Energy Imbalance Market

3rd Revised Straw Proposal

August 13, 2013

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1. Executive Summary

This 3rd revised straw proposal describes the approach the ISO is developing in conjunction with stakeholders for its planned Energy Imbalance Market (EIM). The EIM will allow balancing authorities (BA) throughout the West to participate in a real-time imbalance energy market operated by the ISO. The EIM will dispatch economic bids to efficiently balance supply and load within its footprint, providing substantial benefits:

- **Cost savings:** All EIM participants, including existing ISO market participants, will benefit through serving load by the most economic resources, drawn from a larger pool of resources. The ISO's real-time market optimization matches load with the most efficient supply while ensuring reliability. This will replace the largely manual generation dispatch many balancing areas rely on in the West.
- **Improved renewable integration:** The EIM will help integrate renewable resources by capturing the benefits of geographical diversity of load and resources. Geographical diversity helps integrate variable energy resources because the output variation in one region tends to be counterbalanced by variation in another. Also, a larger footprint creates a larger pool of resources to meet peak loads that occur at different times across a large region.
- **Increased reliability:** Although other balancing area authorities (BAA) that are part of the EIM will retain responsibility for their respective reliability functions, the EIM will increase reliability by providing information on grid conditions across its large footprint. This is in contrast to the current situation in which balancing area authorities have more limited information on generation levels and transmission line flows outside of their balancing area.

Industry leaders in the West have explored and promoted the EIM concept for the last several years. The Western Electricity Coordinating Council (WECC) launched a major initiative and study effort in 2010. Late in 2011, the Western Governors Association appointed the PUC-EIM group to advance the concept and understanding of an energy imbalance market. Several other groups and individual balancing areas are currently exploring implementation options. Many of these efforts have centered on creating a new organization, new systems, and tariff to operate an EIM.

The ISO provided a conceptual proposal to the PUC-EIM group in March 2012 to provide the EIM services through its existing platform. PacifiCorp expressed interest in the ISO proposal, leading to a memorandum of understanding early in 2013. In March 2013, the ISO Board of Governors approved moving forward with the PacifiCorp implementation in parallel with this stakeholder process that will allow other balancing authorities in the West to take advantage of this important service in the future. The PacifiCorp implementation agreement was approved by FERC on June 28, 2013.

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EIM Roles

The EIM will add new roles to the ISO's real-time market:

- **Market Operator:** Similar to its existing role in the ISO market, the ISO will be the Market Operator for the EIM. The Market Operator will run the real-time energy market, dispatch generation resources, and financially settle the market, including generation and load. The ISO will retain its responsibilities as a balancing authority under NERC and WECC rules for the existing ISO balancing area footprint. To ensure the EIM's integrity, the Market Operator will monitor the market's performance and its participants' activities.

  The Market Operator will recover the EIM's costs through administrative charges that are mostly based on each participant's volume of EIM transactions. These ISO derived these administrative charges from the ISO's existing administrative charges.

- **EIM Entity:** An EIM Entity is a balancing authority area and transmission service provider outside of the ISO that elects to participates in the EIM. EIM Entities will retain their responsibilities as balancing authorities under NERC and WECC rules.

- **EIM Entity Scheduling Coordinator:** The EIM Entity Scheduling Coordinator will coordinate and facilitating the EIM in for an EIM Entity. The EIM Entity Scheduling Coordinator will compile generation and load schedules for the EIM Entity BAA and submit them to the Market Operator.

  The EIM Entity Scheduling Coordinator will allocate those costs and revenues in the EIM that is not paid directly to EIM Participating Resource Scheduling Coordinators. Examples include allocations to load or allocations to overall energy transfers to or from the ISO and other EIM Entities participating in the EIM. The EIM Entity Scheduling Coordinator will be also responsible for settling imbalance energy in EIM Entity that is not settled in the EIM.

- **EIM Participating Resource Scheduling Coordinator:** The EIM Participating Resource Scheduling Coordinator is the interface between a resource participating in the EIM and the ISO, as well as between the resource and the EIM Entity Scheduling Coordinator.

  The EIM Participating Resource Scheduling Coordinator submits energy bids to the ISO and also informs the EIM Entity Scheduling Coordinator the amount of generation that it has bid into the EIM. The EIM Participating Resource Scheduling Coordinator is also responsible for its resources' financial settlement in the EIM.

Market Processes

EIM processes will be similar and integrated with the ISO's existing market processes. The primary difference is that the EIM only includes the ISO's real-time market and not in the ISO's day-ahead market. The EIM will have some unique processes to reflect the absence of an ISO day-ahead schedule and to ensure EIM Entities have sufficient generation resources available in the real-time market.

The EIM processes will be as follows:

- **Day-ahead:** Although not part of the ISO's day-ahead market, EIM Entity Scheduling Coordinators will submit load forecasts and anticipated resource base schedules to the ISO in the day-ahead timeframe. The ISO will use this information in its day-ahead planning to inform EIM Entity Scheduling Coordinators of potential infeasible schedules such as those that cause transmission overloads in the EIM footprint.
- **Real-time:** The ISO real-time market that the EIM will operate will be based on the new market design the ISO is proposing under FERC Order No. 764. The market design changes to be implemented in Spring 2014 are designed to better integrate variable energy resources and will consist of two separate market runs, (1) a 15-minute market, and (2) a 5-minute market. Each of these market runs will produce schedules and locational marginal prices (LMPs) for resources.

  Because EIM load and resources will not have day-ahead schedules, the ISO will financially settle EIM schedules relative to base schedules submitted by EIM Entity Scheduling Coordinators. The real-time market will select the optimum supply to meet load based on the energy bids submitted by supply resources.

  The real-time market processes will be as follows:

  - **Submit base schedules and energy bids:** Up to75 minutes prior to each operating hour, EIM Entity Scheduling Coordinators will update their hourly base schedules for each generation resource and inter-tie their balancing area. If the EIM Entity elects to forecast its own load it will also submit an updated load schedule. Also by 75 minutes prior to each operating hour, EIM Participating Resource Scheduling Coordinators will submit hourly energy bids for resources participating in the EIM.
  - **ISO evaluates base schedules for feasibility:** The ISO will evaluate the base schedules for feasibility and notify the EIM Entity Scheduling Coordinators if the base schedules result in transmission overloads or other infeasibilities in their EIM Entity BAA. This provides the EIM Entity Scheduling Coordinator with the opportunity to resolve the identified issues prior to the start of the EIM. If supply is insufficient to meet the load forecast, the ISO will adjust the base schedule load lower which will result in the shortfall being settled through EIM.
  - **ISO verifies flexible ramping capacity sufficiency:** The ISO will evaluate the base schedules to ensure they contain sufficient energy bids to meet flexible ramping requirements in the BAA and notify the EIM Entity Scheduling Coordinators if the base schedules fail the sufficiency test. This provides the EIM Entity Scheduling Coordinator with the opportunity to resolve the identified issues prior to the start of the EIM. However, to prevent "leaning" on ramping capacity between balancing areas, the ISO will limit energy transfers into the EIM Entity in the event the EIM Entity has insufficient ramping capability.
  - **Local market power mitigation process:** The local power mitigation process will run 60 minutes prior to each operating hour for the hourly energy bids. This

process tests for uncompetitive conditions for energy and reduces generators' bids under uncompetitive conditions to the generator's actual costs.

- **15-minute market:** The 15-minute market will run 37.5 minutes prior to each 15-minute interval, producing generation schedules and LMPs. The 15-minute market will start-up and shutdown generators if the EIM Entity allows.

  The 15-minute market will also produce 15-minute granularity inter-tie schedules for imports and exports from each EIM Entity and neighboring balancing areas that are not EIM Entities. The 15-minute market will schedule imports and exports based on the economic energy bids if an EIM Entity allows energy bids at its inter-ties as part of the EIM. There will be options to fix these schedules for the entire operating hour for market participants that want to do so or if the EIM Entity only supports hourly inter-tie scheduling.

  The 15-minute market will not produce import and export schedules between the balancing areas participating in the EIM – it will accomplish these transfers through 15-minute schedule updates of generators within the EIM footprint.

  The ISO will only allow market participants to update 15-minute generation and inter-tie schedules for physical reasons. These include changes to variable energy resource output and generator physical outages. If the schedule changes are known prior to the start of the 15-minute market, the changes will be reflected in the resource's 15-minute market schedule.

- **5-minute market:** The 5-minute market will run 7.5 minutes prior to each 5-minute interval and produce dispatch instructions for generators and produce LMPs. The 5-minute market will not dispatch ancillary services. The EIM Entity will remain responsible for its own ancillary services and operating reserve management. EIM Entity's will retain the ability to dispatch resources out-of-market in their BAA as required to fulfill their responsibilities as balancing authority functional entities under NERC.

Settlement

The ISO will financially settle EIM generation and imports/exports as follows:

- Differences between base schedules and 15-minute schedules will settle at 15-minute LMPs. The applicable EIM Entity Scheduling Coordinator will settle any adjustments to base schedules made prior to an operating hour as specified in its Open Access Transmission Tariff.

- Differences between 15-minute schedules and actual real-time output or flow will settle at 5-minute LMPs.

The ISO will settle EIM load deviations from hourly base schedules based on a weighted-average of the 15-minute and 5-minute LMPs within each load area. These load areas are referred to as load aggregation points (LAPs). The weightings will be (1) the differences between the hourly base schedule and the load forecasts used by the 15-minute market runs, and

(2) the differences between the load forecasts used by the 15-minute and 5-minute markets. Each LMP at the various nodes within a LAP is also weighted by factors the ISO develops to approximate the load's actual physical distribution within each LAP.

The EIM will include under- and over-scheduling penalties to ensure EIM Entities submit balanced schedules with sufficient resources to meet their load. If an EIM Entity elects to use the IS0's load forecasts, then it can avoid exposure to these penalties by scheduling resources within 1 percent of the ISO's forecast. If an EIM Entity does not use the ISO's forecast, or uses the forecast but does not schedule resources with 1 percent of load, then it is subject to penalties if its actual load is more than 5 percent more than scheduled.

EIM settlement will include neutrality accounts that account for differences between payments received from load and payments to generation at LMPs. The ISO will allocate these neutrality accounts consistent with the cost allocation guiding principles the ISO developed with stakeholders in 2012. These accounts and their allocation will be:

- **Real-Time Market BAA Neutrality:** Neutrality charges can be a charge or credit. Neutrality charges can attributed to (1) an excessive rate mitigation measure in the pricing formula for load aggregation points, (2) differences between the Load forecast in the 5-minute market and actual metered Load, (3) uninstructed imbalance energy of generation, (4) regulation energy in the ISO, (5) the real-time marginal loss surplus, and (6) unaccounted for energy.

  Each EIM Entity and the ISO will have its own real-time market BAA neutrality account. However, because the EIM transfers energy between BAAs within the EIM, the ISO will reallocate a portion of the amounts in each BAA's account to other BAA's accounts. The reallocation will be based on the BAA's ratio of overall uninstructed imbalance energy to energy transfers to another BAA.

- **Real-Time Market System Neutrality:** Amounts in this account are the residual neutrality after calculation of the real-time market BAA neutrality above. The neutrality will be allocated to metered demand (load) within the EIM footprint.

- **BAA Real-Time Congestion Balancing Account:** Amounts in this account will arise when the ISO has to re-dispatch generation resources in real-time. These amounts can be either payments or charges, but when the re-dispatch is due to reduced transmission limits between establishment of base schedules (or day-ahead schedules) and real-time the amount will be a charge. This is because the ISO must dispatch generation resources up on the downstream side of a congested constraint at a relatively higher LMP while dispatching generation resources down on the upstream side at a relatively low LMP. Since the ISO's day-ahead market will not model EIM Entity's internal transmission constraints, real-time congestion within an EIM Entity not resolve in the submitted hourly base schedule will result in charges to its BAA real-time congestion balancing account uplift charges.

  Each EIM Entity as well as the ISO BAA will have a separate BAA real-time congestion balancing account. The ISO will allocate the costs of congestion attributable to transmission constraints within each BAA to that EIM Entity's BAA real-time congestion balancing account. This will provide an incentive for EIM Entity Scheduling

Coordinators to submit base schedules that do not result in real-time congestion.

This approach will also result in EIM Entities, and the ISO, incurring charges to their respective BAA real-time congestion balancing accounts because of congestion caused by physical loop flows from other BAAs. However, this approach is consistent with the current approach within WECC in which each BAA is responsible for managing loop flow within their BAA, and the resultant costs, irrespective of the source of the loop flow.

The ISO will allocate the BAA real-time congestion balancing account for its balancing area to ISO load and exports from the ISO balancing area (excluding EIM transfers). The ISO will allocate EIM Entities BAA real-time congestion balancing accounts to the respective EIM Entity Scheduling Coordinators. The EIM Entity Scheduling Coordinators will allocate these amounts according to the EIM Entities Open Access Transmission Tariff.

Convergence bids can increase the volume settled in the market and add to the BAA real-time congestion balancing account in the event of reduced transmission limits in the real-time market. As described above, the ISO will allocate the costs of congestion attributable to constraints within an EIM Entity to that EIM Entity's BAA real-time congestion balancing account. But since the EIM will not include a day-ahead market, there will not be convergence bidding within EIM Entities, and consequently it would not be appropriate to allocate uplift charges attributable to convergence bids to EIM Entities. Therefore, the ISO will allocate any BAA real-time congestion balancing account charges that are attributable to a convergence bid's impact on a constraint within an EIM Entity back to the convergence bidder.

- **Bid Cost Recovery:** The ISO makes payments to generators, referred to as bid cost recovery, in the event market revenues over a day do not cover a resource's bid costs. These costs fall into two categories: (1) energy production above a resource's minimum operating level, and (2) commitment costs, consisting of the costs to start a generator and operate it at its minimum operating level.

  Each EIM Entity as well as the ISO balancing area will have a separate real-time market bid cost recovery account. In allocating bid cost recovery costs to these accounts, the ISO will consider energy transfers between balancing authorities similar to the way it will for the real-time market BAA neutrality account. This transfer will occur differently depending on whether the EIM Entity elects to have the EIM commit generators in the real-time market.

  - If the EIM Entity elects to have the EIM commit generators in the real-time market, then the transfer will include bid cost recovery payment costs for both for energy above minimum load and commitment costs
  - If the EIM Entity does <u>not</u> elect to have the EIM commit generators in the real-time market, then the transfer will include bid cost recovery payment costs only for energy above minimum load.

- **Flexible Ramping Constraint:** As discussed earlier, each EIM Entity and the ISO BAA will be responsible for meeting its own portion of the combined flexible ramping requirements. The flexible ramping requirement for each EIM Entity BAA would be determined similarly to the flexible ramping requirement for the ISO BAA based on the demand forecast change across consecutive intervals plus a stochastic value for demand forecast error and energy production variability within a specific confidence interval. The combined requirement for the entire EIM footprint may be less than the sum of the individual BAA requirements realizing potential diversity benefits in the EIM footprint. Consequently, each BAA will have separate flexible ramping constraint cost accounts. The ISO's allocation of flexible ramping costs within its balancing area will not change. EIM Entity Scheduling Coordinators will allocate these amounts according to their respective Open Access Transmission Tariff.

Resource Sufficiency

The EIM does not include forward resource adequacy requirements because (1) it is a real-time market only, (2) these requirements are more appropriately left to the many diverse local regulatory authorities applicable to EIM participants. Nonetheless, the EIM includes a number of design elements in its real-time market design that ensure each EIM Entity has sufficient resources to meet load. This ensures EIM participants, while gaining the benefits of increased resource diversity, do not inappropriately "lean" on other EIM Entity resources.

The EIM design elements that ensure resource sufficiency include:

- The under-scheduling penalty and resource balancing provisions ensure each EIM Entity provides a balanced load and resource portfolio with sufficient resources to meet its load.
- The BAA real-time congestion balancing accounts provide a strong incentive for each EIM Entity to resolve congestion with their own resources prior to real-time.
- The flexible ramping capacity sufficiency test and limitation on transfers if an EIM Entity fails the check ensures each EIM Entity provides generation resources with sufficient ramping capability to avoid leaning.

The EIM does not include provisions to assess sufficiency of resources comprising hourly base schedules. The ISO believes that this would be extending the resource adequacy in to the real-time market. Resource adequacy is more appropriately addressed through WECC's and local regulatory authorities rules and practices.

California Greenhouse Gas Regulation

Imports of energy into California and generation of energy within California from CO2 emitting resources, result in an obligation for the market participant to surrender compliance instruments to California Air Resources Board (CARB) for the greenhouse gas emissions associated with the energy pursuant to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanism Regulation. Energy generated outside of California that is not imported into California is not subject to this obligation.

The EIM will account for this through the following:

- It will incorporate the cost of the greenhouse gas compliance obligation into its dispatch of generation within an EIM Entity to serve California load, but not consider this cost when it dispatches this generation to serve load outside California.
- It will include a mechanism to calculate the energy produced by each generator within an EIM Entity that serves California load. It will provide EIM Participating Resource Scheduling Coordinators with summary reports listing these amounts. These amounts will be the basis of their greenhouse gas regulation compliance obligation with CARB.
- It will allow EIM Participating Resource Scheduling Coordinators to include the costs of their greenhouse gas regulation compliance obligation in their energy bids.

Greenhouse gas compliance costs will not affect the LMPs in an EIM Entity. Rather, the market optimization will calculate the marginal cost difference between EIM generation serving load in California and serving load outside of California. This difference will be the marginal greenhouse gas regulation compliance cost and will be the rate the ISO will use to calculate a payment to each generator in an EIM Entity for its output that served California load. This payment will be funded by California load through the LMPs within California.

Transmission Service

The ISO proposes for the first year that the EIM operates that there be no charge between the ISO and EIM Entities for the EIM's use of as-available transmission. During this time, as stakeholders gain operational experience and additional balancing authorities consider joining the EIM, the ISO will coordinate with stakeholders to consider various alternatives for the long-term.

Governance

Concurrent with this stakeholder process, the ISO is conducting a separate stakeholder engagement to design a governance structure that will provide stakeholders an immediate voice in EIM matters and also provide a longer term independent EIM structure. The ISO is posting the initial white paper on August 13, 2013 and encourages all interested parties to review and provide feedback in that process.

2. Introduction

All times mentioned in this document are in Pacific Prevailing Time (PPT).

2.1. New Terms

Capitalized terms in this revised straw proposal are defined in Appendix A of the ISO tariff. The paper introduces the following new terms:

Energy Imbalance Market (EIM) is operation of the ISO's real-time market to manage transmission congestion and optimize procurement of energy to balance supply and demand for the combined ISO and EIM footprint. The ISO's real-time market includes a 15-minute market and a 5-minute market.

Market Operator is the ISO.

EIM Entity is a balancing authority and transmission service provider that enters into the pro forma EIM Entity Agreement to enable the EIM to occur in its balancing authority area (BAA). By enabling the EIM, real-time load and generation imbalances within its BAA will be settled through the EIM. The EIM Entity determines which resource types and transmission service is required to be eligible to participate in the EIM within the EIM Entity BAA. For example, an EIM Entity could determine that 15-minute economic bids for imports/exports would not be supported within the EIM Entity BAA even though this functionality is supported by the EIM.

EIM Entity Scheduling Coordinator is the EIM Entity, or a third-party designated by the EIM Entity, that is certified by the ISO and that enters into the pro forma EIM Entity Scheduling Coordinator Agreement, under which it is responsible for meeting the requirements specified in Tariff Section 29[1] on behalf of the EIM Entity. The EIM Entity Scheduling Coordinator is responsible for compiling and submitting balanced schedules for the EIM Entity BAA to the Market Operator, for imbalance energy settlement of resources not participating in EIM, and for distributing costs or revenues from uplift allocations to the EIM Entity BAA.

EIM Participating Resource is a resource located within the EIM Entity BAA that is eligible and elects to participate in the EIM and that enters into the pro forma EIM Participating Resource Agreement, under which it is responsible for meeting the requirements specified in Tariff Section 29. In the 5-minute market, eligible resources are those that can deliver energy, curtailable demand, demand response services or other similar services under the ISO Tariff provided they are enabled by the EIM Entity under its requirements for the delivery of energy or other similar services within its BAA, and may include Generating Units, Physical Scheduling Plants, Participating Loads, Proxy Demand Resources, Non-Generator Resources and Dynamic Transfers. In the 15-minute market,

[1] ISO Tariff Section 29 is not currently used. The ISO intends to aggregate the EIM provisions that result from this initiative and include them in Section 29.

imports and exports that can be scheduled on a 15-minute basis are eligible to participate in addition to all resources eligible to participate in the 5-minute market.

EIM Participating Resource Scheduling Coordinator is the participating resource, or a third-party designated by the resource, that is certified by the ISO and enters into the pro forma EIM Participating Resource Scheduling Coordinator Agreement, under which it is responsible for meeting the requirements specified in Tariff Section 29 on behalf of the resource. The EIM Participating Resource Scheduling Coordinator interfaces with the Market Operator on behalf of resources in an EIM Entity BAA that voluntarily elect to economically participate in the EIM. An EIM Participating Resource Scheduling Coordinator may be an existing Scheduling Coordinator, but it may not be the EIM Entity Scheduling Coordinator.

2.2. Changes to 2nd Revised Straw Proposal

The 3rd revised straw proposal includes the follow changes from the preceding 2nd revised straw proposal:

- Clarifies that the EIM Entity shall determine which resources within its BAA are eligible to participate in the EIM.
- Eliminates the minimum shift optimization and concept of adjusted base schedules.
- Removes the option for the EIM Entity Scheduling Coordinator to submit base schedules every 15-minutes with 15-minute granularity. All base schedules will be submitted hourly with hourly granularity for load, generation, imports and exports.
- Discusses how diversity benefits will be included in the flexible ramping constraint sufficiency test and provides additional discussion on how the flexible ramping constraint requirement is met through the market optimization.
- Refines and provides additional detail of the calculation of real-time market neutrality accounts.
- Modifies the real-time congestion settlement of Convergence Bids on EIM Entity BAA constraints.
- Further discusses the rationale for the first-year proposal for reciprocity between the ISO and EIM Entities in not applying a transmission access charge to dispatches across the BAA boundaries, and the potential for a longer-term EIM transmission access charge.
- Refines the under-scheduling penalty of load.
- Discusses further the exclusion of over-scheduling penalties of generation.
- Allows EIM Participating Resources to submit a separate bid for the GHG compliance obligation costs. The Market Operator will no longer calculate the emission cost for inclusion in the market optimization.
- Adds a section to address settlement of tax liability, if any, from ISO acting as the Market Operator

- Includes minor edits to improve clarity from 2nd revised straw proposal.

2.3. Plan for Stakeholder Engagement

Stakeholder input is essential and critical for the success of new initiatives from policy development to implementation. The EIM stakeholder process will shape the final 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 stakeholder initiative.

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

Item	Date
Post 3rd Revised Straw Proposal and Governance White Paper	August 13, 2013
Stakeholder Meeting (Portland)	August 20, 2013
Stakeholder Comments Due	August 30, 2013
Post Tariff Framework	September 10, 2013
Stakeholder Comments Due (Tariff Framework)	September 20, 2013
Post Draft Final Proposal (DFP)	September 23, 2013
DFP Stakeholder Meeting (Folsom)	September 30, 2013
Tariff Framework Stakeholder Meeting (Folsom)	October 1, 2013
Stakeholder Comments Due (DFP)	October 8, 2013
Board Decision (Policy)	November 7-8, 2013
Post Draft Tariff Language	November 12, 2013
Stakeholder Comments Due (Tariff)	December 5, 2013
Tariff Stakeholder Meeting (Folsom)	December 16, 2013
Post Revised Tariff Language	January 16, 2014
Stakeholder Comments Due (Tariff)	January 23, 2014
Tariff Stakeholder Meeting (Tariff)	January 30, 2014

Table 1- Schedule for EIM Stakeholder Process

3. EIM Design 3rd Revised Straw Proposal

The Energy Imbalance Market (EIM) is a voluntary market for procuring imbalance energy (positive or negative) to balance supply and demand deviations from forward energy schedules through a fifteen minute market and five minute dispatch in the combined network of ISO and EIM Entities. These forward energy schedules, referred to as "base schedules" in this document, consist of hourly forecasts of load, generation and interchange provided by the EIM Entity Scheduling Coordinator hourly granularity.

3.1. Key Roles within EIM

3.1.1. ISO role as Balancing Authority

There is no impact to the current NERC functional entity (e.g., balancing authority and transmission operator) responsibilities of the ISO. Current functions (e.g., ancillary services, operating reserve management, automatic generation control balancing of load and resources, system operating limit and interconnection reliability operating limit management, disturbance control standards events recovery and voltage control) will be handled by the ISO for its BAA.

During any market maintenance activities, the ISO will be responsible for managing and communicating to the resources (static and dynamic) in its respective BAA, and interchange schedules for the current and future hours.

3.1.2. ISO as Market Operator of EIM

The EIM provides the energy imbalance needs of multiple BAAs. As the Market Operator, the ISO will only dispatch resources that are online and for which the EIM Participating Resource Scheduling Coordinator has provided energy bids for EIM dispatch. The Market Operator will assume that resources in the EIM Entity BAA are online if they have a base schedule. Depending options chosen by the EIM Entity, the Market Operator may or may not commit, start-up or shut down any resource in the EIM Entity BAA. A decision needs to be made by the EIM Entity to allow commitment or not of resources in the EIM BAA or configuration management of multi-stage resources like combined cycle resources. The effect of this election is discussed later in Section 3.7.8.3 regarding allocation of costs associated with real-time bid cost recovery.

The Market Operator will send dispatch instructions to the EIM Participating Resource Scheduling Coordinator and the EIM Entity Scheduling Coordinator for generating units that have bid into the EIM.

3.1.3. EIM Entity role as Balancing Authority

There is no impact to the current NERC functional responsibilities (e.g., balancing authority, generator operator, load serving entity, transmission operator) responsibilities of an EIM Entity. Current functions (e.g., ancillary services, operating reserve management, automatic generation control balancing of load and resources, system operating limit and interconnection reliability operating limit management, disturbance control standards events recovery and voltage control) will be handled by the EIM Entity for its BAA.

During any market maintenance activities where regular market runs are briefly suspended, e.g., during a software patch, the EIM Entity will be responsible for managing and communicating to the resources (static and dynamic) in their respective BAA, and interchange schedules for the current and future hours.

The EIM Entity will be responsible for:

a. Ensuring all NERC and WECC standards are met within their system.

b. Providing all NERC and WECC notifications regarding their system.

c. Ensuring all base interchange schedules are below the associated inter-tie limits and make any reliability curtailments as required. The EIM Entity will also be responsible for base interchange tagging functions and validations.

d. Managing their market resources when the market is not (or cannot) manage them as required for congestion or other system conditions. Because management of resources for reasons other than market conditions (i.e., exceptional dispatch) is a reliability function, the need for which is determined by the EIM Entity rather than by the affected resources, changes from base schedules due to exceptional dispatch must be communicated to the Market Operator by the EIM Entity through the EIM Entity Scheduling Coordinator.

e. Approving or denying outages in its system.

f. Ensuring network topology and real-time information is correctly reflected in the real-time market optimization. This includes scheduled outages, forced outages, and accurate telemetry.

g. Determining transmission capability (e.g., system operating limits) for inter-ties and internal constraints as needed for the market, and promptly communicating these limits to the Market Operator. This includes adjusting/conforming limits as required due to differences between actual flow as measured by actual telemetry or state estimator, and the flows calculated by the market model (market flow). Note that small differences between actual and market flows can arise due to differences in the model and actual conditions such as load distribution factors, unscheduled flow, network topology and impedances.

h. Communicating any changes to interchange schedules (real-time curtailments) to the Market Operator, as soon as they are known. These schedule adjustments will eventually be available through e-Tag data, but the e-Tag updates may not be available within the time that the Market Operator needs to begin responding to the base schedules.

There will also be communication between the Market Operator and the EIM Entity to ensure functional coordination. The EIM Entity Scheduling Coordinator role may be provided by the EIM Entity or an agent of the EIM Entity. Note that the relationship between the EIM Entity Scheduling Coordinator and the EIM Participating Resource Scheduling Coordinator may be subject to the FERC standards of conduct and appropriate compliance measures may need to be taken. To achieve this the EIM Entity Scheduling Coordinator must be a separate entity from the

EIM Participating Resource Scheduling Coordinator.

3.1.4. Role as EIM Entity Scheduling Coordinator

The EIM Entity Scheduling Coordinator must meet the certification requirements for a Scheduling Coordinator and all other applicable obligations of a Scheduling Coordinator. In addition, an EIM Entity Scheduling Coordinator is required to submit hourly load forecasts and balanced base supply, demand, and interchange schedules to the Market Operator for the applicable EIM Entity BAA, as well as submitting these schedules to the WECC reliability coordinator. The EIM Entity Scheduling Coordinator will be responsible for all financial obligations arising as a result of meeting these requirements, including financial settlement with non-participating resources within its EIM Entity BAA and neutrality charges and uplifts.

The EIM Entity Scheduling Coordinator will submit outages electronically into the designated outage reporting system using mutually agreed format for the non-participating resources. The ISO currently uses the Scheduling and Logging for the ISO of California (SLIC) system, which will be upgraded in the future to the Outage Management System (OMS). The EIM Entity Scheduling Coordinator will manage all of their EIM non-participating resource outages (adjust start/end times, cancel, submit forced outages).

All information required by the market will be submitted within the required timeframe established by the Market Operator.

3.1.5. Role as EIM Participating Resource Scheduling Coordinator

The EIM Participating Resource Scheduling Coordinator must meet the certification requirements for a Scheduling Coordinator and all other applicable obligations of a Scheduling Coordinator. An EIM Participating Resource Scheduling Coordinator will be responsible for the imbalance energy settlement of its EIM Participating Resources.

The EIM Participating Resource Scheduling Coordinator will submit economic bids to the EIM for EIM Participating Resources that are voluntarily participating in the EIM.

The EIM Participating Resource Scheduling Coordinator will submit outages and de-rates/re-rates electronically into the designated outage reporting system using mutually agreed format. The ISO currently uses the Scheduling and Logging for the ISO of California (SLIC) system, which will be upgraded in the future to the Outage Management System (OMS). The EIM Participating Resource Scheduling Coordinator will manage all of their EIM Participating Resource outages (adjust start/end times, cancel, submit forced outages).

All information required by the market will be submitted within the required timeframe established by the Market Operator.

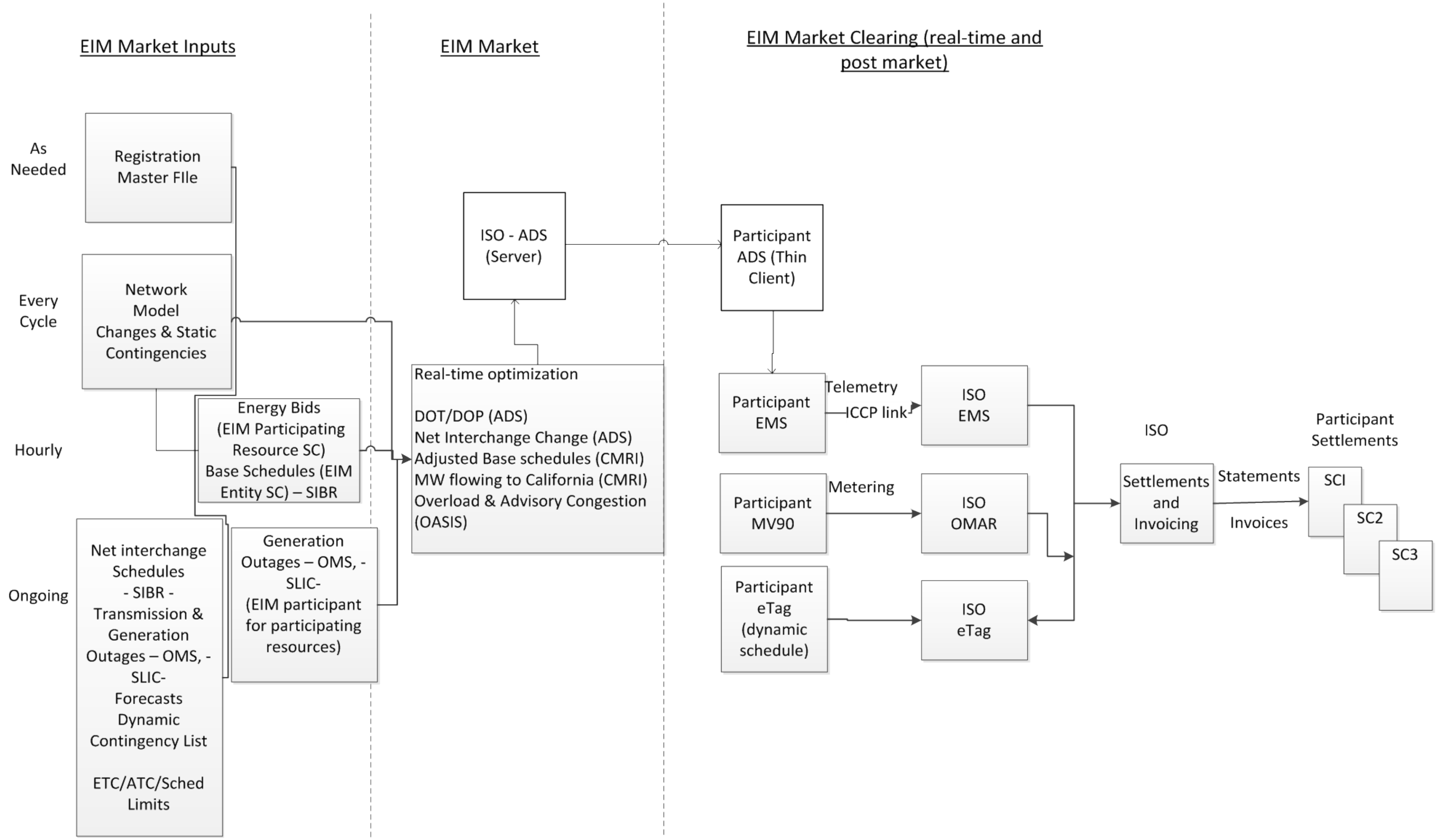

Figure 1. *Energy Imbalance Market Processes*

3.2. EIM Processes

The expected implementation of FERC Order No. 764 will result in a financially binding 15-minute energy schedule in addition to the financially binding 5-minute energy dispatch by RTD. These real-time market changes[2] are scheduled to be implemented in Spring 2014, prior to the implementation of EIM. As a result, the EIM discussion below assumes the FERC Order No. 764 real-time market design changes would already be implemented.

Operation of the EIM requires the exchange of a variety of information between the systems of the Market Operator, EIM Entity, EIM Entity Scheduling Coordinator and EIM Participating Resource Scheduling Coordinator. The timeline shown in Figure 1 highlights the key activities of the Market Operator, EIM Entity Scheduling Coordinator, and EIM Participating Resource Scheduling Coordinator. EIM Entity Scheduling Coordinators with registered resources will be required to submit resource plans and to keep the plans up to date throughout the operating day. The first submission of resource plans for an operating day can be received by 10:00 PPT seven days preceding the operating day. The Market Operator will use these base schedules to provide advisory information on congestion in the EIM area when the ISO publishes its day-ahead market results.

Energy bids for each Trading Hour of a given Trading Day may be submitted after the Day-Ahead Market results are published for that Trading Day, usually by 13:00 PPT the day before; the bids can be subsequently revised or cancelled until 75 minutes prior to the start of the Trading Hour when the real-time market closes. The EIM Participating Resource Scheduling Coordinator indicates that a resource is available for dispatch through EIM by submitting energy bids.

Initial base schedules, with hourly granularity, must be submitted by the EIM Entity Scheduling Coordinator no later than 75 minutes prior to the beginning of each Trading Hour. The Market Operator will perform a Flexible Ramping Constraint sufficiency test and identify unresolved congestion in the submitted hourly base schedule. The EIM Entity Scheduling Coordinator will have an opportunity to resolve identified issues up by submitting final base schedules until 40 minutes before the start of the relevant operating hour. This process seeks to minimize leaning by allowing the EIM Entity Scheduling coordinator to update the hourly base schedule before the start of the first financially binding 15-minute market optimization of the operating hour.

The EIM consists of two market processes that run in parallel with different granularity:

1) The Real-Time Unit Commitment (RTUC) process, which runs every 15 minutes and produces 15-minute schedules and 15-minute LMPs within the EIM Entity BAA and for interchange scheduling points. Interchange schedules with the ISO BAA are determined

[2] Additional information of the proposed FERC Order 764 real-time market design changes can be found at http://www.caiso.com/informed/Pages/StakeholderProcesses/FERCOrderNo764MarketChanges.aspx

currently in the Hour-Ahead Scheduling Process, and will occur instead in RTUC after the ISO's implementation of FERC Order No. 764 every 15 minutes. EIM Participating Resource Scheduling Coordinators that bid into the EIM will receive 15-minute schedules from RTUC. If the EIM Entity supports 15-minute intertie scheduling, imports and exports (to the EIM Entity Area from other BAAs) that provide bids for the 15-minute market will also receive 15-minute schedules. However for such intertie bids no 5 minute dispatch will be determined by EIM. No unit commitment decisions are made by RTUC in the EIM Entity BAA under the current scope of EIM implementation, therefore EIM Participating Resources with bids are considered self-committed and available; however, RTUC may commit and schedule resources in the ISO BAA to displace higher cost energy from EIM Participating Resources while balancing load deviations and managing transmission congestion. It may be possible for the EIM Entity to elect to have the EIM also make commitment decisions for short start resources and multi-stage configuration management.

2) The Real-Time Dispatch (RTD), which runs every 5 minutes and produces 5-minute dispatch instructions and 5-minute LMPs within the EIM Entity BAA and for interchange scheduling points. EIM Participating Resource Scheduling Coordinators that bid into the EIM will receive 5-minute dispatch instructions from RTD. These dispatch instructions will also be sent to the EIM Entity Scheduling Coordinator.

Load forecasts, energy bids, base schedules, and related resource plan data will be submitted via the Scheduling Infrastructure and Business Rules (SIBR) system.

Both RTUC and RTD have multi-interval time horizons where the outcome for the first interval in the horizon is financially binding, whereas the outcomes for subsequent intervals are advisory since they are revised by subsequent market runs. Any changes to dispatch resulting from the 15-minute RTUC binding interval will be settled as instructed deviations from the base schedules. The market operator will publish advisory result information. This advisory information can be used by the EIM Entity Scheduling Coordinator to identify future congestion that may result in the need to modify base schedules for submission in later hours.

The Market Operator will calculate, and EIM Entity Scheduling Coordinator will submit or confirm, actual values for dynamic schedules reflecting the EIM transfers to the Market Operator within 60 minutes after completion of the operating hour, to update these values in accordance with WECC business practices via an update to the e-Tag.

3.2.1. Operational Information Exchange

The overall operational information exchange timeline includes activities prior to the operating day, within the operating day, and after the operating day, as illustrated in the following tables:

Activities Prior to Operating Hour		
Timeline (Pacific Prevailing Time)	**EIM Action**	**Market Operator Action**
OD-7 by 10:00 PPT, to OD-1 by 10:00 PPT By OH-75 minutes: updates to energy bids (OD is operating day. OH is start of operating hour.)	EIM Entity Scheduling Coordinators submit demand forecasts, resource plans, and ancillary service plans with hourly granularity. EIM Participating Resource Scheduling Coordinators submit energy bids for upcoming operating hours and days.	EIM initial base schedules as of OH–75 minutes will establish the initial basis for EIM energy settlements, subject to modification due to unresolved congestion or failure of the flexible ramping constraint sufficiency test. Subsequent instructed or uninstructed deviations will be settled through EIM energy settlements.
OD-7 by 18:00 PPT, to OD-1 by 18:00 PPT		For the next 7 days, the Market Operator will post hourly demand forecasts by load aggregation point. The Market Operator will continue to update load forecasts during OD.
By 10:00 PPT of OD-1	EIM Entity Scheduling Coordinators update hourly demand forecasts, resource plans, and ancillary service plans	Review EIM Entity Scheduling Coordinator hourly load forecasts, resource plans, and ancillary service plans upon submission, and notify EIM Entity Scheduling Coordinators when they do not balance and/or mismatched.
By 13:00 of OD-1		Notify applicable EIM Entity Scheduling Coordinators of anticipated congestion based on submitted resource plans, to allow adjustments to resource plans prior to real-time to mitigate congestion.

Activities Prior to Operating Hour		
Timeline (Pacific Prevailing Time)	**EIM Action**	**Market Operator Action**
By OH–75 minutes	EIM Entity Scheduling Coordinator submits hourly base schedules and resource plans for OH. EIM Participating Resource Scheduling Coordinator energy bids and base schedule for resource for OH.	Bid validation and processing. Base schedule adjustment after OH–75 minutes.
By T-60 minutes		Notifies EIM Entity Scheduling Coordinator if unresolved congestion remains and results of flexible ramping constraint sufficiency test on submitted base schedule.
By T-55 minutes	EIM Entity Scheduling Coordinator submits updated base schedule if necessary.	
By T-45 minutes		Notifies EIM Entity Scheduling Coordinator if unresolved congestion remains and results of flexible ramping constraint sufficiency test on submitted base schedule.
By T–40 minutes	EIM Entity Scheduling Coordinator submits final hourly base schedule for the operating hour	Final base schedule will be used to settle deviations in the real-time market.

Operating Hour Activities		
Timeline	**EIM Action**	**Market Operator Action**
By T-20 minutes Note: This timing may be affected by WECC entities' compliance filings for FERC Order No. 764.	Tagged schedules for static imports and exports must be submitted and approved at least 20 minutes prior to the start of the 15-min interval (T) by the EIM Entity.	
Beginning of dispatch interval –7.5 minutes		1. Update demand forecast for dispatch interval 2. Transfer latest state estimator solution to market system 3. Process updated Variable Energy Resource forecast 4. Run Security Constrained Economic Dispatch (SCED)
Beginning of dispatch interval -2.5 minutes		Send dispatch instructions for the middle of the dispatch interval via ADS and ICCP, and publish LMPs for the dispatch interval via ADS and OASIS.
Beginning of dispatch interval -2.5 minutes	EIM Participating Resources begin ramp to achieve dispatch instructions for middle of dispatch interval	Update Net Scheduled Interchange (NSI) and send NSI to EIM Entities for the dispatch interval midpoint, for use in managing area control error; the NSI reflects the impact of congestion management and reserve sharing events. NSI is assumed to ramp linearly between consecutive dispatch interval midpoints.
Middle of dispatch interval	EIM Participating Resources at instructed levels	

Operating Hour Activities		
Timeline	**EIM Action**	**Market Operator Action**
Within OH + 15 minutes		LMP for hourly settlement interval for net interchange available, including meter settlement locations.
Within OH + 60 minutes	Estimated dynamic schedules (other than with the Market Operator) may be updated by EIM Entity	Checkouts among balancing authorities, including dynamic schedules

Post-Operating Day Activities		
Timeline	**EIM Action**	**Market Operator Action**
3 days after the OD		Initial settlement statements by settlement location, hour, and EIM Participating Resource
By 48 days after the OD	EIM Entity Scheduling Coordinator submits load, resource, and interconnection meter data	
By 55 days after the OD Additional settlement statements occur between these dates		Final settlement statement by settlement location, hour, and EIM Participating Resource

Updates to Operating Day Data		
Timeline	**EIM Action**	**Market Operator Action**
Immediately following a reserve sharing event	EIM Entity deploys energy in response to the reserve sharing event. EIM Entity submits Assisting BAA Load to Contingent BAA Load schedules, for each participant involved in the reserve sharing event. One schedule is created from the Contingent BAA Load to the Contingent Resource for the amount lost.	Receive exceptional dispatch instructions from the EIM Entity Scheduling Coordinator for resources in the EIM Entity BAA deployed in response to an event, pursuant to the reserve sharing group's criteria.
01:00 PPT following the OD+7 containing the reserve sharing event	EIM Entity has the opportunity to offset the Load schedules created by the RSS event by entering Resource to Load schedules, reflecting generation Resources actually utilized to assist in the event.	

3.2.2. Hour-Ahead Process

Both real-time market processes (RTUC and RTD) use the same hourly energy bids that must be submitted by 75 minutes before the start of each hour. Figure 2 below shows the timeline of the hour-ahead process to determine hourly static intertie imports and exports.

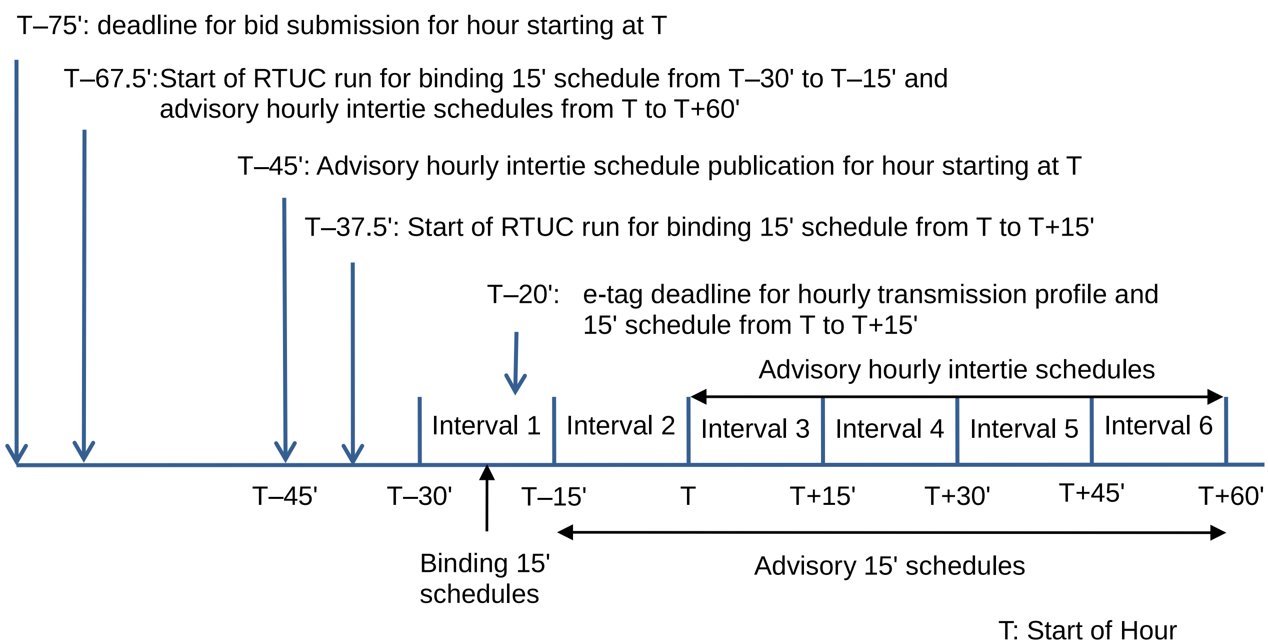

Figure 2. *Timeline of Hour-Ahead Scheduling Process*

The hourly intertie schedules determined by the hour-ahead process for the four 15-minute intervals that comprise the hour starting at "T" are advisory; nevertheless, these hourly intertie schedules across these intervals, as determined by the hour-ahead process, will be held fixed (as price takers) during subsequent market runs, except for 15-minute schedule adjustments in accordance with FERC Order No. 764 or as necessitated by transmission outages or derates.

3.2.3. 15-Minute Real-Time Market (RTUC)

Figure 3 below shows the timeline of the 15-minute real-time market by RTUC given the ISO direction for implementation of FERC Order No. 764.

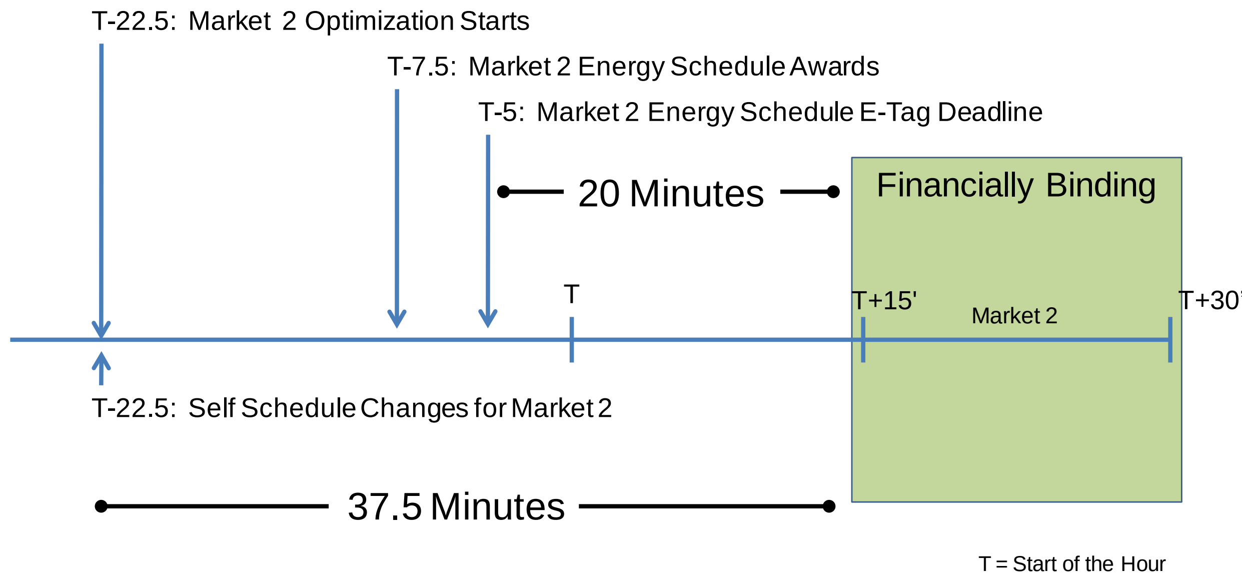

Figure 3. *Timeline of 15-Minute Real-Time Market*

3.2.4. 5-Minute Real-Time Market (RTD)

Figure 4 below shows the timeline of the 5-minute real-time market by RTD.

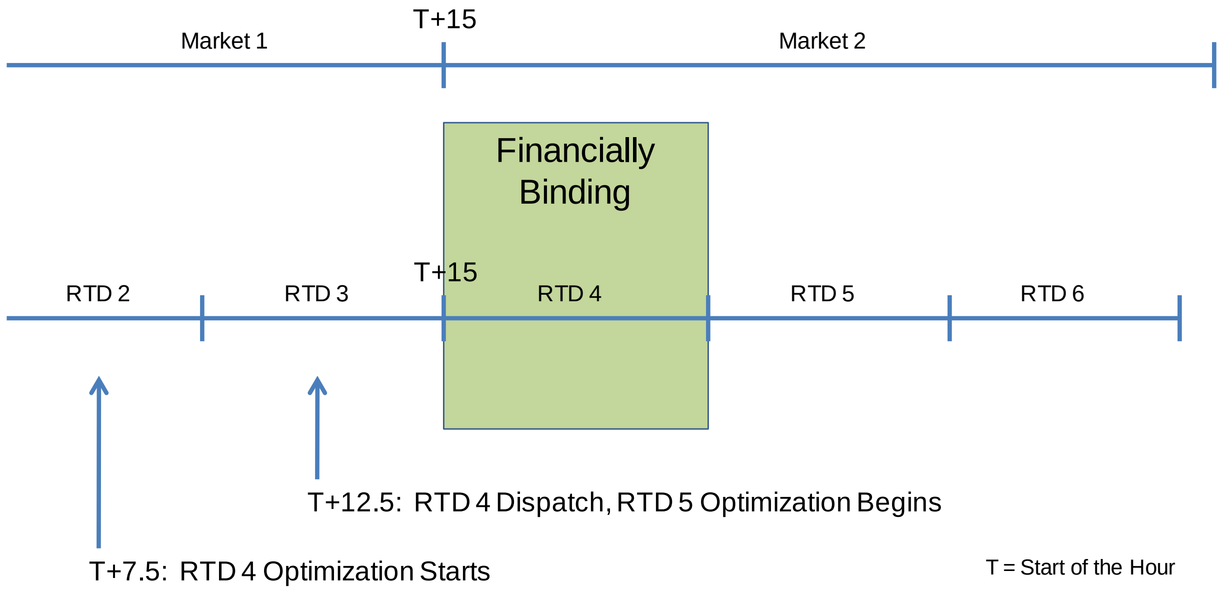

Figure 4. *Timeline of 5-Minute Real-Time Market*

3.2.5. Local Market Power Mitigation (LMPM)

3.2.5.1. Overview

The ISO's proposed EIM design includes provisions to mitigate local market power in the real-time market within each BAA participating in the EIM. This process mirrors local market power mitigation (LMPM) currently applied in the ISO's real-time market. Based on input from the ISO's Department of Market Monitoring (DMM), the ISO has identified the following three design modifications needed to apply these LMPM procedures to the EIM:

1. Real-time LMPM procedures will be applied separately within each BAA by performing tests for constraint competitiveness and bid mitigation only on resources within the same BAA in which a constraint is located. This ensures that resources can only be subject to bid mitigation for local market power within the same BAA in which they are located.
2. No suppliers participating in the EIM will be excluded from the three pivotal supplier test used to determine the competitiveness of constraints on the basis that they may be *net buyers* of energy in the EIM or the overall BAA I which they are located.
3. A separate reference bus will be selected for each BAA for determining shift factors used in LMPM procedures. This reference bus will be selected based on the typography of each BAA, with the goal of selecting a reference bus at which the congestion component of LMPs are least influenced by local market power.

A more description of the ISO's current real-time market power mitigation mechanism is provided in previous documents available on the ISO website.[3]

3.2.5.2. Default energy bids

The ISO is currently proposing to utilize the same methods and standards for setting default energy bids (DEBs) for LMPM in the EIM as is currently used within the ISO. However, the ISO and DMM are seeking input from stakeholders on whether any further modifications to this approach are appropriate for EIM.

In advance of market operation, DEBs reflecting marginal operating costs plus a 10 percent adder are established for each EIM Participating Resource. DEBs are only used to limit market energy bids for resources submitted by EIM Participating Resource Scheduling Coordinators in the event these resources can be effective at relieving congestion that is projected to occur on a in real-time on constraint which has been found to be uncompetitive. This process is described in the following sections of this paper.

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[3] Additional information on the ISO's LMPM process: Tariff Filing (see page 10 – 13) http://www.caiso.com/Documents/Feb21_2013TariffAmendment-LMPM-DocketER13-967-000.pdf,

Revised Draft Final Proposal (see section 4 page 9 through end of section 5 page 13) http://www.caiso.com/Documents/RevisedDraftFinalProposal-DynamicCompetitivePathAssessment.pdf,

July 2011 Board Memo http://www.caiso.com/Documents/110713Decision_LocalMarketPowerMitigationEnhancements-Memo.pdf

For thermal resources, DEBs are typically based on heat rates on file with the ISO and are automatically updated by the ISO to reflect changes in current fuel prices. For resources with limited or stored energy (such as hydro resources with storage), DEBs may reflect the opportunity cost of producing energy in future time periods. Thus, DEBs will be established for each EIM Participating Resource.

EIM Entity Participating Resource Scheduling Coordinators will need to submit information necessary to develop DEBs, such as fuel types, heat rates and any other factors that may be necessary to determine marginal operating costs.

Based on the ISO's review of the initial implementation of EIM with PacifiCorp, the ISO believes it will not be necessary or appropriate to mitigate import or export bids for congestion on scheduling limit constraints between BAs. These constraints are deemed to be competitive under the ISO's current LMPM provisions. However, this may be re-assessed based on actual conditions observed once the EIM is implemented or the specific conditions created by other BAAs that may be incorporated in the EIM..

3.2.5.3.Dynamic competitive path assessment

Prior to the real-time market, the ISO performs a special pre-market run using unmitigated market bids submitted by participant and projected real-time conditions. If congestion occurs on any constraint within the ISO in this mitigation run (excluding scheduling points connecting the ISO with other BAAs), results of this pre-market run are used to assess the competiveness of all constraints on which congestion occurs in this run.

The process used to determine if a path is competitive or not is the *dynamic competitive path assessment* (DCPA). For every transmission constraint that is binding in this pre-market run, ISO calculates a residual supplier index (RSI) based on a three pivotal supplier test, or RSI_3. The RSI_3 is the ratio of supply of potential counter flow (excluding the three largest suppliers) compared to the demand for counter flow needed to relieve congestion on the constraint. Resources with negative shift factors relative to the congested constraint are able to provide counter flow that alleviates congestion. The demand for counter flow is calculated by summing up the level at which resources able to provide counter flow were dispatched in the pre-market run multiplied by each resources shift factor.

The RSI_3 test determines if the three largest suppliers are pivotal for a constraint in terms of counter flow. If they are pivotal, meaning the residual supply of potential counter flow without these three suppliers cannot meet the demand for counter flow, the constraint is deemed non-competitive. Otherwise, the constraint is deemed competitive.

In real-time markets, the counter flow is limited by the 15-minute ramping rate. In other words, the counter flow is evaluated on a 15-minute basis.

Since the ISO has an integrated day-ahead and real-time market, entities that are *net buyers* of energy in the ISO markets over the prior 12 months are excluded from the RSI_3 test.[4] Specifically, while the potential supply of counter flow from net buyers is included in the residual supply that can relieve congestion on a constraint, these net buyers are not included in the three largest suppliers used to perform the RSI_3 test. This reflects the assumption that in the ISOs markets these net buyers do not have any incentive to exercise local market power in the ISO markets.

Participating Resource Scheduling Coordinators will need to submit information that is necessary to perform DCPA to the ISO, such as tolling agreements. This information is necessary to determine the amount of supply controlled by each company and affiliates.

The ISO's DMM has recommended that no suppliers participating in the EIM be excluded from the RSI_3 test used to determine the competitiveness of constraints on the basis that they may be *net buyers* of energy in the EIM. This recommendation reflects the fact that the EIM is only a real-time imbalance market and is not directly linked to a more complete day-ahead energy market as exists in the ISO.

In addition, due to the nature of the EIM, it seems likely that an entity that could be classified as a net buyer over a longer period of time within a BAA may still be a net seller during many individual hours or at some locations in the EIM. Consequently, DMM has recommended that any criteria used to classify entities as net sellers in the EIM may not provide a reliable indicator of their incentive to exercise local market power in the EIM during specific individual hours or at specific locations.

3.2.5.4. LMP decomposition

After the DCPA is complete, the next step in the LMPM procedures is the LMP *decomposition.* This process utilizes results of the DCPA along with congestion pricing results of the pre-market run to determine which resources may have local market power due to congestion on an uncompetitive constraint. This next step involves decomposing the LMP for each resource as follows:

For location *i*:

$$LMP_i = LMP_i^{EC} + LMP_i^{LC} + LMP_i^{CC} + LMP_i^{NC}$$

Where:

LMP_i^{EC} = the energy component,

LMP_i^{LC} = the loss component,

LMP_i^{CC} = the competitive constraint congestion component, and;

LMP_i^{NC} = the non-competitive constraint congestion component.

[4] The ISO identifies net buyers on a quarterly basis by summing all supply and demand settled in the ISO day-ahead and real-time energy markets by each entity.

With constraints being classified into competitive constraints and non-competitive constraints based on DCPA results, the LMP congestion component can be broken into two components: a competitive component LMP_i^{CC} and a non-competitive component LMP_i^{NC}. The competitive component is calculated as the sum of shift factor times shadow price for competitive constraints, and the non-competitive component is calculated as the sum of shift factor times shadow price for non-competitive constraints.

If this decomposition shows that the LMP for a resource includes a positive congestion component for a non-competitive constraints ($LMP_i^{NC} > 0$), this indicates the resource is effective and may have local market power in relieving an uncompetitive constraint. The resource is subject to bid mitigation and may have its market bid lowered to its DEB prior to real-time market.

With the introduction of EIM, the LMP decomposition used to trigger bid mitigation will be adjusted so that mitigation is only triggered if is effective at relieving an uncompetitive constraint within the same BAA in which the resource is located. This will ensure that resources within the ISO are not mitigated due to congestion on uncompetitive constraints in the EIM Entity BAAs, and that resources participating in the EIM are only mitigated to relieve congestion on uncompetitive constraints within the same BAA in which they are located.

The computation of the two LMP components at each pricing node in the system depends on the reference bus selection. Ideally, the reference bus should be at a location free of local market power impact. The LMP at such a reference bus will be used to gauge local market power elsewhere. [5]

Another choice of the reference bus can be the distributed load bus. Distributed load bus is less favorable than ISO's central high voltage buses, because theoretically the distributed load can be affected by market power depending on the load distribution factor. However, for a scattered network lacking a strong transmission backbone, there is often no obvious better choice than the distributed load slack bus.

The ISO will not mitigate resource bids and import or export bids for scheduling limit constraints since these constraints are deemed competitive by definition.

3.3. EIM Input Data

3.3.1. Registration of Market Resources (Master File)

The EIM Participating Resource Scheduling Coordinators will use a resource data template (RDT) to submit resource characteristics (such as ramp rates and minimum and maximum

[5] Based on a study of the ISO system, the best reference bus for use in LMPM procedures within the ISO is the Midway 500 KV bus if path 26 flow is from north to south, and the Vincent 500 KV bus if path 26 flow is from south to north. Midway and Vincent 500 KV buses are located at the center of ISO's bulk high voltage transmission system and are consequently least influenced by market power at different locations within the ISO.

operating capacity) into the Market Operator's Master File. There will be an EIM service agreement, still to be defined.

The EIM Entity Scheduling Coordinators must register all generating resources in the Market Operator's Master File. The resource registration includes operating characteristics like minimum/maximum capacity and ramp rate capability (see Appendix B of the Market Instruments Business Practice Manual), which allow the Market Operator to anticipate these resources' performance. Registration is required for resources that would not explicitly participate in EIM because these resources would still be subject to EIM settlements for their potential uninstructed imbalance energy measure based upon their 5-minute meter. The resource data of non-participating resources is used in the real-time market optimization when the resource is deviating from its base schedule. The market optimization initially assumes that the non-participating resource will seek to return to its schedule in subsequent intervals. The ramp rate capability of the non-participating resource is considered in determining the amount of imbalance energy to be dispatched through the market. For example, assume a non-participating resource was negatively deviating by 10 MW, but in five minutes, based upon its ramp rate, the resource could only increase output by 6 MW, the market optimization would dispatch another resource for 4 MW to make up for the shortfall.

3.3.2. Hourly Base Schedules

Initial hourly base schedules must be submitted by at least 75 minutes before the start of the operating hour. The base schedule will include the operating hour and at least two subsequent hours, The hourly base schedule can be revised based upon results of the flexible ramping constraint sufficiency test and unresolved congestion up until 40 minutes prior to the operating hour.. Base schedules would be submitted through the System Infrastructure and Business Rules (SIBR) system, described in the Market Instruments Business Practice Manual.

The ISO has removed the option to submit base schedules with 15-minute granularity. Hourly schedules with hourly granularity are more appropriate for establishing the starting point of the EIM for the following reasons:

- Simplifies submission of base schedules by EIM Entity Scheduling Coordinator. Only hourly submission of balanced schedule versus every 15-minutes.
- A process exists to update hourly base schedules if the flexible ramping constraint sufficiency test fails or unresolved congestion remains prior to the start of the first financially binding 15-minute market in the operating hour.
- All supply, import, export imbalances from bilateral hourly interval transactions are settled in EIM. No OATT settlement for imbalances.
- All non-participating load imbalances from hourly forward schedules are settled in the EIM using the most efficient resources in the EIM footprint.
- EIM Entity can take full advantage of the real-time intertie scheduling options offered from FERC Order No. 764 design changes with external BAAs
- Under FERC Order No. 764, 15-minute schedules will reflect physical outages from supply. Such 15-minute schedules will be settled as instructed imbalance energy. There

is no uninstructed imbalance energy for supply resources once the physical change is reflected in the 15-minute market optimization.

- Provides consistent base schedule granularity with existing ISO market participants. The base schedule for ISO market participants is the hourly schedule from the day-ahead market.

The EIM Entity Scheduling Coordinator must submit base schedules for all EIM Entity BAA resources and external system resources outside the EIM footprint with import/export schedules between the EIM Entity BAA and other BAAs. These base schedules should balance day-ahead import/export schedules with the ISO and the EIM Entity BAA demand forecast; they should reflect all hourly forward market schedules, hourly bilateral contracts, hourly variable energy resource (VER) forecasts, and estimated transmission losses.

Hourly base schedules must be submitted (which may be 0 MW) for all generating resources including third-party generators, and must include disaggregation of day-ahead import/export schedules between the EIM Entity BAA and ISO, and disaggregation of forward export schedules to other BAAs. Base import schedules to an EIM Entity BAA from BAAs other than ISO must be submitted at the relevant intertie scheduling points. The EIM Entity Scheduling Coordinator need not submit base load schedules because these will be derived from the demand forecast for the EIM Entity BAA, estimated transmission losses, and an assumed load distribution.

The hourly base schedule for each resource must be within the economic bid range of the submitted energy bid for each operating hour. For this reason, each EIM Participating Resource Scheduling Coordinator provides to the EIM Entity Scheduling Coordinator the energy bid ranges (without price information) of its respective resources participating in the EIM. For each resource, the sum of the maximum economic operating limit, regulation reserve MW – up, operating reserve MW – spinning, and operating reserve MW – supplemental shall not exceed the resource's maximum capacity, and the minimum economic operating limit minus the regulation reserve MW – down shall not be less than the minimum capacity, for each operating hour when the resource is operating. In applying these principles, the Market Operator will recognize periods when the resource is in start-up or shut-down as exceptions.

Each EIM Entity Scheduling Coordinator's resource plan is required to offer sufficient energy bid range to serve its obligations at all times. EIM Entity Scheduling Coordinators must satisfy their energy obligations by scheduling energy from third parties and/or having sufficient bids submitted by EIM Participating Resource Scheduling Coordinators for dispatch by EIM with sufficient dispatchable operating range.

3.3.3. Supply and Flexible Ramping Constraint Sufficiency

The Market Operator performs the ISO day-ahead market, and will advise EIM Entity Scheduling Coordinators of congestion within their BAAs that would result from the hourly base schedules. EIM Entity Scheduling Coordinators should use this advisory information to resolve congestion prior to submitting the final hourly base schedule at T-40'. Updates to the hourly base schedule received prior to the start of the EIM will be settled according to the EIM Entity's tariff.

After the submission of hourly base schedule by the EIM Entity Scheduling Coordinator and energy bids by the EIM Participating Resource Scheduling Coordinators, the Market Operator will provide results of a supply adequacy analysis for each EIM Entity BAA for that operating hour. The supply adequacy analysis will be based on the EIM Entity's or Market Operator's demand forecast, base schedule for non-participating resources received from the EIM Entity Scheduling Coordinator. and energy bids received from the EIM Participating Resource Scheduling Coordinators.

An EIM Entity shall be deemed to have insufficient energy supply if the sum of base schedules from non-participating resources and the sum of the highest quantity offers in the energy bids from EIM Participating Resources is less than the total demand forecast for the associated EIM Entity BAA. (Note that the term "resources" includes interchange with other BAAs.) Similarly, an EIM Entity shall be deemed to have excessive energy supply if the sum of base schedules from non-participating resources and the sum of the lowest quantity offers in the energy bids from EIM Participating Resources is greater than the total demand forecast for the associated EIM Entity BAA.

The Market Operator will notify the EIM Entity Scheduling Coordinators of the results of the supply adequacy analyses. The EIM Entity Scheduling Coordinators for EIM Entities with inadequate or excessive energy supply shall make the appropriate modifications to the base schedules from non-participating resources no later than 40 minutes prior to the operating hour. In the event that the affected EIM Entity Scheduling Coordinators do not resolve the issue, and it contributes to a reliability problem within the affected EIM Entity BAA at or prior to real-time, the EIM Entity may take appropriate actions regarding the EIM Entity BAA, including interruption of load or resources, curtailment of schedules, and/or manual deployment of resources, if deemed necessary. The EIM Entity's actions under these circumstances should be communicated to the Market Operator.

The Market Operator will perform a series of flexible ramping constraint sufficiency tests prior to commencing the EIM. The EIM Entity Scheduling Coordinator will have an opportunity to re-submit the hourly base schedule if it fails the flexible ramping constraint sufficiency test or to resolve congestion or address demand forecast changes up to 40 minutes prior to the operating hour which is just before the start of the first financially binding EIM 15-minute market for the operating hour.

The following timeline outlines the evaluation and update of hourly base schedules will occur prior to the start of the operating hour:

T-75 Submit Initial Base Schedule

T-67.5 Start Flexible Ramping Constraint Sufficiency Test

T-60 Market Operator notifies EIM Entity Scheduling Coordinator if base schedule passed sufficiency test. If base schedule passed sufficiency test, no further action by EIM Entity Scheduling Coordinator is required unless to resolve congestion.

T-55 EIM Entity Scheduling Coordinator submits updated base schedule if prior sufficiency test failed or to resolve congestion or address demand forecast changes.

T-52.5 Market Operator runs flexible ramping constraint sufficiency test

T-45 Market Operator notifies EIM Entity Scheduling Coordinator if updated base schedule passed sufficiency test. If updated base schedule passed sufficiency test, no further action by EIM Entity Scheduling Coordinator is required unless to resolve congestion.

T-40 EIM Entity SC submits 2nd updated base schedule if prior sufficiency test failed or to resolve congestion or address demand forecast changes.

T-37.5 Start of the first financially binding 15-minute market optimization of the operating hour. If 2nd updated base schedule fails the sufficiency test, no incremental transfers to the EIM Entity BAA will occur for the operating hour. If congestion is not resolved, uplift will accrue through the BAA Real-Time Congestion Balancing Account.

The hourly base schedule from T-40 will be the basis for measuring imbalance settlement in the EIM. The EIM Entity Scheduling Coordinator hourly base schedule, from a settlement basis, is equivalent to a day-ahead schedule (hourly granularity) within the ISO. Deviations from the base schedule and the 15-minute market schedule will be settled at the 15-minute LMP.

3.3.4. Market Operator Demand Forecasting

The Market Operator develops short-term and mid-term forecasts by Demand Forecast Zone within each EIM Entity BAA, separately from the ISO BAA, to provide input data for RTUC and RTD time horizons. The short-term forecast produces a value every 5 minutes for the duration of the Market Operator's dispatch horizon, which has 5-minute granularity and extends several dispatch intervals out through a 4.5-hour horizon. The mid-term forecast produces hourly values for the next hour through the next 7 days. The Market Operator aggregates its short-term demand forecasts along with 15-minute schedule updates and static base schedules, including interchange schedules into and out of the EIM footprint (EIM Entity and ISO), to determine the amount of supply to be dispatched by the market for the upcoming dispatch interval.

The 15-minute demand forecast for each of the intervals in RTUC will be derived based on the corresponding three 5-minute demand forecasts approximately 40 minutes prior to the starting of 15 minute interval.

The demand forecast will be based on historical data, applicable meteorological data, and the State Estimator solution. It will be produced separately for each load aggregation point and then aggregated for each BAA. The costs associated with the gathering and processing of required information to establish the load forecast will be recovered by the Market Operator through the EIM administrative rate.

3.3.5. EIM Entity Scheduling Coordinator Demand Forecasting

The EIM Entity Scheduling Coordinator may elect to provide their own demand forecast as part of the hourly base schedules. The EIM Entity Scheduling Coordinator may provide non-binding day-ahead forecasts by 10:00 PPT for the next 7 days (informational only), and must update its forecast for each operating hour and the following 6 to 10 hours by at least 75 minutes prior to that operating hour, as part of its hourly base schedule submission via the SIBR system. The EIM Entity Scheduling Coordinator's demand forecast should be net of "behind-the-meter" generation that is not registered as a resource. When a registered resource is electrically located behind a load settlement location meter, the net load will be calculated by netting the load meter and the generator meter.

If the EIM Entity Scheduling Coordinator does not use the Market Operator demand forecast to submit base schedules for its resources, the process to determine under- and over-scheduling charges will apply.

The Market Operator will produce a demand forecast for each EIM Entity BAA for each 15-minute and 5-minute interval to be used in the 15-minute and 5-minute real-time markets irrespective of whether the EIM Entity Scheduling Coordinator elects to provide their own demand forecast or use the Market Operator demand forecast for base schedule balancing.

3.3.6. Load Scheduling Requirements

As EIM provides opportunities for EIM Entities to support each other for optimal management of imbalance energy, one significant concern to existing ISO market participants and to potential participants in EIM has been how to ensure that each EIM Entity continues to meet its obligations to manage its imbalance energy, without "leaning" on other participants. Requiring each EIM Entity to have balanced base schedules ensures that the EIM footprint as a whole has a balanced initial schedule, but a remaining task is to ensure that the base schedules are realistic.

One aspect of this task is to ensure that participants in EIM do not come into the EIM's real-time horizon with insufficient supply to meet their forecasted demand. The demand included in EIM Entity Scheduling Coordinators' base schedules is not required to match their actual firm demand at each settlement location in each dispatch interval, but EIM Entity Scheduling Coordinators that do not schedule load accurately in aggregate may be subject to neutrality or offset charges in settlements, or other adjustment of imbalance energy payments attributable to inaccurate scheduling.

If the EIM Entity Scheduling Coordinator chooses to submit base schedules for their resources using the Market Operator load forecast they can minimize exposure to charges for under- or over-scheduling. If an EIM Entity Scheduling Coordinator using the ISO load forecast submits base schedules for their resources within +/- 1% of the Market Operator load forecast, the EIM Entity Scheduling Coordinator would not be exposed to under- or over-scheduling penalties. If the EIM Entity Scheduling Coordinator submits resource schedules outside of this threshold, the process to determine under- and over-scheduling charges will apply. In addition, the Market Operator will adjust the base load for the hour to match the net supply in the base schedules. This adjusted base load will be distributed net of transmission losses to the load nodes in the relevant load aggregation point using the applicable load distribution factors to yield the adjusted base load, which is the reference for calculating load imbalance for real-time settlement.

If the EIM Entity Scheduling Coordinator does not use the Market Operator demand forecast to submit base schedules for its resources, the process to determine under- and over-scheduling charges will apply. In addition, if the base schedules for resources do not balance the EIM Entity Scheduling Coordinator load forecast within +/- 1%,the Market Operator will adjust the base load for the hour to match the net supply in the base schedules. This adjusted base load will be distributed net of transmission losses to the load nodes in the relevant load aggregation point using the applicable load distribution factors to yield the adjusted base load, which is the reference for calculating load imbalance for real-time settlement.

The availability of virtual bidding in the ISO's day-ahead market and the use of a residual unit commitment process following the day-ahead market eliminate the need for under- and over-scheduling charges within the ISO's BAA.

3.3.6.1. Charges for Under-Scheduling

A fundamental principle is that each EIM Entity will have a balanced schedule for each operating hour, which would provide sufficient resources for that BAA to operate reliably without "leaning" on other EIM Entities or on the ISO. EIM then provides an opportunity for EIM Entities and EIM Participating Resources within their areas to operate more efficiently than they could on their own. To achieve this result during each hour, if an EIM Entity Scheduling Coordinator's load imbalance is more than 5% (but at least 2 MWh) at a load aggregation point, that EIM Entity Scheduling Coordinator will be subject to an under-scheduling charge.[6] Based on stakeholder input on the appropriate pricing of the under-scheduling charge, the ISO is accepting suggestions for a tiered approach to this charge, applying a charge to load deviations exceeding 5% of the base load for the relevant load aggregation points at 125% of the aggregate LMPs at these locations, and increasing to 200% of the aggregate LMPs for under-scheduled deviations exceeding 10%.

An additional incentive against under-scheduling is provided through the allocation of revenue resulting from the under-scheduling penalty. The under-scheduling penalties will be collected over a month and allocated to BAAs that have not incurred a penalty in the relevant month. Thus, only BAAs that have not leaned on the EIM are eligible to receive the revenue collected through the penalty.

[6] An initial concept discussed in the EIM Design Straw Proposal and Issue paper matches an EIM Entity's resource locations with negative imbalance energy and the lowest LMPs with the EIM Entity's load locations with positive imbalance energy and lowest LMPs, to obtain a LMP difference between resource and load locations that would be multiplied by the resource imbalance energy required to offset its load imbalance energy. With further analysis, the ISO has concluded that this mechanism would not achieve the desired purposes. Basing the charge on a LMP difference could recover costs due to congestion that participants in EIM could defer until real-time by under-scheduling in their base schedules, but would not reflect overall increases in market prices due to under-scheduling, because resource and load LMPs could be affected equally.

The under-scheduling penalty proposed here is similar to the Interim Scheduling Charge that was applied in the ISO's market prior to implementation of convergence bidding. The Interim Scheduling Charge imposed a $150/MWh charge on demand deviations from under-scheduling of 15% to 20%, and $250/MWh for under-scheduling exceeding 20%, with certain exceptions. In this EIM design proposal, the under-scheduling charge has a smaller threshold band that is proposed to match SPP's under-scheduling charge, and with this level of threshold, a lower charge is appropriate.

3.3.6.2. Charges for Over-Scheduling

A related issue concerns the potential for over-scheduling.[7] For example, participants within an EIM Entity could try to mask congestion that may occur in real-time, or to avoid de-committing generation to avoid start-up costs, by over-scheduling their load. To the extent that load is over-scheduled, supply resources would also need to be over-scheduled to maintain a balanced base schedule within the EIM Entity, and real-time deviations by the supply resources would face settlement costs in addition to the settlement of load deviations. The ISO observes that to the extent that congestion and/or system-wide impacts of excess generation occur, the mechanisms that the ISO is now proposing for charging cost offsets within the EIM Entity in which they occur will keep responsibility for these costs within the affected EIM Entity. Thus, no over-scheduling charges are currently proposed in this 3rd revised straw proposal. The ISO will monitor the EIM market performance, and will propose revisions to the design if a need for an over-scheduling penalty develops, and if the ISO's offset cost allocation does not provide adequate disincentives for over-scheduling.

Stakeholder comments suggesting that an over-scheduling penalty may be needed offer an example in which an EIM Entity provides a balanced base schedule of 110 MW from generation to load, but in real-time the actual load is 100 MW and the generation decreases to 100 MW to balance the load. If the LMPs are $70 for the load and $20 for the generator, the generator pays $200 in the energy settlement and the load is paid $700, netting this entity $500 in revenue. The outcome in this example depends on additional assumptions, including that there is transmission congestion between the generator and the load, leading to the LMP difference. If the initial 110 MW base schedules would be infeasible by exceeding the transmission constraint's limit, the ISO's BAA real-time congestion balancing account proposal would assign the $500 cost to the EIM Entity Scheduling Coordinator, which would allocate this cost among loads and generators within the EIM Entity containing the constraint. It is possible that the constraint could be located in a different EIM Entity, but it is not clear that this situation will occur in the initial EIM implementation, and changes in EIM design can considered if it arises later.

If the base schedules are feasible by having flows within the transmission constraint, although the constraint would have been at its limit, the fact that a LMP difference remains after the example's load and generation have reduced from 110 MW to 100 MW means that there must be a second generator on the first generator's side of the constraint. The second generator must have an increased output to offset the reduction in the first generator's output, for the congestion to still be present. For example, the second generator could be at the same location as the first

[7] The initial concept discussed in the EIM Design Straw Proposal and Issue paper, in which a load imbalance during any hour of more than 4% (but at least 2 MW) would subject that EIM Entity Scheduling Coordinator to an over-scheduling charge. Similar to SPP's under-scheduling charge, the process would follow similar steps of matching the EIM Entity's resource locations with positive imbalance energy and the highest LMPs with its load locations with negative imbalance energy, to obtain a LMP difference that would be multiplied by the resource imbalance energy required to offset its load imbalance energy. Similar to the charges for under-scheduling, further analysis found this process to be less effective than desired for concerns other than congestion management.

generator and have a bid price of $20, which makes it the marginal resource that sets the LMPs on its side of the constraint, as the market optimization uses as much of its bid as possible to serve load at the more expensive load location. The first generator would pay $200 due to its reduced output, which would be paid to the second generator, keeping revenue in balance on that side of the constraint. On the load side of the constraint, other generation would have been decremented to balance the reduced load. The $700 received by the load would be paid by the other generation on the load side of the constraint, based on savings in operating costs as reflected by their economic bids. At worst there are payments between market participants for the changes in their settlement quantities relative to their base schedules, but this does not seem to be a sufficient reason to create a penalty.

Stakeholder comments suggest that generation and/or imports in an EIM Entity Scheduling Coordinator's base schedule may overstate their actual deliveries, such as materially overstating a VER forecast or including imports from VERs as firm imports without adequate balancing reserves. Uncertainty in VER forecasts is one factor that goes into the requirements for flexible ramping constraint for each EIM Entity, and the 3rd Revised Straw Proposal describes the sufficiency test, bidding requirements and settlement features concerning the flexible ramping constraint. Issues of whether BAAs that are the source of pre-scheduled imports from VERs to EIM Entities from non-EIM BAAs provide adequate balancing resources and operating reserves exist today, and are not changed by EIM implementation. The resolution of these issues is outside the scope of this stakeholder process.

The ISO is still evaluating the need of an over-scheduling penalty. The current ISO position is to monitor for the need for the over-scheduling during the initial implementation and then if the penalty is needed to include in a future EIM stakeholder initiative to develop EIM enhancements. However, the ISO will confirm in the draft final proposal if monitoring is sufficient, if monitoring is deemed insufficient an over-scheduling penalty will be included in the initial EIM design.

3.3.7. Resource Plans and Updates

Additional data, including energy bids, must be submitted hourly, 75 minutes before the start of each hour for each EIM Participating Resource that will participate in the EIM for the operating hour. Base schedules include bilateral and self-scheduled supply from resources registered in the Market Operator’s Master File, including sources and sinks registered in NAESB’s Electric Industry Registry, equal to scheduled demand including losses. The Market Operator utilizes resource plan data along with the energy bid curves, load forecasts, and the Market Operator’s state estimator to determine the dispatch instructions for EIM Participating Resources, the resulting Net Scheduled Interchange (NSI) for the ISO and EIM Entity BAAs, and Locational Marginal Prices (LMPs) for imbalance energy settlement. EIM Entity Scheduling Coordinator resource plans include ancillary service plans for resources meeting the EIM Entities reserve obligation for its BAA or Reserve Sharing Group, which the Market Operator uses to ensure that EIM dispatch does not consume unloaded capacity that is reserved for ancillary services nor issues conflicting instructions when reserve capacity is dispatched by the EIM entity.

The EIM Entity Scheduling Coordinator resource plan covers a seven-day horizon (with hourly detail for each resource) beginning with the operating day, and contains the following:

- Base schedule
- Energy Bid MW Range (Not price)
- Regulation Reserve MW – Up
- Regulation Reserve MW – Down
- Operating Reserve MW – Spinning
- Operating Reserve MW – Supplemental
- Minimum Economic Operating Limit – Resource's economic minimum output for each operating hour, equal to or greater than the resource's minimum capacity.
- Maximum Economic Operating Limit – Resource's economic maximum output for each operating hour, equal to or less than the resource's maximum capacity.

Resource characteristics, such as ramp rates and minimum and maximum operating capacity, will be registered in the Market Operator's Master File, and as such they need not be part of the resource plan submission. Resource ramp rates may have a segmented profile of at least one segment and optionally having multiple segments, as detailed in the [Market Instruments Business Practice Manual]. For multi-stage generating resources (e.g., combined cycle generation), each resource configuration may have separate resource characteristics. Note that unless the EIM Entity elects to allow resource commitment in the EIM area, configuration management of a multi-stage resource like a combined cycle resource will be manually self-managed by the EIM participant and will not be eligible to cost recovery for commitment or transition costs.

Static information in the Master File should be updated whenever resource operating and technical characteristics have persistent changes, and in the outage management system when there are short-term limitations. Dynamic information in the resource plan will be the base schedule, the energy bid, and related hourly data, submitted through SIBR. The energy bid consists of several bid components described in detail in the [Market Instruments Business Practice Manual]. The most relevant of these bid components for EIM Participating Resources is the energy bid component, which contains the energy bid that will be used for EIM dispatch. Resource capacity designated for ancillary services or other reliability functions within the EIM Entity BAA will be reserved and not be subject to EIM dispatch.. The Market Operator will limit EIM dispatch within the submitted energy bid. The EIM Entity Scheduling Coordinator may further constrain the EIM dispatch with Exceptional Dispatch instructions as needed to dispatch ancillary services or resolve reliability issues within the EIM Entity BAA.

The same energy bids are used by 15-minute RTUC and 5-minute RTD for all intervals of that hour. The use of the bids in RTUC solves multiple issues. If the energy bids were not used in RTUC, and assuming for simplicity that imbalance energy is zero for both EIM Entity BAA and ISO BAA, the absence of the energy bids in the 15-minute process but use of energy bids in the 5-minute RTD would cause re-dispatch of energy in the 5-minute interval that would be settled based on the 5-minute LMP prices. This would not be appropriate because it creates divergence between the 15-minute and 5-minute prices even without changes in system conditions. Another reason for favoring the use of the energy bids in the 15-minute RTUC is the fact that the 15-

minute prices are less volatile and hence most of the required imbalance energy can be separated and settled on 15-minute and only small changes due to uncertainty or small changes in system conditions can be settled on the 5-minute RTD LMP prices.

The energy bids are submitted through the SIBR system by the EIM Participating Resource Scheduling Coordinator. They can be a combination of self-schedules without a bid price and a stepwise incremental energy bid curve with up to 10 segments. Energy bid curves must be monotonically non-decreasing for generating resources.

Resource capacity can be optionally reserved for EIM Entity use from the top and bottom portion of a submitted energy bid. The Market Operator will not dispatch that reserved capacity; this capacity may be used by the EIM Entity for ancillary services within their system or for fulfilling shared reserve requirements with other BAAs, or for exceptional dispatch by the EIM Entity as necessary. However, any such dispatch must be reflected in the revised base schedule submitted by the EIM Entity Scheduling Coordinator for the relevant resource so that it is incorporated in the EIM schedules and dispatch instructions.

EIM Participating Resources are considered self-committed in a particular hour if they have a base schedule or they submit an energy bid and/or an energy self-schedule greater than zero. If a resource is unavailable due to an outage or derates, the Market Operator's outage management system provides more detailed information than could be provided in market bids. The Market Operator's market system automatically and continuously tracks each resources' status such as: on-line or off-line, in startup or shutdown processes, or subject to minimum run times or off-line times, as well as other limits including maximum starts per day and daily energy limitations.

EIM Participating Resource Scheduling Coordinators are required to keep the resource data up-to-date during the operating day. In the event of a required change in the resource due to physical resource changes, the EIM Participating Resource Scheduling Coordinator is responsible for notifying the Market Operator of required changes through the Market Operator's outage management system, to allow the Market Operator to reflect the change within its dispatch horizon.

Telemetry is required for all generating resources in the EIM Entity BAA and all interties, as well as major substations, to produce an accurate State Estimator solution. The State Estimator solution is very important for accurate EIM dispatch instructions. Small generating units can be aggregated and registered as an aggregate market resource. Metering is required for the aggregated resource.

The EIM Participating Resource Scheduling Coordinator must submit planned generation outages. In its transmission operator role, the EIM Entity must submit planned transmission outages, in the Outage Management System (OMS), described in the Outage Management Business Practice Manual, at least 7 days in advance and preferably up to 30 days in advance. The EIM Participating Resource Scheduling Coordinator must also revise these planned outages whenever their timeline or conditions change. Additionally, the EIM Participating Resource Scheduling Coordinator must submit forced generation outages, and the transmission operator role of the EIM Entity must submit forced transmission outages, in the OMS as soon as possible, and in accordance with the outage management provisions in the ISO tariff so that they are considered in the EIM dispatch.

3.3.8. Intertie Schedules with Other Balancing Authorities

For interchange transactions included in a resource plan, the EIM Entity Scheduling Coordinators will be responsible for ensuring that e-Tags are created and processed for bilateral schedules between BAAs that are arranged prior to the real-time horizon (T-40 of the operating hour) of the EIM, as required by NERC, NAESB, and WECC standards and business practices, and may be required to create and process e-Tags within BAAs by the transmission providers' business practices. These e-Tags are managed by the WECC Interchange Tool (WIT). However, e-Tag updates are not required for real-time dispatches within between EIM Entities and the ISO when issued by the Market Operator, until the end of an operating hour. The Market Operator will manage dynamic schedules reflecting intra-hour incremental transfers between the ISO and the EIM Entity BAA, with initial values that may be non-zero at the beginning of an operating hour if these e-Tags represent imbalance energy dispatched in hourly or 15-minute intervals as well as 5-minute intervals (or may be zero if they only include schedules for imbalance energy dispatched in 5-minute intervals), and updates after the operating hour to reflect EIM dispatches for purposes of inadvertent energy accounting. No individual resources e-Tags are needed since the Market Operator will issue an aggregate dynamic schedule with each EIM Entity BAA. The EIM will not support dynamic transfers with external BAAs unless there are pre-existing dynamic schedules or pre-existing pseudo-ties registered as EIM Participating Resources.

The EIM Entity Scheduling Coordinator must submit intertie schedules with other BAAs at the relevant intertie scheduling points. The Market Operator will use this information to enforce intertie constraints in the EIM at the relevant interties. The EIM Entity would be responsible for matching e-Tags and for managing schedule curtailments at these interties. Furthermore, EIM Entity Scheduling Coordinator must update these intertie schedules, when applicable, as part of the hourly base schedule revision or prior to the start of the 15-minute market. If updated prior to the 15-minute market, the deviation from the hourly base schedule will be settled at the 15-minute LMP. Until the schedule change is reflected in the 15-minute market, the deviation will settle at the 5-minute LMP.

Assuming the EIM Entity and a neighboring BAA both support economic bidding of 15-minute intertie scheduling in support of FERC Order 764, participation in the EIM at the intertie between EIM BAA and neighboring BAA may occur. An intertie energy bid indicating that it is available to be dispatched on a 15-minute basis must be submitted to be considered for EIM 15-minute market. For inter-tie bids that clear the EIM resulting in 15-minute intertie schedules at interties between EIM Entity BAAs and other external BAAs, the relevant EIM Entity Scheduling Coordinator must submit to the Market Operator the corresponding hourly transmission profile and 15-minute energy profiles from the respective intertie tags. The hourly transmission profiles must be submitted hourly at least 40 minutes before the start of the hour.

The Market Operator will notify the EIM Entity if an intertie receives a 15-minute market schedule change at T-22.5 before the start of actual flow. The EIM Entity must confirm through the EIM Entity Scheduling Coordinator by updating the energy profile on the e-Tag by 20 minutes before the start of 15-minute interval. If the final 15-minute energy profile on the e-Tag is different than the 15-minute market schedule, this will result in deviations which will be settled at the 5-minute price.

3.3.9. Reserve Sharing Schedules

EIM Entities remain responsible for their DCS compliance, or their share of such compliance under the terms of a reserve sharing group agreement. A reserve sharing group may include members that do not directly participate in the EIM. Nothing in the operation of the EIM should prohibit these entities from continuing to participate in the reserve sharing group, or to subject these entities to changes in their internal business practices. Such deployment is not currently anticipated to be performed as part of this market design's functionality. Details of each reserve sharing group's procedures are established as agreements among its members, are not expected to change due to their participation in EIM, and are believed to be consistent with the proposed EIM operation.

EIM Entities, and reserve sharing groups of which EIM Entities are members, will continue to be responsible for deploying operating reserves and regulation in conformance with NERC and WECC standards. The energy schedules implemented for deployment of reserves are either reflected in the hourly base schedules, if time permits, or in exceptional dispatch instructions, in which case they are settled in EIM as bilateral (self-scheduled) transactions, with changes in resource output balanced with other changes in resource output or in tagged interchange. As with all bilateral transactions in the EIM, any deviation between the hourly base schedules and actual meter values at each settlement location will be subject to EIM settlement at the appropriate LMP. However, resource deviations that are reported to the Market Operator as responses to contingency events or EIM exceptional dispatches will be settled as instructed imbalance energy, rather than as uninstructed imbalance energy by the affected resources.

All operating reserve contingencies and resource plan adjustments in response to contingencies should be immediately reported to the Market Operator. Until resource plan updates are received, the Market Operator will continue to send dispatch instructions based upon pre-event operating limits. After resource plan updates are received and EIM dispatches reflect the updated self-schedules and operating limits, the Market Operator will account for the dispatches in the NSI values that it provides to EIM Entity Scheduling Coordinators. To the extent a EIM Entity Scheduling Coordinator's actual response differs from the resource plan adjustment, the EIM Entity Scheduling Coordinator is expected to supply a resource plan update showing the actual resources that have deployed during the event by no later than 01:00 PPT seven days after the operating day in which the event occurred, for settlement purposes. The resource plan update is not an EIM function; however, the EIM Entity Scheduling Coordinator is responsible for truing up deviations for use in EIM settlement. Obligations to update e-Tags that may be required for reserve deployment continue to be governed by NERC and WECC standards and business practices.

In some cases, EIM Entities as transmission operators maintain transmission reliability margins as constraints on transmission capacity, to accommodate the potential deployment of reserves. In this case, the EIM Entity must include this adjustment in the transmission capacity that it reports to the Market Operator as being available to EIM.

3.3.10. Load Aggregation Points (LAPs)

Traditionally Load Aggregation Points (LAPs) were constructed around retail load service BAAs. Ultimately, this is up to the EIM Entity to decide the definition of the LAPs with their

BAA. It is important that regardless of the granularity of the LAPs, the load distribution factors (LDF) are accurate. The Market Operator will use its own state estimator of the EIM Entity load to create the LDFs since the Market Operator will be responsible for LDFs. Currently the LAPs in the ISO are the same as the utility service territories. The mapping of loads to the nodes is done in the network model. The Market Operator validates and normalizes the LDFs for each LAP to ensure that their sum is 1. Non-conforming loads that do not conform to the default load distribution (e.g. – pumps, auxiliary station load) may be treated as a custom LAP with a separate forecast. The EIM Entity has the responsibility to define LAPs, and the definition should depend on its needs. The number of LAPs will also determine the effort in managing multiple load forecasts. The expected granularity of the LDFs for the EIM Entity LAPs and how the Market Operator calculates them is determined by the network model.

The Market Operator will maintain a Load Distribution Factor (LDF) library for the LAPs to distribute the corresponding demand forecast to load nodes for power flow calculations. The LDFs would be smoothed and adopted using the State Estimator solution and would be maintained for various seasons, day types (e.g., workday, weekday/holiday), and day periods (e.g., on-peak, off-peak).

The ISO recently started publishing the LDFs used to derive the market solution, and will keep them up to date. LDFs are needed ultimately for accurate dispatch and to avoid transmission overloads. Behind-the-meter generation that is bid is challenging, and these should be identified. Data to calculate LDFs is either received directly from meters or, if not available, from the state estimator.

The Market Operator is calculating LDFs for day ahead and hour ahead only. (Seasonal and annual LDFs are used for the ISO's congestion revenue rights process, which are not part of the EIM.) There will not be two way communication between the Market Operator and the EIM Entity Scheduling Coordinator on what their load forecast is at the LDF level. The LAP imbalance is valued at the aggregate LMP price based on the weighted average of the nodal LMPs weighted by the LDFs. The EIM Entity Scheduling Coordinator is encouraged to review and verify LDF accuracy.

The calculation of LDFs for LAPs and generation distribution factors (GDFs) for aggregate generating resources will automatically accommodate changes in transmission and generation due to outages. GDFs are used where several units in a plant are metered together as a single unit and there are no transmission constraints between the units.

LAP definitions are part of the Market Operator's full network model and thus are fixed for a period of time, but changes in LAP definitions may be revised when changes are needed, when new model versions are implemented.

3.3.11. Variable Energy Resource Production Forecast

The Market Operator will produce a variable energy resource (VER) energy production forecast every 5 minutes separately for each VER in the EIM Entity BAA based on historical data, applicable meteorological data, and the State Estimator solution or based on persistent forecast following telemetry of these resources. The forecast will have a 5-minute granularity and will be produced for several hours to provide input data for the RTUC and RTD time horizons. The 15-

minute renewable energy production forecast for each of the intervals in RTUC would be derived as the average of the corresponding three 5-minute forecasts.

As part of the FERC Order No. 764 market design changes, the ISO has modified its Participating Intermittent Resource Program. Under the new program, VERs can submit hourly economic bids while using the 15-minute and 5-minute ISO forecast as an upper limit on their energy production. The hourly base schedule submitted by the EIM Entity Scheduling Coordinator is at hourly granularity for the VER's output. The ISO will use the forecast at T-37.5 to establish the 15-minute schedule. If the LMP is greater than the resource's energy bid, the resource will receive a 15-minute schedule equal to its forecast. The difference between the hourly base schedule and the 15-mintue schedule will settle at the 15-minute LMP and be considered instructed imbalance energy. The ISO will then use the forecast at T-7.5 to establish the 5-minute market dispatch. If the LMP is greater than the resource's energy bid, the resource will receive a 5-minute dispatch equal to its forecast. The difference between the 15-minute schedule and 5-minute dispatch will settle at the 5-minute LMP and be considered instructed imbalance energy. Any difference between the 5-minute dispatch and 5-minute meter will be considered uninstructed imbalance energy and will settle at the 5-minute LMP.

The cost for the ISO to provide the forecasting service is currently $0.10 per MWh of metered output. However, the EIM Participating Resource Scheduling Coordinator can use an independent forecast to schedule its output ,which would waive the $0.10 per MWh service charge. The EIM Participating Resource Scheduling Coordinator must be certified by the Market Operator to use its own forecast for scheduling and can be decertified due to poor forecast accuracy and/or strategic scheduling that undermines market efficiency.

The EIM Participating Resource Scheduling Coordinator may also submit renewable energy production forecast as rolling 5-minute schedule updates for each VER in their system for several hours through SIBR. If 5-minute granularity is submitted, the Market Operator will use this to determine the 5-minute dispatch.

3.3.12. Network Constraint and Contingency Definition

Transmission operators within the EIM Entity BAA must specify the network constraints and associated limits that the EIM solution must observe in the EIM Entity BAA's network and interties with other BAAs. The limits may be physical MVA or MW limits under base case and contingencies, scheduling limits for intertie transactions based on electronic tags, or contractual limits on transmission interfaces where the EIM Entity BAA has transmission rights. The EIM Entity must also specify the critical contingencies that need to be enforced in the EIM. The definition of the contingencies can be done in Market Operator's Supplemental Market Data Management (SMDM). The EIM Entity Scheduling Coordinator shall update limits on transmission interfaces and scheduling limits as part of base schedule submission through SIBR.

The transmission operator role of the EIM Entity must submit forced transmission outages, in the OMS as soon as possible, and in accordance with the outage management provisions in the ISO tariff so that they are considered in the EIM dispatch.

3.4. EIM Optimization

3.4.1. Optimal Dispatch

The RTUC which would clear the EIM every 15 minutes is a multi-interval Security Constrained Unit Commitment application that optimally commits and schedules resources over successive 15-minute intervals to balance supply and demand in the combined ISO-EIM Entity footprint. EIM Entities may elect the option to have their resources participate in the RTUC unit commitment. Under this option, participating resources with energy bids may be flagged for optimal commitment in each 15-minute interval subject to applicable inter-temporal constraints; resources with zero base schedules would be assumed offline and available for startup, whereas resources with nonzero base schedules would be assumed online and available for shutdown. For EIM Entities that elect to opt out from unit commitment, the commitment status of their EIM Participating Resources is given and not optimized. Under the no-commitment option, any EIM Participating Resource with an energy bid is considered online. The RTUC produces 15-minute energy schedules and LMPs. The reference for calculating imbalance energy for the 15-minute energy schedules is the base schedule.

The RTD which would clear the EIM every 5 minutes is a multi-interval Security Constrained Economic Dispatch application that optimally dispatches resources over successive 5-minute intervals to balance supply and demand in the combined ISO-EIM Entity footprint. The RTD produces 5-minute dispatch instructions and LMPs. The reference for calculating imbalance energy for the 5-minute dispatch is the corresponding 15-minute market energy schedule.

Both RTUC and RTD are advanced optimization applications that model transmission losses accurately, complex resource operating characteristics, such as combined cycle gas turbine plant states and dynamic ramp rates, and are capable of enforcing complex network constraints and contingencies.

3.4.2. Congestion Management

RTUC and RTD enforce network constraints within the ISO BAA and the EIM Entity BAAs, ISO and the EIM Entities' interties, and any external transmission corridor where ISO or the EIM Entity have contractual rights. The EIM Entity as a transmission operator must specify the network constraints, including contingencies, and the associated limits that Market Operator needs to enforce in EIM. Furthermore, the EIM Entity Scheduling Coordinator base schedules must not violate any of these constraints. Finally, EIM Participating Resource Scheduling Coordinators must submit energy bids with sufficient generating capacity in EIM to enable efficient congestion management on these constraints. If an EIM Entity BAA does not have sufficient bids to resolve congestion, the relevant transmission constraints will be relaxed in the market clearing solution and the EIM Entity will become responsible for managing its congested constraints through other means, since the EIM design does not propose to include a must-offer requirement based on potential congestion.

The marginal congestion component of the 15-minute and 5-minute LMPs in all locations (both ISO BAA and EIM Entity BAA) will include congestion contributions from binding network constraints within the ISO-EIM Entity footprint. The marginal congestion revenue from the imbalance energy settlement, net of any TOR/ETC refunds, and net of any liquidation of convergence bids related to congestion in the EIM BAA would be allocated through the BAA real-time congestion balancing account discussed in Section 3.7.8.2.

The EIM is only dispatching resources within the EIM footprint to meet real-time imbalances. In doing so the EIM will operate within as available transmission rights that are made available by the EIM Entity. As part of EIM implementation, the Market Operator will utilize a network model tool which can monitor and control for actual flows within the EIM network. In addition the market operator will coordinate measures, where applicable, to ensure EIM dispatch does not exacerbate constraints affected by loop flow. The basic principle behind the tool is optimized generation dispatch within path limits and constraints with the potential to counter loop flow on either side of a flow gate.

3.4.3. Flexible Ramping Constraint and Future Product

On December 13, 2011, the ISO implemented a new flexible ramping constraint[8] in the market optimization for RTUC and RTD. This constraint is necessary to address certain reliability and operational issues observed in the ISO's operation of the grid. The ISO has observed that in certain situations reserves and regulation service procured in the real-time and units committed for energy in RTUC lack sufficient ramping capability and flexibility to meet conditions in RTD market intervals during which conditions may have changed from the assumptions made during the prior procurement procedures.

The enforcement of the flexible ramping constraint in the RTUC can give rise to opportunity costs for resources that resolve the flexible ramping constraint. A resource specific opportunity cost can result if the resource is not awarded incremental ancillary services or committed incremental energy. The shadow price of the constraint reflects the marginal units resource specific opportunity cost.

On December 12, 2011, FERC issued an order that accepted the flexible ramping constraint and suspend it for a nominal period, to become effective December 13, 2011, as requested, subject to refund and established hearing and settlement judge procedures to consider contested factual issues involving ISO's proposed Upward Flexible Ramping Constraint. The settlement hearing was held to address issues regarding the compensation and cost allocation.

As a result of the settlement, the compensation and cost allocation were modified from the original ISO proposal. The compensation is equal to the lesser of: 1) $800/MWh; or 2) the greater of: (a) zero (0), or (b) the Real-Time Ancillary Services Marginal Price for Spinning Reserves for the applicable fifteen-minute RTUC interval; or (c) the Flexible Ramping Constraint Shadow Price minus 75% of the maximum of (i) zero (0), or (ii) the Real-Time System Marginal Energy Cost, calculated as the simple average of the three five-minute Dispatch Interval System Marginal energy costs in the applicable fifteen-minute RTUC interval.

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

The cost in the ISO BAA is allocated 75% to measured demand 25% to gross negative uninstructed imbalance energy of supply. The supply allocation uses a two-step process. First on a daily basis, the ISO determines a daily rate equal to 25% of the total daily costs divided by total daily gross supply negative deviations for the applicable trading day. Each Scheduling Coordinator is assessed its share of these daily costs based on its daily gross negative uninstructed deviations calculated by resource. Second, at the end of each trading month, the ISO reverses the daily amounts assessed to Scheduling Coordinator and calculates a monthly rate equal to 25% of the total monthly costs divided by the total monthly gross supply uninstructed negative deviations.

When the ISO received Board approval of the upward flexible ramping constraint, the ISO committed to start a stakeholder process that would develop an upward/downward flexible ramping product[9]. The flexible ramping product would allow economic bids to be submitted, allow procurement of both upward and downward ramping capability, and procure the product in the day-ahead market. The ISO suspended the stakeholder process due to FERC Order No. 764 and plans to recommence the stakeholder initiative after the compliance filling is made in November 12, 2013. Therefore, the flexible ramping product design will not be finalized prior to EIM design being submitted for Board approval, but is an important future feature of the real-time market design.

The upward flexible ramping constraint will be in effect when EIM goes into production in Fall 2014. The constraint is a key element of the real-time market to ensure sufficient upward ramping capabilities are available or committed in the RTUC and that ramping capability is managed in RTD. Resources across the EIM footprint will be eligible for compensation (as described above) if the resource is used to resolve the flexible ramping constraint. Note that since no operating reserves are being procured in the EIM Entity BAA the default Real-Time Ancillary Services Marginal Price for Spinning Reserves for the applicable 15-minute RTUC interval shall be zero for the EIM Entity BAA. The flexible ramping constraint requirement will be determined by the Market Operator based upon upward ramping needs for each BAA in the EIM. The flexible ramping requirement for each EIM Entity BAA would be determined similarly to the flexible ramping requirement for the ISO BAA. The combined requirement for the entire EIM footprint may be less than the sum of the individual BAA requirements realizing potential diversity benefits in the EIM footprint. The flexible ramp sufficiency test for an EIM Entity BAA will reflect a pro rata share of these diversity benefits. If the flexible ramp sufficiency test passes, the market will enforce an hierarchical set of flexible ramping constraints over all BAA combinations to allow the most economic resources across all BAAs to meet the overall requirement reflecting any diversity benefits. Otherwise, the flexible ramping constraint will be enforced separately for an EIM Entity BAA that fails the flexible ramp sufficiency test and the net import interchange for that BAA will be bounded for the operating hour at the last 15-minute schedule before that hour.

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

The ISO currently does not require ISO day-ahead schedules to include unloaded capacity to meet the flexible ramping constraint. This is because the ISO does not enforce the constraint in the day-ahead market. The ISO's residual unit commitment process in the day-ahead market does ensure sufficient unloaded capacity if the cleared demand is lower than the ISO forecasted demand. Resources with residual unit commitment awards are required to bid in the real-time market. In addition, the ISO can commit resources in RTUC if additional unloaded capacity is needed. Under the proposed flexible ramping product, the day-ahead market would include both a flexible ramping up and flexible ramping down constraint. In addition, the ISO is currently considering must-offer obligations[10] for resource adequacy units that meet flexibility requirements as defined in the bilateral capacity market.

Each EIM Entity will need to meet its flexible ramp capacity requirement in the resource plan submitted by the EIM Entity Scheduling Coordinator. In the process to evaluate the resource plan, the Market Operator will verify that the resource plan has sufficient bid in ramping capability to meet the EIM Entity BAA flexible ramping requirement. If the EIM Entity elects not to allow unit commitment in RTUC, then only the bid range of online resources will be considered in calculating ramping capability (resources with economic bids are considered online under this option). If the EIM Entity elects to allow unit commitment in RTUC, then all resources with economic bids and are available for the 15-minute RTUC commitment (online or offline) will be eligible to ensure sufficient ramping capability. This addresses concerns raised in the previous stakeholder meeting of a hypothetical EIM Entity Scheduling Coordinator submitting a base schedule of Load = 100 MW and Wind = 100 MW. While the schedule is balanced, the hypothetical EIM Entity Scheduling Coordinator would need to also have additional economic bids from resources with upward ramping capability in order to meet the flexible ramp capacity requirements. In this case the variability of 100MW wind resource will be factored into the EIM Entity BAA flexibility requirements.

The flexible ramping requirement for each EIM Entity BAA will be determined using the similar methodology used for the ISO BAA. The Market Operator for the EIM will determine the amount of 5-minute flexibility requirements for each BAA individually and then again for the aggregate of the EIM footprint. The following methodology will be used to determine the flexibility requirements:

a) Develop a daily 5-minute granular forecast of gross load, wind and solar production.

b) Determine a daily 5-minute net load by netting the gross load by the wind and solar production forecasts

c) Develop a series of daily 5-minute net load curves by introducing forecast error uncertainty based on historical forecast error pattern.

[10] Additional information is available at http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx

d) Develop a distribution of the changes in the 5-minute net load by calculating the difference between the net load at time (t+5 minute) by the net load at time (t) for each 5-minute interval of the day and repeat for the series of net load represent forecast error.

e) Analyze the distribution of changes in 5-minute net load and identify the +/-X% confidence level of the distribution. The ISO has proposed a 90%-95% confidence level as the appropriate level for establishing the flexible ramping requirement.

f) The above process is be performed individually for each BAA and in aggregate for the combined EIM footprint.

g) For the purpose of flexible ramping sufficiency test in the EIM Entity BAA, a minimum requirement for the EIM will be determined considering the proportional amount of the combined flexibility requirement and the transfer capability into the EIM Entity BAA from other BAAs in the EIM footprint.

h) For the purpose of procurement on a 15-minute basis, the 5-minute requirements can be aggregated into a 15-minute requirement by summing the three 5-minute interval requirements into a 15-minute requirement for each 15-minute RTUC interval.

The Market Operator will apply a ramp sufficiency test[11] for each EIM Entity BAA to verify that the submitted resource plan by the relevant EIM Entity Scheduling Coordinator has sufficient ramp capability to meet the flexible ramping constraint requirement of the EIM Entity BAA in each 15-minute interval. If the ramp sufficiency test fails for an EIM Entity BAA, the Market Operator will constrain the net import interchange for that EIM Entity BAA during the operating hour to not exceed the last 15-minute schedule interchange before that hour, effectively not allowing additional imports in that BAA from the rest of the EIM; this may lead to scarcity and high administrative energy prices in that EIM Entity BAA but isolate such scarcity prices from other areas.

The Market Operator will calculate the flexible ramping constraint requirement for each BAA individually and a requirement for the EIM footprint which recognizes the diversity benefits of the EIM. The diversity benefit will then be allocated to individual EIM Entity BAAs for use in the flexible ramping constraint sufficiency test. The total system requirement will not exceed the sum of the individual BAA flexible ramping constraint requirements, since in this case, the requirement can be met with no transfers between BAAs.

The individual EIM Entity BAA requirement for the flexible ramp sufficiency test will be calculated as follows:

$$FRR'_i = \max\left(\max(0, FRR_i - NIC_i), FRR_i \frac{TFRR - DB}{TFRR}\right)$$

Where:

[11] The ISO held a technical workshop on August 13, 2013 that provides detailed examples the sufficiency test and formulation of the flexible ramping constraint. The presentation is available at http://www.caiso.com/Documents/Technical%20workshops%20Aug%2012%20and%2013,%202013

FRR'_i is the flexible ramp requirement for EIM Entity *i* with diversity benefit;

FRR_i is the flexible ramp requirement for EIM Entity *i* without diversity benefit;

NIC_i is the available net import capability of EIM Entity *i*, not consumed by base schedules or EIM scheduled transfers prior to the operating hour;

TFRR is the total flexible ramp requirement for the entire EIM footprint without diversity benefit (the sum of FRR_i for all BAAs in the EIM including the ISO BAA); and

DB is the EIM diversity benefit.

This requirement reflects a pro rata share of potential EIM diversity benefits, bounded from below by the available net import capability.

The Market Operator will perform a series of flexible ramping constraint sufficiency tests prior to commencing the EIM. The EIM Entity Scheduling Coordinator will have an opportunity to re-submit the hourly base schedule if it fails the flexible ramping constraint sufficiency test or to resolve congestion up to 40 minutes prior to the operating hour which is just before the start of the first financially binding EIM 15-minute market for the operating hour.

The sufficiency test will be performed for each EIM Entity BAA after T−75 minutes, T−55 minutes, and T−40 minutes for the Trading Hour starting at T. The Market Operator will use the following data to evaluate the hourly base schedule.

- Initial schedules at T−7.5'
- EIM Participating Resources energy bids and ramp rates
- 15-minute flexible ramping requirements reduced by any diversity benefit up to available net import capability at T−7.5'

The sufficiency test is cumulative. The EIM Entity BAA must meet flexible ramping requirements for each 15 minute interval of the hour:

Interval 1: 15-minute ramp from T−7.5 to T+7.5

Interval 2: 30-minute ramp from T−7.5 to T+22.5

Interval 3: 45-minute ramp from T−7.5 to T+37.5

Interval 4: 60-minute ramp from T−7.5 to T+52.5

Upon completion of the flexible ramping sufficiency test, the Market Operator will enforce separate flexible ramping constraints in the market optimization for each EIM Entity BAA, the ISO BAA, and the entire EIM footprint. The potentially lower requirements for each BAA reflect the benefits of reduced uncertainty and volatility across the EIM footprint used in the sufficiency test. By considering the transfer capability in the individual BAA constraints, the market optimization can select the most efficient resources across the EIM footprint to meet both individual BAA requirements and the system requirement.

To illustrate the proposal, consider the following example:

BAA	Flexible Ramping Requirement (MW)	Flexible Ramping Requirement with diversity benefit (MW)	Flexible Ramping Sufficiency Test
ISO	300	N/A	N/A
EIM_1	200	$200 \times 600 / 650 = 184.62$	✓
EIM_2	150	$150 \times 600 / 650 = 138.46$	✗
ALL	650	600	

Table 2 – Flexible Ramping Sufficiency Test Results

The flexible ramping requirements used in the flexible ramp sufficiency test for each BAA consider the EIM diversity benefits. EIM_1 passes the ramp sufficiency test, whereas the test fails for EIM_2. The available power transfer capability between the participating BAAs does not limit diversity benefits and is as follows:

	ISO	EIM_1	EIM_2
ISO		80	80
EIM_1	80		20
EIM_2	80	20	

Table 3 – Available power transfer capability between BAAs

Since EIM_2 fails the ramp sufficiency test, it will be isolated from the rest of the EIM, i.e., there will be no net additional imbalance energy import into that BAA. The flexible ramping constraints limits will be as follows:

BAA	Minimum Flexible Ramping Capacity Limit (MW)
ISO	220 = 300 – 80
EIM_1	120 = 200 – 80
EIM_2	150*
ISO+ EIM_1	500 = 300 + 200

Table 4 – Market Optimization Constraint Limits – EIM_2 Fails Test

The flexible ramping constraint for EIM_2 will probably not be satisfied, hence it will be relaxed with the price reflecting such scarcity; however, it will still be enforced at the relaxed limit to reduce the likelihood of scarcity in EIM_2. The minimum flexible ramping capacity limits for the ISO and EIM_1 are reduced by the 80 MW available power transfer capability between these areas. The minimum flexible ramping capacity limit for both areas effectively allows the requirement in one area to be met by resources in the other area, but only within the available power transfer capability.

If EIM_2 had passed the ramp sufficiency test, the flexible ramp capacity constraints limits would have been as follows:

BAA	Minimum Flexible Ramping Capacity Limit (MW)
ISO	140 = 300 – 80 – 80
EIM_1	100 = 200 – 80 – 20
EIM_2	50 = 150 – 80 – 20
ISO+ EIM_1	400 = 300 + 200 – 80 – 20
ISO+ EIM_2	350 = 300 + 150 – 80 – 20
EIM_1+ EIM_2	190 = 200 + 150 – 80 – 80
ALL	600

Table 5 – Market Optimization Constraint Limits – All BAAs Pass Test

This example shows the benefits of EIM participation to reduce uncertainty and volatility across the EIM footprint utilizing the power transfer capability across the EIM BAAs.

3.4.4. Scarcity

The EIM formulation includes a single power balance constraint for the entire EIM footprint. Imbalance energy scarcity in meeting demand deviations in that footprint can manifest because of either insufficient energy bids or inadequate ramp capability. In these cases, the power balance constraint is relaxed at an administrative penalty cost, which should be higher than the bid cap. Then, the marginal energy component of the LMPs is that administrative penalty cost signaling imbalance energy scarcity. The power balance mismatch would actually be made up by regulating resources in each BAA. The associated regulating energy would be settled at the applicable LMP, which would include the administrative marginal energy penalty price.[12]

3.5. EIM Output Results

This section describes the EIM output data and provides references to the systems and interfaces that would be used to receive it.

3.5.1. 15-Minute Energy Schedules

The financially binding 15-minute market energy schedules calculated by RTUC will be available for the EIM Participating Resource Scheduling Coordinators that represent EIM Participating Resources at the California Market Results Interface (CMRI). The 15-minute energy schedules are flat energy schedules over the relevant 15-minute interval. The imbalance energy calculated for the resource will be calculated as the algebraic difference between the 15-minute energy schedule and the 15-minute base schedule for the relevant resource would be settled at the 15-minute LMP.

[12] Additional information about the power balance constraint and scarcity pricing is provided in the Business Practice Manual for Market Operations (e.g., sections 7.5.2 and 7.5.3), which is available at http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market Operations.

3.5.2. 5-Minute Dispatch Instructions

The financially binding 5-minute dispatch instructions calculated by RTD will be communicated to the EIM Participating Resource Scheduling Coordinator's business systems through an interface to the Market Operator's Automated Dispatch System (ADS) to the EIM Participating Resource Scheduling Coordinator as well as the to the EIM Entity for resources on regulation.. The dispatch instructions will also be sent to the EIM Entity Scheduling Coordinator. The dispatch instructions will include the dispatch operating target (DOT) in MW that should be attained at the midpoint of the relevant 5-minute interval, as well as the dispatch operating point (DOP), which is the calculated dispatch trajectory from the midpoint of the previous 5-minute interval, considering the applicable resource static or dynamic ramp rate. The instructed imbalance energy is calculated as the integral of the algebraic difference between the DOP and the 15-minute Energy schedule for the relevant resource would be settled at the 5-minute LMP.

3.5.3. Dynamic Imbalance Schedule to Net Schedule Interchange

As a result of the EIM optimal dispatch to resolve dynamic energy imbalances and congestion management, the net schedule interchange values may change for every 5-minute interval, with ramping within intervals being tracked by the ISO's EMS. The net schedule interchange variation shall be modeled as a dynamic schedule between the ISO and EIM Entity for AGC control accuracy. This will help the AGC system to track these changes and reduce unnecessary AGC movements as a response to instructed deviations in the output of generating resources within EIM Entity BAA.

3.5.4. 15-Minute and 5-Minute Locational Marginal Prices

The 15-minute and 5-minute LMPs, calculated by RTUC and RTD, will be published for all nodes and LAPs in the EIM Entity BAA on the Open Access Same-time Information System (OASIS).

3.5.5. 15-Minute and 5-Minute Binding Transmission Constraints and Shadow Prices

The list of binding transmission constraints in the ISO-EIM Entity footprint in the 15-minute and 5-minute market solutions obtained from RTUC and RTD will be published on OASIS. OASIS will also publish the relevant limits and associated shadow prices. Information regarding binding constraints for advisory intervals will also be published.

3.5.6. Protected Data

The Market Operator publishes additional market data on the California Market Results Interface (CMRI). The data provided is not publicly available and will require that the EIM Participating Resource Scheduling Coordinator execute a Non-Disclosure Agreement (NDA) in order to access the information. Protected data that relates to the EIM and may be of interest to EIM Participating Resource Scheduling Coordinators are as follows:

- Real-time shift factors used by RTUC and RTD in enforcing network constraints.

- Transmission constraint limits for the critical set of network constraints enforced by RTUC and RTD. This is a superset that includes the binding network constraints, which are published on OASIS.

3.6. EIM System Operations

3.6.1. Ancillary Services

An EIM Entity will be responsible for procuring and maintaining their own Ancillary Services to meet their BAA obligations or obligations to reserve sharing groups..

3.6.2. Contingency Dispatch

The current EIM framework does not include the procurement or dispatch of ancillary services in EIM Entity BAA. Each BA is responsible for meeting NERC and WECC reliability standards in its respective BAA. Specifically, each BA is responsible for frequency and tie-line control with an appropriate use of their Automatic Generation Control (AGC). The EIM dispatches and demand forecast deviations will be netted for each EIM Entity BAA to produce a dynamic net interchange schedule for AGC purposes.

Regarding contingency dispatch, each EIM Entity is responsible for dispatching contingency reserves in their BAA to recover from contingencies that involve loss of generation or interties. Furthermore, EIM Entities may also have the need for exceptional dispatch in their BAA to address system reliability or stability concerns that are not modeled or resolved by EIM, such as voltage collapse scenarios. For these reasons, generating capacity should be reserved from EIM Entity resources from the top and bottom of their energy bid to be used for ancillary services or exceptional dispatch. The EIM Scheduling Coordinator must inform the Market Operator of this dispatch for native needs by revising the base schedule of the affected resources. If the resources change in schedule is received before the 15-minute market for the relevant interval, these exceptional dispatch instructions will settled at the 5-minute price. The Market Operator will reflect 15-minute schedule in the 5-minute dispatch instructions.

Although contingency dispatch is not currently in the EIM framework, it can be provided to interested EIM Entities as an additional service.

3.6.3. Exceptional Dispatch

EIM Exceptional Dispatches are those dispatches that are necessary to be performed outside the EIM optimization, to maintain reliability and address any transmission reliability issue occurring in the EIM Entity BAA for which the Market Operator is not able to enforce via normal economic dispatch and transmission constraints. For example, if there is requirement to dispatch a resource in the EIM Entity BAA due to a voltage stability issue that is not incorporated into the flow based limitations of the model, then such a dispatch is an exceptional dispatch to the EIM dispatches.

The Market Operator will not issue Exceptional Dispatches to EIM Participating Resources. The EIM Entity may do so for EIM Entity BAA purposes. These dispatches would still register as imbalance deviations and would be settled at the LMP with no specific Exceptional Dispatch settlement from the Market Operator until such reliability based constraints on the resources are incorporated into the 15-minute market.

Exceptional dispatch from the EIM Entity Scheduling Coordinator to the EIM Entity BAA generating resources will be declared by the EIM Entity Scheduling Coordinator to the Market Operator to coordinate the movement of the resource in the EIM and the actual reliability need of EIM Entity BAA in real-time. Any exceptional dispatch instructions from the EIM Entity Scheduling Coordinator to the EIM Entity BAA generating resources will be communicated to the Market Operator's real-time market applications via a direct interface.

3.6.4. Interaction with WECC Reliability Coordination

The Market Operator will be able to inform the WECC Reliability Coordinator (RC) of EIM's dispatches and to enforce constraints if requested by the RC. Because EIM will operate only with bids submitted by EIM Participating Resource Scheduling Coordinators, and will not adjust self-schedules, coordinated reliability curtailments such as through WECC's Unscheduled Flow Mitigation Plan (UFMP) or RC intervention in mandating schedule curtailments remain the role of the EIM Entity. An EIM Entity may choose to take such actions after the EIM Market Operator notifies the EIM Entity that the Market Operator observes congestion or other conditions and has no effective bids for resolving it, or may choose to take reliability actions separately, based on its own procedures. Any actions taken by the EIM Entity will be communicated to the EIM Market Operator via updates from the base schedules, interchange tags, transmission limit adjustments, or outage and derate information.

The ISO will determine through discussion with the RC, if the ISO as EIM Market Operator should inform the RC of over-generation, unresolved congestion, or other issues that the ISO sees within EIM Entities' BAAs, or that the RC and EIM Entities will prefer for that coordination to occur between the RC and the EIM Entities.

3.6.5. Seams Coordination and Interaction with WECC Congestion Management

Except in emergency conditions, congestion management is automatically activated when an actual or potential constraint is observed in real-time. Under certain conditions, additional congestion management procedures may be initiated through WECC's Unscheduled Flow Mitigation Procedure (UFMP). An EIM Entity or other balancing authority may initiate the UFMP if applicable for conditions under its jurisdiction, in which case the Market Operator will adjust the affected schedules as determined by the UFMP. If the UFMP has not been initiated, the Market Operator will manage congestion directly in the EIM dispatch by automatically activating constraints as flows using the transmission capacity available to EIM. This will cause EIM to dispatch its available bids to provide appropriate reductions in flows as needed to manage the constraints, to the extent that the resources can be effective in managing the constraints, by decrementing resources that contribute to congestion and incrementing resources that can provide counter-flow. The EIM will not automatically initiate the UFMP, but will alert EIM Entities to conditions that EIM cannot resolve, which may require the EIM Entity to initiate the procedures under WECC regulations.

EIM's congestion management process will use its effective resources to remove congestion before curtailing any existing schedules, because dispatches issued by EIM are considered to have a priority level lower than any existing self-schedules. The EIM settlements directly assign the cost associated with relieving congestion to the schedules that have uninstructed deviations and are impacting a particular constrained flow gate, as well as setting LMPs for EIM dispatches based on their contribution to causing or relieving congestion. Thus, the EIM's congestion management process is a cost-based mechanism for curtailing or adjusting schedules to provide imbalance energy to support scheduled flows. The result is that flows resulting from the EIM dispatch will provide counter-flows for congestion, and thereby support scheduled flows that may otherwise need to be curtailed through UFMP.

EIM's congestion management, and EIM Entities' use of UFMP when EIM has exhausted its available, effective market bids, can be supplemented by market-to-market and market-to-non-market coordination agreements between EIM Entities and other BAAs. Subject to the EIM Entities' dynamic transfer policy dynamic transfers to EIM Entities may make resources outside the EIM footprint available to the EIM to add to EIM's ability to manage congestion as well as to balance load and supply variations, and thereby reduce the need to utilize UFMP. A presentation at the WECC Seams Issues Subcommittee's November 2010 meeting[13] explained that the specific details used in some market areas (e.g., Southwest Power Pool's Congestion Management Process, "CMP") would not meet the needs for coordination with a comprehensive central market such as the ISO operates, and proposed a workable framework that addresses (1) routine market dispatch and (2) mutual assistance for congestion management. The issues with CMP include:

- Firm market flows in CMP include long-term contracts, and CMP distinguishes non-firm flows, whereas all transmission sold by ISO is equivalent to hourly firm.
- Loads in ISO depend more on imports from other parts of WECC. Imports to ISO use transmission for which entities sell their transmission rights through external BAAs to ISO market participants.

Routine market dispatch for seams coordination can build on the EIM's functionality for external-to-internal market integration, using dynamic transfer functionality. EIM includes external sources and sinks in its market network model to accurately model flows between EIM and BAAs with which it coordinates. External resources may then participate in EIM as dynamic transfers, including aggregations and partial resources.

Mutual assistance for congestion management then builds on accepted principles within WECC, for instances when the EIM footprint or another BAA has insufficient resources itself (including dynamic transfers approved by EIM Entity with other BAAs) to effectively manage congestion. WECC has established procedures for path ratings, and the EIM Market Operator and other system operators would use a similar process to agree on limits for coordinated flowgates and

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13 Available at http://www.wecc.biz/committees/StandingCommittees/MIC/SIS/SIS111510/Lists/Exhibits/1/WECC_SIS_EIM_MarketCoordination_20101109_final.doc and http://www.wecc.biz/committees/StandingCommittees/MIC/SIS/SIS111510/Lists/Presentations/1/WECC%20SIS%20Market2Market%20StrawProposal%2020101115_final.ppt)

criteria for resources that are responsible for contributing to enforcement responsibilities, such as flow contributions with PTDFs exceeding 10%, as in UFMP. The proposed mutual assistance for congestion management simplifies CMP to the following steps among participants in this mutual assistance process:

1. The EIM Market Operator and other system operators model the full WECC network, define external constraints in its model, and prepare to enforce constraints in step 4.
2. Load and generation forecasts and other data are exchanged at a granularity no larger than UFMP zones or equivalent, for accurate flow modelling.
3. When one system operator forecasts real-time congestion, other system operators determine their own firm market flows on the coordinated flowgate.
4. Each system operator then enforces the coordinated flowgate to prevent further increases of its flow, allowing real-time redispatch to reduce flow.
5. Each system operator sends updated schedules and dispatch as part of the UFMP.

If a balancing authority initiates the UFMP, the EIM and the WECC UFMP can work with each other to manage congestion on constrained flowgates and handle curtailments of energy schedules as appropriate. The UFMP would prescribe curtailments of those e-Tags that are not included in market flows, while the Market Operator would prescribe curtailment of market flows in the event that EIM energy bids become available that would be effective in managing the applicable constraint and that EIM has not already utilized. The Market Operator will continue activation of congested constraints until flows are sufficiently less than the transmission capacity available to EIM. This will ensure that EIM continues to provide the maximum amount of congestion relief possible given its available bids, thereby reducing needs for a balancing authority to initiate UFMP.

The WECC Enhanced Curtailment Calculator (ECC) will receive all tagged transactions involving the EIM footprint. (ECC has not yet been implemented, but is currently under development by the WECC Reliability Coordinator. This discussion is based on a preliminary understanding of how ECC will operate, and will be revised as needed based on the specific design of ECC.) Under EIM operations, balancing authorities will be responsible during UFMP events for prescribed curtailment of certain types of tagged transactions and coordination with the market flow relief that the Market Operator must achieve internally through its market operations. The WECC UFMP will be responsible for prescribing curtailment of those tags involving the Market Operator for which impacts are not included in EIM flows. These include e-Tags for schedules with external parties that are sourced or sunk in the EIM footprint and e-Tags for interchange transactions from self-scheduled resources.

Dynamic e-Tags for EIM flows will not be updated for EIM dispatch until the end of the operating hour, and thus be explicitly not managed by the UFMP. Provided that the Market Operator is able to obtain flow gate limits from ECC that should be maintained by EIM dispatches, the EIM congestion management process will notify the EIM Participating Resource Scheduling Coordinators through the Automated Dispatch System (ADS) by 2.5 minutes before the affected dispatch interval of the schedule adjustments due to the constraint, and the shadow price of the flow gate responsible for the curtailment will be available on OASIS.

3.6.6. Load Curtailment

The EIM can dispatch price-responsive demand, such as pump load or exports (on a 15 minute basis) from the EIM Participating Resource Scheduling Coordinators, based on submitted energy bids. The EIM will not dispatch price-inelastic demand; demand management and load shedding would be coordinated between the EIM Entity and the Utility Distribution Companies (UDCs) outside of EIM. Widespread load shedding would constitute a market disruption.

3.6.7. Market Disruption

In the case where a market disruption or a contingency event affects an EIM Entity BAA in the EIM footprint, the Market Operator would maintain the EIM for unaffected EIM Entity BAAs by enforcing a net interchange constraint for the affected EIM Entity BAA to decouple it from the EIM footprint.

A similar approach would be employed for contingency dispatch in the ISO. Although contingency dispatch is not a market disruption because the ISO uses a special market application (RTCD) for it, contingency dispatch is currently not in the scope of EIM. Therefore, if the ISO suffers a contingency within its BAA, the RTCD would only dispatch resources in ISO to recover from the disturbance. Resources in EIM Entity BAAs would not be dispatched to assist in that recovery; similarly a contingency in an EIM Entity BAA would not affect ISO resources. Nevertheless, RTUC and RTD would continue to run during a ISO contingency and produce dispatch instructions for resources in EIM Entity BAAs to balance the remaining EIM footprint by excluding the ISO, for which dispatch instructions would be produced by RTCD. This can be achieved by isolating the ISO from the rest of the EIM footprint by enforcing a net interchange constraint in RTUC and RTD for the ISO, set at the last scheduled interchange value before the occurrence of the contingency.

3.6.8. Business Continuity

In the event that the EIM Entity loses communication with the Market Operator, the EIM Entity will be responsible for managing its BAA imbalance needs without the EIM dispatch.

3.7. EIM Settlement and Accounting

3.7.1. Settlement of Non-Participating Resources

Since participation in the EIM is voluntary, the EIM Entity Scheduling Coordinator will be responsible for the settlement of deviations from resources that are not participating in the EIM. There may be an impact on the EIM Entity's interaction with load and resources within its BAA, such as definition of an Hourly Pricing Proxy used to settle energy imbalance under Schedule 4 and generator imbalance and under Schedule 9 of its open access transmission tariff (OATT).

The Market Operator will settle, with the EIM Entity Scheduling Coordinator, deviations at the locational marginal price at the corresponding resources and load. The EIM Entity may choose to pass these charges to the resources/load causing the energy imbalance, or continue to use their existing Hourly Pricing Proxy.

3.7.2. Instructed Imbalance Energy

Instructed imbalance energy is calculated as the algebraic difference between the 5-minute dispatch operating point (DOP), which is the dispatch trajectory from the previous 5-minute interval mid-point to the next one, and the base schedule. The instructed imbalance energy is settled in two tiers:

a) 15-minute instructed imbalance energy; and

b) 5-minute instructed imbalance energy.

The 15-minute instructed imbalance energy is calculated as the algebraic difference between the 15-minute energy schedule, which is the outcome of RTUC, and the 15-minute base schedule for the relevant resource; the 15-minute instructed imbalance energy is settled at the 15-minute LMP.

The 5-minute instructed imbalance energy is calculated as the algebraic difference between the DOP, which is the outcome of RTD, and the 15-minute energy schedule for the relevant resource; the 5-minute instructed imbalance energy is settled at the 5-minute LMP.

3.7.3. Uninstructed Imbalance Energy

Uninstructed deviations between the dispatch instruction for a resource and its real time operating level are settled at the resource's LMP. Resources with financial settlement based on energy delivered in each dispatch interval, with separate price calculations for instructed and uninstructed energy, may be deemed to be settled using cost-based LMPs, and therefore not subject to uninstructed deviation charges.[14]

For generating resources, participating loads (i.e., dispatchable pumps and other demand response market resources), and dynamic import/export schedules with external resources, uninstructed imbalance energy is calculated as the algebraic difference between the 5-minute meter data and the DOP. This uninstructed imbalance energy is settled at the 5-minute LMP.

For static or 15-minute import/export schedules at scheduling points with the ISO or an EIM Entity BAA, uninstructed imbalance energy is derived from the operational adjustments (OA) to the respective hourly or 15-minute e-tags. This uninstructed imbalance energy is settled at the straight average of the three 5-minute LMPs for the relevant 15 minute market interval.

For non-participating load (i.e., loads that are not dispatchable for demand response), uninstructed imbalance energy is calculated as the algebraic difference between the hourly meter data and the base schedule. This uninstructed imbalance energy is settled at the hourly volumetric weighted average LMP of the 15-minute and 5-minute markets in that hour for the relevant Load Aggregation Point (LAP). The LMPs will be weighted by the load forecast deviations in the respective markets, but the weighted average will be bounded by the most extreme LMP in the population. The load forecast deviation in a 15-minute market is measured

[14] The ISO does not currently use an Uninstructed Deviation Charge other than settlement of real-time at the resource location's LMP. The ISO has proposed limitations on bid cost recovery payments and possibly other payments based on deviations.

with reference to the corresponding base load schedule for that interval. The load forecast deviation in a 5-minute market is measured with reference to the load forecast that was used to clear the corresponding 15-minute market. Any remaining neutrality charge is allocated based upon the metered demand of the LAP.

3.7.4. Unaccounted For Energy (UFE)

UFE is attributable to meter measurement errors, power flow modeling errors, energy theft, statistical load, profile errors, and distribution loss deviations. It is the difference between the net energy delivered (generation, imports, demand and exports) into the Utility Distribution Company (UDC) service area, adjusted for UDC service area losses, and the total measured demand within the UDC area adjusted for distribution losses using distribution system loss factors approved by the local regulatory authority.

UFE is treated as imbalance energy and it is the MW neutrality aspect of the respective UDC. Note that UDC role is separate from the EIM Entity. The UDC is also different from a load aggregation point (LAP), because metered boundaries are needed to define UDCs but may not be present for LAPs. Additional discussions are needed to define the specific make-up of the UFE service area for EIM Entities in conjunction with the needed metering points to calculate UFE for each service area.

Losses in each UFE are estimated based on the AC power flow solution. Meters are required on all boundary ties of each UDC. UFE in each UDC is calculated as the mismatch between supply/import, demand/export, and estimated losses. UFE is included in the Real-Time Market BAA Neutrality calculation and allocation.

3.7.5. Inadvertent Energy Accounting

In the WECC region, each BAA is responsible for tracking inadvertent energy and administering inadvertent payback through processes established by WECC. This responsibility does not change with EIM.

To assist BAAs within the EIM with accounting for inadvertent energy between BAAs, the Market Operator will maintain a dynamic schedule with resources in each EIM Entity BAA. Therefore the EIM transfers will not constitute inadvertent energy. Because each EIM Entity Scheduling Coordinator has a balanced schedule at the beginning of each 15-minute interval, the initial energy profile for each of these dynamic schedules may initially show zero MW that may be zero MW if these e-Tags represent only imbalance energy dispatched in 5-minute intervals (or may be non-zero if they include scheduled energy for hourly or 15-minute intervals). Within 60 minutes after the end of each operating hour, the Market Operator will calculate the integrated energy during the hour for the sum of all EIM deviations within each BAA, and update the dynamic schedules with the calculated value for the integrated energy. Any subsequent updates would occur within the requirements of WECC, NERC, and NAESB standards and business practices.

3.7.6. Settlement Metering

Settlement metering is required for all Generators within an EIM Entity BAA. Generators will have the option to either be a Scheduling Coordinator Metered Entity (SCME) or a ISO Metered

Entity (ISOME). Generation values associated with SCME must be submitted according to current submittal formats and time periods captured within ISO Metering Business Practice Manual (BPM). Those electing to be an ISOME must meet current Tariff and Metering BPM requirements related to ISO Metered Entity. If becoming an SCME, the data from the EIM Entity is deemed Settlement quality meter data but will comply with a set of defined standards by the ISO if no local authority standards exist.

Concurrent with its compliance with FERC Order No. 764, ISO is making 5- minute metering a requirement for generation resources. This 5-minute requirement will also apply to generating resources of the EIM Entity BAA. This includes all generators whether bidding into EIM or not bidding. This is to reduce the risk of neutrality. However, load resources will continue to be submitted in hourly values similar to today's market.

3.7.7. Interchange Meter Data

Settlement metering is not required for interchange points between EIM Entity BAA and ISO if they are tagged. The Market Operator will utilize e-Tag information used for interchange checkout between the ISO and the EIM Entity. The e-Tag is deemed delivered and is thus equivalent to metering. The dynamic interchange capacity between ISO and EIM Entity must be tagged but it does not require meter data because it will not be settled; it will only be used for interchange checkout and as an input to the ISO and EIM Entity's AGC net scheduled interchange. The imbalance energy settlement will take place at the resource specific level, hence meter data are required for each resource separately.

The Market Operator does need telemetry data for interchange locations between the EIM Entity BAA and other BAAs as well as e-Tag information (schedule and originating/receiving BAA).

3.7.7.1.e-Tagging

All scheduled energy from imports and exports must be e-Tagged including the awarded imbalance energy of dynamic schedules that crosses BAA boundaries. The e-Tag must reflect the point of receipt and point of delivery that was declared in market bid submittal. The Market Operator will use the WECC Interchange Tool to receive e-Tag information related to the EIM Entity BAA's interchange points with other BAAs that are not ISO.

The ISO will maintain a dynamic schedule with resources in each EIM Entity. Although each EIM Entity Scheduling Coordinator has a balanced base schedule before the beginning of each operating hour, the initial energy profile for each of these dynamic schedules will show non-zero MW (or may be zero if just participating in 5-minute dispatch) at the beginning of an operating hour if these e-Tags include imbalance energy dispatched in hourly or 15-minute intervals. Within 60 minutes after the end of each operating hour, the Market Operator will calculate the integrated energy during the hour for the sum of all EIM dispatches within each BAA, and update the dynamic schedules with the calculated value for the integrated energy, in accordance with WECC business practices. Any subsequent updates would occur within the requirements of WECC, NERC, and NAESB standards and business practices.

3.7.8. Neutrality and Uplift Allocations

In 2012, the ISO developed a set of cost allocation guiding principles with stakeholders. The seven principles are:

1. **Causation**: Costs will be charged to resources that benefit from the service the ISO procures through the market or drive procurement decision and resulting costs.
2. **Comparable Treatment**: Similarly situated resources and/or market participants should receive similar allocation of costs and not be unduly discriminated against.
3. **Accurate Price Signals**: The cost allocation design supports the economically efficient achievement of state and federal policy goals by providing accurate price signals from the ISO market.
4. **Incentivize Behavior**: Providing appropriate incentives is key to an economically efficient market
5. **Manageable**: Market participants should have the ability to manage exposure to the cost allocation.
6. **Synchronized**: The cost drivers of the allocation should align as closely as possible to the selected billing determinant.
7. **Rational**: Implementation costs/complexity should not exceed the benefits that are intended to be achieved by allocating costs.

The ISO currently separates market uplifts by the day-ahead market and real-time market. The ISO currently has four real-time market uplifts, but these will change under the FERC Order No. 764 market design:

CC6477	Real-Time Imbalance Energy Offset[15]
CC6774	Real-Time Congestion Offset
CC6678	Real-Time Bid Cost Recovery Allocation
CC7024	Flexible Ramp Up Cost Allocation

The remainder of this section will discuss each of the offsets/allocations above. The proposed treatment seeks to isolate offsets and allocation by BAA. The ISO and EIM Entities are responsible for developing their own allocation methodologies for their BAA share of the neutrality accounts or uplifts. Under the combined EIM-ISO real-time market optimization real-time transfers between BAAs must be incorporated in determining the final BAA offset costs where appropriate.

[15] BPM configuration guides for the charge codes (CC) are available at http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

3.7.8.1.Real-Time Imbalance Energy Offset

The real time imbalance energy offset is a neutrality charge that settles difference between demand imbalance energy and losses charges/credits and supply imbalance energy and losses charges/credits. Under FERC Order No. 764 market design changes, the real time imbalance energy offset is significantly reduced Since load, generation, imports and exports are settled in the same markets, the primary drivers of the offset will be eliminated. Currently, non-participating load is settled at the average hourly RTD price, internal generation is settled at the weighted 10-minute average price for instructed imbalance energy and the simple 10-minute average price for uninstructed imbalance energy, and real-time imports/exports are settled at the hourly HASP price. These settlement differences lead to high levels of the real-time energy offset.

Under FERC Order No. 764, non-participating load is settled at the hourly weighted average price based upon the load aggregation point forecast used in the market optimization. Static intertie transactions are settled at the 15-minute market price. Dynamic schedules and internal generation are settled at the 15-minute market price and the RTD price[16]. The real-time market optimization determines instructed imbalance energy for imports, exports, and internal generation based upon the load forecast. By settling non-participating load, which is metered on an hourly basis, at the weighted average price based upon load forecast used in the market optimization, the system marginal energy cost component of the LMP will not result in differences between what load is charged and what import, exports, and generation are paid for 15-minute market awards and real-time dispatches.

Neutrality can be either a positive or negative. Under EIM, neutrality charges/credits will be recovered though the (1) Real-Time Market System Neutrality and the (2) Real-Time Market BAA Neutrality. Neutrality charges can be attributed to (1) an excessive rate mitigation measure in the pricing formula for load aggregation points, (2) differences between the Load forecast in RTD and actual metered Load, (3) uninstructed imbalance energy of generation, (4) regulation energy in the ISO, (5) the real-time marginal loss surplus, and Unaccounted for Energy. The Real-Time System Neutrality accounts for across BAA settlement imbalances whereas the Real-Time Market BAA Neutrality accounts for within BAA settlement imbalances.

Since multiple load serving entities can be included in a load aggregation point (LAP), the FERC Order No. 764 design includes an excessive rate mitigation measure. The mitigation measure ensures that if there are minimal net load deviations over the hour, a single load serving entity is not responsible for settlement of the entire real-time market forecast at a calculated high rate. Differences between the RTD forecast and actual meter result in neutrality. Instructed imbalance energy of generation is equal to the RTD forecast. The payment from load to generation instructed imbalance energy is equal. However, the EIM settles total load uninstructed imbalance energy. Load uninstructed imbalance energy is the deviation between the base

[16] A spreadsheet that models settlement under FERC Order No. 764 market design changes is available at http://www.caiso.com/Documents/FERC%20Order%20No%20764%20market%20changes%20-%20meetings%7CWeb%20conference%20Feb%2012,%202013

schedule and meter. The deviation can be further decomposed in to the instructed energy to generation and the load forecast error from RTD. The load forecast error from RTD is settled at the weighted average price; however, there is not an offsetting settlement of generation. This results in neutrality in a given LAP. As discussed above, the settlement of instructed imbalance energy of generation and the load forecast used in the market optimization are equal. Thus the payment from load to generation is equal. However, the EIM settles both instructed and uninstructed imbalance energy from generation. Uninstructed imbalance energy of generation is settled at the 5-minute LMP; however, there is not an offsetting settlement of Load. Uninstructed imbalance energy will be offset by either regulation energy or EIM transfers, or inadvertent transfers. This results in neutrality in a given BAA.

Regulation Up and Regulation Down result in energy settlement as the BAA manages area control error within the 5-minute RTD interval. In the ISO, regulation energy is considered instructed imbalance energy and is settled at the 5-minute LMP. In the EIM Entity, energy that results from units providing regulation is settled as uninstructed imbalance energy at the 5-minute LMP. As a result, for the ISO, regulation energy is a separate component of the ISO neutrality account; whereas, the EIM Entity's regulation energy is embedded in the resource's uninstructed imbalance energy. Regulation energy may be offset by other uninstructed imbalanced energy in the opposite directions.

The marginal loss surplus is a credit that arises because the marginal loss component in the LMP of resources exceeds actual losses. The difference between marginal loss collected based on the marginal loss component of the LMP and actual loss is included in the neutrality account by BAA.

3.7.8.1.1. Real-Time Market BAA Neutrality Settlement

The real-time market BAA neutrality account shall be calculated on a 5-minute basis for each BAA. The real-time market neutrality amount shall be calculated as the sum of the settlement amounts for instructed imbalance energy, uninstructed imbalance energy, unaccounted for energy, real-time net scheduled interface, real-time ancillary service congestion revenues, and convergence bid awards, if applicable, less the BAA real-time congestion balancing account.

The real-time net scheduled interface change settlement amounts represents settlement amounts for the energy which flows between the BAAs as a result of EIM. The real-time net scheduled interface settlement amount is calculated as the real-time net schedule interchange direction flow (MWhs) multiplied the LMP of the pricing node at the corresponding intertie.

The real-time market BAA neutrality amount will be adjusted further based upon the 5-minute proportional transfers between BAAs. The proportional amount of the neutrality charge/credit will be transferred between BAAs. The proportional transfer is determined hourly using five minute settlement intervals. It is calculated as the sum of net scheduled interchange (exports from BAA) divided by the sum of absolute value of uninstructed imbalance energy load, the absolute value of supply uninstructed imbalance energy, and the net scheduled interchange out of the BAA For example, assume a BAA #1 is exporting an incremental 5 MWh to BAA #2 in the hour as a result of the EIM. If BAA #1 Load hourly uninstructed imbalance energy is equal to 30 MWh and supply hourly uninstructed imbalance energy is equal to -15 MWh, then 10% of the BAA #1 neutrality account will transfer to BAA #2.[17]

This same approach will be used for real-time bid cost recovery discussed below, but on a daily basis using five minute settlement intervals.

In the ISO, this neutrality account will be allocated to measured demand (metered demand + exports) excluding the dynamic transfers between BAAs. The neutrality account for an EIM Entity BAA will be allocated to the EIM Entity Scheduling Coordinator and then allocated by the EIM Entity according to its tariff.

3.7.8.1.2. Real-Time Market System Neutrality Settlement

The Real-Time Market System Neutrality shall be calculated on a 5-minute basis for the entire Real Time Market. The Real-Time Market System Neutrality shall account for any non-neutral Settlement amounts which result from across BAA Settlement. The Real-Time Market System Neutrality shall be calculated on a 5-minute basis for entire Real-Time Market. The Real-Time Market Neutrality amount shall be calculated as the sum of the Settlement Amounts for IIE, UIE, UFE, Real-Time Market BAA Neutrality, Real-Time Ancillary Service Congestion Revenues, and Virtual Awards, if applicable, less the Real-Time Congestion Balancing Account. This neutrality account will be allocated to metered demand (Load) across the EIM footprint.

3.7.8.2. Real-Time Congestion Offset

The current real time congestion offset will be replaced by an new separate neutrality account for each BAA, the BAA Real-Time Congestion Balancing Account. The neutrality account arises from re-dispatch of generation resources from the base schedule to resolve real-time constraints in each BAA. All resources within the EIM footprint (ISO BAA and EIM Entity BAA) can impact constraints throughout the EIM footprint. The impact of a resource on a constraint is measured as the shift factor of the resource to the relevant constraint. The BAA real-time balancing account can be determined based on the product of the change of binding constraint flow the base flow and the shadow price of the binding constraint in the BAA[18]. The contribution can be both positive and negative; however, changes in the transmission system between establishment of the hourly base schedule and actual flow result in additional costs that must be recovered through the balancing account.

In the ISO, change in flow for a resource is the difference between the day-ahead schedule and meter. For the EIM Entity, change in flow for a resource is the difference between the 15-minute base schedule and meter.

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[17] 10% = 5 / (30 + 15 + 5) The ISO has posted a spreadsheet showing the calculation with this 3rd Revised Straw Proposal

[18] The ISO Department of Market Monitoring has posted a discussion paper that presents analysis performed to estimate the contribution to the real-time congestion offset from various factors. The discussion paper is available at http://www.caiso.com/Documents/DiscussionPaper-Real-timeRevenueImbalance_CaliforniaISO_Markets.pdf

Each BAA will have its own real-time congestion balancing account. For each constraint in a BAA, the Market Operator will sum across all resources in the EIM footprint the product of the resource shift factor and change in flow. There is no transfer of costs between BAA because the BAA Real -Time Congestion Balancing Account is based upon the constraints within each BAA.

The creation of BAA specific congestion balancing accounts provide a financial incentive for EIM Entity Scheduling Coordinators to submit base schedules free of congestion. The BAA real-time congestion balancing account allocates the cost of infeasible hourly base schedules to the EIM Entity Scheduling Coordinator that submitted the infeasible base schedule directly attributed to constraints within its BAA.

As several stakeholder have highlighted, convergence bidding can increase the size of the BAA real-time congestion balancing account. Convergence bids are scheduled in the day-ahead market and then liquidated in the 15-minute market. The entire convergence bidding day-ahead schedule is a change in flow in real-time. If the node where the convergence bid cleared has a positive shift factor to the relevant constraint, this will impact the congestion balancing account of the BAA. Since the ISO does not model the EIM Entity in the day-ahead market, the ISO previously proposed to not settle ISO convergence bids for real-time congestion due to EIM Entity constraints. The convergence bidder is not subject to day-ahead congestion in the EIM Entity BAA, so it is not appropriate for the convergence bid to be charged or paid for real-time congestion due to EIM Entity constraints. However, based upon additional discussion the ISO is recommending a different settlement approach to resolve two issues: (1) if the constraint was not binding in day-ahead, the convergence bid should not have all congestion differences not settled, and (2) potential gaming due to the different settlement of physical and virtual schedules when convergence bids create a credit to the balancing account.

The proposed settlement approach assigns the real-time congestion uplift on EIM Entity BAA constraints into a virtual bucket and physical bucket. Then in direct proportion to out-of-market congestion revenues received by virtual and physical schedules allocates (1) the physical bucket to the BAA real-time congestion balancing account of the EIM Entity and (2) the virtual bucket to the convergence bid schedules.

If the virtual schedule creates a credit to the out-of-market congestion uplift, then no allocation is made to the virtual schedules. If the virtual schedule creates a charge to the out-of-market congestion uplift, then the virtual bucket is allocated to convergence bid schedules in proportion to each schedules congestion revenue that is collected through the out-of-market congestion uplift[19].

With regards to convergence bidding impact on constraints within the ISO BAA, the ISO is continuing to improve modeling consistency between the day-ahead market and real-time market

[19] The ISO held a technical workshop on August 12, 2013 that provides detailed examples of the allocation. The presentation is available at http://www.caiso.com/Documents/Technical%20workshops%20Aug%2012%20and%2013,%202013

for ISO constraints. In addition, the ISO has commenced a Full Network Model Expansion[20] stakeholder initiative to provide additional visibility across WECC within the day-ahead market. The initiative will improve day-ahead market results by reflecting potential real-time loop flows within the integrate forward market optimization.

The ISO will allocate the ISO Real-Time Congestion Balancing Account to measured demand, as is currently done with the Real-Time Congestion Offset. The ISO is improving the modeling consistency between the day-ahead market and real-time market and may commence an ISO stakeholder initiative to evaluate changes in the ISO allocation methodology. The EIM Entity Real-Time Congestion Balancing Account will be allocated to the EIM Entity Scheduling Coordinator and then allocated by the EIM Entity according to its tariff.

3.7.8.3.Real-Time Bid Cost Recovery Allocation

The real-time bid cost recover contains two cost categories: (1) energy and (2) commitment costs. The energy component includes energy awards, ancillary services awards, and flexible ramping constraint awards. The energy component occurs when a resource receives a financially binding energy schedule or dispatch that is lower that its economic bid. This can occur because the real-time market optimization covers the financially binding interval and advisory intervals up to four hours in to the future are ramp constrained. For a resource, the market optimization ensures the resource is economic over the entire time horizon, but does not ensure a resource is economic in the financially binding interval. Commitment costs include minimum load cost and start up costs. Commitment costs are considered in the 15-minute market optimization which in addition to establishing 15-minute schedules will also commit short start units.

Real-time bid costs are netted against real-time revenues over the trade date. If revenues exceed costs, a resource receives no bid cost recover payment. If costs exceed revenue for a resource over the day, the shortfall is paid to the resource. The energy category will net energy awards, ancillary services awards and flexible ramping constraint award revenue and energy costs over the day. The commitment cost category will net start-up costs and minimum load energy revenue and costs over the day.

In the EIM, EIM Entities have the option of including unit commitment for their BAA. If an EIM Entity does not elect to have unit commitment in the 15-minute market, the commitment costs are not considered in the market optimization. The EIM Entity must compensate resources that our committed outside of the EIM according to its tariff. No resources in the EIM Entity BAA will be compensated for commitment costs in the EIM. Resources in the EIM Entity BAA can be compensated for real-time bid cost recovery due to the energy component.

The ISO proposes to calculate each component of the real-time bid cost recovery for each BAA. The ISO will sum the energy cost payments made to resources within the BAA and separately sum the commitment costs made to resources within the BAA. Allocations of energy related bid cost recovery costs in the BAA, transfers between BAA will be considered similar to the

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

methodology discussed in Section 3.7.8.1. Since real-time bid cost recovery for resources is calculated on a daily basis, the daily transfers will be the daily sum of the absolute value all uninstructed imbalance energy of load and supply. There is no netting of the two categories prior to calculating the financial amount of the transfers of each component. If a category's revenue exceeds its costs over the day, no transfer between BAAs will occur.

If the EIM Entity elects not to allow real-time unit commitment through EIM, no transfer of commitment costs from other BAAs that allow unit commitment in the EIM will occur. If the EIM Entity elects to allow unit commitment through EIM, the unit commitment costs in a BAA will consider the transfers between BAA similar to how the energy cost recovery payments are allocated above.

The ISO will combine the energy and commitment components after considering BAA transfers in to a single real-time bid cost recovery allocation amount and will allocate to measured demand. The two components for and EIM Entity BAA will be allocated to the EIM Entity Scheduling Coordinator and then allocated by the EIM Entity according to its tariff.

3.7.8.4. Flexible Ramping Constraint

As discussed in Section 3.4.3, the Market Operator will enforce a flexible ramping constraint requirement for the ISO BAA and each EIM Entity BAA. The costs of resolving the flexible ramping constraint for each BAA will be calculated for each BAA separately based upon the individual BAA requirement. A BAA is only responsible for its associated flexible ramping requirement and not the other BAA requirement even if flexible ramping capability is procured in one BAA to meet another BAA's requirements.

The ISO will allocate the cost of its flexible ramping constraint based upon the current cost allocation (75% Load, 25% Supply). The cost of the flexible ramping constraint for each EIM Entity BAA will be allocated to the EIM Entity Scheduling Coordinator and then allocated by the EIM Entity according to its tariff.

3.7.9. Financial Adjustments

Based on the transfer of funds related to EIM and non-EIM settlement calculation results, applicable interest, invoice payment or shortfall settlements will occur. The Market Operator Payment Calendar (anticipated to match the ISO payment calendar) will be followed for the purposes of issuing settlement statements, exchanging invoiced funds, submitting meter data and submitting settlement disputes.

3.7.10. EIM Administrative Costs

The Market Operator will include an EIM administrative rate in its tariff filing of the market design. These rates will be in effect for October, November and December 2014.

The current ISO Grid Management Charge annual revenue requirement and cost of service study was filed and approved by FERC to be effective from January 1, 2012 through December 31, 2014. The ISO will commence a stakeholder process to update the cost of service study and annual revenue requirement, which will be filed with FERC in 2014 to become effective in 2015 for both the ISO's BAA and the EIM footprint.

3.7.10.1. EIM Initial Fee

The ISO has presented an initial fee of $0.03 times the total annual energy usage of the EIM Entity BAA. The initial rate was determined by dividing the total projected costs to implement EIM for the entire Western Interconnection by the total annual energy usage of the interchange less the ISO energy usage. The total project costs were linearly related to the amount of load that would be participating in EIM, but the start-up fee charged to individual entities may not necessarily conform to this same linear relationship. This start-up fee covers the capital and O&M costs associated with setting up the EIM for the EIM Entity. The start-up fee will be approved by FERC through individual implementation agreements. In the case of PacifiCorp, the EIM initial fee is $2.1M to be paid to the ISO through specific payment milestones that are consistent with the implementation agreement.

3.7.10.2. EIM Administrative Rate

The ISO derived an EIM administrative charge by evaluating the components of its existing administrative charges and determining what aspects of the services provided are attributable to EIM functions. Two stakeholders commented that the resulting rate of 19 cents seemed low, and one raised a question about the impact on anticipated volume of participation. The 19 cents represents the amount all users of these real-time services pay – it is not a new charge but rather a way to evaluate the actual costs of running the elements of the ISO market that the ISO will be offering as EIM functions. Because the rate is driven by the volume for the entire market, including California, that gets the services that the EIM participants will be purchasing, the volume of participation by PacifiCorp does not affect the overall rate. The $96 million figure was derived from data filed with FERC as part of the ISO 2012 GMC restructuring – it is the cost of all real time services provided by the ISO, and the 500TWh is the allocated portion of real-time volumes. As noted above, the ISO will be updating the studies for its rate case in 2014.

The explanation below walks through how the ISO derived the EIM-specific rate for the services that are a subset of the full market services provided by the ISO.

Currently, the ISO's overall administrative charge is made up of three components or services: (1) Market Services, (2) System Operations and (3) CRR Services. Market services charge encompasses all activities in issuing bids to schedules in both the Day Ahead Market and Real Time Market. The system operations charge encompass all activities in dispatching energy on the grid and balancing area activities such as transmission planning. The third component, CRR services encompasses activities surrounding Congestion Revenue Rights. The ISO has used activity based accounting to identify and capture costs based on significant activities, and then allocated those activities to the appropriate service bucket. The cost of service study supporting the current GMC structure[21] was filed and approved with FERC to be effective 2012.

Conceptually EIM is made up of two components (1) the real-time market portion of the Market Services and (2) the real-time dispatch portion of System Operations. CRR Services are not

[21] Additional information on the design of the Grid Management Charge is available at http://www.caiso.com/Documents/2012%20Budget%20and%20grid%20management%20charge

applicable to the EIM. To determine an EIM rate the cost of service study was expanded to break down Market Service and System Operations into their components and then combine real-time market and real-time dispatch to derive and EIM administrative rate. After performing this analysis for EIM the allocations came out as follows:

- Market Services 63% real-time market and 37% day ahead market
- System Operations 48% real-time dispatch and 52% balancing area services
- CRR Services Not applicable

Using the 2012 rates and allocation from the 2012 cost of service study result in the following:

Market Services Rate	9 cents per MWh
Day-ahead market	3 cents per MWh
Real-time market	6 cent per MWh
Systems Operations Rate	27 cents per MWh
Real-time dispatch	13 cents per MWh
Balancing area services	14 cents per MWH

Combining the real-time components for EIM

Real-time market	6 cents per MWh
Real-time dispatch	13 cents per MWh
Total EIM	19 cents per MWh

The volume the rate is applied to is the gross imbalance energy of both load and generation. There is a minimum volume set at 5% of the gross generation and 5% of the gross load. This EIM administrative cost covers staff and portions of ISO systems used to support EIM functionality. EIM revenue will be applied to the ISO GMC components which reduces the costs that need to be recovered from ISO market participants. The following examples illustrates the administrative cost:

Example 1 – Imbalance Energy Exceed Minimum Threshold

Base Schedule:	Generation = 100 MWh	Load = 100 MWh
Imbalance Energy	Generation = (20 MWh)	Load = 30 MWh
Administrative Cost	Generation = 20 x $0.19 = $3.80	Load = 30 x $0.19 = $5.70

Example 2 – Imbalance Energy Does Not Exceed Minimum Threshold For Generation

Base Schedule:	Generation = 100 MWh	Load = 100 MWh

Imbalance Energy	Generation = 4 MWh	Load = 30 MWh
Administrative Cost	Generation = 5 x $0.19 = $0.95	Load = 30 x $0.19 = $5.70

3.7.10.3. Summary of Costs to Transact in EIM

Type of Cost	Generation	Load
EIM administrative cost	The formula below applies to all generation settled in the EIM; does not affect the existing ISO market participant fee. The charge applies to imbalances for all resources in the BA whether bidding or not. Max(5% x Gross Generation, Generation Imbalance) x $0.19 administrative fee	The formula below applies to all load settled in the EIM; does not affect the existing ISO market participant fee Max(5% x Gross Load, Load Imbalance) x $0.19 administrative fee
Bid Segment Fee	$0.005 per bid segment	$0.005 per bid segment
SCID fee	$1000/month per SCID	

3.7.11. Dispute Resolution

Dispute resolution is managed through the Customer Inquiry, Dispute and Information (CIDI) tool. Refer to the **CIDI User Guide** for more information.

3.8. Transmission Service

Since the transfer capability between the ISO and initial EIM Entities may be limited, the ISO proposes that in the initial EIM implementation, there would initially be no charge between the ISO and EIM Entities for EIM's use of as-available transmission. Further consideration of transmission service could be informed by actual EIM operational experience or when additional balancing authorities consider participating in EIM. It should be understood that the ISO is not proposing to have no transmission access charge. Instead, the ISO recognizes that transmission customers in all BAAs (including EIM Entities) already pay transmission access charges. In the ISO's BAA, the transmission access charge (TAC), which is described below in Alternative 2, applies to load and exports (excluding load and exports using Transmission Ownership Rights) from the ISO's market footprint, and does not apply to incremental or decremental scheduling or dispatch of supply resources within the market footprint. The following discussion recognizes that EIM extends the real-time market footprint to include EIM Entities in addition to the ISO's BAA, and thus extends the concepts of the ISO's TAC to the new real-time market footprint including EIM Entities. Among the alternatives outlined below, Alternative 1 would simply rely on the ISO's and each EIM Entity's existing transmission access charges to collect their transmission revenue requirements, and recognize that EIM's function is to dispatch supply resources within the combined real-time market footprint. Alternative 2 would modify this by taking a step toward a regional transmission rate design, by applying a portion of each entity's transmission revenue requirement as a blended EIM TAC.

For purposes of ongoing consideration of potential transmission service rates, this section outlines three potential methods for compensation for transmission use of EIM, and presents a preliminary comparison of principles for their consideration:

- No-cost transmission use is available through EIM, being dispatched on an as-available basis, with existing transmission rates (which have been set without an EIM existing) continuing in place,
- Creation of a transmission access charge to real-time withdrawals in the ISO and EIM footprints, or
- Incorporation of a transmission charge into a shadow price for transfers between the ISO and EIM Entity BAAs, similar to a congestion shadow price.

Consideration of stakeholder comments from previous versions of this straw proposal raises a fourth alternative for discussion purposes: to maintain comparable treatment among all ISO market participants (a) without regard for participation in EIM, and (b) without regard for scheduling in the day-ahead versus real-time market, the ISO's transmission access charge could be revised to apply only to load and to wheeling schedules (not to exports from the ISO).

Further details of these alternatives are as follows:

Alternative 1: No-Charge, As-Available Transmission:

Not charging for EIM use of transmission would reflect reciprocity among the ISO and EIM Entities by mutually waiving transmission charges between these areas for the optimized energy dispatches that EIM produces. This should either be considered as a transitional mechanism for one year, or a permanent structure based on reciprocity among the BAAs that comprise EIM. The existing transmission rates of the ISO and EIM Entities were not based on an expectation that an EIM would exist. As a result, transmission revenue recovery will fully compensated by existing transmission rates, without consideration of additional revenues from EIM transfers across the EIM footprint. It is unclear how much transfer will occur under EIM. The first year of EIM can be used to produce a year of data on EIM usage, which can then be used for further consideration of a transmission recovery mechanism in future years. Further, establishing a transmission recovery mechanism that has not been informed by actual operational experience of an EIM in the WECC region may undermine the expected efficient dispatch benefits that are expected under EIM. As a result, it is reasonable and prudent to take time to observe how market trends develop through EIM for a year before establishing a rational and sustainable transmission recovery mechanism for EIM for future years.

The ISO will maintain its current transmission access charge during this period, except for energy dispatched within the ISO and EIM footprints. Similarly, transmission operators and transmission service providers within EIM Entity BAAs may maintain their existing transmission rates for deliveries within their BAA and for transactions with BAAs that are not EIM Entity BAAs. An EIM Entity may require that all EIM Participating Resources within the EIM Entity's BAA (including its dynamic transfers or Participating Resources that bid into EIM using its interties with non-EIM BAAs) must be transmission customers (long-term or otherwise, at the discretion of its transmission service provider) of a transmission service provider between the Participating Resource's location and an intertie to another EIM Entity. If an EIM Participating Resource wishes to bid into EIM beyond its existing transmission contracts, the transmission service provider may determine whether or not it would be responsible for non-firm transmission service charges, excess usage charges, or other charges. To encourage formation of new EIM Entities, an EIM Entity is not required to contract for transmission through another EIM Entity area.

With regards to the transmission service the EIM Entity is making available between the ISO and the EIM Entity, such transmission service is effectively a Transmission Ownership Right. Therefore the claim that there is a disparity between charges that would accrue to use of such transmission service in the day-ahead market and the EIM, is not accurate. According to the Section 17.3.3.(3) of the CAISO tariff, the use of TORs by an indentified balanced schedule is not subject to Transmission Access Charges and is not allocated and according to Section 17.3.3 (4) are not allocated ISO access charge revenues. Therefore there is comparability when the EIM Entity is effectively making such capacity available for EIM not as a participating transmission owner but rather as an EIM transmission service provider of its rights.

Alternative 2: EIM Transmission Access Charge:

The second approach would extend the principles of the ISO's current transmission rate design, to a consistent design for EIM transmission service. This approach would consider an access charge to load and exports to BAAs that are not EIM Entity BAAs, based on the amount of positive demand deviation consumed in real-time. The access charge could be determined based on the ratio of transmission revenue requirement that is associated with incremental real-time demand versus the total amount of demand. For example, if the volume of incremental instructed and uninstructed demand deviations that is settled through EIM (including real-time dispatch within the ISO's BAA) amounts to 10% of total demand in the ISO and EIM BAAs, one approach would be to recover 90% of each transmission provider's revenue requirement through its otherwise applicable transmission rates; the remaining 10% could be pooled into an EIM-wide revenue requirement for recovery from the instructed and uninstructed demand deviations, using a uniform real-time access charge.[22] The transmission access charge could be a blended access charge for all real-time incremental ISO and EIM demand, or a regional access charge that would apply only to EIM demand within EIM Entities while the ISO demand would remain responsible for paying the ISO transmission and wheeling access charges. Under the access

[22] A variation for implementing this alternative would be to establish the EIM-wide component of the transmission rate based on the first year's EIM operation, accumulate its revenue in a tracking account within each EIM Entity, and credit the revenue to the following year's transmission revenue requirement for transmission providers within the EIM Entity.

charge approach, no charge would be incurred for incremental 15-minute or 5-minute transfers between the ISO and EIM Entity BAAs, or among EIM Entity BAAs.

This alternative extends the principles established by the ISO's existing transmission access charge. Under FERC goals that include elimination of rate pancaking and the use of single system access charges, the ISO uses a transmission access charge within its controlled grid that uses a two-tiered structure. A single grid-wide "postage stamp" rate recovers the costs of "high voltage" transmission facilities (at or above 200 kV) from all transmission customers (loads and exports), while the individual participating transmission owners recover the transmission revenue requirements of local "low voltage" transmission facilities (below 200 kV) from the customers in their own service areas. Placing responsibility for the access charge on withdrawals from the ISO controlled grid ensures the least-cost dispatch of supply resources, without hurdles between supply resources affecting their dispatch. The high-voltage transmission revenue requirements of all participating transmission owners are merged, and new high-voltage transmission capital investments by participating transmission owners are immediately included in the grid-wide component. Participating transmission owners convert existing contracts and ownership rights to transmission service on the ISO controlled grid, which reduces the transmission capacity that the ISO must reserve for the exercise of within-the-hour scheduling rights, frees the capacity for scheduling by market participants, and reduces congestion costs. This ensures that no transmission customer pays pancaked rates, and provides access to and incentives to expand the regional transmission system. The ISO's transmission access charge does not preclude a utility that pays the grid-wide access charge from adopting different retail rate designs within its service area. A transition mechanism applied over a 10-year period from the original utility-specific rates to the single grid-wide rate. Alternative 2 actually has little difference from Alternative 1 in the first year of EIM operation if the percentage of total revenue requirements allocated to Alternative 2's EIM transmission access charge is initially zero. Before EIM operation begins, there is little real data on which to base an assumption of how EIM's volume of imbalance energy will compare to the total demand of EIM Entity BAAs. Using an initial percentage of zero can simplify the initial EIM implementation while these alternatives are compared to others that may be offered, and while actual EIM operations can be observed.

Alternative 2 could enable transmission providers or rights-holders to make their transmission available to EIM even if they are separate companies from the EIM Entity itself. While such transmission providers or rights-holders would continue to use their transmission for scheduling or resale prior to the EIM timeframe, they could be assured of recovering transmission revenues for the portion of their capacity that is made available to and used by EIM.

Alternative 3: Transfer Charge as a Minimum Shadow Price:

The third approach would incorporate a transmission charge based on the amount of transfer from one BAA to another. These transfers could be between the ISO and EIM Entity BAAs, or from one EIM Entity BAA to another EIM Entity BAA. A "soft" transmission constraint across EIM Entity BAA boundaries would set a minimum shadow price that would be incurred for inter-BAA transfers to occur, or changes in market flows across BAA boundaries could be calculated and allocated somehow as a transmission access charge, despite being dispatched from a broad pool of resources. By incorporating the transmission cost into the real-time dispatch optimization, LMPs would reflect the cost of transmission. As a result, rather than allocating the cost for use of transmission, transmission costs would be explicitly incorporated into the LMP energy prices that are settled for EIM's incremental energy. However, this approach would impose a constraint on cost-based dispatch among resources in different EIM Entities, and would disadvantage suppliers in one EIM Entity's BAA from meeting energy needs in a different EIM Entity, due to adding a cost for moving energy between BAAs. Indeed, in studies of the potential benefits of EIM implementation, "friction" on transactions between BAAs is modeled in this way, as a "hurdle rate" in base cases as a proxy to represent conditions without an EIM. Also, attempting to allocate transmission revenue requirements through a mechanism that resembles congestion pricing, by depending on the volume of transfers between EIM Entity BAAs, may result in over- and under-collections of the transmission revenue requirements.

Alternative 4: Transmission Access Charge Applicable to Load and Wheeling:

Some stakeholder comments have urged that a foundational principle should be non-discriminatory open access to transmission for all market participants, including across different market timeframes: day-ahead versus real-time versus EIM. The goal of non-discriminatory open access is meaningfully applied between market participants who are similarly situated, but participating resources within the ISO and BAAs that are EIM Entities are not similarly situated as resources in BAAs that are not EIM Entities and do not operate within the same market rules as EIM Entities.

An argument made in comments to support this alternative is that different treatment across market timeframes would encourage shifting market activity into the market with the lower transmission rate, such as transmission access charges applicable to day-ahead scheduling but not for EIM dispatch. This concern appears to be exaggerated given this straw proposal's multi-faceted approach to ensuring resource sufficiency, in which participants in EIM must start with pre-arranged base schedules and will face financial settlement consequences if their base schedules are infeasible or under-scheduled. Because EIM relies on transmission capacity that remains available in real-time, after forward scheduling is complete, EIM cannot be counted on to provide incremental supply resources for serving load in real-time. A remaining concern could be that base schedules could be sub-optimal by including expensive generation in order to reduce transmission costs, which would be replaced by optimized EIM dispatches. Within the ISO's BAA, the existing transmission access charge as well as the rate designs of Alternatives 1 and 2 above avoid incentives to selectively schedule supply resources to avoid transmission charges. Existing transmission rate designs undoubtedly vary between potential EIM Entities, but one structure would expect transmission customers who participate in EIM to have long-term network service, which again can avoid incentives to selectively schedule supply resources to avoid transmission charges.

The discussion of Alternative 3 above shows the disadvantages of applying what is essentially a "hurdle rate" between the ISO and EIM Entities. Nevertheless, if equal access to all market participants in the ISO's market across all market timeframes were a primary goal, another way to accomplish this would be to assess the ISO's transmission access charge only to load within the ISO's BAA and to wheeling schedules (which impose transmission costs but would not otherwise contribute to the ISO's transmission revenue requirement), and not to exports on any intertie in any market. (This alternative does not evaluate how this might apply within EIM Entities' BAAs.) The ISO's volume of exports is small compared to its loads, so the percentage impact on the ISO's transmission access charge would be limited. In contrast, the intent would be to promote the efficiency of the overall regional market, and avoid any perception of discrimination between market participants.

The ISO is not proposing here that Alternative 4 should be adopted, but is describing it to encourage comments on a broad range of alternatives.

Example:

The consideration of these alternatives and principles may be facilitated by considering how a dynamic schedule would function between the Market Operator if these dynamic schedules represent both the energy for hourly or 15-minute intervals, and imbalance energy dispatched in 5-minute intervals and due to deviations in resource output. Assume that an EIM Entity has scheduled an import to the ISO prior to the real-time EIM time horizon, which is the initial energy value in its dynamic e-Tag. Through EIM, changes in demand and resource output result in (a) an increase in the import to the ISO BAA, (b) a decrease in the import, or (c) enough change in the ISO's and EIM Entity's real-time deviations from forward schedules that the final flow between BAAs is an export from the ISO. In each of these cases, there is no difference in the incremental cost per MWh imposed by EIM's transmission usage that appears in the difference between the e-Tag's initial value and final update. Alternatives 1, 2, and 4 above would apply a uniform transmission rate per MWh of EIM transmission usage in each case. Alternative 2 could also apply a regional transmission rate. However, Alternative 3 does not ensure that the same incremental transmission rate would apply in each case. This supports the proposal initially of Alternative 1, to have no transmission charge between the ISO and EIM Entities during the first year of EIM operation, as directions such as Alternative 2 are considered further in the long-term.

Underlying Principles and Next Steps:

As EIM becomes established as a regional market mechanism, designing an appropriate EIM transmission service rate will be among the critical issues, but reaching consensus may take time and more information than is available now. For this reason, the ISO continues to propose moving forward with Alternative 1 (reciprocity in not assessing a transmission access charge between the ISO and EIM Entities) for at least the first year of EIM operation. The ISO continues to invite stakeholder input on this issue, and will formulate its strategy for stakeholder engagement based on that input. If a direction becomes clear for establishing an alternative transmission service rate design prior to the October 2014 EIM implementation date, the ISO will consider that goal. At this time, the approach of initially setting the EIM transmission rate to zero (i.e., Alternative 1) will allow understanding its relationship with the EIM based on actual experience before adopting a more complex approach, and is consistent with both Alternatives 1 and 2.

There is reason to distinguish between transfers occurring in real time within the EIM as opposed to exports from the ISO controlled grid. Transmission service for transactions in real-time markets (such as EIM) need not be priced on the same basis as transmission service in forward markets. The overall EIM design discourages exports that take place in forward markets from shifting to real-time to take advantage of more favorable transmission pricing. The EIM's operation will be an integrated with the ISO real-time market. Any entity bidding into the ISO real-time market will be bidding into the EIM. Since the EIM market represents an expansion of the ISO real-time market, rather than a separate market, EIM transactions are not like exports and need not be priced as exports. Different pricing for exports and for transactions within the EIM (which are not exports) is not unduly discriminatory. Exports are demand bids and entities scheduling exports are thus similarly situated to load, which incurs a transmission charge in real-time. The ISO proposal is intended to mean no additional fee. Load will continue to pay transmission access charges under the tariff applicable to the grid to which it is connected: the ISO access charge or the charge under the OATT of the relevant EIM Entity. Because load will continue to pay the relevant transmission access charge, there is no under-collection of revenues and no increased charges.

This discussion is intended to advance this issue as far forward as possible before presenting the EIM design to the ISO governing board, in the hope that greater consensus can be achieved. The first step is to establish design principles and further explore the options and alternatives presented by the ISO and in stakeholder comments received to date, and ultimately consider experience from actual EIM operations to further inform the discussion. Proceeding in this manner ensures that EIM will be implemented as planned and allow adequate time to resolve remaining issues. However, the ISO does not believe it is necessary nor appropriate to require that a longer-term EIM transmission service rate be established, effective, and settled at non-zero prices on the October 2014 implementation date.

3.9. Greenhouse Gas Emission Costs for Imports into California

The ISO is committed to working with the California Air Resources Board (CARB) and all market participants through this stakeholder process to ensure that greenhouse gas (GHG) costs are accounted for properly. In particular, this section of the paper was prepared in consultation with the California Air Resources Board (CARB) staff. CARB is in the initial stages of formulating draft amendments to both the Mandatory Reporting and Cap-and-Trade regulations. ARB will propose modifications necessary to facilitate the implementation of the EIM, as needed. Modifications to the Mandatory Reporting Regulation (MRR) will follow and support the proposed modifications to the Cap-and-Trade regulation.[23]

Entities that import energy into California have an obligation to surrender compliance instruments to CARB for the greenhouse gas emissions associated with the energy pursuant to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanism Regulation. In the ISO's existing day-ahead and real-time markets, internal generation and

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[23] Relevant CARB websites are:

GHG reporting website: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm

Cap-and-Trade website: http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm

Mandatory Reporting Regulation: (MRR): http://www.arb.ca.gov/cc/reporting/ghg-rep/regulation/mrr-2012-clean.pdf

Cap and Trade Regulation: http://www.arb.ca.gov/cc/capandtrade/ct_rf_april2013.pdf import resources include the cost for acquiring these compliance instruments in their submitted energy bids. However, this specific approach is not appropriate for EIM Participating Resources because a portion of the imbalance energy dispatched by the EIM from these resources will not be imported into California as it will serve demand outside California. Thus, only the imbalance energy portion that is imported into California would be subject to a GHG compliance obligation.

Previously, the ISO proposed to calculate the GHG cost to be used within the market optimization. In this proposal, the ISO will allow EIM Participating Resources to submit a bid adder which reflects the cost of GHG compliance. This bid adder can include the cost of allowances, uncertainty on the final resource specific emission factor, and other costs with GHG compliance. The combined energy bid and GHG compliance bid adder will be subject to the market bid cap of $1000.00. The GHG compliance bid adders are not subject to local market power mitigation; however, the energy bid will be.

In order to achieve an efficient dispatch of resources inside the EIM Entity BAA and comply with CARB requirements, the EIM dispatch algorithm will evaluate the differences in GHG costs that these resources incur so that the energy from among a number of resources with different GHG bids may be differentiated.

The following design elements are proposed as the desirable outcome for incorporating GHG emission costs into the dispatch and pricing of the real-time EIM transactions:

- Produce an efficient dispatch that takes into account all appropriate costs including GHG costs.
- Treat GHG emission costs in the same manner for energy produced in California and energy produced in EIM Entities outside California and imported into California.
- Produce prices that reflect the marginal cost of serving locational demand taking into account all appropriate costs including GHG costs.
- Allow individual resources' to submit GHG compliance bid adders based upon the resource's emission properties and compliance costs. Add the GHG compliance bid adder to energy produced from those resources that are selected for import into California.
- Comply with CARB requirements, in particular, that energy produced by EIM Participating Resource outside California and imported into California is assignable to the EIM Participating Resource Scheduling Coordinator of the resource that generated the energy.

The Security Constrained Economic Dispatch (SCED) formulation in RTUC and RTD can be modified to address these requirements. The following sections describe a method for real-time optimal dispatch that accounts for the greenhouse gas emission costs of resources in EIM Entity BAAs. However, prior to this technical discussion, the following sections first address the expected interface between CARB regulatory requirements and the EIM.

3.9.1. CARB Regulatory Requirements and the EIM

This section of the paper addresses CARB regulatory requirements applicable to EIM operation. In support of the Cap-and-Trade Program, entities with a reporting requirement are required to submit annual reports under the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, sections 95100- 95157) (Mandatory Reporting Regulation or MRR). Electric power entities that import, export, or wheel electric power relative to the physical border of California, whether at the bulk transmission level or at lower voltage levels, *must submit an emissions data report for the previous calendar year no later than June 1 of each calendar year*, pursuant to Section 95103(e) and comply with the requirements of Section 95111, Data Requirements and Calculation Methods for Electric Power Entities, of the MRR.

3.9.1.1.Registration Requirements from CARB

Emission Factors. A GHG emission factor must be established for each EIM Participating Resource. CARB calculates emission factors for use in the California Electronic Greenhouse Gas Reporting Tool (Cal e-GGRT), which must be used by electric power entities for submitting annual emissions data reports. The emission factors calculated by CARB must be used for reporting GHG emissions, pursuant to Section 95111(b)(2) which states that the CARB *Executive Officer shall calculate facility-specific or unit-specific emission factors*. To calculate emission factors for *Specified Facilities or Units* located outside California, pursuant to Section 95111(b)(2)(A)-(C), CARB may either use data voluntarily reported by owners or operators under Section 95112, data obtained from the U.S. Environmental Protection Agency (EPA), or data obtained from the Energy Information Administration (EIA). However, CARB only calculates emission factors for reporting purposes after the fact, but not in advance of the calendar year. For example, for calendar year 2014, ARB will calculate emission factors in March-April 2015 for use by electric power entities in reporting to ARB on or before June 1, 2015. .

Compliance Instrument Tracking System Service (CITSS). If the EIM Participating Resources and their EIM Participating Resource Scheduling Coordinators are currently not registered in CITSS, they must do so prior to participating in EIM. CITSS facilitates the entity in obtaining compliance instruments and meeting compliance requirements. More information on the Cap-and-Trade Program, CITSS, and compliance requirements can be found at this website: http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm

Registration of Anticipated Import Resources. EIM Participating Resource Scheduling Coordinators must register anticipated import resources after the conclusion of each calendar year for which an emissions data report is required. These include all EIM Participating Resources, including generators located in the EIM Entity BAA and resources that will be the source of imports bid into the EIM at the EIM Entity BAA interties that connect with balancing authority areas other than the ISO. To support the reporting requirements in the MRR, by February 1 of each year, electric power entities are required to register anticipated specified sources of power that they intend to claim in June 1 emissions data report filings, pursuant to section 95111(g)(1). CARB will use the registration information to calculate emission factors for the specified sources submitted which will then be used by electric power entities in their June 1 emissions data reports.

A copy of the registration spreadsheet template for registering specified facilities, as required by section 95111(g) of the GHG Mandatory Reporting Regulation, is available here, www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/specified_facility_registration.xlsx which is posted on this CARB webpage, http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/ghg-rep-power.htm The completed spreadsheet should be emailed to CARB by the February 1 deadline to ghgreport@arb.ca.gov with the subject line: "Registration of Specified Electricity Import and Export Sources."

3.9.1.2.Communication of GHG Obligation

During EIM operation, EIM Participating Resource Scheduling Coordinators will submit a bid to cover the costs of GHG compliance. The EIM Participating Resource Scheduling Coordinator will be notified through the dispatch if a resource is deemed to have been imported in to California as a result of the EIM optimization. If an EIM Participating Resource is deemed to have been imported in to California by the market optimization, the resource will be compensated at the marginal GHG cost.

EIM Output Data, e-Tags, and Imports. The current CARB methodology for determining the GHG obligation for imports relies on the import quantity listed on the corresponding e-Tag As described in section 3.7.6. of this paper that addresses Interchange Meter Data, the Market Operator will create e-Tags as part of the interchange checkout between the ISO and the EIM Entity. The dynamic interchange capacity between the ISO and an EIM Entity BAA will be tagged at the aggregate interchange level, but individual e-tags for imports and exports at the resource level will not be created. Alternatively, to facilitate GHG reporting under the EIM, the ISO will calculate the output of each EIM Participating Resource that is imported to California. This amount will be reportable to the CARB as part of an annual emissions data report and will be the basis of the GHG compliance obligation. The approach for determining the energy from each EIM Participating Resource that is imported to the ISO is described in detail further below.

Submission and Verification of Annual Emissions Data Reports. EIM Participating Resources Scheduling Coordinators that deliver energy that was imported into California must report these imports to CARB as part of an annual emissions data report due by June 1 following the calendar year of the transactions. For example, the EIM Participating Resource Scheduling Coordinator would file an emissions data report with CARB by June 1, 2015 for any EIM imports which occurred in calendar year 2014. EIM Participating Resource Scheduling Coordinators are required to obtain third-party verification of their emissions data reports.

3.9.2. Expanded SCED with GHG Emission Costs

The Security Constrained Economic Dispatch (SCED) formulation in RTUC and RTD can be modified to address the requirements of complying with the California GHG regulations and in determining the amount of energy from each EIM Participating Resource that is imported into California. In the following we describe a method for real-time optimal dispatch that accounts for the greenhouse gas emission costs of resources in EIM Entity BAAs.

The offer cost for generators at nodes inside California will include the cost of any GHG emissions within their energy bid. This is rather straightforward since all power produced in California that produces GHG emissions is required to procure needed GHG allowances.

For the energy produced outside California, there must be a mechanism to determine whether the energy is consumed outside California or imported into California. If it is deemed to be consumed outside California, it will not be required to procure GHG allowances and so that cost can be excluded from the SCED optimization. If it is deemed to flow into California, the EIM Participating Resource Scheduling Coordinator will be responsible for procuring adequate GHG allowances and so the GHG compliance cost should be reflected in the SCED optimization.

We propose modifying the SCED optimization formulation to achieve the following goals:

- Allow the augmented SCED to select energy produced by EIM Participating Resources outside California for import into California based upon the resource's GHG compliance bid adders.
- Include GHG compliance bid adders in the dispatch cost of EIM Participating Resources outside California that produce energy deemed to be imported into California
  - EIM Participating Resources outside California that do not emit GHG and will not be required to procure GHG allowances would be expected to submit a bid adder at $0/MWh since their marginal cost of GHG allowances is zero.
  - EIM Participating Resources outside California that are GHG-emitting resources will submit non-zero GHG compliance bid adders. When deemed to import energy into California the resource will have GHG related costs that are non-zero in the SCED objective function for the portions of their output that is allocated to import energy into ISO.
  - EIM Participating Resources outside California that are deemed to import energy into California will be assigned GHG costs that depend upon their emission characteristics.
  - EIM Participating Resources whose energy is deemed to serve load outside California would not be assigned GHG emission costs.
  - Load in EIM Entity BAAs outside California will not be assessed GHG emission costs.

To illustrate the method, we consider a simple network configuration that consists only of the ISO and a single EIM Entity BAA. Furthermore, day-ahead and base schedules are ignored for simplicity, as well as ancillary services, transmission losses, and inter-temporal constraints, focusing on a single time period. We also leverage the fact that the net imbalance energy export from each EIM Entity BAA, exclusive of import/export imbalance energy schedules to other BAAs, is imbalance energy imported into the ISO BAA.

The following notation is used to formulate the problem.

i Node index in ISO.

j Node index in EIM Entity BAA.

k Oriented transmission line index.

G_i Imbalance energy dispatch for generator at node i.

G_i^{MIN} Minimum capacity for generator at node *i*.

G_i^{MAX} Maximum capacity for generator at node *i*.

L_i Distributed load forecast at node *i*.

C_i Incremental energy bid for generator at node *i*.

C_G GHG compliance bid adder.

$S_{i,k}$ Shift Factor of power injection at node *i* on transmission line *k*.

F_k Active power flow on transmission line *k*.

F_k^{MAX} Active power flow limit on transmission line *k*.

E Net imbalance energy export from EIM Entity BAA.

E_j Net imbalance energy export from EIM Entity BAA allocated to generator *j*.

LMP_i Locational Marginal Price at node *i*.

λ Shadow price of power balance constraint.

μ_k Shadow price of active power flow limit constraint on transmission line *k*.

η Shadow price of net imbalance energy export allocation constraint.

R_G Greenhouse gas emission revenue.

R_{Gj} Greenhouse gas emission revenue distribution to generator at node *j*.

The term net export allocation is from the perspective of the EIM Entity Area to the ISO.

A simplified mathematical formulation is as follows:

$$\min\left(\sum_i C_i\, G_i + \sum_j \left(C_j\, G_j + C_G\, E_j\right)\right)$$

subject to:

power balance: $\sum_i (G_i - L_i) + \sum_j \left(G_j - L_j\right) = 0$

transmission line flow: $F_k \equiv \sum_i S_{i,k}\,(G_i - L_i) + \sum_j S_{j,k}\,\left(G_j - L_j\right) \leq F_k^{MAX}, \mathit{for\ all}\ k$

net export allocation: $E \equiv \sum_j \left(G_j - L_j\right) \leq \sum_j E_j$

generator limits: $G_i^{MIN} \leq G_i \leq G_i^{MAX}, for\ all\ i$
$G_j^{MIN} \leq G_j \leq G_j^{MAX}, for\ all\ j$

allocation limits: $0 \leq E_j \leq G_j, for\ all\ j$

The LMPs are determined as follows:

$$LMP_i = \lambda + \sum_i S_{i,k}\, \mu_k\,, for\ all\ i$$

$$LMP_j = \lambda + \sum_j S_{j,k}\, \mu_k + \eta, for\ all\ j$$

Where, the marginal loss component is missing because transmission losses are ignored.

The GHG compliance revenue is calculated as follows:

$$R_G = -\eta\ E$$

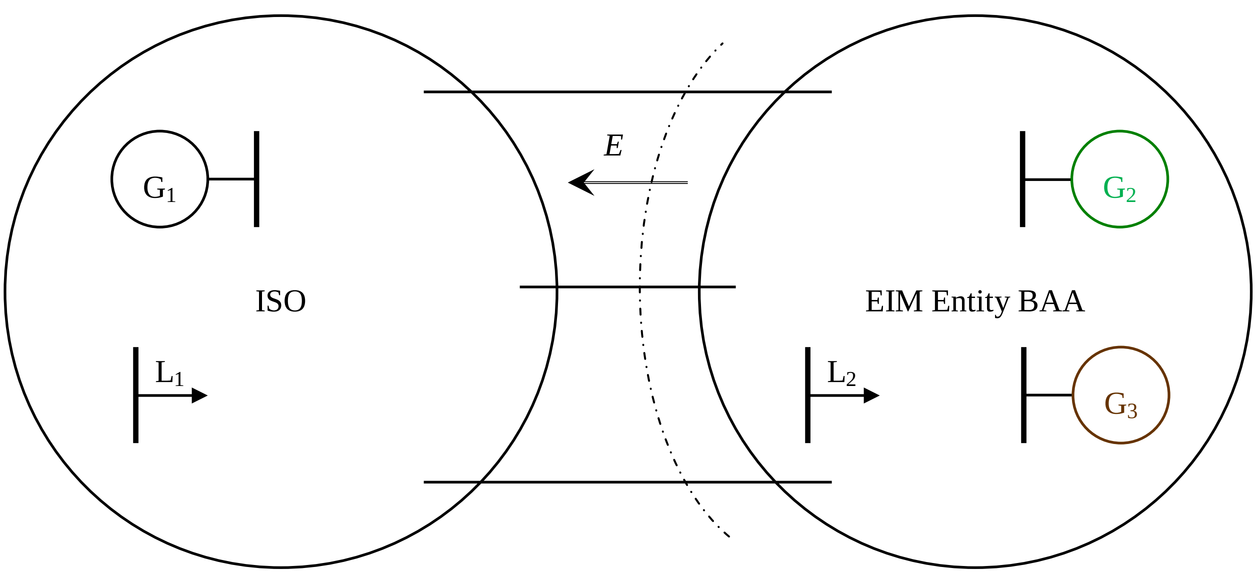
This revenue is then distributed to the optimal net imbalance energy export allocations as follows:

$$R_{Gj} = -\eta\ E_j$$

The following examples show the application of this method under different scenarios.

3.9.2.1.Example 1

One generator and a load are in the ISO, and two generators and a load are in the EIM Entity BAA, as shown in the figure below.



The power transfer (E) between the BAAs is limited to 100MW. The resource data is as follows:

Load	Forecast (MW)
L_1	200
L_2	50

Generator	Minimum (MW)	Maximum (MW)	Energy Bid ($/MWh)	GHG Compliance Bid Adder ($/MWh)
G_1	0	300	50	-
G_2	0	200	35	0
G_3	0	200	30	6

Generator G_2 is a non-emitting resource with a GHG compliance bid adder of zero, whereas G_3 is an emitting resource with a GHG compliance bid adder of $6.00. They are both less expensive than G_1. Therefore, the power export from the EIM Entity BAA to the ISO is binding at the optimal solution at 100MW. The optimal dispatch and export allocation are as follows:

Resource	Dispatch (MW)	Export Allocation (MW)	LMP ($/MWh)
G1	100	-	50
G2	100	100	30
G3	50	0	30
L1	200	-	50
L2	50	-	30

Example 1: μ = –$15/MWh; η = –$5/MWh

Generator G_3 is the least expensive resource for serving Load L_2, and as such it sets the LMP in the EIM Entity Area to $30/MWh. However, for serving Load L_1, a $6/MWh additional GHG compliance cost would be incurred to G_3, making G_2 more effective for that purpose. Consequently, G_2 is dispatched with its energy all exported to the ISO at the limit of the power transfer capability. The balance of 100MW of L_1 can only be served by G_1, which sets the LMP in the ISO to $50/MWh.

The LMP difference of $20/MWh is made up by the marginal congestion cost of $15/MWh and the marginal GHG compliance cost of $5/MWh. The marginal congestion cost can be easily verified if the power transfer limit is relaxed by 1MW to 101MW, in which case one additional MWh from G_2 will displace 1MWh from G_1 for a net benefit of $15. The marginal GHG compliance cost can be easily verified if the export allocation (which carries the GHG compliance cost) is relaxed by 1 MW to 99MW, in which case one additional MWh from G_3 will displace 1MWh from G_2 for a net benefit of $5. It is interesting to note that there is a non-zero marginal GHG compliance cost in the optimal solution even when all the exported energy is allocated to the non-emitting resource G_2 who bid zero. This is because the cost of that export to California is $5/MWh higher than otherwise available energy from G_3.

The marginal congestion cost of $15/MWh and the marginal GHG compliance cost of $5/MWh on a 100MWh energy export result in a congestion revenue of $1,500 and an GHG compliance revenue of \$500, respectively. Assuming that the GHG compliance revenue is distributed to the optimal export allocations, the settlement is as follows:

Resource	Energy Cost	GHG Compliance Cost	Total Cost	Energy Payment	GHG Compliance Payment	Total Payment
G_1	\$5,000	-	\$5,000	\$5,000	-	\$5,000
G_2	\$3,500	\$0	\$3,500	\$3,000	\$500	\$3,500
G_3	\$1,500	\$0	\$1,500	\$1,500	\$0	\$1,500
L_1				–\$10,000		
L_2				–\$1,500		
Congestion Revenue				\$1,500		
GHG Compliance Revenue				\$500		

Where it is assumed that GHG compliance costs for G_1 are included in the energy bid (cost) and recovered through the energy payment, and as such they are not shown explicitly. It can be seen in the settlement results above that the total payment to each generator is sufficient to cover the respective energy and GHG compliance costs.

3.9.2.2.Example 2

This is a variation on the first example where G_3 reduces its bid price to \$28 to become a more competitive exporter to California compared to G_2, taking into account the additional GHG compliance bid of \$6/MWh. In this case, the optimal dispatch and export allocation are as follows:

Resource	Dispatch (MW)	Export Allocation (MW)	LMP (\$/MWh)
G_1	100	-	50
G2	0	0	28
G_3	150	100	28
L1	200	-	50
L2	50	-	28

Example 2: $\mu = –\$16/\text{MWh}$; $\eta = –\$6/\text{MWh}$

G_3 is the least expensive resource for serving L_2, and as such it sets the LMP in the EIM Entity Area to \$28/MWh. It is also the least expensive resource for serving L_1 at \$34/MWh (including the \$6/MWh GHG compliance cost). Consequently, G_3 is dispatched at 150MW with 100MW exported to the ISO at the limit of the power transfer capability. The balance of 100MW of L_1 can only be served by G_1, which sets the LMP in the ISO to \$50/MWh.

The LMP difference of \$22/MWh is made up by the marginal congestion cost of \$16/MWh and the marginal GHG compliance cost of \$6/MWh. The marginal congestion cost can be easily verified if the power transfer limit is relaxed by 1MW to 101MW, in which case one additional MWh from G_3 will displace 1MWh from G_1 for a net benefit of \$16. The marginal GHG compliance cost can be easily verified if the export allocation (which carries the emission cost) is relaxed by 1 MW to 99MW, in which case 1MWh from G_3 will not incur emission costs for a benefit of $6.

The marginal congestion cost of $16/MWh and the marginal GHG compliance cost of $6/MWh on a 100MWh energy export result in a congestion revenue of $1,600 and an GHG compliance revenue of $600, respectively. Assuming that the GHG compliance revenue is distributed to the optimal export allocations, the settlement is as follows:

Resource	Energy Cost	GHG Compliance Cost	Total Cost	Energy Payment	GHG Compliance Payment	Total Payment
G_1	$5,000	-	$5,000	$5,000	-	$5,000
G_2	$0	$0	$0	$0	$0	$0
G_3	$4,200	$600	$4,800	$4,200	$600	$4,800
L_1				–$10,000		
L_2				–$1,400		
Congestion Revenue				$1,600		
Emission Revenue				$600		

It can be seen in the settlement results above that the total payment to each generator is sufficient to cover the respective energy and emission costs.

3.9.2.3.Example 3

This is a variation on the second example where the available maximum capacity of G_3 is reduced to 75MW in addition to reduced bid price of $28/MWh as in Example 2. In this case, G_2 is dispatched to make up for the remaining 75MW and the optimal dispatch and export allocation are as follows:

Resource	Dispatch (MW)	Export Allocation (MW)	LMP ($/MWh)
G_1	100	-	50
G_2	75	75	29
G_3	75	25	29
L1	200	-	50
L2	50	-	29

Example 3: μ = –$15/MWh; η = –$6/MWh

G_3 is the least expensive resource for serving L_2; one additional MW of L_2 will divert 1MW of G_3 export to L_2 saving $6/MWh on GHG compliance costs and that export will be made up by one additional MW from G_2 at a net cost of $29/MWh, which is the LMP in the EIM Entity BAA. The balance of 100MW of L_1 can only be served by G_1, which sets the LMP in the ISO to $50/MWh.

The LMP difference of $21/MWh is made up by the marginal congestion cost of $15/MWh and the marginal GHG compliance cost of $6/MWh. The marginal congestion cost can be easily verified if the power transfer limit is relaxed by 1MW to 101MW, in which case one additional MWh from G_2 will displace 1MWh from G_1 for a net benefit of $15. The marginal GHG compliance cost can be easily verified if the export allocation (which carries the GHG compliance cost) is relaxed by 1 MW to 99MW, in which case 1MWh from G_3 will not incur GHG compliance costs for a benefit of $6.

The marginal congestion cost of $15/MWh and the marginal GHG compliance cost of $6/MWh on a 100MWh energy export result in a congestion revenue of $1,500 and GHG compliance revenue of $600, respectively. Assuming that the GHG compliance revenue is distributed to the optimal export allocations, the settlement is as follows:

Resource	Energy Cost	GHG Compliance Cost	Total Cost	Energy Payment	GHG Compliance Payment	Total Payment
G_1	$5,000	-	$5,000	$5,000	-	$5,000
G_2	$2,625	$0	$2,625	$2,175	$450	$2,625
G_3	$2,100	$150	$2,250	$2,175	$150	$2,325
L_1				–$10,000		
L_2				–$1,450		
Congestion Revenue				$1,500		
Emission Revenue				$600		

It can be seen in the settlement results above that the total payment to each generator is sufficient to cover the respective energy and GHG compliance costs.

3.9.2.4. Example 4

This is a variation on the third example where a new resource G_4 is introduced in the EIM Entity BAA with a generating capacity of 100MW, a GHG compliance bid adder of $3.00/MWh, and an energy bid of $30/MWh, while the power transfer capability is increased to 300MW. Therefore, the resource data is as follows:

Generator	Minimum (MW)	Maximum (MW)	Energy Bid ($/MWh)	GHG Compliance Bid Adder ($/MWh)
G_1	0	300	50	-
G_2	0	200	35	0
G_3	0	75	28	6
G_4	0	100	30	3

The purpose of this example is to show that the LMP in the ISO would include the GHG compliance costs for imports; this effect was masked in the previous examples because the more expensive resource G_1 was setting the LMP in the ISO. In this case, without a binding power transfer limit, G_2, G_3 and G_4 are dispatched to serve both loads L_1 and L_2. The optimal dispatch and export allocation are as follows:

Generator	Dispatch (MW)	Export Allocation (MW)	LMP ($/MWh)
G_1	0	-	35
G_2	75	75	29
G_3	75	25	29
G_4	100	100	29

Example 4: μ = $0/MWh; η = –$6/MWh

G_3 is the least expensive resource for serving L_2 and G_4 is the least expensive resource for serving L_1; consequently, both resources are dispatched at their maximum capacity. G_2 is marginal for serving L_1 and sets the LMP in the ISO to $35/MWh. One additional MW of L_2 will divert 1MW of G_3 export to L_2 saving $6/MWh on GHG compliance costs and that export will be made up by one additional MW from G_2 at a net cost of $29/MWh, which is the LMP in the EIM Entity BAA.

Since there is no transmission congestion, the LMP difference of $6/MWh amounts to the marginal GHG compliance cost of $6/MWh. The marginal GHG compliance cost can be easily verified if the export allocation (which carries the GHG compliance cost) is relaxed by 1 MW to 199MW, in which case 1MWh from G_3 will not incur GHG compliance costs for a benefit of $6.

The marginal GHG compliance cost of $6/MWh on a 200MWh energy export results in an GHG compliance revenue of $1,200. Assuming that the GHG compliance revenue is distributed to the optimal export allocations, the settlement is as follows:

Resource	Energy Cost	GHG Compliance Cost	Total Cost	Energy Payment	GHG Compliance Payment	Total Payment
G_1	$0		$0	$0		$0
G_2	$2,625	$0	$2,625	$2,175	$450	$2,625
G_3	$2,100	$150	$2,250	$2,175	$150	$2,325
G_4	$3,000	$300	$3,300	$2,900	$600	$3,500
L_1				–$7,000		
L_2				–$1,450		
Congestion Revenue				$0		
Emission Revenue				$1,200		

It can be seen in the settlement results above that the total payment to each generator is sufficient to cover the respective energy and GHG compliance costs. Furthermore, all export allocations receive the marginal GHG compliance cost irrespective of the resources's GHG compliance bid.

3.9.3. Major Characteristics of the Proposed GHG Formulation

The major features of the proposed method are as follows:

- The net imbalance energy export from each EIM Entity BAA, exclusive of import/export imbalance energy schedules to other BAAs, is imbalance energy imported into the ISO BAA. This energy would be allocated optimally to supply resources in the respective EIM Entity BAA.
- The net imbalance energy export allocation to supply resources in each EIM Entity BAA does not depend on the location of these resources; no shift factors are used in this allocation. The rationale is that this allocation is an accounting problem, which is irrelevant to the actual flow of energy on the network; in other words, supply resources in each EIM Entity BAA are only differentiated in terms of their respective energy and GHG compliance costs, not in terms of their physical location.
- Each supply resource in an EIM Entity BAA can bid its GHG compliance cost.
- The GHG compliance bid for each supply resource in an EIM Entity BAA represents a cost to the respective EIM Participating Resource Scheduling Coordinator for complying and acquiring the necessary greenhouse gas emission credits required by CARB for energy imports to California. This bid is added to the objective function for an efficient cost-effective imbalance energy dispatch.
- If the net imbalance energy export from an EIM Entity BAA is negative, there is no associated net imbalance energy export allocation or GHG compliance cost. Otherwise the net imbalance energy export allocation constraint is binding and it may have a non-zero shadow price.
- GHG compliance costs are reflected through the net imbalance energy export allocation shadow prices in the locational marginal prices (LMPs) in the EIM Entity BAAs through a fourth component that is the same for all locations in that BAA. This LMP component is negative and can be seen as a cost adder to the marginal energy component to reflect the marginal cost of GHG compliance in EIM Entity BAAs for energy exported to ISO. This fourth LMP component is absent or zero for locations in ISO, and other BAAs that do not participate in EIM, because in these cases the cost of GHG compliance is included in the energy bids; hence it is already reflected in the marginal energy component.
- The absence of the fourth LMP component for locations in ISO results is no impact on existing Market Participants. They do not have to modify their systems to account for it.
- As a result of the imbalance energy settlement, the ISO would collect GHG compliance revenue for the net imbalance energy export from each EIM Entity BAA at the respective net imbalance energy export allocation constraint shadow price, similarly to the congestion revenue. Distributing this revenue back to the optimal net imbalance energy export allocations in addition to the imbalance energy settlement at the LMP would adequately compensate supply resources in EIM Entity BAAs for their energy and GHG compliance costs without a need for any side payments or uplift.

- The proposed methodology is very general and robust and it does not depend on the particular network configuration or how the various BAAs are interconnected. Therefore, it is readily expandable to any number of BAAs in the full network model with any number of EIM Entity BAAs and any BAA interconnection pattern.
- Static or dynamic imports to an EIM Entity BAA through interties with BAAs other than the ISO may also participate in EIM. The proposed methodology for GHG compliance costs can be extended to these imports so that their GHG compliance bids are included in the objective function, similar to the treatment of other EIM Participating Resources.
- The ISO will report the portion of the 15-minute energy schedule and the portion of 5-minute energy dispatch that is associated with energy imports to ISO for all EIM Participating Resources as part of the real-time market results publication. The relevant EIM Participating Resource Scheduling Coordinators will be responsible for aggregating and reporting these energy imports to CARB after each calendar year in accordance with CARB regulations.

3.10. Market Rule Oversight

The ISO continues to engage with stakeholders to develop an EIM governance model that would accommodate other entities joining as well. In the EIM straw proposal published in April, we discussed various options, including a market administrator model, a market operator model, and a hybrid model. A number of parties commented in general terms suggesting the need for more in-depth discussion with interested stakeholders. To that end, we are increasing our focus on this important topic to ensure that we provide stakeholders with a governance model that supports effective operation of the EIM and takes into account the interests of all entities considering participation.

We have posted a proposal for stakeholder consideration and intend to run a stakeholder engagement specifically dedicated to governance. We intend to complete the process and be ready to move forward with implementation on a time frame that tracks that of the EIM tariff filing. The governance proposal will be discussed at the August 20, 2013 stakeholder meeting in Portland.

3.11. Other Items

3.11.1. Market Rule Structure

The ISO proposes that the EIM rules shall be contained in a discrete part of the ISO tariff to the extent this structure provides additional clarity to all EIM Entities, EIM Entity Scheduling Coordinators, EIM Participating Resource Scheduling Coordinators and EIM Participating Resources. The ISO intends to aggregate the EIM provisions as Section 29 of the tariff. However, provisions generally applicable to the relationship between the ISO and market participants may be provided for by reference as applicable to EIM Entities, EIM Entity Scheduling Coordinators, EIM Participating Resource Scheduling Coordinators and EIM Participating Resources.

3.11.2. Market Monitoring

The EIM shall include market monitoring, which services shall be provided by the ISO Department of Market Monitoring (DMM). These services are included in the EIM administrative charges. DMM monitors markets administered by the ISO for potential ineffective market rules, market abuses, market power or violations of FERC market rules prohibiting provision of false information or market manipulation.

DMM also co-ordinates with other ISO business units that review and monitoring the performance and quality of the ISO markets. DMM provides recommendations about potential market design flaws or ineffective market rules to the ISO and FERC. DMM may also perform analysis and review cases to collect information about certain market trends or behaviors. If DMM determines there is sufficient credible information that a violation of FERC or ISO market rules has occurred, the issue will be referred to FERC for further review.

3.11.3. Process for New EIM Entities Joining

New balancing authorities joining the EIM must will pay an initial fee to cover start-up costs. This payment will be established through an implementation agreement for commitments between the Market Operator and joining EIM Entity.

The ISO encourages BAs interested in participating in the EIM to engage with the ISO as early as possible. Implementation requires sufficient time (12-18 months) for the associated EIM Entity BAA network model and other system changes to be accomplished.

The ISO anticipates that later implementations will be established based on an annual commitment cycle with an associated 12-18 month implementation effort to follow, depending upon the complexity of the BAA. Implementation of an EIM Entity following any particular annual commitment cycle would be aligned with the ISO's Spring/Fall software release cycles.

3.11.4. Third Party Arrangements and OATT Provisions

EIM Entities may engage in discussions with third parties, including EIM Participating Resource Scheduling Coordinators, and enter into binding agreements or modify existing agreements with these third parties to implement the approved terms and conditions of the EIM as necessary and appropriate. EIM Entities must also amend their OATT to provide for the EIM consistent with the Market Operator tariff.

3.11.5. Compliance

Each EIM Entity, EIM Entity Scheduling Coordinator, EIM Participating Resource Scheduling Coordinator and EIM Participating Resource shall comply with all federal, state, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power, including FERC, NERC, WECC; or any court or governmental tribunal, in each case, having jurisdiction over them in connection with the performance of its obligations under the EIM. The current functional responsibilities associated with compliance with reliability standards for each EIM Entity, EIM Entity Scheduling Coordinator, EIM Participating Resource Scheduling

Coordinator and EIM Participating Resource are not intended to be modified, changed or otherwise amended as a result of participation in the EIM.

3.11.6. Enforcement Protocol

EIM Entity Scheduling Coordinators and EIM Participating Resource Scheduling Coordinators will be responsible for adherence with the Market Operator tariff relating to the Enforcement Protocol, which is anticipated to be the same as in the ISO tariff. The purpose of this portion of the Market Operator Tariff is to enforce appropriate market behavior. Failure to follow the guidelines identified will result in penalties and a disqualification from receipt of Enforcement Protocol proceeds that the Market Operator distributes annually.

3.11.7. ISO Tax Liability

To the extent that the ISO would incur any tax liability as a result of the EIM, as Market Operator or as central counterparty to EIM transactions, for example, the ISO will pass those taxes on to the EIM Entity Scheduling Coordinator for the EIM Entity area where the transactions triggered the tax liability. While the ISO is still analyzing potential tax liability, it has not to date identified any tax liability that would result from the EIM.

4. Appendix

The table below includes a list of acronyms that appear in this document. Definitions are provided when they are helpful in setting the context of this document, and others can be found in the ISO's Definitions and Acronyms Business Practice Manual available at:

http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Definitions and Acronyms

Acronym	Term
AC	Alternating Current
ACOPE	AC Optimal Power Flow
ADS	Automated Dispatch System
AGC	Automatic Generation Control
ALFS	Automated Load Forecast System
ATC	Available Transfer Capability
AS	Ancillary Services
BA	Balancing Authority
BAA	Balancing Authority Area
BCR	Bid Cost Recovery
BPM	Business Practice Manual
CARB	California Air Resources Board
CMP	Congestion Management Process
CMRI	ISO Market Results Interface
DMM	Department of Market Monitoring
DOP	Dispatch Operating Point
DOT	Dispatch Operating Target
EIM	Energy Imbalance Market
EMS	Energy Management System
ETC	Existing Transmission Contract
FERC	Federal Energy Regulatory Commission
FNM	Full Network Model
FOR	Forbidden Operating Region

Acronym	Term
GDF	Generation Distribution Factor
GHG	Greenhouse Gas
GMC	Grid Management Charge
GOP	Generator Operator
ICCP	Inter-Control Center Communication Protocol
IIE	Instructed Imbalance Energy
IROL	Interconnection Reliability Operating Limit
ISO	California Independent System Operator Corporation
ISO ME	ISO Metered Entity
LAP	Load Aggregation Point
LDF	Load Distribution Factor
LMP	Locational Marginal Price
LSE	Load Serving Entity
MO	Market Operator
MP	Market Participant
MSC	Market Surveillance Committee
MW	Megawatt
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation, or its successor.
NSI	Net Scheduled Interchange
OATT	Open Access Transmission Tariff
OASIS	Open Access Same-Time Information System
OMAR	Operational Meter Analysis and Reporting
OMS	Outage Management System
OD	Operating Day
OH	Operating Hour
PTDF	Power Transfer Distribution Factor
RA	Resource Adequacy

Acronym	Term
RDT	Resource Data Template
RTCD	Real-Time Contingency Dispatch
RTD	Real-Time Dispatch
RTED	Real-Time Economic Dispatch
RTUC	Real-Time Unit Commitment
SaMC	Settlements and Market Clearing
SC	Scheduling Coordinator
SCED	Security Constrained Economic Dispatch
SC ME	Scheduling Coordinator Metered Entity
SE	State Estimator
SIBR	Scheduling Infrastructure and Business Rules system
SLIC	Scheduling and Logging system for the ISO
SMDM	Supplemental Market Data Management
SOL	System Operating Limit
SPS	Special Protection Scheme
TAC	Transmission Access Charge
TOP	Transmission Operator
TOR	Transmission Ownership Right
UDC	Utility Distribution Company
UFE	Unaccounted For Energy
UFMP	Unscheduled Flow Mitigation Procedure
UIE	Uninstructed Imbalance Energy
VER	Variable Energy Resource
WECC	Western Electricity Coordinating Council
WIT	WECC Interchange Tool