Generator Contingency & RAS Modeling

Revised Issue Paper & Straw Proposal

November 7, 2016

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Revision History

Date	Revision
11/07/2016	Initial Release

1. Executive summary

This initiative considers incorporating additional transmission system reliability considerations into the ISO market. 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. 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 loss due to remedial action scheme (RAS) operation in the dispatch.

Modeling for the loss of generation in the security constrained economic dispatch will result in more efficient and reliable operation of the transmission system.

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.[1] 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.[2]

Remedial action schemes are a cost effective and reliable method of increasing the transfer capability of transmission systems. The transmission system relies on an already large and increasing amount of remedial action scheme armed generation. The ISO operators currently manage constraints related to remedial action schemes outside the market through manual intervention or in the market using static nomograms which approximately represent the constraint. Neither approach is optimal. The proposed market design changes to recognize the remedial action schemes in the market will result in the most efficient and reliable generation 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 emergency ratings binding.[3] 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 potentially reducing overall production cost.

The ISO changed the focus of this initiative relative to the previous issue paper. The previous issue paper focused on securing deliverable contingency reserves considering the loss of

[1] This behavior is shown in Section 6.2.2.1.
[2] This behavior is shown in Section 6.2.1.1.
[3] This behavior is shown in Section 6.2.1.2.

specific generators on the system. Rather than focus on a point in time after deployment of contingency reserves, the initiative now focuses on the system impact immediately after the contingency event. Because reliability standards do not allow for any corrective timeframe in which to resolve potential overloads, the proposed changes allow for no corrective timeframe, and as such do not consider the deployment of contingency reserves. The ISO will now focus its efforts on ensuring transmission security immediately after generation loss alone or due to remedial action scheme operation. The new focus allows the ISO to realize the benefits of remedial action schemes in the market while addressing issues that carry higher reliability risk.

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 alone or due to 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. Changes to this proposal

The ISO changed the focus of this initiative. In the previous version of the issue paper, we grouped the issue of procuring deliverable contingency reserves with ensuring a transmission secure dispatch for the loss of generation. It was not optimal to group the two issues together because each issue is concerned with a different operating timeframe; procuring deliverable contingency reserves is a 10-minute issue, while ensuring a transmission secure dispatch for loss of generation is an immediate issue.

We will now focus on the system impact immediately after the contingency event. Because reliability standards do not allow for any corrective timeframe in which to resolve potential overloads, the proposed changes allow for no corrective timeframe, and as such do not consider the deployment of contingency reserves. The ISO will now focus its efforts on ensuring transmission security immediately after generation loss alone or due to remedial action scheme operation. The new focus allows the ISO to realize the benefits of remedial action schemes in the market while addressing issues that carry higher reliability risk.

In response to the issue paper, stakeholders were concerned about the potential complexities involved with procuring deliverable contingency reserves, the size of the issue to be resolved, and the impact of virtual bids and unit commitment on any proposal.

The ISO made the following changes to address stakeholder comments:

(1) In Section 5, we pivoted the initiative to focus on potential transmission overloads due to generation loss which addresses ISO operations' and regional transmission planning's highest priority issues from a reliability standpoint, and allows for a considerably less complex solution.

(2) In Section 5.1.3, we added a brief discussion on the total size of remedial action scheme arm-able generation in the market to illustrate the potential capacity that may not be accurately modeled in the security constrained economic dispatch.

(3) In Section 6, we added proposed markets in which to enforce generator contingencies and a brief discussion on the treatment for virtual demand and supply.

4. Stakeholder engagement

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

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 enable the functionality within its EIM entity area. The EIM Governing Body will have an advisory role in approving the policy resulting from this initiative.

Date	Event
Wed 4/19/2016	Issue paper
Mon 4/25/2016	Stakeholder conference call
Fri 5/13/2016	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
January 2017	Revised straw proposal posted
February 2017	Second revised straw proposal posted
April 2017	Draft final proposal posted
July 2017	Board of Governors

5. Background & issues

The ISO must ensure a transmission feasible dispatch. There are two aspects of transmission feasibility to consider:

(1) the system must be secure after the loss of a generation 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 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 element alone or in combination with a transmission element due to remedial action scheme operation.

5.1. Discussion

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 pricing in congestion where no congestion really exists and may be inaccurately reflecting the locational cost of supply. In Section 5.1.4, 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 5.1.5, 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.[4]

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.[5]

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.

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.

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

[5] 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.

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.

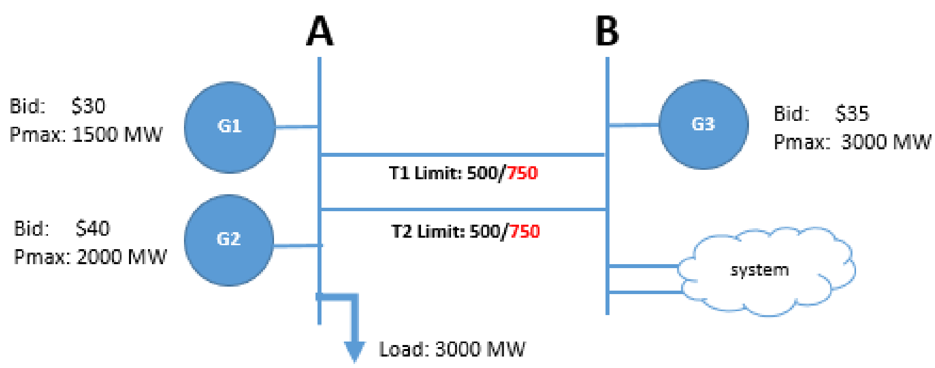
5.1.2. Insecure transmission given the potential loss of generation

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 <u>not</u> 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.[6] 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.

[6] 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.

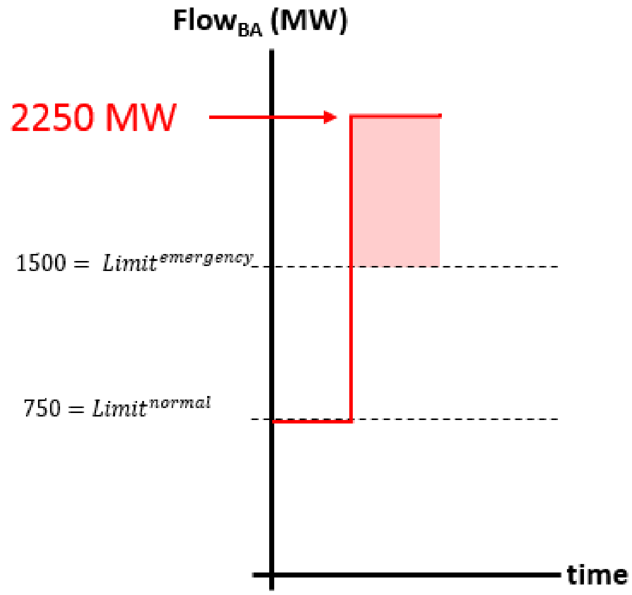
750 megawatts flow from B to A which respects the 1000 MW normal transfer limit and the 750 MW emergency transfer limit.

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 does consider generation loss

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

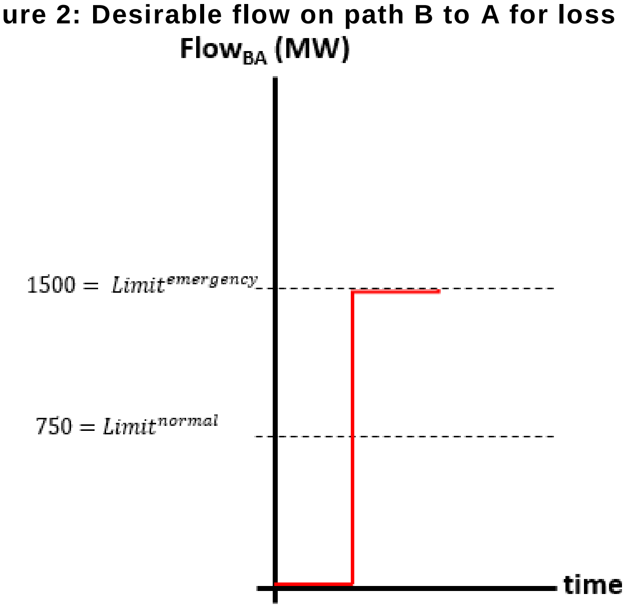
We now add the generator contingency into the set of contingencies.

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. 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.

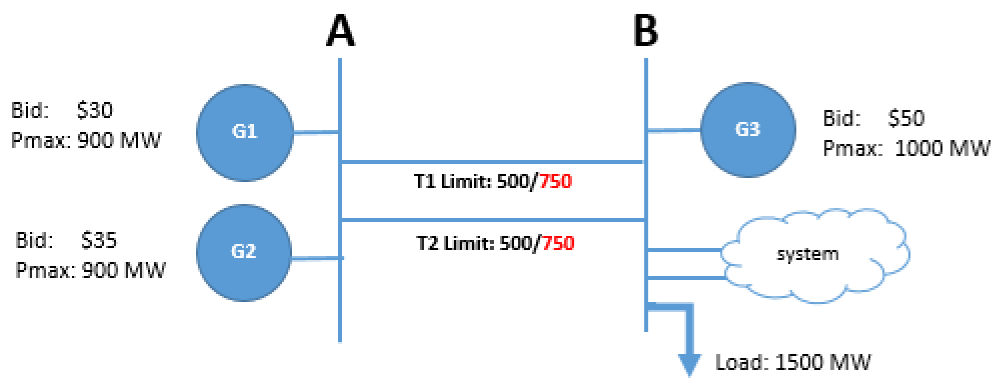
5.1.4. Production cost savings realized when modeling RAS generation loss

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 not 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.

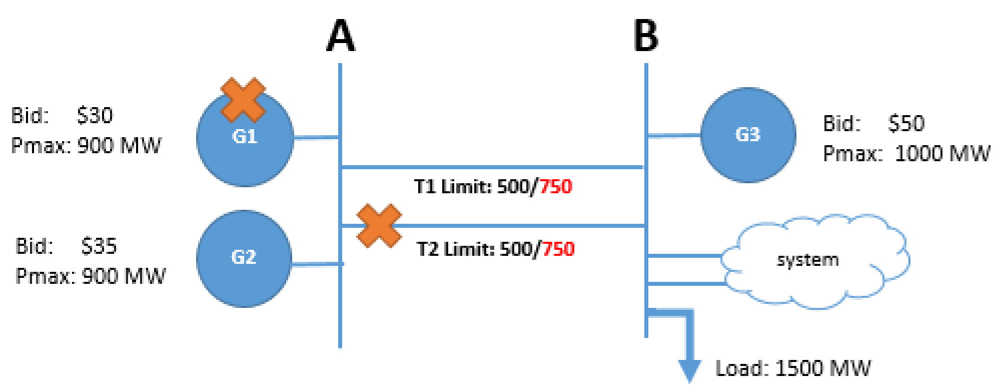
As shown in the Path Flow table above, the loss of transmission line T2 and subsequent remedial action scheme loss of generator G1 would result in transmission line T1 to be loaded under its emergency rating (0 MW). The market could have dispatched the cheaper generator G2 higher in the base case if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

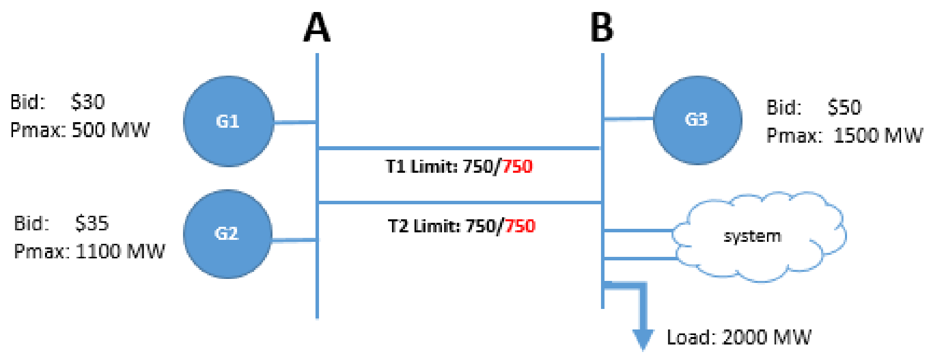
5.1.5. Accurate pricing of generation associated with remedial action schemes

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 <u>not</u> 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

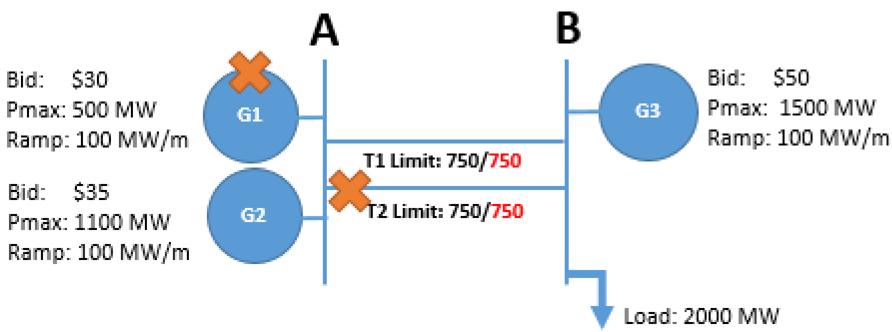
2,000 MW of load. In this example, the preventive constraint for the loss of T2 binds with a shadow cost of $15.

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 flows 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 that removes G1 from service; <u>all of which is being produced by G2</u>.

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 shift factors which 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.

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. Formulation

6.1.1. 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
^{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
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*
$\boldsymbol{G}$	generation schedule vector
$g(\boldsymbol{G})$	power balance equation
$h_m(\boldsymbol{G})$	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*

6.1.2. 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.

6.1.3. 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:

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

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

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

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

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

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

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:

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

(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:

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

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 generation capacity ignoring capacity and ramp rate limits:

$$GDF_{o_g,i} = \begin{Bmatrix} -1 & i = o_g \\ G_{i,\max} \Big/ \sum_{\substack{i=1 \\ i \neq o_g}}^{N} G_{i,\max} & i \neq o_g \end{Bmatrix}, \begin{cases} i = 1,2,\dots,N \\ g = 1,2,\dots,K_g \end{cases}$$

(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:

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

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:

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

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

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

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

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 $GFF_{i,m}^{g}$ (simplified above to the network topology shift factor $SF_{i,m}^{g}$) multiplied by the shadow cost of the generator contingency constraint (μ_m^g).The generator on contingency ($i = o_g$) is charged $GFF_{o_g,m}^{g}$ multiplied by the shadow cost of the generator contingency constraint (μ_m^g). 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.

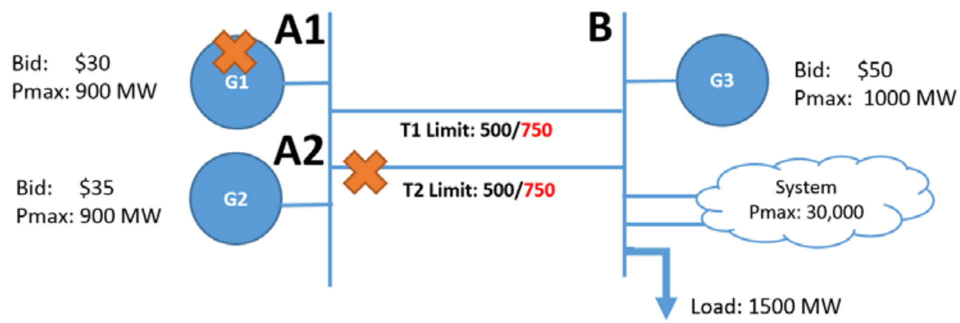
6.2. Examples

6.2.1. 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.

6.2.1.1. 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:

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

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

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 6.1.3, 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:

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

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

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 ($\text{G1 Energy Award} \cdot (SF^0_{A1,AB}) \cong 900\ \text{MW}$) 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

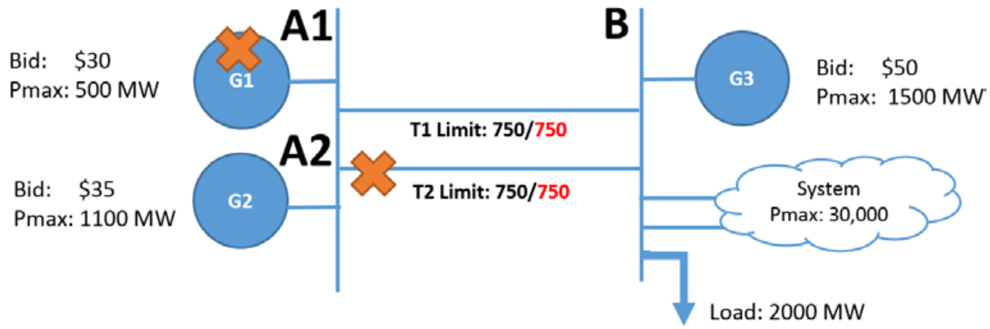
Both G1 and G2 contribute to the normal limit congestion, therefore, both are charged the $15 in congestion from A to B.

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

6.2.1.2. 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:

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

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

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 6.1.3, 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:

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

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

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 ($\mu^{\text{RAS}}_{\text{AB}}$) 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 $\mathrm{GFF^{RAS}}_{\mathrm{A1,AB}}$). Because node A1 has a network topology shift factor of 1 ($\mathrm{SF^{g}}_{\mathrm{A1,AB}}$) to the constraint, all of the portion of energy distributed to bus A ($\mathrm{G1\ Energy\ Award}\cdot(\mathrm{GFF^{RAS}}_{\mathrm{A1,AB}}) \cong 17\ \mathrm{MW}$) is charged $\mathrm{\mu^{RAS}}_{\mathrm{AB}}$ in congestion.

Generator G2 is charged the $15 in congestion from A to B because its full output has a network topology shift factor of 1 ($\mathrm{SF^{g}}_{\mathrm{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.

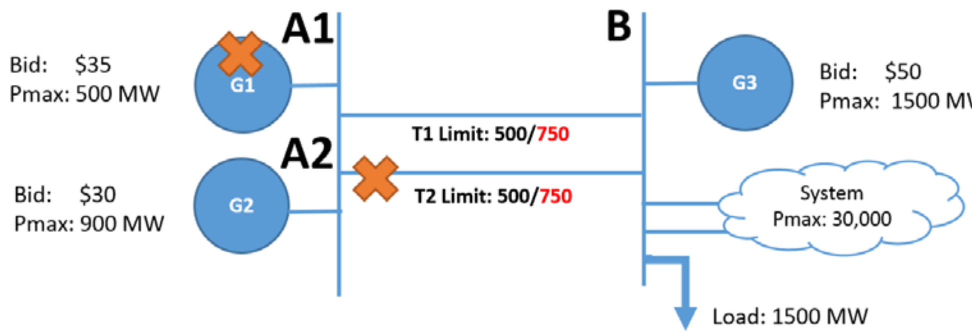
		Normal		Loss of G1+T2		
Generator (i)	**λ^0**	**$SF^0_{i,AB}$**	**μ^0_{AB}**	**$GFF^{RAS}_{i,AB}$**	**μ^{RAS}_{AB}**	**LMP**
G1	$50	1	$0	0.033742	$15	$49.49
G2	$50	1	$0	1	$15	$35
G3	$50	0	$0	0	$15	$50

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

6.2.1.3. 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:

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

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

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 6.1.3, 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:

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

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

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

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

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 ($\text{G1 Energy Award} \cdot (GFF^{RAS}_{A1,AB}) \cong 7\text{ MW}$) is charged μ^{RAS}_{AB} in congestion.

Generator G2 is charged a total of $20 for its contribution to the congestion from A to B due to the normal constraint ($\mu^{0}_{AB}=\$15$) and the remedial action scheme preventive constraint ($\mu^{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

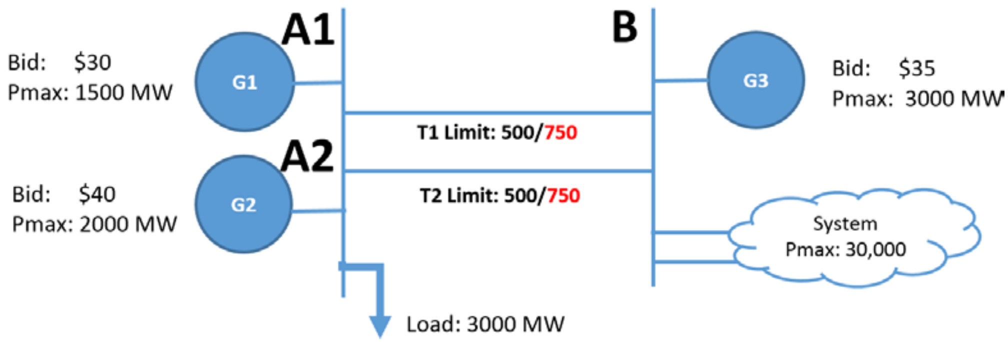
Settlement

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

6.2.2. Secure transmission after generator loss

6.2.2.1. 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:

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

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

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:

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

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

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:

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

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

As discussed in Section 6.1.3, 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 ($\mu^{\text{G1}}_{\text{BA}}$) 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:

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

$$1{,}439 \text{ MW} = 1500\cdot(0) + 1414\cdot(0.956522) + 86\cdot(1)$$

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:

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

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:

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

$$77 \text{ MW} = 1500\cdot(0) + 1414\cdot(0) + 86\cdot(0.895522)$$

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:

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

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 ($\text{G1 Energy Award} \cdot (GFF^{G1}_{A1,BA}) \cong 1414\ \text{MW}$) 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.

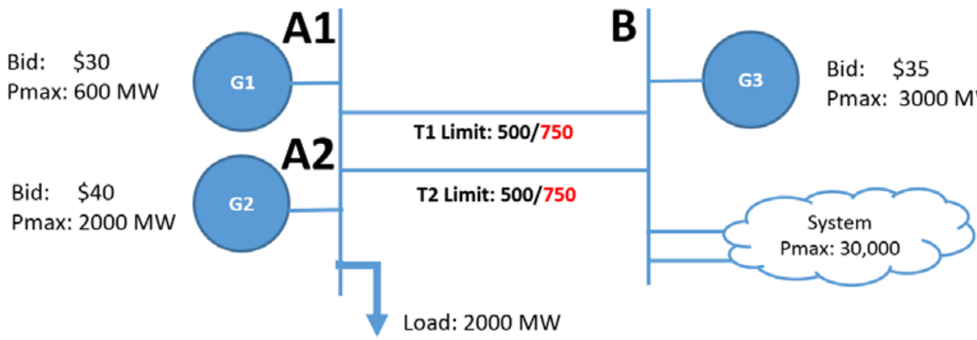
		Normal		Loss of T1		Loss of G1		Loss of G2		Loss of G3		
Generator (i)	**λ^0**	**$SF^0_{i,BA}$**	**μ^0_{BA}**	**$SF^{T1}_{i,BA}$**	**μ^{T1}_{BA}**	**$GFF^{G1}_{i,BA}$**	**μ^{G1}_{BA}**	**$GFF^{G2}_{i,BA}$**	**μ^{G2}_{BA}**	**$GFF^{G3}_{i,BA}$**	**μ^{G3}_{BA}**	**LMP**
G1	$40	0	$0	0	$0	0.942857	$5	0	$0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

6.2.2.2. 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:

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

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

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:

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

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

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 ($\mu^{\text{T1}}{}_{\text{AB}}$) 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:

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

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

As discussed in Section 6.1.3, 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:

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

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:

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

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

As discussed in Section 6.1.3, 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:

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

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:

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

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

As discussed in Section 6.1.3, 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:

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

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

6.3. 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.

6.4. 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.

6.5. 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 determines it is appropriate.

6.6. Congestion revenue rights considerations

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

7. Next steps

The ISO will discuss the issue paper with stakeholders during a teleconference to be held on November 15, 2016. Stakeholders should submit written comments by December 2, 2016 to InitiativeComments@caiso.com.