generator in the day-ahead market, should

[8] The remedial action scheme generator does however contribute to certain congestion on the system in the form of small increases to flows on all emergency constraints after the generation loss is distributed across the system. This phenomenon is shown in the proposal through the calculation of the generator flow factors.

the physical generator contingency constraint be enforced even without the physical generator being committed under the proposal?

SCE is concerned that scheduling the system in the day-ahead market for potential loss of virtual supply may be inappropriate. Allowing virtual supply/demand to participate at the generator node is appropriate because the intent of virtual bidding is to better predict real-time conditions. In order to prevent gaming and support convergence between the day-ahead and real-time market, the ISO will treat the virtual supply the same as physical supply. The ISO will enforce the contingency on the generator node regardless of whether it receives physical or virtual bids at the node. Other ISOs that currently model generation loss in their real-time markets are currently seeking enabling the functionality in their day-ahead markets to prevent virtual traders from gaming the generator contingency node due to the modeling difference between the two markets. In the day-ahead market, virtual bids will be charged for the congestion caused by the generator contingency by receiving the appropriate energy price. The virtual bids will then be liquidated in the real-time market.

There would be an issue if the ISO did not consistently enforce the contingency in both the day-ahead and real-time markets. If the contingency was not applied to the generator node in the day-ahead market, a virtual bidder at the location would receive a higher energy price in the day ahead because it would not be charged for transmission congestion caused by the contingency. If the contingency is then applied in the real-time market, the energy price would be lower due to the congestion charge and the virtual supply would buy back at a lower energy price in the real-time market.

As discussed at the May 5, 2017 Market Surveillance Committee meeting, the ISO must ensure that the generator contingency node receives the appropriate real-time settlement of day-ahead positions by enforcing the constraint in both markets regardless of if there is virtual or physical supply at the node.

6.10. Energy imbalance market considerations

The policy issues that this initiative addresses are within the scope of and will affect the ISO’s energy imbalance market where an EIM Entity wishes to enable the functionality within its balancing area.

The ISO will make the generator and remedial action scheme preventive constraint feature available to EIM Entities. Any EIM Entity can work with the ISO to enforce generator or remedial action scheme contingencies if it would like to model more accurately the production cost of the scheme in the security constrained economic dispatch.

6.11. Impact on real-time congestion imbalance offset

In response to the revised issue paper and straw proposal, PG&E expressed concern over potential revenue inadequacy in the real-time market caused by changes in the modeled commitment between the day-ahead and real-time markets.

6.11.1. The proposed model may impact real-time congestion imbalance offset

The ISO recognizes that a difference in generation distribution factors between the day-ahead and real-time market caused by changes in the commitment pattern between the two markets may positively or negatively impact real-time congestion imbalance offset. While the ISO understands that real-time congestion imbalance offset is not necessarily a bad thing and can be considered a cost of providing system reliability, it still feels that the concern at least warrants an analysis of the potential impact this policy may have on real-time congestion imbalance offset.

A similar phenomenon exists today when ISO market operators lower transmission ratings in the real-time market to protect for new threats to reliability. When limits are lower in the real-time market than they were in the day-ahead market, and the constraints are binding, there is no counter-party buy-back of the excess generation schedules; instead, the market incurs real-time congestion imbalance offset.

Similarly, the generator and remedial action scheme constraints reserve a certain amount of transmission capacity in the day-ahead market based on the resources committed in the day-ahead market. When the real-time market solves, the generator and remedial action scheme constraints will reserve either more or less transmission capacity based on the resources committed in the real-time market. In the event that the constraint reserves more transmission capacity in the real-time market, it is equivalent to lowering the transmission limits in the real-time market, and the ISO may incur real-time congestion imbalance offset.

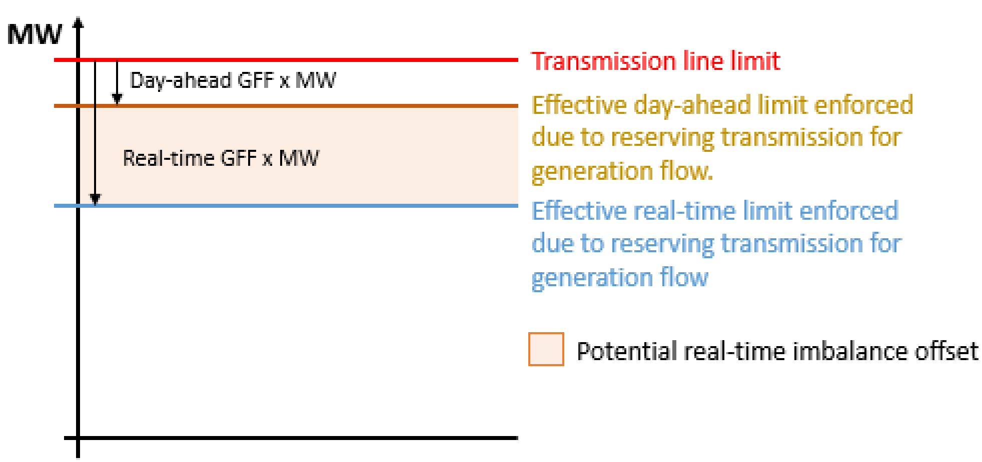


Figure 3: Illustration of different quantities of transmission reserved on a constraint in the day-ahead and real-time markets

6.11.2. Analysis on potential impact

The ISO analyzed the potential impact on real-time congestion imbalance using actual market data for the time period from January 2016 through January 2017. The ISO calculated the differences in generation flow factors between the day-ahead market and fifteen-minute market based on actual unit commitments. Using the calculated generation flow factors from the day-ahead market and fifteen-minute market, the ISO calculated how much transmission would need to be reserved in each market on each constraint to account for a large remedial action scheme generation loss. For each constraint, the difference between the fifteen-minute and day-ahead transmission reservation multiplied by the constraint's fifteen-minute market shadow price is the estimated real-time congestion imbalance impact from changing generation flow factors.

Over the 12 month study period, we found that the estimated net real-time congestion imbalance from all constraints caused by differences in day-ahead and fifteen-minute market generation flow factors was a $148,341 surplus.

Over the 12 month study period, 51% of the observations positively impacted the real-time congestion imbalance offset account (added money to the account), while 49% of observations negatively impacted the real-time congestion imbalance offset account (subtracted money from the account).

In practice not all binding constraints would be in a generator contingency or remedial action scheme case. This means that not all the constraints would be affected by changes in the generation distribution factors as implicitly assumed when netting all the imbalances. The ISO therefore calculated the gross negative real-time congestion imbalance, i.e. summed only the negative imbalances, to provide a bookend to the analysis. The calculated gross negative impact was $44,609 over the 12 month study period.

Given the results of the analysis, the ISO believes that this is a low-risk issue that does not require any further policy development.

6.11.3. Proposal to measure impact going forward

In its comments on the revised straw proposal, PG&E thanked the ISO for its analysis on the potential impact this initiative would have on real-time congestion offset. While the analysis addressed previous concerns, PG&E now asks that the ISO track the real-time congestion offset impact going forward after implementation. The ISO will track the impact going forward after implementation and publish those results for stakeholders.

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6.12. Congestion revenue rights considerations

The ISO proposes to directly model the generator contingency constraints in the congestion revenue rights market model the same way it proposes to model the generator contingency constraints in the day-ahead and real-time market.

The proposed changes to the day ahead and real time markets will impact the congestion revenue rights allocation and auction processes. Design changes will allow generators and load to hedge potential incurred congestion charges.

6.12.1. The CRR market does not currently model the new constraints

The ISO proposes to address potential revenue inadequacy in the CRR market that would be caused by a simultaneous feasibility test (SFT) in the CRR auction and allocation process that does not model the new generator contingency constraints introduced in this initiative. This potential revenue inadequacy would be introduced solely due to this initiative, and as such should be resolved as part of this initiative.

The security constrained economic dispatch, which is the core component of the ISO market, determines a dispatch that produces feasible flows considering transmission constraints in the base case as well as in the transmission contingency cases. That is, the security constrained economic dispatch produces a single dispatch that will be feasible for the base case and for all transmission contingencies without any re-dispatch. To ensure the congestion revenues resulting from the dispatch will be adequate to compensate CRRs (absent any changes to the transmission system as modeled in the base case and contingencies), the CRR allocation and auction process assesses the simultaneous feasibility of the CRRs that it allocates and auctions. The simultaneous feasibility test for CRRs evaluates whether scheduling injections and withdrawals that correspond to the CRRs would produce flows on the transmission constraints that are feasible in the base case and transmission contingency cases that are reflected in the CRR FNM. That is, the CRR SFT attempts to model the same transmission constraints that are modeled in the security constrained economic dispatch. It also models a fixed set of CRRs for the base case and a subset of transmission contingencies in the same way that the security constrained economic dispatch models a fixed dispatch in the base case and transmission contingencies. One can show that the security constrained economic dispatch market will collect sufficient congestion revenue to pay the CRRs.

When the generator contingency constraints are added to the security constrained economic dispatch, the market will reserve transmission capacity to account for the potential loss of generation. Similar to the current security constrained economic dispatch, a single dispatch will produce feasible flows considering transmission constraints in the base case as well as in the transmission contingency cases. However, for a given generator contingency, the dispatch that is feasible for the base case and transmission contingencies may no longer be feasible for the generator contingency. The security constrained economic dispatch determines the appropriate amount of transmission capacity to reserve to account for the generator contingency. The SFT for CRRs must take into account the transmission flows resulting from the generator contingencies. Net congestion rents may change when the ISO reserves transmission capacity to protect for the generator contingencies.

The ISO proposes to adjust the CRR auction and allocation appropriately to recognize the mechanics of the new day-ahead market constraints and maintain revenue adequacy.

6.12.2. Demonstration of the issue

While the example is slightly exaggerated, the easiest way to demonstrate the potential for revenue inadequacy if the ISO does not directly model the new generator contingencies in the CRR allocation and auction is to examine the example from ***Section 6.4.2.1*** above.

Day-ahead market result. Recall the results that the day-ahead market produces when modeling the potential loss of T1, G1, G2, and G3. Note that the ***contingent loss of G1*** causes the path from B to A to bind at its emergency limit of 1,500 MW. When this contingency binds, it results in the market reserving 1,414 MW of transmission capacity from B to A (in other words, the market only schedules 86 MW across a path that has a 1,500 MW emergency limit).

Contingency:		Normal		Loss of T1		Loss of G1		Loss of G2		Loss of G3			
Monitored:		BAFlow<1000		BAFlow<750		BAFlow<1500 **(binds)**		BAFlow<1500		BAFlow<1500			
Generator (i)	**λ^0**	**$SF^0_{i,BA}$**	**μ^0_{BA}**	**$SF^{T1}_{i,BA}$**	**μ^{T1}_{BA}**	**$GFF^{G1}_{i,BA}$**	**μ^{G1}_{BA}**	**$GFF^{G2}_{i,BA}$**	**μ^{G2}_{BA}**	**$GFF^{G3}_{i,BA}$**	**μ^{G3}_{BA}**	**LMP**	**Award**
G1	$40	0	$0	0	$0	0.942857	$5	0	$0	0	$0	$35.29	1500
G2	$40	0	$0	0	$0	0	$5	0.956522	$0	0	$0	$40	1414
G3	$40	1	$0	1	$0	1	$5	1	$0	0.895522	$0	$35	86

The market awards a 1,500 MW schedule from G1 to load, a 1,414 MW schedule from G2 to load, and an 86 MW schedule from G3 to load. It reserves 1,414 MW of transmission capacity from B to A for the potential loss of generator G1.

The market collects a net $7,495 in congestion revenue (1,500 MW x $4.71 + 1,414 MW x $0 + 86 MW x $5.00 = $7,495).

CRR market result <u>without</u> generator contingencies modeled. The results below show the CRR market result if the CRR market is not enhanced to model the generator contingencies. Assuming that market participants ask for as many CRRs as can be injected at all locations and withdrawn at the load, the CRR market does not reserve any transmission capacity for the potential loss of generation. Note that the ***contingent loss of T1*** causes the path from B to A to bind at its emergency limit of 750 MW. The CRR market does not reserve any extra transmission capacity to account for the potential loss of generation.

Contingency:		Normal	Loss of T1	Loss of G1	Loss of G2	Loss of G3	
Monitored Element:		BAFlow<1000	BAFlow<750 **(binds)**	BAFlow<1500	BAFlow<1500	BAFlow<1500	
Generator (i)	**Ask**	**$SF^{0}_{i,BA}$**	**$SF^{T1}_{i,BA}$**	**$GFF^{G1}_{i,BA}$**	**$GFF^{G2}_{i,BA}$**	**$GFF^{G3}_{i,BA}$**	**Award**
G1	1500 G1->L	0	0	Not Enforced	Not Enforced	Not Enforced	1500
G2	1500 G2->L	0	0	Not Enforced	Not Enforced	Not Enforced	750
G3	3000 G3->L	1	1	Not Enforced	Not Enforced	Not Enforced	750

The CRR market awards a 1,500 MW CRR from G1 to load, a 750 MW CRR from G2 to load, and a 750 MW CRR from G3 to load. It reserves 750 MW of transmission capacity from B to A for the potential loss of transmission line T1 as currently modeled as an N-1 contingency.

If these CRRs were to be settled at the difference in the marginal congestion component in the day-ahead market, they would collect $10,815 (1,500 MW x $4.71 + 750 MW x $0 + 750 MW x $5.00 = $10,815).

Recall from above that the day-ahead market only collects a net $7,495 in congestion revenues. The CRR settlement will leave the CRR balancing account short by **$3,320** ($7,495 in day-ahead market collections minus $10,815 in disbursements equals a $3,320 shortfall).

It is clear from the example that the CRR market must model the generator contingencies in order to remain revenue adequate.

6.12.3. Proposed enhancements to the CRR market

The ISO proposes to add the generator and remedial action scheme constraints into the CRR market in the same way it proposes to add the constraints to the day-ahead market. The CRR market will thus limit CRR flows on transmission lines to respect expected post-contingency power flows given the potential loss of generation on the system. There are no proposed changes to the objective function.

6.12.3.1. Generator and remedial action scheme transmission constraints

During the simultaneous feasibility test, transmission constraints will be enforced. The ISO will attempt to make these transmission constraints, to the extent possible, consistent with the transmission constraints that are enforced in the day-ahead market. For generator and remedial action scheme type contingencies, the transmission constraints that are used in the simultaneous feasibility test are the emergency ratings of transmission lines and transformers.

Flow Constraints for each constraint, *g*	$\sum_{i=1}^{N} X_i \cdot GFF_{i,g} \leq hourlyTTC_g$	$GFF_{i,g}$ is the generator flow factor (calculated as the aggregate impact on the constraint from the locations where the injection is distributed) for the i^{th} control variable on the g^{th} generator/RAS constraint. HourlyTTC_g is the limit for the g^{th} constraint. X_i is the MW quantity of CRRs awarded.

Similar to the generator flow factor calculation used in the day-ahead and real-time market, the CRR market will use a calculated generator flow factor based on the CRR full network model and derived generation distribution factors. Recall that o_g is the contingency generator (or in this case the contingency generator node):

$$GFF_{i,g} = SF_{i,g} \qquad \forall i \neq o_g$$

$$GFF_{i,g} = \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF_{i,g}\, GDF_{o_g,i} \qquad i = o_g$$

We define the generator distribution factor (GDF) in the next section.

6.12.3.2. Generation distribution factor calculation methodology

In its comments, PG&E suggested that the ISO seek a generation distribution factor calculation methodology to use in its congestion revenue rights market that would be an accurate representation of the factors that the resource would experience from hour to hour in the day-ahead market. The ISO agrees that it should base its generation distribution factor calculation methodology on committed capacity rather than production, and utilize a historical monthly and seasonal average.

The ISO thus proposes to use the following methodology to calculate generation distribution factors per generator or remedial action scheme contingency, per resource, per month, per time-of-use period.

$$GDF_{o_g,i} = \begin{Bmatrix} -1 & i = o_g \\ 0 & i \notin S_{FR} \wedge i \neq o_g \\ \left(\frac{1}{N}\right) \cdot \sum_{t \in H} \left(\frac{u_{i,t} \cdot G_{i,max,t}}{\sum_{i \in S_{FR}, i \neq o_g} \left(u_{i,t} \cdot G_{i,max,t} \right)} \right) & i \in S_{FR} \wedge i \neq o_g \end{Bmatrix}$$

Where,

> *H is the set of hours in the season (or month) in the time period of interest (e.g. peak or off-peak),*
>
> *N is the number of hours in H*
>
> *t is the hour within H*
>
> $u_{i,t}$ *is the unit commitment status in hour t*

The ISO will use the previous year's seasonal average generation distribution factor in its annual allocation/auction process and the previous year's monthly average generation distribution factor in its monthly allocation/auction process.

6.12.3.2.1. Accuracy of the methodology

The ISO runs the congestion revenue rights market for two time periods: peak and off-peak. For each of these periods, the ISO only uses one transmission system model and similarly proposes to use a representative generation distribution factor for each time-of-use period, for each resource, for each generator and remedial action scheme contingency. The difference between the two congestion revenue rights market models and the varying hour-to-hour day-ahead market model commonly leads to revenue imbalance. The ISO sought to discover how accurate its congestion revenue rights market generation distribution factors would have been when compared to actual day-ahead market generation distribution factors for the time period from January 2016 through January 2017.

Over the 12 month study period, the ISO found that the 94.7% of day-ahead market hours had resource generation distribution factors within 0.005 of the generation distribution factor that would have been modeled in the congestion revenue rights market. 97.3% of day-ahead market observations were within 0.01 of the generation distribution factor that would have been modeled in the congestion revenue rights market. Finally, 99% of day-ahead market observations were within 0.02 of the generation distribution factor that would have been modeled in the congestion revenue rights market.

Given the results of the analysis, the ISO is comfortable with the accuracy of the proposed generation distribution factor methodology.

6.12.3.2.2. Impact on revenue imbalance

The ISO analyzed the potential impact on congestion revenue rights revenue inadequacy using actual market data for the time period from January 2016 through January 2017. The ISO applied the methodology described above to calculate generation distribution factors that would have been used in the congestion revenue rights market for peak and off-peak periods. The ISO calculated the differences in generation flow factors between the congestion revenue rights market and the day-ahead market based on actual unit commitments. Using the calculated generation flow factors from each market, the ISO calculated how much transmission would have been reserved in each market on each constraint to account for a large remedial action scheme generation loss. For each constraint, the difference between the congestion revenue rights market and day-ahead market transmission reservation multiplied by the constraint's day-ahead market shadow price is the estimated congestion revenue rights imbalance impact from generation distribution factors that vary between the two markets.

Over the 12 months modeled, the ISO estimates that the potential net imbalance from all constraints caused by differences in congestion revenue rights market and day-ahead market generation flow factors was a $199,352 deficit.

Over the 12 months modeled, 39% of the observations positively impacted imbalance account (added money to the account), 45% of observations negatively impacted the imbalance account (subtracted money from the account), and 16% of the observations had no impact on the imbalance account.

Given the results of the analysis, the ISO views the potential for revenue imbalance due to the introduction of generation distribution factors as negligible, and is therefore comfortable using the generation distribution factor methodology proposed above.

6.12.3.3. Contingency enforcement

The ISO will enforce generator and remedial action scheme contingencies that are expected to be enforced in the day-ahead market in the appropriate month, and time of use. The decision of which contingencies to protect for will be made through the existing outage planning process that occurs during the CRR market set-up today.

In the annual CRR process, the ISO will enforce generator and remedial action scheme contingencies that are expected to be enforced in the day-ahead market in the appropriate season and time of use as of the time that the annual CRR FNM is released.

The Division of Market Monitoring demonstrated a potential consequence of the congestion revenue rights market granularity difference from the day-ahead market. It shows the potential opportunity for market participants to receive higher payments on congestion revenue rights that would be valued lower in auction when a generator contingency or remedial action scheme is only modeled for a portion of the month in the day-ahead market. The ISO reviewed potential remedial action schemes and only found a few that may not be enabled, and therefore not enforced, for the entirety of a month; the rest will be enabled and enforced all month. In the past three years, remedial action schemes were not physically enabled/disabled coincident with the start of a month on only two occasions. The majority of the remedial action schemes the ISO intends to model are enabled all year. As is current practice today, the ISO operations engineering team plans to work with participating transmission owners to coordinate the cutin/cut-out of the few remedial action schemes that may not be enabled coincident with the start of a month.

As it relates to enforcement of generator contingencies in the congestion revenue rights market, the ISO will make decisions on which contingencies to enforce through the existing outage planning process that occurs during the congestion revenue rights market set-up today. If the engineering team finds a scenario requiring the enforcement of generator contingencies in a given month, it will communicate this with the congestion revenue rights team as it does today. The congestion revenue rights team will follow its existing rules for deciding whether it is necessary to model the contingency in the congestion revenue rights market.

6.12.3.4. Settlement

The CRRs will clear the same way they do today in both the allocation and auction; the only difference being the amount cleared will respect the generator contingency flow constraint discussed in this section. The CRRs will settle against day-ahead market congestion the same way they do today.

Below we use the same example from above to demonstrate how the CRR market will award CRRs once it models for the potential loss of generation.

CRR market result <u>with</u> generator contingencies modeled. The results below show the CRR market result if the CRR market is enhanced to model the generator contingencies. Assuming that market participants ask for as many CRRs as can be injected at all locations and withdrawn at the load, the CRR market now reserves capacity for the potential loss of generation. Note that the ***contingent loss of G1*** causes the path from B to A to bind at its emergency limit of 1,500 MW. The CRR market reserves 1,414 MW of transmission capacity on the path from B to A, which accounts for the potential loss of G1.

Contingency:		Normal	Loss of T1	Loss of G1	Loss of G2	Loss of G3	
Monitored:		BAFlow<1000	BAFlow<750	BAFlow<1500 **(binds)**	BAFlow<1500	BAFlow<1500	
Generator (i)	**Ask**	**$SF^{0}_{i,BA}$**	**$SF^{T1}_{i,BA}$**	**$GFF^{G1}_{i,BA}$**	**$GFF^{G2}_{i,BA}$**	**$GFF^{G3}_{i,BA}$**	**Award**
G1	1500 G1->L	0	0	0.942857	0	0	1500
G2	1500 G2->L	0	0	0	0.956522	0	1414
G3	3000 G3->L	1	1	1	1	0.895522	86

The CRR market awards a 1,500 MW CRR from G1 to load, a 1,414 MW CRR from G2 to load, and an 86 MW CRR from G3 to load. It reserves 1,414 MW of transmission capacity from B to A for the potential loss of generator G1.

If these CRRs were to be settled at the difference in the marginal congestion component in the day-ahead market, they would collect $7,495 (1,500 MW x $4.71 + 1,414 MW x $0 + 86 MW x $5.00 = $7,495).

Recall from above that the day-ahead market collects a net $7,495 in congestion revenues. The CRR settlement will leave the CRR balancing account neutral ($7,495 in day-ahead market collections minus $7,495 in disbursements equals a $0 account balance).

7. Next steps

The ISO will discuss the issue paper with stakeholders during a teleconference to be held on July 7, 2017. Stakeholders should submit written comments by July 14, 2017 to InitiativeComments@caiso.com.

Attachment D – CAISO Board Memorandum

Generator Contingency and Remedial Action Scheme

California Independent System Operator Corporation

Memorandum

To: ISO Board of Governors

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

Date: September 12, 2017

Re: **Decision on generator contingency and remedial action scheme modeling proposal**

This memorandum requires Board action.

EXECUTIVE SUMMARY

Management proposes to enhance the ISO market's security constrained economic dispatch models to include the potential loss of individual generators and to model remedial action schemes. Remedial action schemes are designed to automatically disconnect generators or load in the event of an unexpected loss of service of a transmission line to prevent system overloads. Currently, the ISO market models the potential unexpected loss of transmission lines to ensure that electrical flows do not exceed transmission system limits, but does not model the potential unexpected loss of a generator. The ISO market currently only has limited means to account for remedial action schemes and does not explicitly model them. As a result, grid operators must manage the potential for generator contingencies and remedial action schemes mostly through manual actions.

Management's proposal to include the unexpected loss of a generator and remedial action schemes in the ISO market models will improve the market dispatch, decrease out-of-market actions, and appropriately price each generator's contribution to congestion in the market. The proposed enhancements will also allow the market to more fully utilize generation that is part of a remedial action scheme.

At its September 6, 2017 general session meeting, the EIM Governing Body voted to approve the element of this initiative, which is on the Board's consent agenda for the September 19 meeting, proposing that EIM entities are allowed the option to have the ISO model generator contingencies and remedial action schemes in their respective balancing areas. Additionally, the Governing Body voted to provide verbal advisory input to the Board supporting Management's proposal to model generator contingencies and remedial action schemes in the real-time market.

Management proposes to apply this functionality to the ISO balancing area and to allow EIM entities to use this functionality in their respective balancing areas.

Management proposes the following motion:

> ***Moved, that the ISO Board of Governors approves the proposal to implement the generator contingency and remedial action scheme modeling described in the memorandum dated September 12, 2017; 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 proposed tariff change, as described in the memorandum dated September 12, 2017.***

BACKGROUND

ISO and EIM balancing area operators must plan in order to meet unscheduled changes in system configuration and generation dispatch in accordance with North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) requirements. Generators must be operated at output levels that ensure that transmission lines are not overloaded if generation or transmission is unexpectedly lost. The ISO and EIM balancing area operators accomplish this by establishing and operating within system operating limits to ensure system security.

A secure transmission system is able to withstand the unexpected loss of transmission or generation, including generation loss resulting from remedial action scheme operation. Remedial action schemes are network upgrades that detect and automatically disconnect generation or load on the system in the event of a transmission contingency.

Currently, the potential for generator contingencies are not considered by the ISO's security-constrained economic dispatch. This requires ISO and EIM balancing area grid operators to constantly monitor the potential for generator contingencies that could result in electrical flows exceeding operating limits. Grid operators take manual actions to prepare the system so that electrical flows do not exceed limits in the event of a generator contingency. These manual actions consist of out-of-market interventions based on offline studies and manual review and analysis. Similarly, the current market does not model remedial action scheme operation.

Remedial action schemes are becoming more common in the ISO and energy imbalance market balancing areas because they enable the transmission system to relatively inexpensively accommodate new renewable generation. Remedial action schemes enable new generation without having to increase transmission capacity because they typically are designed to trip-off the generator if a transmission line it is connected to is unexpectedly lost. Consequently, no additional redundant transmission capacity is needed to ensure electrical flows are not exceeded if there is a transmission contingency. Remedial action schemes involve approximately 19,800 MW of generation within the ISO balancing area alone.

Because the ISO market currently has only limited means to account for remedial action schemes, it tends to overly constrain the output of the generators connected to them. This requires grid operators to manually dispatch these generators above the market dispatch to take full advantage of the remedial action schemes.

PROPOSAL

Management proposes enhancements to include potential generator contingencies and remedial action scheme operations into the ISO market models. The ISO will select the specific generator contingencies and remedial action schemes to model as required to reliably manage its balancing area as based on engineering analyses and outage studies. EIM entities would have the option to select the potential generator contingencies or remedial action schemes that the real-time market will model in their balancing area, but would not be required to do so. This is consistent with their existing authority to determine specific transmission constraints that the market models in their respective balancing areas.

These enhancements will enable the market models to calculate how electrical flows will change if one of these events occurs. This modeling will ensure electrical flows will not exceed transmission limits by reflecting the potential change in flows in locational marginal prices, which will ensure generators are dispatched to appropriate output levels. Other independent system operators and regional transmission operators employ similar methods to account for the loss of generation in their markets.

If a generator unexpectedly trips off, frequency responsive devices on the other generators throughout a balancing area automatically increase the output of these other generators to replace the lost generation. Management's proposed enhancements will calculate the change in electrical flows on the transmission system, given this automatic response, and determine the appropriate amounts of transmission capacity to reserve to account for this potential change in flows. This modeling uses the same methodology that grid operators currently use as part of manual studies.

The proposed enhancements incorporate the impact of these potential changes in electrical flows into the congestion component of locational marginal prices. For example, if additional transmission capacity needs to be reserved to account for the potential changes in electrical flows when a generator is lost, the congestion component of the generator's locational marginal price will increase, decreasing the generator's locational marginal price. This will result in the market dispatching the generator to a lower output than it otherwise would have, which frees up additional transmission capacity to prepare for the potential unexpected loss of the generator.

As described above, the proposed enhancements will also account for generators that are connected to remedial action schemes that automatically trip the generator off when transmission is lost. Transmission generally has multiple lines so transmission capacity remains if an individual line is lost. Secure grid operation typically requires generators to be operated at output levels that will not instantaneously overload transmission if an individual line is lost. Since a generator that is part of a remedial action scheme will automatically trip-off if transmission is lost, the enhanced modeling will not reserve capacity on transmission connected to the remedial action scheme to account for this generator's output. This will decrease the congestion component of the generator's locational marginal price, increasing the generator's locational marginal price. This will result in the market dispatching the generator to a higher output than it otherwise would have, more fully accounting for the remedial action scheme in the market. The enhanced modeling will also account for any load that is also connected to the remedial action scheme.

Management proposes to implement these modeling enhancements in both the day-ahead and real-time markets. Corresponding changes will also be made to the model used for the congestion revenue rights market and allocation process. This will ensure the congestion revenue rights the ISO issues can be fully funded by the day-ahead market.

The ISO will select the specific generator and remedial action schemes to model as required to reliably manage its balancing area as based on engineering analysis and outage studies. Because EIM entities are responsible for reliability in their respective balancing areas, they would have the opportunity to select any potential generator contingencies or remedial action schemes in their balancing area to be modeled.

POSITION OF THE PARTIES

Stakeholders generally support Management's proposal because it will reduce out-of-market actions by modeling generation contingencies and remedial action schemes in the market.

Southern California Edison does not support Management's proposal because, as it claims, a generator connected to a remedial action scheme would receive higher locational marginal price than another generator at the same location that is not part of the remedial action scheme. SCE maintains this will diminish incentives for new generators to expand transmission capacity rather than installing remedial action schemes, distorting the ISO's interconnection process.

Management believes the locational marginal prices for generators connected to remedial action schemes under the proposed enhancements will be correct because they appropriately value these generators' contributions to congestion on the system and result in the generators' most efficient dispatch. The proposal does not affect the interconnection process, because it is the ISO and the transmission owner that decide the most cost-efficient network upgrades based on interconnection reliability studies, as opposed to potential market prices. The ISO's interconnection process will continue to be based on the results of reliability studies and fixed infrastructure costs. When studies indicate that the system can no longer support generation participating in remedial action schemes, the ISO will require other transmission upgrades.

A stakeholder comment matrix is included as Attachment A. The Market Surveillance Committee provided a formal opinion on Management's proposal, which is included as

Attachment B. The Department of Market Monitoring provided comments in their Market Monitoring Report, which is included in the informational reports of the September Board materials.

Finally, at its September 6, 2017 general session meeting, the EIM Governing Body voted to approve the element of this initiative, which is on the Board's consent agenda for the September 19 meeting, proposing that EIM entities are allowed the option to have the ISO model generator contingencies and remedial action schemes in their respective balancing areas. Additionally, the Governing Body voted to provide verbal advisory input to the Board supporting Management's proposal to model generator contingencies and remedial action schemes in the real-time market.

CONCLUSION

Management requests the ISO Board of Governors approve the changes described above. The generator contingency and remedial action scheme modeling will improve the market dispatch, decrease out-of-market actions, and appropriately price each generator's contribution to congestion in the market.

Attachment E – List of Key Stakeholder Dates

Generator Contingency and Remedial Action Scheme

California Independent System Operator Corporation

List of Key Dates in the Stakeholder Process for this Tariff Amendment[1]

Date	Event
April 20, 2016	CAISO publishes issue paper
April 25, 2016	CAISO hosts stakeholder conference call and web conference on issue paper
May 16, 2016	Stakeholders submit comments on issue paper
November 7, 2016	CAISO publishes revised issue paper and straw proposal
November 15, 2016	CAISO hosts stakeholder conference call and web conference on straw proposal
November 18, 2016	CAISO Market Surveillance Committee hosts public meeting and web conference discussing initiative
December 9, 2016	Stakeholders submit comments on straw proposal
April 3, 2017	CAISO publishes revised straw proposal
April 11, 2017	Stakeholders submit comments on revised straw proposal
June 30, 2017	CAISO publishes revised draft final proposal
July 7, 2017	CAISO hosts stakeholder conference call and web conference on draft final proposal
July 18, 2017	Stakeholders submit comments on draft final proposal
July 24, 2017	CAISO publishes amended draft final proposal to reflect Energy Imbalance Market Governing Body's authority to include providing advisory input on those aspects of the proposal relating to the real-time market
August 28, 2017	CAISO Market Surveillance Committee posts opinion on initiative[2]
March 30, 2018	CAISO publishes draft tariff revisions
April 16, 2018	Stakeholders submit comments on draft tariff revisions
April 26, 2018	CAISO hosts stakeholder conference call and web conference on draft tariff revisions

[1] *See* http://www.caiso.com/informed/Pages/StakeholderProcesses/GeneratorContingency_RemedialActionSchemeModeling.aspx for links to all documents.

[2] *Available at* http://www.caiso.com/Documents/MSCFinalOpinionGeneratorContingencies_RemedialActionSchemes-Aug28_2017.pdf.