Energy Imbalance Market
Year 1 Enhancements

Draft Final Proposal

February 11, 2015

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1 Introduction

The Energy Imbalance Market (EIM) is a real-time market to dispatch economic bids voluntarily offered by participating resources to efficiently balance supply, transfers between balancing authority areas (BAA), and load across its footprint. The EIM extends the ISO's real-time market and leverages the FERC Order No. 764 market design changes implemented in May 2014. As such, the EIM includes a fifteen minute market and five minute dispatch across the combined network of the ISO and EIM balancing authorities.

The EIM Year 1 Enhancements includes proposed design changes to address FERC compliance, commitments made during the original stakeholder process, and others identified during implementation. The initiative will have two phases. The first phase will address design changes that the ISO believes should be implemented when NV Energy joins the EIM in October 2015. These items are planned for Board decision in March 2015 to allow appropriate time for FERC filings of ISO tariff changes, necessary EIM Entity open access transmission tariff (OATT) changes, and design certainty needed to commence implementation activities. The second phase will address items that benefit from six months of operational experience with the EIM.

The following lists the currently items in phase 1:

Settlement of non-participating resources – the ISO uses several real-time energy categories to account for the operational characteristics of non-participating resources. The ISO will provide additional clarity on these energy categories which will ensure the same calculation of instructed imbalance energy and uninstructed imbalance energy across the EIM area.

Greenhouse gas flag and cost based bid adder – FERC directed the ISO to develop a flag to allow participating resources to opt out of being considered for EIM transfer into the ISO and modify the GHG bid adder to be based upon the actual compliance cost of the participating resource.

Use of ATC for EIM transfers – based on discussions with NV Energy, it plans to use available transmission capacity (ATC) and not contractual rights to support EIM transfers. Financially binding base schedules are established at T-40 and the final resource sufficiency evaluation is performed. However, firm transmission can be tagged up until T-20 which may change the available transmission capacity to support EIM transfers.

Enforcement of EIM transfer limits – the ISO currently enforces EIM transfer limits by restricting the change in net schedule interchange to the transfer capability made available by transmission customers of the EIM Entity. This change would enforce the EIM transfer limit at each intertie scheduling point.

Additional elements in resource sufficiency evaluation and application to ISO BAA – the ISO is proposing to include differences between hourly schedules assumed at T-40 and imports/exports actually tagged at T-20 in the capacity test of the hourly resource sufficiency evaluation. In addition, the ISO proposes to extend the capacity test and flexible ramping test at

T-40 to the ISO. In the event, the ISO fails the test, EIM transfers into the ISO will be restricted the same as other EIM BAAs.

Administrative pricing rules – the ISO is clarifying its administrative pricing rules in the event of a market disruption or suspension. In one scenario, the ISO proposes to use the day-ahead price. Since there is not a day-ahead price for EIM Entities, a different administrative price must be selected for this scenario.

EIM administrative charge – on January 5, 2015, the ISO Board approved a temporary change to the EIM administrative charge since the current design was collecting revenues in excess of expectations. The redesign of the EIM administrative charge will mirror the existing ISO grid management charge to ensure all market participants are charged the same for real-time market services.

Flexible ramping constraints BAA combinations – currently the EIM enforces flexible ramping constraints for all combinations of BAAs in the EIM footprint. This approach is not scalable as additional EIM entities join. The ISO is proposing to limit the number of flexible ramping constraints enforced to a single system-wide constraint and individual BAA constraint for each BAA in the EIM footprint.

The following lists the current items planned in phase 2. This paper only addresses the phase 1 items and does not include a further discussion of these phase 2 items.

Potential EIM wide transmission rate – the ISO committed to review a potential transmission charge based upon six months of operational data. A discussion of potential approaches was included in the EIM Draft Final Proposal.

Dynamic market power mitigation on EIM transfers – in the EIM Go-Live Enhancements, the ISO committed to look at an additional dynamic trigger for including EIM transfer constraints into the EIM area in the market power mitigation process. For example, if EIM transfer capability into the EIM area exceeds the historical imbalance needs of the EIM BAA, then in those hours the EIM transfers constraint could be excluded from the market power mitigation process.

Flow entitlements for base schedules/day-ahead schedules – the ISO committed to evaluate adding this functionality if there is material impact on the constraints within an EIM BAA from other EIM BAAs or the ISO in the EIM footprint. Currently the real-time congestion offset is based solely upon where the constraint is located. This enhancement would allocate a portion of an EIM BAA's real-time congestion offset to other EIM balancing authority areas if the other EIM BAA's base schedule flows exceed agreed upon flow entitlements.

Bidding rules on external EIM interties – currently the EIM design allows full discretion to the EIM entity as to whether real-time economic bidding is allowed on intertie scheduling points with BAAs outside the EIM footprint. The ISO does allow real-time economic bidding on all intertie scheduling points of the ISO, including those intertie scheduling points whose location is equivalently the same as those that support EIM transfers. This may result in inefficient market outcomes when an economic bid on the ISO intertie scheduling point is sourced in or wheels through an EIM entity.

Additional transition period measures – on January 5, 2015, the ISO Board approved a one year transition period for new EIM entities. The transition period prices energy at the last economic bid instead of the $1000 relaxation parameters when constraints must be relaxed. The ISO also considered including graduated bid caps during the one year transition period, but based on stakeholder comments this design element was deferred to this initiative.

Long-term GHG design change – several stakeholders requested that the ISO evaluate long-term design changes that may require changes in CARB regulations. The need for a potential long-term design change could arise if EIM transfers into the ISO BAA are limited by the number of EIM participating resources willing to be deemed delivered to the ISO through their GHG bids.

Additional items identified during implementation – the ISO will also consider additional design changes and clean up items identified. While many of the items in phase 2 require one year of operational data to finalize possible design changes, this does not preclude the ISO from seeking Board approval on other design elements earlier.

2 Plan for Stakeholder Engagement

Stakeholder input is essential and critical for the success of new initiatives from policy development to implementation. The EIM Year 1 Enhancement stakeholder process will shape the market design and policies through a series of proposals, meetings and written stakeholder comments. Stakeholders should submit comments to EIM@caiso.com. Table 1 below lists the planned schedule for the EIM Year 1 Enhancements stakeholder initiative.

The ISO is committed to providing ample opportunity for stakeholder input into our market design, policy development, and implementation activities.

This initiative assumes a basic understanding on the EIM design which went live on November 1, 2014. Please review the EIM Draft Final Proposal for additional information on the EIM design including: definitions, policy decisions, resources sufficiency evaluation, settlements, and neutrality accounts. The EIM Draft Final Proposal is posted at http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyImbalanceMarket.aspx.

Item	Date
Post Draft Final Proposal	February 11, 2015
Stakeholder Meeting	February 18, 2015
Stakeholder Comments Due	February 25, 2015
Board of Governors Decision	March 26-27, 2015
Phase 2 Stakeholder Activities	TBD

Table 1 - Schedule for EIM Year 1 Enhancements Stakeholder Initiative

3 Changes from Issue Paper and Straw Proposal

Settlement of non-participating resources – the ISO is not proposing any changes to the settlement of non-participating resources as outlined in the issue paper / straw proposal. Several stakeholders did not support the ISO's proposal to remove ISO tariff language that restricted EIM non-participating resources from receiving bid cost recovery (BCR). Upon further review, the ISO does not believe an ISO tariff modification is needed to align imbalance energy settlement of EIM non-participating resources with the imbalance energy settlement of ISO resources. The ISO will continue to monitor, investigate, and resolve inadvertent settlement of BCR for both EIM non-participating resources and ISO resources with day-ahead schedules that are not re-bid into the real-time market.

GHG flag and cost based bid adder – based on stakeholder feedback the ISO modified the original proposal to provide additional flexibility and comply with FERC's June 19 Order. Each hour, an EIM participating resource will submit a single MW quantity and price at which the resource is willing to be deemed delivered to the ISO. The GHG bid is independent of the energy bid range of the resources, effectively creating a "flag" during intervals when the GHG bid segment is zero. The cost based bid adder has also evolved through the stakeholder process. On a daily basis, the ISO will calculate a maximum allowed bid price based upon the resource's highest heat rate and the GHG compliance obligation costs. In each hour, the EIM participating resource bid price must be less than or equal to the maximum allowed daily price.

Enhancement to the resource sufficiency evaluation – the ISO will consider differences between base schedules at T-40 and actual tagged values at T-20 when determining if the EIM entity has a sufficient aggregate bid range from EIM participating resources for the operating hour. Based on stakeholder feedback, the ISO will develop a monthly probability that hourly imports and exports will tag different values. In addition, the resource sufficiency evaluation will be performed on the ISO BAA.

Mandatory 15-minute bidding on intertie scheduling points – based on stakeholder feedback and the need for additional discussion on the re-bidding of day-ahead or base schedules, the ISO has deferred this item to phase 2.

Establishment of EIM transfer limits using ATC – the ISO has provided additional discussion based upon the January 8, 2015 stakeholder meeting regarding the settlement of deviations from base schedules for imports/exports and the method for establishing the dynamic schedule used to support EIM transfers. These details and the stakeholder responses are addressed in the body of this paper.

Modification of the EIM transfer limits – the ISO held a technical workshop to discuss the optimization formulation. The approach includes a small cost applied to transfers to ensure the most direct EIM transfer path is used for tagging the energy profile of the dynamic schedule that supports the EIM transfer between BAAs.

Administrative pricing rules – the ISO has clarified that the price that must be used in the event that FMM or RTD prices are not available is the OATT approved price used for market suspension.

EIM administrative charge – this item was added to Phase 1 after the issue paper and straw proposal. On January 5, 2015, the ISO Board approved a temporary change to the EIM administrative charge since the current design was collecting revenues in excess of expectations. The redesign of the EIM administrative charge will mirror the existing ISO grid management charge to ensure all market participants are charged the same cost for the same real-time market services.

Flexible ramping constraints BAA combinations – This item was added to Phase 1 after the issue paper and straw proposal. Currently the real-time market enforces flexible ramping constraints for all combinations of BAAs in the EIM footprint. This approach is not scalable as additional EIM entities join. The ISO is proposing to limit the number of flexible ramping constraints enforced to a single system wide constraint and individual BAA constraint for each BAA in the EIM footprint.

4 Settlement of Non-Participating Resources

Currently non-participating resources can receive fifteen minute market (FMM) schedule changes due to manual dispatches or physical changes in the resource known prior to the start of the FMM interval. These FMM schedule changes are considered instructed imbalance energy and the deviation from base schedules is settled at the FMM price. In the real-time dispatch (RTD) any known manual dispatch different than the FMM schedule known prior to the start of RTD is considered instructed imbalance energy and is settled at the RTD price. Any remaining difference between the FMM schedule and meter is considered uninstructed imbalance energy and is settled at the RTD price. The current implementation treats FMM schedules as block schedules. Block schedules do not reflect the operational characteristics of the non-participating resource, such as the resource's ramp rate.

The current ISO EIM tariff and PacifiCorp OATT, narrowly considers physical changes as forced outages and forecast changes for variable energy resources in FMM only. This is not consistent with the calculation of expected energy from ISO resources who self-schedule their day-ahead award into the real-time market (RTM). ISO resources who self-schedule in the RTM are equivalent to a non-participating resource with a base schedule. As a result of this inconsistency, the determination of uninstructed imbalance energy differs within the ISO BAA and the EIM entity BAA. Uninstructed imbalance energy is used as the denominator when determining the pro-rata share of bid cost recovery uplift and the real-time imbalance energy offset that is transferred between BAAs. The ISO proposes to align the calculation of expected energy across the EIM area by including additional energy categories that apply to ISO resources who self-schedule in the RTM to changes from base schedule of EIM non-participating resources.

Expected energy is the total energy that is expected to be generated or consumed by a resource, based on the dispatch[1] of that resource, as calculated by the RTM, and as finally modified by any applicable dispatch operating point (DOP) corrections. Expected energy includes the energy scheduled in the hourly base schedule and it is calculated "after-the-fact," i.e, after the operating day.

Expected energy is calculated for generating units, system resources, resource-specific system resources, non-generator resources, and participating loads (e.g, pumps). The calculation is based on the hourly base schedule and the DOP trajectory for the three-hour period around the target trading hour (including the previous and following hours), the applicable FMM or RTD LMP for each dispatch interval of the target trading hour, and any manual dispatch. All dispatch intervals are five minutes in duration.

The following are energy categories[2] used in the FMM and RTD to reflect the operational characteristics of a non-participating resource:

Standard Ramping Energy (SRE) – Instructed imbalance energy (IIE) produced or consumed in the first two and the last two dispatch intervals due to hourly base schedule changes. SRE is a schedule deviation along a linear symmetric 20-minute ramp across hourly boundaries.

Ramping Energy Deviation (RED) - IIE produced or consumed due to deviation from the standard ramp because of ramp constraints, start-up, or shut-down.

Derate Energy (DRE) - Extra-marginal IIE produced or consumed due to minimum load overrates or maximum capacity derates.

Manual Dispatch Energy (MDE) – IIE produced or consumed due to a deviation as a result of an instruction from the EIM Entity.

Optimal Energy (OE) - Any remaining IIE after accounting for all other IIE subtypes constitutes OE.

For energy categories derate energy, manual dispatch energy, and optimal energy, separate expected energy calculations are made for the FMM schedules and RTD instruction.

The ISO previous stated that an ISO tariff change BCR would be needed to change the settlement of EIM non-participating resources. Upon further review, the ISO does not believe

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1 Non-participating resources, while not providing economic bids, have a dispatch instruction calculated that reflects the physical characteristics of the resource. While the non-participating resource is not responding to the dispatch instruction, the calculated value is used to settle deviations from base schedules.

2 For additional information on the calculation of energy types please refer to the Attachment C of the BPM for Market Operations available at http://bpmcm.caiso.com/BPM%20Document%20Library/Market%20Operations/Appendices_Market%20Operations_V41_clean.doc

an ISO tariff modification is needed to align imbalance energy settlement of EIM non-participating resources with the imbalance energy settlement of ISO resources with day-ahead awards that are not re-bid in to the real-time market. The ISO will continue to monitor, investigate, and resolve inadvertent settlement of BCR for both EIM non-participating resources and ISO resources with day-ahead awards that are not re-bid in to the real-time market.

The EIM entity's OATT should not restrict the ISO settlement of imbalance energy, if an EIM entity is using the locational marginal price for settling EIM non-participating resources. The OATT must recognize the instructed imbalance energy from the energy categories above will occur based upon the operational characteristics of the non-participating resource.

5 GHG Flag and Cost Based Bid Adder

Imports of energy into California and generation of energy within California from greenhouse gas emitting resources are subject to the California cap on greenhouse gas emissions regulated by the California Air Resources Board (CARB). Energy generated outside of California that is not imported into California is not subject to this regulation.

The EIM has been designed so that the greenhouse gas compliance costs will not affect the locational marginal price (LMP) in an EIM BAA when load is met from generation external to the ISO. The market optimization will calculate the marginal cost difference between EIM generation serving load in the ISO and serving load outside of the ISO. This difference will be the marginal GHG regulation compliance cost and will be the rate the ISO will use to calculate a payment to each generator in an EIM BAA for its output that served ISO imbalances. This payment will be funded through the price paid within the ISO for imbalance energy.

The current EIM design allows a participating resource scheduling coordinator (SC) to submit a GHG bid adder to reflect its willingness to be deemed delivered to the ISO when there is an EIM transfer into the ISO. The GHG bid adder is not mitigated, with the only restriction being that the combined energy bid and GHG bid adder must be less than or equal to the $1000 energy bid cap. A participating resource SC can submit a high GHG bid adder to reduce the probability that the resource will not be deemed delivered to the ISO. However, a high GHG bid adder does not guarantee that the resource will never be deemed delivered to the ISO and as a result subject to CARB rules.

In FERC's June 19 Order approving the EIM design, FERC directed the ISO to include a flag which would allow an EIM participating resource SC to opt out completely from consideration for EIM transfer into the ISO. In addition, FERC directed the ISO to design the GHG bid adder to be based upon the expected cost of GHG compliance obligations. The remainder of this section describes the proposed design of the flag and cost based GHG bid adder, which is consistent with and arguably superior to FERC's directive.

On an hourly basis by T-75, the EIM participating resource SC will submit a single MW quantity and single bid price expressing its willingness to be deemed delivered to the ISO. The MW quantity is independent of the energy bid curve submitted, thus the total output of the EIM participating resource up to the MW quantity bid is eligible to be deemed delivered to the ISO. It is important to note that market optimization will naturally limit EIM transfers into the ISO to the

bid in MW quantity from all EIM participating resources in the EIM footprint. There will not be an explicit constraint limiting EIM transfers into the ISO.

The ISO is not proposing an explicit flag to allow additional flexibility to EIM participating resources. However, an EIM participating resource can, through its bid, accomplish the same objective of not being considered for EIM transfers into the ISO by bidding zero MW, effectively a flag. In addition, the ISO will set the default value of the MW bid to zero. If an EIM participating resource SC, does not submit a MW bid, it will not be considered for EIM transfer into the ISO because the MW quantity will be set to zero. This satisfies FERC's directive and allows participants enhanced flexibility.

The ISO proposes to use a process similar to establishing the GHG cost adder included in the default energy bids[3] of ISO resources. This includes a variable cost option and a negotiated rate option. The negotiated rate option may be used for new participating resources that do not have an emission rate used by the CARB in assessing GHG compliance obligations. However, rather than calculating a GHG cost curve, the ISO will calculate a single daily value based upon the maximum heat rate of the EIM participating resource.

Under the variable cost option, on a daily basis, the ISO will calculate a single GHG cost. The ISO proposes to calculate each unit's greenhouse gas emissions cost based on the unit's heat rate characteristics, as registered with the ISO, the applicable GHG allowance price, and using the resource's emission rate. The standard GHG emission rate is documented in the US EPA Subpart C[4] default emission factors. For example, the standard GHG emission rate for natural gas calculated under US EPA is 0.053072 mtCO2e/mmBTU. Similar to the default energy bids of ISO resources, there will be a 10% adder to the calculated cost. An EIM participating resource SC must submit a GHG bid price equal to or less than its GHG cost, but not less than zero. If an EIM participating resource SC submits a GHG bid price above the GHG cost of the EIM participating resource, the GHG bid price will be set to the calculated GHG cost. If a resource submits a MW quantity, but fails to submit a GHG bid price, the default will be the calculated GHG cost.

If an EIM entity allows economic participation in the FMM by imports on EIM external interties, the imports will also submit an hourly GHG MW quantity and bid price. If the import is registered as a resource specific resource, the GHG emissions rate authorized by CARB for the specific resource will be used in the calculation of the maximum GHG cost. If the import is registered as a system resource, the GHG emissions rate authorized by CARB for the source external BAA will be used in the calculation of the maximum GHG cost.

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3 For additional information, please review section 39.7.1 of the ISO tariff available at http://www.caiso.com/rules/Pages/Regulatory/Default.aspx

4 CARB's regulation referenced these U.S. EPA figures as published in the Federal Register on December 17, 2010. Available here: http://www.arb.ca.gov/cc/reporting/ghg-rep/regulation/subpart_c_rule_part98.pdf

6 Management of EIM Transfers and Intertie Scheduling Limits

This section outlines how the ISO enforces scheduling constraints in the market optimization to ensure the energy from base schedules and EIM transfers in the FMM and RTD are consistent with intertie scheduling limits. This section was previously titled *Establishment of EIM Transfer Limits Using ATC* because concerns were raised that the NV Energy (NVE) implementation would create unique issues not present when contractual rights were used to support transfers between BAAs. It is more appropriate to discuss how EIM transfers limits and intertie scheduling limits are used to ensure the energy from EIM transfers is within path limits and tagged consistent with Western Electricity Coordinating Council (WECC) scheduling practices.

By assuming that available transfer capability (ATC) will used to facilitate EIM transfers between NVE, ISO and PacifiCorp (PAC) when NVE joins the EIM in October 2015, concerns were initially raised regarding potential operational timing issues because actual ATC for the upcoming operating hour may not be fully known until T-20 (when all schedules are required to be submitted in WECC). In fact, final base schedules for the hour are already financially binding at T-40 and used for the final resource sufficiency evaluation for the upcoming operating hour. This is not unique to EIM and was grappled with by the ISO when it designed the FMM. FERC Order 764 only required 15-minute scheduling, but did not require a 15-minute transmission product or changes to WECC tagging deadlines. The timing of the FMM was established to ensure that the real-time market was not dependent upon changes in WECC business practices. The ISO now proposes to extend this concept in support of EIM transfers.

PacifiCorp's EIM implementation relies upon the PacifiCorp Interchange Rights Holder (PIRH) mechanism. An existing transmission customer allows its firm intertie rights to be used for EIM transfers (without charge or compensation). This mechanism was developed in light of the fact that interties between ISO and PacifiCorp West (PACW) and PACW and PacifiCorp East (PACE) are fully subscribed on a firm basis and have other transmission providers, customers, owners or path operators. Although firm rights through a non-EIM BAA are used to support PacifiCorp EIM transfers, this does not alter how intertie scheduling limits are enforced in the FMM and RTD. This proposal does not affect the management of EIM transfers using the PIRH, nor would it affect management of EIM transfers using a similar mechanism(s) to account for other ownership rights.

The ISO BAA does not have firm or non-firm transmission priorities inside the ISO. External to the ISO, if there is available transmission capability (ATC) available on a path, it may be purchased on a firm basis by transmission customers who are then issued a reservation. Once a reservation is issued, the same capacity may not be sold to any other customer on a firm basis for the same period of time as the first customer's reservation. However, the transmission provider (TP) is allowed to sell ATC on a non-firm basis up to the total transfer capability (TTC) of the path. For example, if a path's TTC is 400 MW, and the path is fully subscribed on a firm basis for 400 MW, there is no firm ATC for sale, but the TP can sell up to 400 MW on a non-firm basis.

In the West, transmission customers have up until T-20 to schedule their reservation. At T-20, it is always possible that not all of the firm reservations have actually been scheduled and so

there would be ATC on the line for non-firm use. In such a case, the TP can allow the non-firm transmission customers' transmission schedules to flow up to the total transfer capability (TTC) limit of the path, including the firm schedules. It is also possible that some paths are not fully sold firm, in which case both firm and non-firm schedules can flow and there may even by ATC left over which is not being scheduled or used by anyone.

The scenario outlined above was recognized when the ISO developed the FMM. The ISO has developed market rules to ensure that the energy profiles that will be tagged for ISO market awards are consistent with WECC scheduling practices. The ISO currently has an hour ahead scheduling process (HASP) to ensure that hourly block schedules do not exceed intertie scheduling limits which in turn ensures that SCs are able to obtain external transmission for these awards in adjacent BAAs. For example, assume two SCs are bidding on an intertie scheduling point with a scheduling limit of 300 MW. The ISO does not require the potential incremental schedules to be tagged prior to start of the HASP, but cleared schedules must be tagged by T-20. SC #1 is bidding 200 MW at $50.00 and plans to use firm transmission in an adjacent BAA. SC #2 is bidding 200 MW at $40.00 and is planning to use non-firm transmission on the same transmission line to the ISO. Assuming the unconstrained LMP at the intertie scheduling point would be $55.00, the ISO market will award SC #1 a 100 MW import and SC #2 a 200 MW import. (SC #1's bid will be marginal, setting the LMP at the scheduling point to $50.00.)) When SC #1 submits an e-Tag to support its 100 MW import, it will tag 100 MW of firm transmission on the external line and the external BAA can award 200 MW of non-firm transmission to SC #2 to support its 200 MW import without overselling firm transmission. The market rules to award HASP hourly block schedule is not unique to the HASP market optimization. In all market runs for FMM and RTD, the optimization enforces constraints that ensure awarded energy schedules are within path limits of the intertie scheduling point.

Post Order 764 market design changes, the hour ahead scheduling process (HASP) is used to award hourly block schedules changes from ISO day-ahead hourly schedules; however, the prices are advisory. Hourly block schedules that clear the HASP are considered price takers in the financially binding FMM intervals and settled at the FMM price. The HASP is a special run of the real-time unit commitment process (RTUC) covering seven 15-minute intervals. The run starts at T-67.5 and provides results at T-52.5. Hourly block schedules cleared in the HASP must be tagged by T-20. If the hourly block import is not tagged, the SC will be paid the FMM price for the first and second FMM interval of the operating hour and charged the RTD price for the first six 5-minute intervals of the operating hour. For the third and fourth FMM intervals, the operational adjustment resulting from the HASP hourly block schedule not being tagged will be reflected in the FMM schedule, thus there is no settlement. However, in the ISO the SC is subject to the hourly schedules decline charge for the third and fourth FMM intervals. This hourly schedules decline charge is a measure by the ISO to ensure hourly schedules are tagged at their HASP award by T-20.

The ISO considered including the HASP in the EIM as a mechanism to use for establishing the final hourly base schedules, but this would require establishing base schedules earlier than the current EIM deadline of T-40. Finalizing base schedules earlier would not be beneficial because

this would reduce the opportunities for the EIM entity to make adjustments necessary to ensure its BAA passes the resource sufficiency evaluation for the operating hour.

The ISO does not require base schedules to be tagged at T-40, which is the same as for any hourly schedule (awarded in the day-ahead or through HASP) within the ISO. The FMM assumes that the base schedules or ISO hourly schedules will tag by T-20. If a different energy profile is tagged at T-20, there will be imbalance settlement at the FMM and RTD price. The EIM entity is responsible for managing the transmission priority within its BAA. Therefore, if a firm rights holder scheduled at T-20 an energy profile that required a non-firm schedule to be curtailed, then both the firm rights holder and the non-firm rights holder would have imbalance settlement within the EIM for difference between their base schedules and actual tagged energy profile. Since the RTD market optimization for the first 5-minute interval of the operating hour commences at T-7.5, EIM participating resources are re-dispatched if needed to keep schedules within intertie scheduling limits. Any imbalance from base schedules is settled with the appropriate EIM participating resource SC or EIM entity SC.

6.1 Enforcement of Intertie Scheduling Limits

The ISO describes the method to assess ATC of intertie scheduling points in Appendix L of the ISO tariff. For each intertie scheduling point, the ISO determines the ATC independently in the import and export direction. In addition, the calculation will consider encumbrances from specific contractual scheduling rights that reduce the available transmission capacity on a transfer path that can be schedule through the market optimization. For example, the ISO has existing transmission contracts which prohibit the ISO from using the available transmission on the associated intertie scheduling point until after a specified time prior to the operating hour.

In the FMM and RTD, the market enforces intertie scheduling limits to ensure energy schedules do not exceed transmission path limits. Intertie scheduling limits under this proposal would similarly be applied to EIM external interties, EIM internal interties, and intertie scheduling points that share both EIM external interties and EIM internal interties.

An EIM external intertie is an interface between an EIM BAA and a non-EIM BAA. The base schedule imports and exports are assumed to flow at their base schedule MW level unless updated information has been communicated to the ISO by the EIM entity prior to the start of an FMM market optimization. In the FMM, 15-minute economic bids and dynamic transfers (including dynamic schedules used to tag EIM transfers) compete for available transmission not used by base schedules. The market optimization ensures transmission path limits are not exceeded and allows counterflows on base schedules. As a result, the total directional change can exceed the intertie scheduling limit. For example, assume an import transfer capability of 500 MW, base schedule imports of 100 MW, and base schedule of exports of 150 MW. Incremental schedules to 15-minute economic bids and dynamic transfers in the import direct can be made up to 650 MW (500 – 100 + 150). In RTD only dynamic transfers can be dispatched. So continuing the example above, assume that FMM imports were awarded 65 MW in the FMM and dynamic transfers were awarded 10 MW, then incremental RTD award to dynamic transfers can be made up to 575 MW (500 – 100 + 150 - 65 – 10).

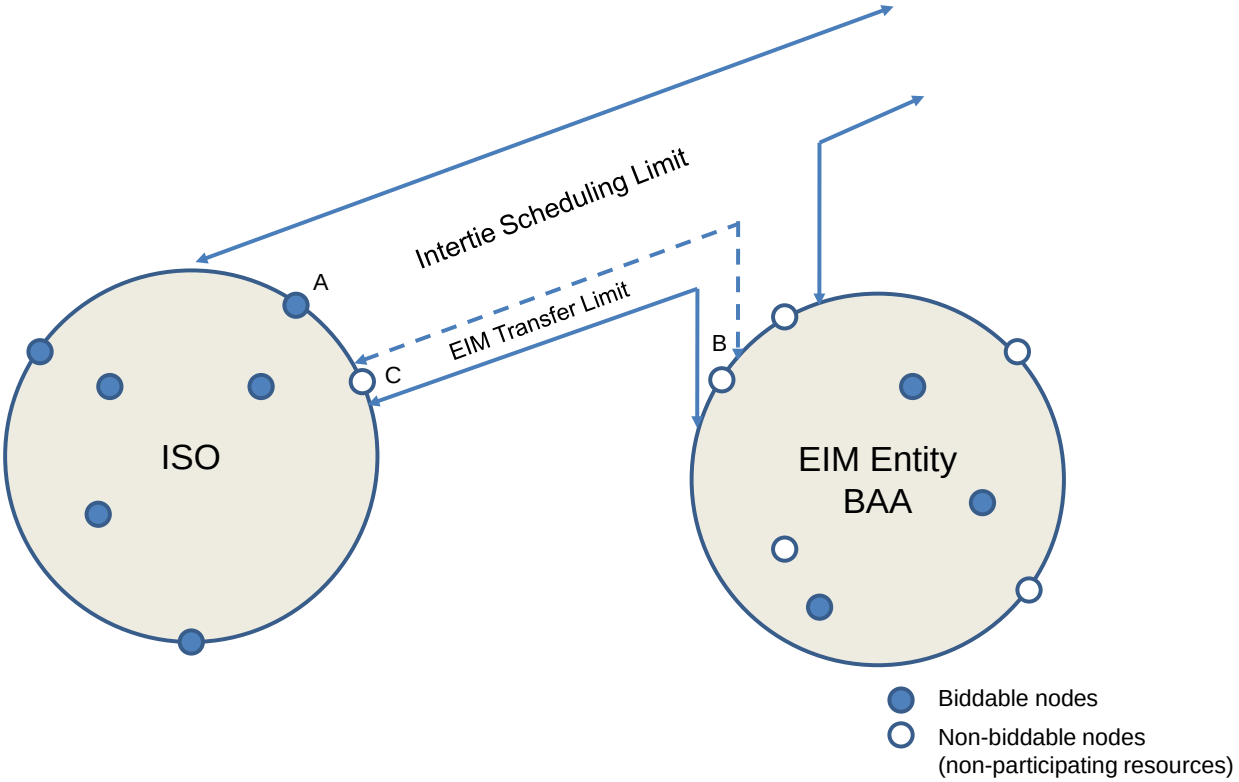
An EIM internal intertie is an interface between two EIM BAAs, including the ISO. There are two types of EIM internal interties: an interface directly between two EIM BAAs, and an interface which goes through a non-EIM BAA. The first type of EIM internal interties is expected between the ISO and NVE. The second type is done today between the ISO and PacifiCorp.

For the first case, where an interface is directly between two EIM BAAs, the full intertie scheduling limit is available to support EIM transfers in both the FMM and RTD. Base schedules at these intertie scheduling points are assumed delivered and will not be modified by the market optimization. In the event of a transmission derate of the intertie scheduling point, there will be imbalance settlement because the base schedules will be cut outside of the market until the new intertie scheduling limit is enforced in the market optimization. In both the FMM and RTD, the EIM transfer limit will equal the intertie scheduling limit which considers unused transmission and counterflows on base schedules when determining incremental EIM transfers that can be scheduled. As will be discussed in the next section, the transmission profile on the dynamic schedule to support EIM transfers should not limit EIM transfers below the transmission capability of the intertie scheduling limit.

For the second case, where an interface is through a non-EIM BAA, there is not an intertie scheduling limit equal to the total path rating because the transmission limit is managed by the non-EIM BAA. As a result, the transmission profile through the non-EIM BAA must be observed and will restrict EIM transfers to the associated limit. In addition, the non-EIM BAA may enforce different limits on the amount of incremental change that can occur in the FMM and RTD. This is the case today with PacifiCorp and BPA and why the EIM transfer is tagged on both dynamic and static schedules. However, the intertie schedule limit between the ISO and BPA in not solely an EIM internal intertie.

For intertie scheduling points that share both an EIM external intertie and an EIM internal intertie, all economic bids compete for available transmission capability. As illustrated in Figure 1, the intertie schedule limit exceeds the EIM transfer limit for the EIM internal intertie. The intertie scheduling limit is represented by the solid blue lines. The EIM transfer limit is represented by the dashed line.

Figure 1 - Example of an EIM External Intertie and EIM Internal Intertie Sharing the Same Intertie Scheduling Limit



All economic bids compete for available transmission beyond base schedules allowing for counterflows of base schedules. In the FMM, the economic bids at point A and the EIM transfer at point C compete equally for available transmission capacity. If 15-minute imports on the EIM external intertie (point A) are more economic than dispatching resources up within the EIM entity to support an EIM transfer, the available transmission capability will be awarded to the 15-minute imports. In RTD, only dynamic transfers at A (either a dynamic schedule or pseudo-tie) and the EIM transfers at C will compete for any available transmission capability not awarded in the FMM. Assuming that the economic bids from EIM participating resources in the EIM entity are more economic that all 15-minute economic bids at point A, the EIM transfer limit will be binding before the total intertie scheduling limit is binding.

The intertie scheduling limit ensures that energy schedules are within the transmission path limits of the system. All economic bids compete equally for available transmission. Only when an EIM internal transfer uses transmission through a non-EIM BAA can the EIM transfer limit be less than the intertie scheduling limit.

6.2 Establishing Dynamic Schedule to Tag EIM Transfers

Real-time tracking of net scheduled interchange and use of e-Tags for dynamic schedules between the ISO and EIM Entities accomplish two purposes: calculation and tracking of scheduled versus inadvertent energy, and to account for transmission usage through non-EIM

balancing authority areas. This process ensures that EIM transfers remain within the capacity that is available to EIM, that an EIM Entity's automatic generation control does not act to reverse EIM's dispatches of imbalance energy, and that EIM's dispatches do not have an appearance of being inadvertent energy. When an EIM transfer uses a transmission path using EIM participants' rights through non-EIM balancing authority areas, the normal e-Tag process and existing standards ensure that the non-EIM transmission service providers have approved the use of the transmission capacity. To be clear, these processes do not mean that only this information is available to the reliability coordinator or the Enhanced Curtailment Calculator (ECC) that is currently being planned and developed, since the ISO is able to provide resource-specific dispatch data for these reliability purposes. In other words, there is no loss of detail by using the dynamic e-Tags for tracking of real-time scheduled energy and documenting approval of transmission paths.

As discussed above, for EIM internal interties directly between two EIM BAAs, the dynamic schedule used to establish the EIM transfer limit should not be more restrictive than the intertie scheduling limit. The EIM transfer limit is the transmission profile on the dynamic schedule submitted no later than T-40. The transmission profile should reflect the total transfer capability (TTC) of the intertie scheduling point less any contractual encumbrances plus counterflows on base schedules. The ISO proposes that the expected energy prior to the operating be set based upon the results of the HASP process which will include advisory EIM transfers for each of the four 15-minute interval in the upcoming operating hour. The final energy profile will be updated with 60 minute after the operating hour, as is done with all dynamic transfers.

The following is an example illustrates how the transmission profile will be calculated to maximize EIM transfers. The ISO is evaluating the automation of this process as part of the implementation with NVE.

Assumptions:

TTC in import direction = 500 MW
TTC in export direction = 400 MW
Encumbrances import direction = 100 MW
Encumbrances export direction = 100 MW
Base schedules in import direction = 350 MW
Base schedules in export direction = 150 MW
HASP advisory EIM transfer in import direction = 100 MW

Calculations of dynamic schedule:

Import transmission profile = 550 MW = 500 – 100 + 150
Import expected energy = 100 MW
Export transmission profile = 650 MW = 400 – 100 + 350
Export expected energy = 0 MW

The example above will allow the maximum EIM transfers to occur from dispatching EIM participating resources. The intertie scheduling limit will be binding before the EIM transfer limit would be binding.

As discussed further in section 6.4, the modification of the EIM transfer limits from net scheduled interchange to contract path, requires that it be determined which EIM BAA creates the dynamic schedule to support EIM transfers. For EIM internal interties between BAAs not including the ISO, each BAA will create a dynamic schedule in the export direction for each intertie scheduling point. For EIM internal interties between the ISO and an EIM BAA, the EIM BAA creates both an import and export dynamic schedule. For simplification, assume there is a single intertie scheduling point between the ISO and NVE and a single intertie scheduling point between NVE and PACE, the following dynamic schedules would be created:

Creator	Direction
NVE	ISO to NVE
NVE	NVE to ISO
NVE	NVE to PACE
PACE	PACE to NVE

There is no change proposed for the existing PacifiCorp implementation or future EIM entities using transmission rights through a non-EIM BAA. For EIM internal interties using rights through a non-EIM BAA, the dynamic and static schedules need to be established by T-40 to allow for the limits to be enforced in the first financially binding FMM run of the operating hour.

6.3 Settlement of hourly import/export imbalances between T-40 and T-20

The ISO does not require hourly base schedules to be tagged prior to T-20, although an EIM entity may require tags prior to establishment of final base schedules at T-40. The e-Tag timing requirement for EIM hourly base schedules is the same as ISO hourly schedules.

The imbalance charges[5] for differences between the hourly base schedule and the final tagged schedule are borne by the market participant. For participating imports/exports, the deviations will be settled directly with the EIM participating resource SC. For non-participating intertie schedules, the deviations will be settled directly with the EIM entity SC, but then allocated to the market participant according to the rules of the EIM entity OATT. The EIM entity SC will have all necessary settlement data to pass through the imbalance energy settlement.

[5] At the January 5, 2015 stakeholder meeting, the ISO reviewed various settlement examples. See slides 35 to 40 in the presentation available at http://www.caiso.com/Documents/Agenda-Presentation_EIMYear1Enhancements_Jan8_2015.pdf

The following summarizes the imbalance settlement that will occur if the final e-tag submitted at T-20[6] differs from the base schedule:

T to T+30: Difference between the base schedule and e-Tag settle at the RTD price

T+30 to T+60: Difference between base schedule and e-Tag settle at the FMM price

The settlement is appropriate because EIM participating resources will be re-dispatched to support the change in hourly import and export schedules that were assumed in the FMM. For example, assume an intertie scheduling limit in the import direction of 100MW and the load forecast of the EIM footprint does not change. A non-participating import has a base schedule at T-40 of 80MW on an EIM internal intertie. In the first two FMM intervals, it was economic to dispatch down EIM participating resources in EIM BAA#1 by 20MW to allow a 20MW EIM transfer into the EIM BAA #1 from EIM BAA #2. Based on information available to the FMM market optimization, the intertie scheduling limit would allow an additional import across the transmission path of 20 MW. The EIM participating resources in EIM BAA #1 buy back at the FMM price. The EIM participating resources in EIM BAA #2 are paid at the FMM price for the incremental FMM schedule. At T-20, the non-participating import submits a final tag with an energy profile of 100MW which is approved. In RTD, the EIM participating resources in EIM BAA #2 are dispatched down 20MW which reduces the EIM transfer into the BAA #1 by 20MW. The EIM participating resources in BAA #2 buy back at the RTD price. The non-participating import is paid the RTD price.

The ISO also supports additional intertie bidding options such as a single economic schedule change per operating hour and full economic participation in the FMM on EIM external interties. In the FMM, the ISO observes the transmission profile of the tag and will not award an FMM schedule not supported by the transmission profile across non-EIM BAAs. As a result, unlike non-participating imports and exports, intertie bids participating in the FMM must be supported by an e-Tag prior to the start of the first FMM interval of the operating hour or T-40.

6.4 Modification of EIM Transfer Limit Constraints

The current EIM implementation enforces the EIM transfer limit by ensuring the changes in net scheduled interchange schedules between BAAs in the EIM are within the aggregate transmission rights made available to support EIM transfers. This implementation approach is appropriate for the initial implementation with PacifiCorp; however, the ISO believes that as more BAAs join the EIM, the EIM transfer limits should be considered by intertie scheduling point. This will allow for multiple transmission providers to offer EIM transfer capability and to account for the energy schedule changes that must be supported and tagged through several individual dynamic schedules. In addition to EIM transfer limits and intertie scheduling limits, the market optimization also enforces physical limits to ensure actual flows on transmission paths are within physical limits.

[6] If the final tag is submitted prior to the start of the second FMM interval of the operation hour, the last three intervals of the operating hour will settle at the FMM price and be subject to the hourly schedules decline charge.

EIM BAAs may be interconnected with the ISO directly, through another EIM BAA, through a Non-EIM BAA, or a combination thereof. The EIM entity for an EIM BAA may have made transmission rights available on a direct interconnection with the ISO, on a direct interconnection with another EIM BAA, or on an indirect interconnection with the ISO or another EIM BAA through one or more non-EIM BAAs. The red arrows in the figure below illustrate such transmission rights. These transmission rights are essential to the EIM transfers for each BAA in the EIM footprint as they both allow and constrain the optimal exchange of imbalance energy among the BAAs in the EIM Area.

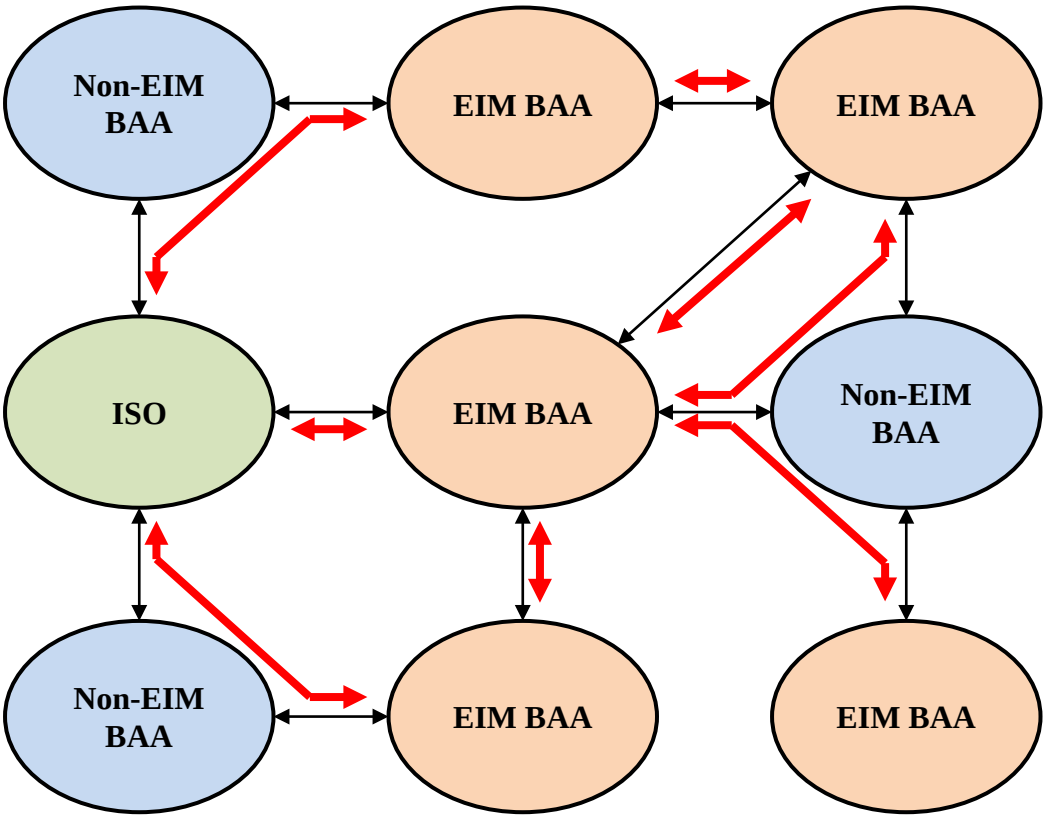


Figure 2 - Potential Transmission Available to Support EIM Transfers

The EIM Transfer is an algebraic quantity (positive for export and negative for import) for the net energy exchange between a given BAA and the remaining BAAs in the EIM Area. The market optimization must determine energy schedules among the EIM BAAs and the ISO from the optimal EIM Transfers of the BAAs in the EIM Area using the available transmission rights without violating them. These EIM transfers can then be tagged to the relevant interties among the BAAs.

The ISO posted a technical paper to discuss the market formulation to determine which schedules will be updated to tag EIM transfers[7]. This draft final proposal discusses the policy implications of this new market formulation.

EIM transfer cost – The technical paper discusses the EIM transfer cost as an "intertie transmission cost." But the objective of including a transfer cost is not to recover transmission revenues between EIM BAAs, but rather to ensure the most optimal path or paths for the EIM transfer are used. The EIM transfer cost will result in the market optimization, in scheduling EIM transfers, placing a higher priority on the most optimal path over less optimal paths. It will establish this priority using several factors:

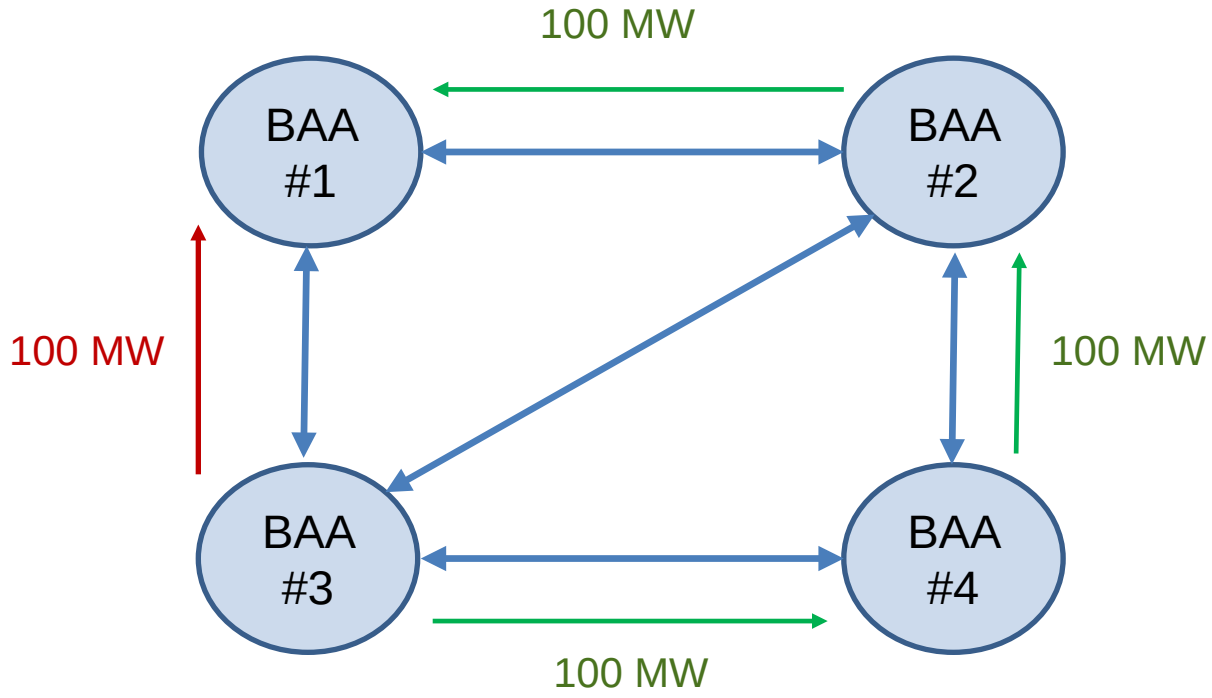
- Direct paths will have higher priority over indirect paths.
- Paths that 5-minute scheduling is allowed on will have higher priority over paths that only 15-minute scheduling is allowed on.
- Paths with firm transmission will have higher priority over paths with non-firm transmission
- Paths that experience with less-frequent curtailments will have higher priority than paths with more-frequent curtailments

The relative priorities of these factors will be based on the specific circumstances of the paths and experience gained during market simulation and refined during actual operations and will be detailed in the business practice manual.

This approach also minimizes the number of tags which must be updated and reduces the complexity of settling the financial value of the EIM transfer used for neutrality calculations. See the example in Figure 3 below. The blue lines represent the intertie scheduling points between each BAA participating in the EIM. There is a 100 MW transfer into BAA #1. The red arrow is the most direct path to tag the transfer and settle the financial value of the EIM transfer. The export tag from BAA #4 will be updated to reflect the 100MW transfer into BAA #1. The financial value of the transfer will be an export in BAA #4 and an import in BAA #1 at the default generation aggregation point of BAA #4. The green arrow also supports a 100 MW transfer into BAA #1; however, multiple tags must be updated and there the financial value of the EIM transfer must include an import and export settlement for all of the BAAs that the EIM transfer wheeled through.

[7] The technical paper is available at http://www.caiso.com/Documents/TechnicalPaper-EnergyImbalanceMarket-EnergyTransferScheduling.pdf

Figure 3 - Equivalent tagging for 100 MW transfer to BAA #1



The transfer cost will be a small cost in the market optimization for determining the schedule that will be tagged for EIM transfers. These costs will reflect the relative priorities of various paths for scheduling EIM transfers, as described above. While not explicit costs, these costs allow the market optimization to recognize the value of scheduling on more optimal paths over scheduling on less optimal paths. Thus, even though the ISO will administratively determine these costs and set them to as small as value as possible that will allowing various paths' priorities to be recognized, these costs will reflect the efficiency gains of scheduling over the most optimal paths.

The transfer cost will not be explicitly settled; however, the transfer cost can be reflected in locational marginal costs (LMPs) in two ways:

- The transfer cost will be reflected in LMPs if an individual EIM transfer limit is binding.
- The transfer cost can influence the market dispatch and consequently affect LMPs.

Otherwise, the transfer cost will not affect LMPs.

During market simulation, the ISO will determine the appropriate level of the transfer cost balancing the benefits of the transfer costs with the impact to locational marginal costs. The ISO, as the market operator, will determine the appropriate level of the transfer cost, not each EIM entity. If an EIM entity has multiple paths to support EIM transfers, the ISO will consult with the EIM entity to determine the priority order of the paths. However, the transfer costs used to implement the priority order will be determined by the ISO. The transfer costs will be documented in the business practice manual. In addition, stakeholders requested that the

maximum transfer cost that can be used should be included in the ISO tariff. The ISO will include the maximum transfer cost in the ISO tariff after the appropriate level is determined through market simulation.

This transfer cost approach may be able to be leveraged and extended in the future as a means to implement any future EIM transmission charges. This will be discussed in phase 2 of this initiative.

Financial value of EIM transfer in RTIEO calculation – currently the real-time imbalance energy offset accounts for the financial value of the EIM transfer. The price used is the LMP where the relevant EIM transfer is tagged. The EIM BAA exporting is charged the LMP and the EIM BAA that is importing is paid the LMP for the MW of the EIM transfer. This is ensures that each BAA is balanced when calculating the real-time imbalance energy offset. Since the intertie scheduling point is not the location where generation within an EIM BAA is dispatched, the ISO proposes to use the default generation aggregation point of the exporting EIM BAA to determine the financial value of the EIM transfer. This is appropriate because the energy transfer system resource is a single resource representing all generation resources in an EIM BAA.

7 Import/Export Deviations and the Resources Sufficiency Evaluation

The ISO proposes to apply the capacity test and flexible ramping test to the ISO BAA at T-40. The test will ensure there is sufficient ramping capability within the ISO to meet 15-minute net load changes following the HASP. In the event the ISO fails the tests, additional EIM transfers into the ISO above the last FMM interval of the proceeding operating hour will not be allowed. This is the same treatment for all BAAs in the EIM area.

Hourly ISO schedules from day-ahead and HASP are not required to be tagged until T-20. Hourly base schedules from EIM entities are also not required to be tagged until T-20. As a result, the assumed hourly schedules that are used in the resource sufficiency evaluation may differ from what is actually tagged. When there is a difference, a BAA may at T-20 have insufficient upward or downward ramping capability.

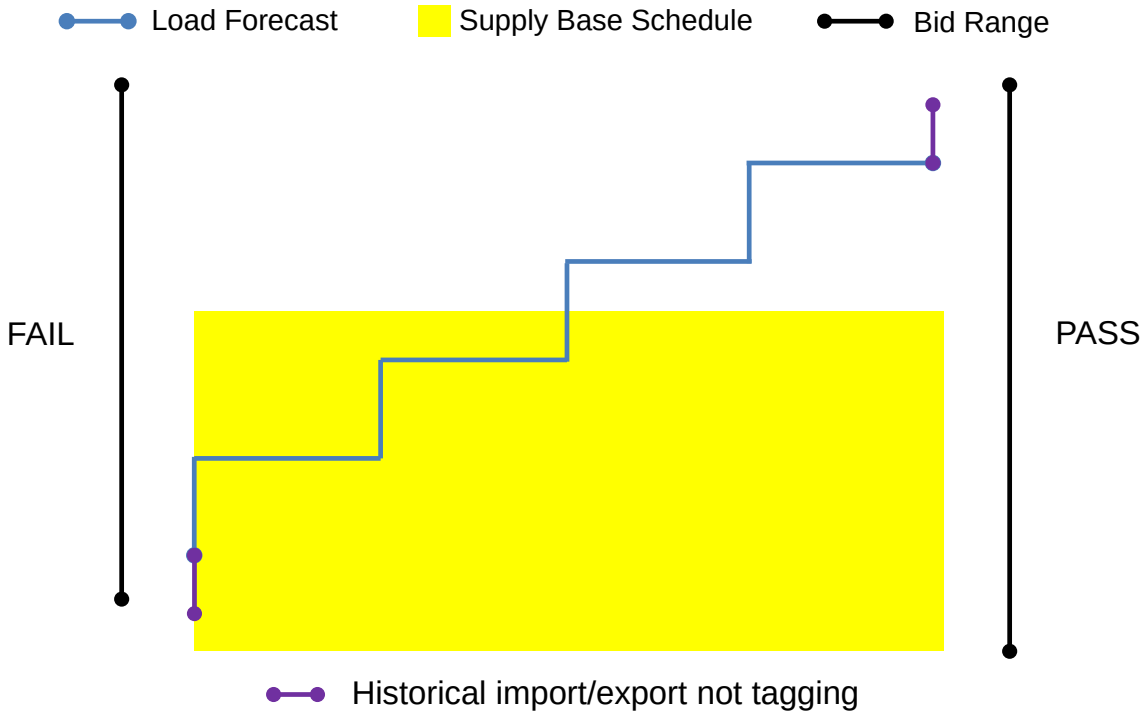
In determining the flexible ramping requirement for an individual BAA, the failure to tag an hourly schedule at the base schedule amount will increase the flexible ramping requirement for that BAA since this increases uncertainty. For example, an import tagged below its ISO base schedule will result in an operational adjustment that increases the upward dispatch in RTD. This additional upward dispatch in RTD is included in the historical analysis used to set the upward flexible ramping requirement. If an export is tagged below its EIM base schedule, this will increase downward dispatch in RTD and will be included in the historical analysis used to set the downward flexible ramping requirement.

While operational adjustments are considered in determining the flexible ramping requirements used in the flexible ramping test, the ISO proposes two additional mechanisms to ensure that differences between intertie schedules at T-40 and the final tagged schedule do not allow continued leaning on EIM.

First, the ISO proposes to calculate and publish, for each BAA, the hourly scheduling error of imports and exports whose final tag schedules differ from either the EIM base schedule or ISO hourly schedules. This hourly scheduling error will be calculated over a month between the 15th day of the prior month and the 15th day of the current month. The scheduling error will be included in the hourly capacity test of the upcoming month. This will ensure transparency across the EIM footprint as to the difference between schedules considered in the hourly capacity test and allow the EIM entity to make necessary arrangement to increase the bid range of EIM participating resources prior to the start of the upcoming month. The ISO considered calculating the hourly scheduling error on a rolling basis; however, this would provide insufficient time for the EIM entity to increase the bid range from participating resources which could result in additional failures of the resource sufficiency evaluation.

Secondly, if a BAA has historically high import/export schedule changes between T-40 and T-20, the ISO proposes to add an hourly block schedule difference that must also be met in addition to the capacity test that ensures the bid range from participating resources can meet the 15-minute granular net load forecast for the operating hour. For example, assume a BAA historically has 100 MW of imports with which do not tag according to the base schedules. The BAA would need to have sufficient upward bid range of EIM participating resources to meet the load forecast plus an additional 100 MW available to replace the potential 100 MW reduction in imports. Figure 4 shows the additional hourly block schedule error that must be covered as the purple bars added to the 15-minute load forecast. The bid range of participating resources must support moving from hourly granularity of the base schedules to 15-minute granularity of the RTUC load forecast and the import/export schedule changes that historically occur between T-40 and T-20.

Figure 4 - Hourly Block Schedule Error Included in Resource Sufficiency Evaluation



On a monthly basis, the ISO will calculate histograms of the percentage of the difference between imports and exports scheduled at T-40 and final tagged imports at T-20. The ISO will calculate these histograms in accordance with the following:

- The calculation will be done independently for the upward and downward directions.
- Imports and exports will not be netted against each other.
- If imports tag higher than the base schedules, additional downward bid range will be required. If imports tag lower than the base schedules, additional upward bid range will be required.
- If exports tag higher than the base schedules, additional upward bid range will be required. If exports tag lower than base schedules, additional downward bid range will be required.
- The scheduling error does will not consider the root cause of the difference when calculating the histogram.
- The percentages will be calculated by dividing the difference between the T-40 base schedule and the T-20 actual tagged value of the base schedule imports or exports.

The differences between imports and exports scheduled at T-40 and final tagged imports at T-20 will be calculated as follows:

Import histogram data

(Base schedule imports – actual tagged imports) / base schedule imports

Export histogram data

(Base schedule exports – actual tagged exports) / base schedule exports

Initially, the hourly capacity test will ensure 95% of the historical T-20 tagged imports/exports can be met by the bid range of EIM participating resources. The incremental requirement combines the over-scheduled imports and the under-scheduled exports. The decremental requirement combines the over-scheduled imports and the under-scheduled exports. The additional capacity test requirements can be derived as follows:

Additional incremental requirement

97.5^{th} percentile of import histogram * gross import base schedule – 2.5^{th} percentile of export histogram * gross export base schedule

Additional decremental requirement

97.5^{th} percentile of export histogram * gross export base schedule – 2.5^{th} percentile of import histogram * gross import base schedule

The percentage of imports/exports under/overscheduling to be met through the resource sufficiency evaluation will be configurable and documented in the business practice manual. In addition, the business practice manual will document the hours used to establish the histogram. Initially, the ISO anticipates the histogram to be calculated hourly; however, based upon operational experience it may be appropriate to group similar hours to increase the sample set of the histogram.

8 Administrative Pricing Rules

The ISO, in a separate stakeholder initiative[8], is revising its administrative pricing rules. The administrative pricing rules apply to the EIM, but in instances where the proposed rules use ISO day-ahead prices and schedules, a specific rule for the EIM must be developed since EIM is only the real-time market.

Through the pricing enhancements stakeholder process, the ISO is proposing to apply administrative pricing based on the nature of events and the number of market intervals impacted. This tiered approach aligns with practices in other ISOs. When the ISO reaches the point of having a market disruption or suspension, there is a high likelihood that the ISO may not be able to rerun the markets in a manner that would reflect a realistic solution. Under these conditions a rerun of the market will usually not be possible or would require the ISO making assumptions and approximations that will potentially lead to the market rerun results being challenged after the fact. This would actually be detrimental to the market certainty required under these conditions. The ISO pricing is an ex post mechanism, unlike other ISOs that rely on ex ante pricing, because an ex post mechanism may have the option of using the best available data.

The proposal improves price certainty for market participants during a market disruption or market suspension. In addition, the proposal seeks to establish market prices that reflect, to the extent possible, systems conditions during the period when market prices are missing. The process for determining the administrative price for the real-time market considers a three-tier approach; specifically,

1. If FMM prices are missing for three or fewer consecutive intervals or if the RTD market prices are missing for 11 or fewer consecutive intervals, then the ISO will preserve the current administrative pricing of using the last best price for each market accordingly.
2. If the FMM prices are missing for more than three consecutive intervals or the RTD prices are missing for more than 11 consecutive intervals under normal system conditions, then
    a. If the RTD prices are not available but the FMM prices are available, then missing RTD prices will be filled in with the FMM prices, regardless of how many intervals are missing as long as the missing prices are related to a market disruption and the market is unable to produce prices. Conversely, if the FMM

[8] Additional information is available at http://www.caiso.com/informed/Pages/StakeholderProcesses/PricingEnhancements.aspx

prices are missing but RTD prices are available, the RTD prices will be used to fill in the FMM prices by using the simple average of the three RTD prices.

b. If both the FMM and RTD prices are not available, in the ISO day-ahead prices for same period are used. In the EIM, the EIM Entity must provide the ISO with the administrative price, such as a proxy price.

Thus, the same administrative pricing calculation will be applied except in the scenario where there are no real-time market prices available. In this event, the ISO will use the OATT approved price used by the EIM Entity during a market suspension to settle imbalance within the EIM Entity BAA. For imbalance within the ISO BAA, the ISO will use the day-ahead price.

9 EIM Administrative Charge

The ISO grid management charge is the mechanism by which the ISO recovers ongoing operational costs from ISO market participants. The EIM administrative charge is the mechanism the ISO uses to recover ongoing operational costs from EIM market participants. The objective of the EIM administrative charge design is to charge ISO market participants and EIM market participants the same cost for similar real-time market services.

After go-live with PacifiCorp, the EIM administrative charges exceeded revenue expectations. Based on the current level of charges, the annual payments to the ISO would surpass four times the budgeted revenue. Management expected the minimum EIM administrative charge, except in rare cases, to exceed the EIM administrative charges the ISO allocates to EIM market participants based on energy imbalances. On January 5, 2015, the ISO Board[9] approved applying only the minimum charge to the EIM entity SC while the redesign of the administrative charge could be completed through the EIM year 1 enhancements stakeholder initiative.

The original design of the EIM administrative charge was a single per MWh rate applied to gross imbalances based on deviations from base schedules that occur into and within the EIM entity balancing area. The EIM administrative rate is based on the ISO's grid management charge by combining elements of two components: (1) the real-time market portion of the ISO market services charge and (2) the real-time dispatch portion of ISO system operations charge. The EIM administrative charge is fixed for a three year period and is updated by completing a cost of service study. In addition, the EIM administrative charge provisions include a minimum charge to ensure ongoing operational costs can be recovered independent of EIM imbalance volumes.

Currently, the ISO's grid management charge is made up of three components or services: (1) market services, (2) system operations and (3) congestion revenue rights (CRR) services. The market services charge encompasses all activities involved with clearing supply and demand in both the day-ahead market and real-time market. The system operations charge encompasses

[9] The Board memo is available at http://www.caiso.com/Documents/DecisionModificationEIM_AdministrativeChargeDesign-Memo-Jan2015.pdf. See also FERC Docket No. ER15-850-000 (proposing the change approved by the Board).

all activities in dispatching energy on the grid and balancing area activities such as transmission planning. Both the market services charge and system operations charge are allocated to load, generation, imports and exports. The third component, CRR services, encompasses activities surrounding CRRs and is allocated to CRR holders.

Since the energy imbalance market only includes the ISO's real-time market, the cost of service study was expanded to break down the ISO grid management charge components into their associated real-time market activities. The costs attributable to real-time market activities were then used to calculate a percentage of the ISO market services pro forma rate and ISO system operations pro forma rate that is applicable to EIM market participants. The ISO pro forma rates are calculated during the cost of service study by dividing total costs by estimated billing determinant volumes. The portion of the market services rate and the system operations rate were then combined to derive a single EIM administrative rate of $0.19/MWh

Unlike the ISO's grid management charge, the original EIM administrative rate was established once every three years and does not change if volumes or total costs change during the three year period. For example, if volumes in the ISO market were lower than the forecasted values used to establish the pro forma market services rate or system operations rate, the ISO rates would be increased to ensure the total costs are recovered. To address this concern and maintain a simplified structure, a minimum EIM administrative charge of 5% load and exports plus 5% generation and imports was adopted. The difference between the minimum EIM administrative charge and the EIM administrative costs allocated directly to EIM market participants was allocated to the EIM entity scheduling coordinator. This approach, as well as the single rate, were intended to simplify the overall approach to recovery of the ISO's administrative costs.

By applying a single EIM administrative rate to all imbalances in an EIM balancing authority area, the costs allocated to EIM market participants is greater than the charge that would have been allocated for the same services to ISO market participants. The difference occurs because the billing determinant volumes used for the ISO market services rate and system operations rate are lower than the EIM administrative rate billing determinant.

The ISO proposes to align the EIM administrative charge with the ISO grid management charge. The EIM administrative charge will be split into two separate charges: the EIM market services charge and the EIM system operations charge. This is warranted because the billing determinants differ between the two charges.

The EIM market services charge is allocated to gross instructed imbalance energy that is the result of the market optimization and excludes instructed imbalance energy this occurs out of the market optimization. The billing determinant includes both FMM and RTD market optimization results and is calculated as follows:

> **FMM** = Gross FMM Instructed Imbalance Energy excluding FMM Manual Dispatch Energy

RTD = Gross RTD Instructed Imbalance Energy excluding RTD Manual Dispatch Energy Standard Ramping Deviation, Ramping Energy Deviation, Residual Imbalance Energy, and Operational Adjustments.

The EIM system operations charge is allocated to gross real time energy flow which is the absolute difference between the meter and the base schedules.

The ISO propose that while the EIM entity continues to participate in the EIM, if ISO costs or forecasted volumes change, the EIM market services rate and/or EIM system operations rate will be updated when the ISO grid management charge rates are updated. The ISO rates for the market services charge and system operations charge are updated, as needed, on quarterly basis if actual collection/under-collection exceeds the greater of 2% or $1 million of annual cost/revenue. To update the EIM administrative charges, the real-time market percentage determined in the cost of service study will be multiplied by the new ISO rates. This percentage is valid for three years and updated by a new cost of service study. In addition, the EIM charges will go to four decimal points, same as ISO rates, and not be rounded to the nearest cent.

The ISO has updated the ISO grid management charge three times since January 2012: twice in 2012 and once in 2013. The following table shows how the EIM administrative charges would have been updated.

Table 2 - Historical Changes in EIM Administrative Charge Rates

ISO Grid Management Charge	1/1/12	7/1/12	10/1/12	1/1/13	8/1/13	1/1/14	1/1/15
Market Services	$0.0851	$0.0950	$0.0840	$0.0931	$0.0754	$0.0867	$0.0876
System Operations	$0.2845	$0.2845	$0.2845	$0.2872	$0.2874	$0.2890	$0.2978
Cost of Service Study	1/1/12	7/1/12	10/1/12	1/1/13	8/1/13	1/1/14	1/1/15
EIM % of ISO Market Services	67%	67%	67%	67%	67%	67%	61%
EIM % of ISO System Operations	48%	48%	48%	48%	48%	48%	45%
EIM Administrative Charge	1/1/12	7/1/12	10/1/12	1/1/13	8/1/13	1/1/14	1/1/15
Market Services	$0.0570	$0.0637	$0.0563	$0.0624	$0.0505	$0.0581	$0.0534
System Operations	$0.1366	$0.1366	$0.1366	$0.1379	$0.1380	$0.1387	$0.1340
Total	$0.1936	$0.2003	$0.1929	$0.2003	$0.1885	$0.1968	$0.1874

The ISO proposes to only charge the minimum charge if the EIM entity has decided to withdraw from the EIM and requests suspension of the EIM. During the six month termination period, both the EIM market services charge and the EIM system operations charge will be allocated to 5% load and exports plus 5% Generation and Imports.

10 BAA Combined Flexible Ramping Constraints

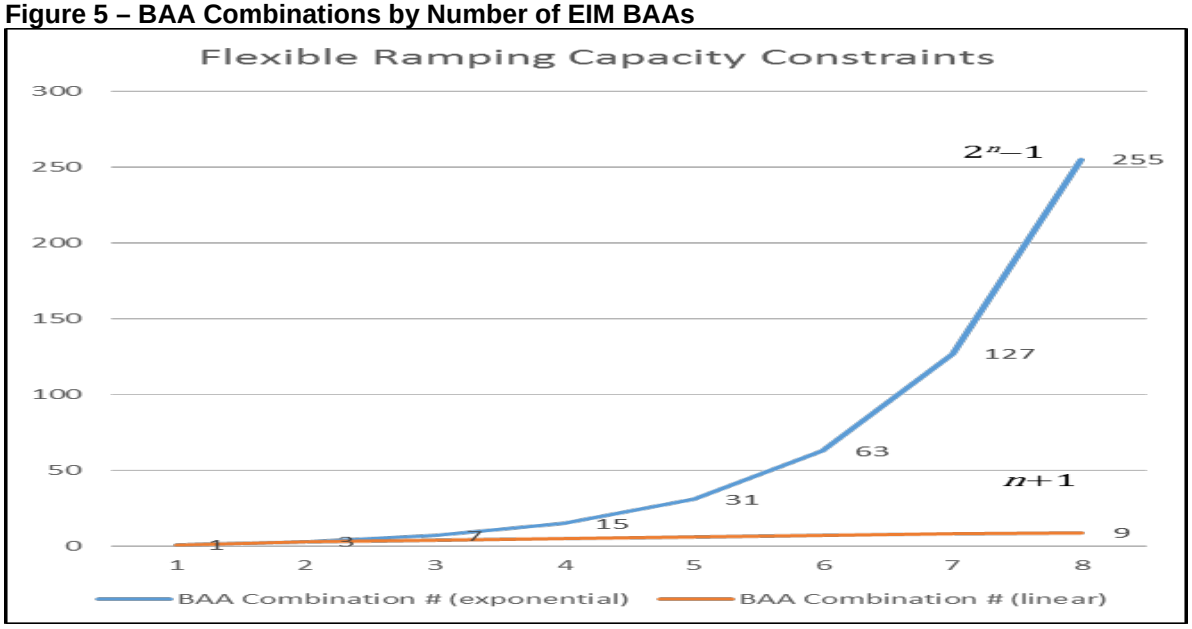
In the current implementation of the EIM, the ISO calculates a flexible ramping requirement and enforces a flexible ramping constraint for all combinations of BAAs participating in the EIM. Currently, there are seven combinations for PACE, PACW, and the ISO. It is important to note, that in all constraints except the system wide footprint, the requirement is reduces by the available EIM transfer capability into the individual BAA or combination. The constraints are as follows:

1. PACE >= PACE Requirement – Available EIM transfer capability in from PACW and ISO
2. PACW >= PACW Requirement – Available EIM transfer capability in from PACE and ISO
3. ISO >= ISO Requirement – Available EIM transfer capability in from PACE and PACW
4. PACE + PACW >= PACE + PACW Requirement – Available EIM transfer in from ISO
5. PACE + ISO >= PACE + ISO Requirement – Available EIM transfer in from PACW
6. PACW + ISO >= PACW + ISO Requirement – Available EIM transfer in from PACE
7. PACE + PACW + ISO >= System Requirement

Since each of the constraints cannot be less than zero, as EIM transfer capability increases, the likelihood that a constraint other than system requirement (#7) would be binding in the market optimization. However, it is important to maintain the individual BAA constraints because this constraint may binding if the BAA fails the hourly resource sufficiency evaluation because incremental EIM transfers from the other BAAs in the EIM will be not be allowed.

With the addition of NVE, the number of flexible ramping constraint combinations will increase to 15 constraints. As the additional BAAs join the EIM the use of combined constraints becomes unmanageable as illustrated in Figure 5. It is important to note, that for each combination constraint a separate requirement must also be calculated.

Figure 5 – BAA Combinations by Number of EIM BAAs



The ISO proposes to only enforce the system wide constraint and the individual BAA constraints. So when NVE joins the EIM in Fall 2015, the following constraints will be enforced in the market optimization:

1. PACE >= PACE Requirement – Available EIM transfer in from PACW, ISO & NVE
2. PACW >= PACW Requirement – Available EIM transfer in from PACE, ISO & NVE
3. ISO >= ISO Requirement – Available EIM transfer in from PACE, PACW & NVE
4. NVE >= NVE Requirement – Available EIM transfer in from PACE, PACW & ISO
5. PACE + PACW + ISO + NVE >= System Requirement

11 Next Steps

The ISO plans to discuss this draft final proposal with stakeholders during a stakeholder meeting in Las Vegas, NV to be held on February 18th. The ISO requests comments from stakeholders on the proposed market design changes described in this draft final proposal. Stakeholders should submit written comments by February 25th to EIM@caiso.com.