Energy Imbalance Market

Revised Straw Proposal

May 30, 2013

Table of Contents

1. Executive Summary

1.1. Energy Imbalance Market (EIM) Concept

An Energy Imbalance Market (EIM) manages real-time imbalances on the grid economically, reliably, and automatically. Deviations in supply and demand occur in real time resulting in a mismatch, or imbalance, between available electricity versus what is needed by consumers. Balancing Authorities (BAs) have traditionally tried to manage these imbalances by relying on manual dispatches and extra power reserves. An EIM solves these imbalances in real-time with more precision through an automated five-minute energy dispatch service. EIM's automation and economic dispatch lower costs for participants and become even more valuable as additional renewable resources connect to the grid.

The California ISO (ISO) provides this energy imbalance market service today to its existing customers through advanced systems that automatically balance deviations every five minutes. The ISO's real-time market and 5-minute dispatch systems have been tested and proven to be effective over four years, and now the ISO offers to extend this service to other balancing authorities in the West. By extending its existing infrastructure, the ISO can offer the EIM services to other BAs at low cost and low risk to new participants. The ISO approach is also highly scalable, meaning that new BAs can be added incrementally when they are ready.

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 BAs are currently exploring implementation options. Many of these efforts have centered on creating a new organization and new systems and tariff to operate an EIM. The ISO provided a conceptual proposal to the PUC-EIM group in March 2012, providing the sought-after EIM services through its existing platform. PacifiCorp expressed interest in the ISO proposal, leading to a memorandum of understanding early in 2013. In March of 2013 the ISO Board of Governors approved moving forward with the PacifiCorp implementation in parallel with this stakeholder process to design the details and tariff changes necessary to allow other balancing authorities in the West to take advantage of this important service.

The EIM being developed by the ISO will allow other BAs to leverage the benefits of real-time balancing while also maintaining all of their existing authority. BAs will remain responsible for procuring or self-providing reserves and other ancillary services. The EIM will not change North American Electric Energy Reliability Corporation (NERC) and WECC responsibilities for resource adequacy, reserves, or other BAA reliability-based functions for the EIM Entity.

The EIM will, however, change how participating BAs deal with imbalances in real time. All BAs will start the hour with balanced generation and forecast demand. Imbalances occur because generation and load typically vary slightly from what is scheduled and forecast. Resources within the EIM BAA will be able to provide bids so the EIM can dispatch them to manage these imbalances. The EIM will automatically look across the expanded ISO-EIM footprint and dispatch the most economic bids available to meet these imbalances. The real-time optimization will determine the least cost mix of resources and dispatch them to resolve these imbalances while also respecting limits on the transmission system, alleviating overloads or congestion.

1.2. Benefits of an Energy Imbalance Market

The EIM provides reliability and economic benefits to both existing market participants and new EIM Entities by utilizing the ISO 15-minute market and real-time dispatch. The ISO EIM model offers the following features:

a) It leverages the ISO’s existing five-minute real-time market and dispatch, along with its pending addition of a real-time 15-minute market, so resources within each EIM Entity BAA can be economically and automatically dispatched in real time. EIM uses RTD to dispatch resources every 5 minutes to rebalance supply and demand for the upcoming 5-minute interval and several subsequent intervals. This look-ahead dispatch horizon is important for ensuring smooth following of variations in load and variable energy resources’ output.

b) It enhances reliability through real-time visibility and situational awareness of resources and transmission across the ISO and EIM Entity footprints.

c) It captures the benefits of geographical diversity of load and resources. As an example, wind resources produce at different times in the northwest than in the southwest. Loads peak at different times across the region as the sun moves westward. EIM moves resources to take advantage of this diversity.

d) It potentially reduces load following capacity requirements by accessing a wider portfolio of resources to ensure electricity is available where and when it is needed.

e) It provides easy and economical entry/exit. New EIM Entities will pay for set-up costs based upon the size of their system and will pay ongoing fees depending upon their participation level. As volumes increase in the future, the administrative charges should be lower for all participants.

As new BAs join the EIM, additional annual benefits will accrue to both the new customers and existing ISO and EIM customers.

All interested entities in the West are encouraged to participate in this stakeholder process to shape the design of the EIM offered by the ISO in a way that is attractive to all new and existing customers.

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.

Market Operator is the ISO.

EIM Entity is a balancing authority 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.

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 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 is responsible for meeting the requirements specified in Tariff Section 29. In the 5-minute market, eligible resources may include Generating Units, Physical Scheduling Plants, Participating Loads, Proxy Demand Resources, Non-Generator Resources and Dynamic Schedules. In the 15-minute market, 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 EIM Entity Scheduling Coordinator, 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

[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.

with the Market Operator on behalf of resources in an EIM Entity BAA that voluntarily elect to economically participate in the EIM.

2.2. Changes to Straw Proposal and Issue Paper

This revised straw proposal includes the follow changes from the preceding issue paper and straw proposal:

- Clarified and expands definition of new terms. Ensures consistent usage of new terms throughout the revised straw proposal.
- Discusses the minimum shift optimization to establish the adjusted base schedule.
- Includes proposal for local market power mitigation.
- Includes proposal for allocation of real-time market uplifts.
- Discusses the flexible ramping constraint and planned flexible ramping product.
- Introduces proposal for settlement of transmission service.
- Introduces proposal for greenhouse gas emission costs.
- Establishes a parallel stakeholder initiative to discuss market rule oversight.

2.3. Plan for Stakeholder Engagement

Stakeholder input is essential and often critical for the success of new initiatives from policy development to implementation. The ISO is committed to provide ample opportunity for stakeholder input into our market design, policy development, and implementation activities. 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.

Item	Date
Post Revised Straw Proposal	May 30, 2013
Stakeholder Meeting (Folsom)	June 6, 2013
Stakeholder Comments Due	June 14, 2013
Post 2nd Revised Straw Proposal	July 2, 2013
Stakeholder Meeting (Phoenix)	July 9, 2013
Stakeholder Comments Due	July 19, 2013
Post Draft Final Proposal	August 13, 2013
Stakeholder Meeting (Portland)	August 20, 2013
Stakeholder Comments Due	August 27, 2013

Post Draft Tariff Language	September 16, 2013
Stakeholder Comments Due	September 23, 2013
Stakeholder Meeting (Folsom)	September 30, 2013
Board Decision	November 8, 2013

Table 1- Schedule for EIM Stakeholder Process

3. EIM Design 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 forecasts of load, generation and interchange provided by the EIM Entity Scheduling Coordinator. If necessary, the base schedules for the generating units that the EIM Entity Scheduling Coordinator has provided will be adjusted by the Market Operator prior to the start of the imbalance energy market optimization to alleviate transmission congestion in the EIM Entity BAA that is caused by base schedules. The Market Operator will communicate to the EIM Entity Scheduling Coordinator the adjusted base schedules and whether the base schedule cause unresolved congestion within the EIM Entity BAA. The adjusted base schedules for load, generation and interchange are the basis for calculating imbalance energy for settlements.

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.

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. The Market Operator will not commit, start-up or shut down any resource in the EIM Entity BAA at least in the current scope of EIM implementation.

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.

During any market maintenance activities, 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.

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. Submitting and maintaining their system operating limits (inter-ties and internal constraints) as needed for the market. 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 in 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 adjusted schedules.

There will also be communication between the Market Operator and the EIM Entity to ensure functional coordination.

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 load forecasts and balanced base supply, demand, and interchange schedules to the Market Operator. 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.

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 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.

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 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.

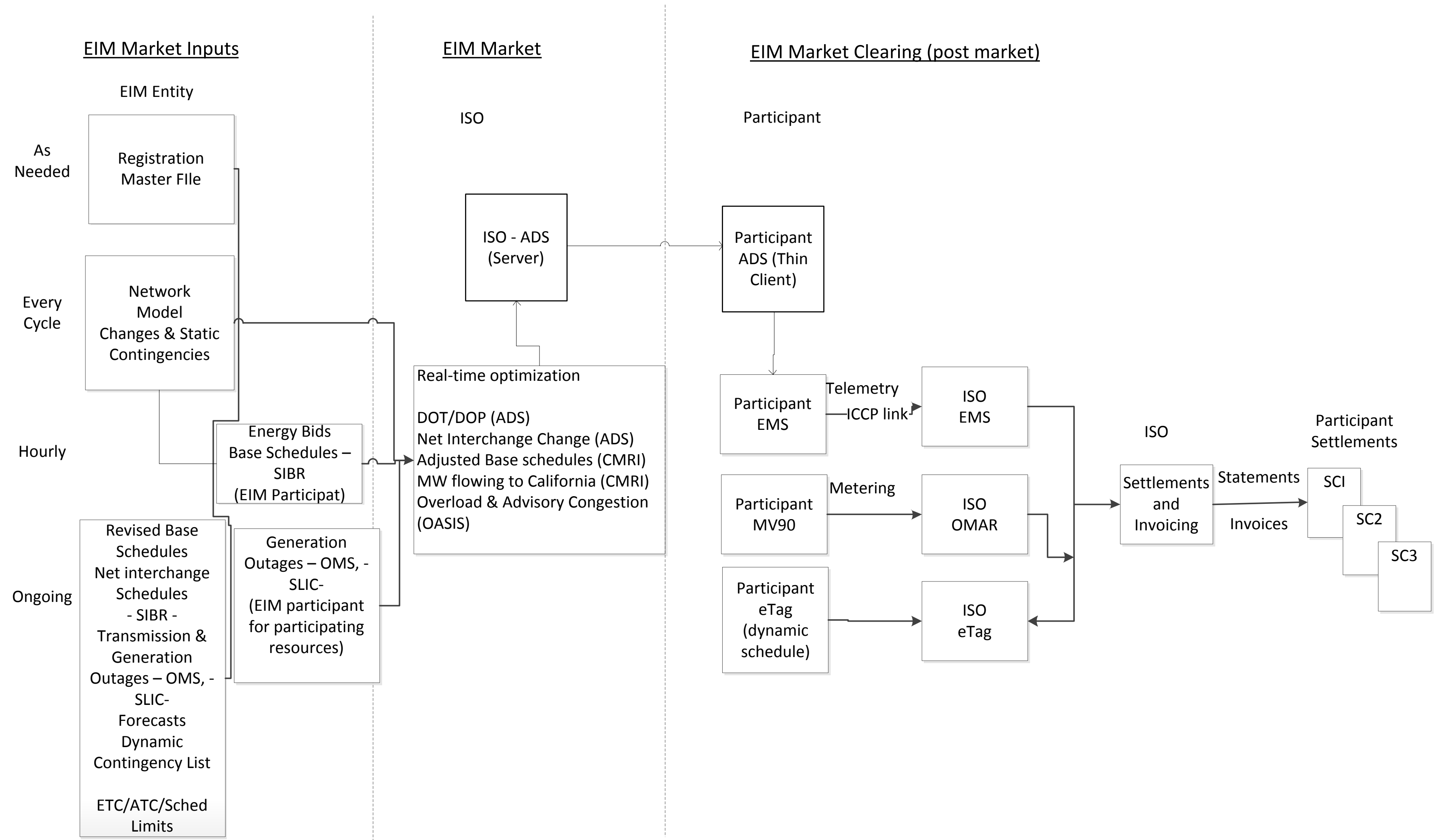


Figure 1. *Energy Imbalance Market Processes*

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.

Base schedules, with a granularity of 15 minutes, must be submitted by the EIM Entity Scheduling Coordinator no later than 75 minutes prior to the beginning of each Trading Hour, and may be updated in real-time, as frequently as every 15 minutes, until 40 minutes before the start of the relevant 15-minute market.

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 currently in the Hour-Ahead Scheduling Process, and will occur instead in RTUC after the ISO's implementation of FERC Order No. 764. 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

[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

the EIM Entity Area from other BAAs) that provide bids for the 15-minute market will also receive 15-minute schedules. 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.

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. RTUC contains a pre-process before the market optimization to ensure that 15-minute base schedules are balanced and feasible with respect to transmission losses and any congestion within the EIM Entity BAA. In other words, all congestion shall be resolved either by adjusting the base schedules or relaxing the corresponding transmission constraint limit in the EIM Entity BAA to the original limit plus the amount of unresolved overload. The Market Operator will only relax transmission constraints if no other means of obtaining an initial base schedule is feasible within transmission limitations, and will alert the affected EIM Entity Scheduling Coordinator to this condition. The balanced and transmission feasibility pre-process will not include inter-temporal constraints or commitment adjustments to calculate the financial reference points or the so called adjusted base schedules. The EIM 15-minute imbalance energy and 5-minute imbalance energy settlement is based on the difference between the 15-minute and 5-minute dispatch, respectively and the calculated 15-minute adjusted base schedules.

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 deviations from the 15-minute adjusted base schedules.

The Market Operator will calculate, and EIM Entity Scheduling Coordinator willl submit or confirm, actual values for dynamic schedules 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. EIM Participating Resource Scheduling Coordinators submit energy bids for upcoming operating hours and days.	EIM base portfolios as of OH–75 minutes will establish the initial basis for EIM energy settlements, subject to adjustments for 15-minute intervals. 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 demand forecasts, resource plans, and ancillary service plans	Review EIM Entity Scheduling Coordinator 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 Submission base schedules and resource plans for OH. EIM Participating Resource Scheduling Coordinator energy bids for OH.	Bid validation and processing. Base schedule adjustment after OH–75 minutes.
By T–40 minutes	EIM Entity Scheduling Coordinator submits base schedule update for 15 min interval starting at T.	Base schedule adjustment after T–37.5 minutes.

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.	Approve tags.
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)

Operating Hour Activities		
Timeline	**EIM Action**	**Market Operator Action**
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	
Within OH + 15 minutes		LMP for hourly settlement interval for net interchange available, including meter settlement locations.
Within OH + 60 minutes	Estimated dynamic schedules 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.

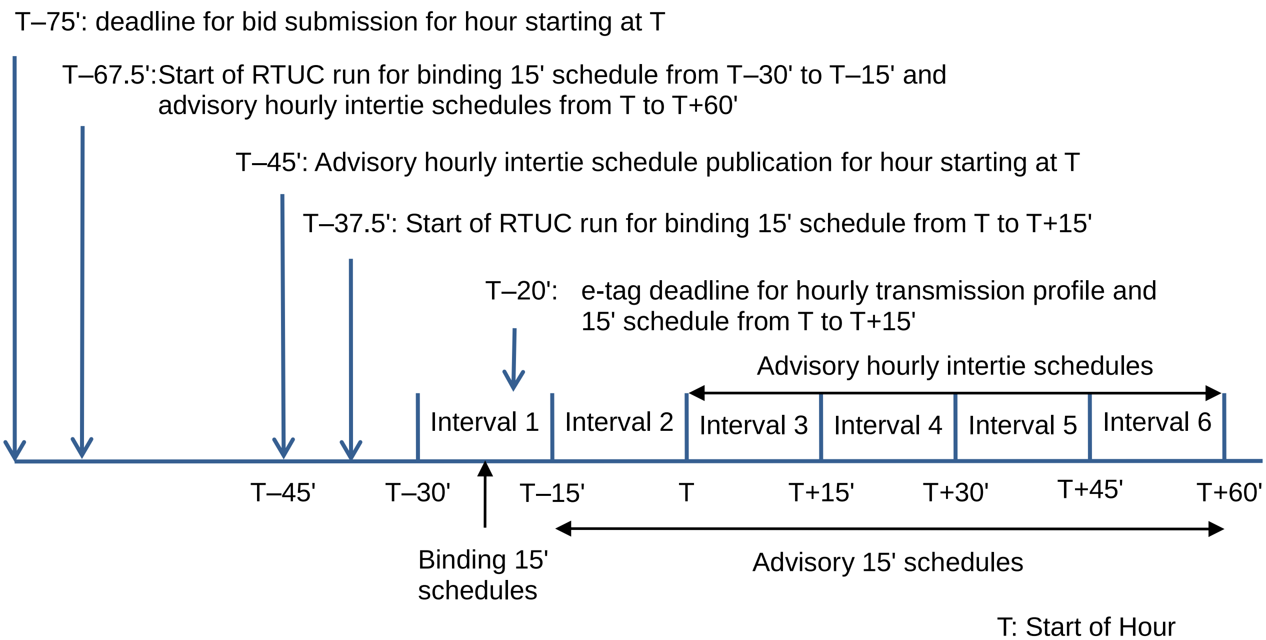


***Figure 2.** Timeline of Hour-Ahead Scheduling Process*

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.

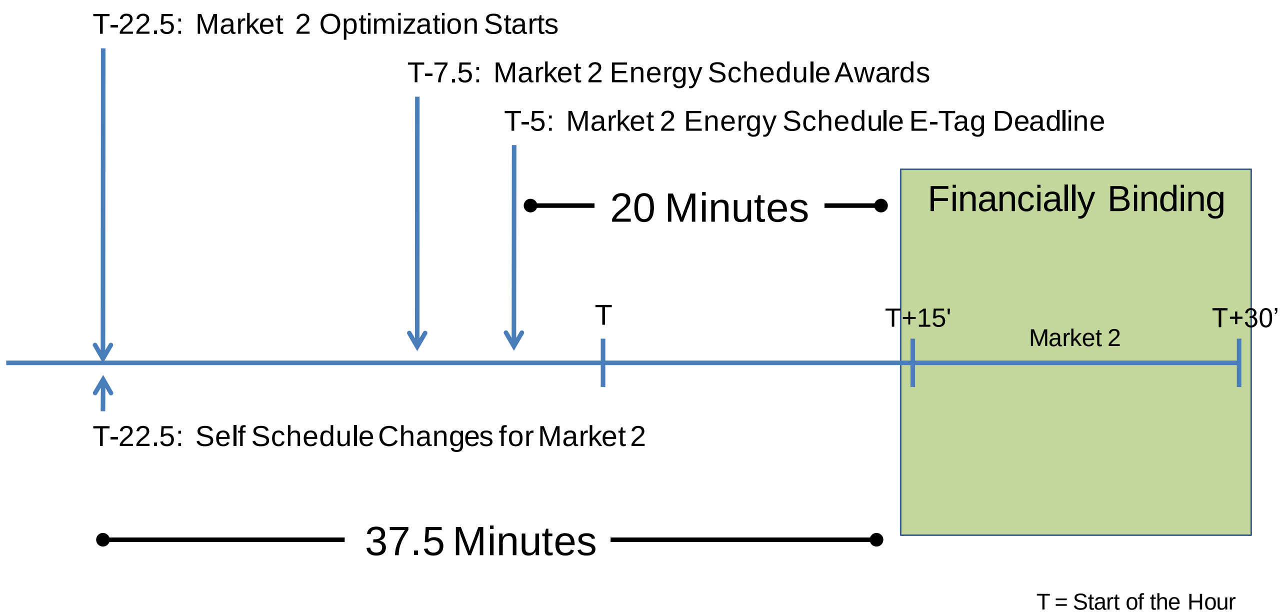


Figure 3. *Timeline of 15-Minute Real-Time Market*

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

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

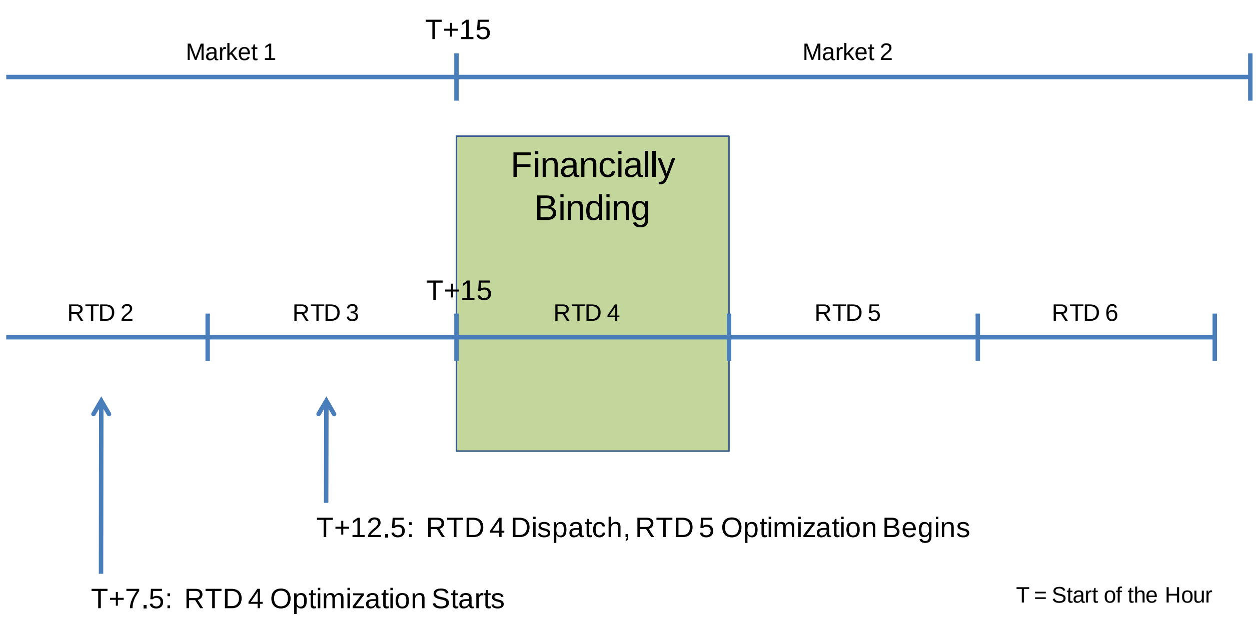


Figure 4. *Timeline of 5-Minute Real-Time Market*

3.2.5. Local Market Power Mitigation (LMPM)

ISO will mitigate localized market power in the real-time market. The real-time market LMPM starts in the hour-ahead process for the operating hour, and continues in the subsequent RTUC runs. As a result, a resource could potentially be mitigated multiple times in real-time. If a bid is mitigated in a prior process (Hour-ahead or RTUC), the mitigated bids will be carried through the rest of the hour, and potentially be mitigated again in a later RTUC.

ISO's market power mitigation mechanism consists of two important parts: mitigation based on LMP decomposition, and dynamic competitive path assessment (DCPA) based on the residual supplier index (RSI). DCPA is an online process to determine if a path is competitive or not. The path competitiveness is an input for the actual mitigation process.

The "LMP decomposition" approach only requires a single all constraint run. This run produces dispatches and prices that are potentially impacted by market power. The second step is to perform the DCPA to determine path competitiveness. With the path competitiveness designation, the third step is to "decompose" the LMP.

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.

The LMP congestion component is calculated as the sum of shift factor times shadow price for all constraints. With constraints being classified into competitive constraints and non-competitive constraints, 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. The competitive and non-competitive path designation is from the DCPA results.

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.

The LMP decomposition depends on the choice of reference bus. Based on ISO study, the mitigation reference bus for 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 free of market power.

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.

Dynamic competitive path assessment is performed after the all constraints run. For every binding transmission constraint in the all constraints run, ISO will calculate a residual supplier index (RSI). The RSI is the ratio of counter flow capacity supply excluding the three largest suppliers and the original counter flow provision. Resources with negative shift factors are able to provide counter flow, and counter flow alleviates congestion. The RSI test is to see if the three largest suppliers are pivotal for a constraint in terms of counter flow. If they are pivotal, which means the residual counter flow capacity supply cannot reach the original counter flow provision, 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. The three largest suppliers withdraw their counter flow supply by ramping down continuously for 15 minutes, and the residual suppliers try to make up by continuously ramping up for 15 minutes.

EIM Participating Resource Scheduling Coordinators will need to submit information that is necessary to perform DCPA to the ISO, such as tolling agreements. The ISO will use the same DCPA and LMPM methodology to mitigate power for EIM Participating Resources.

The mitigation reference bus for EIM Participating Resources does not have to be the same as the ISO's mitigation reference bus. For an EIM Entity BAA with scattered network topology and without a high voltage transmission backbone, there is not an obvious/good location that can be free of market power. In this case, the ISO will use the load distributed slack bus for the EIM Entity BAA as the mitigation reference bus.

The ISO will not mitigate resource bids and import or export bids for scheduling limit constraints.

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 operating capacity) into the Market Operator's Master File. EIM Participating Resource Scheduling Coordinator resource bids will be treated as Dynamic Resource Specific System Resources. There will be an EIM service agreement, still to be defined.

3.3.2. Base Schedules

Base schedules must be submitted by at least 75 minutes before the start of the operating hour, for each 15-minute interval in that hour and for at least two subsequent hours; these base schedules can be revised as frequently as every 15 minutes thereafter, until the run of the last real-time market for the relevant interval (T-40'). Base schedules would be submitted through the System Infrastructure and Business Rules (SIBR) system, described in the Market Instruments Business Practice Manual.

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 ISO and the EIM Entity BAA demand forecast; they should reflect all forward market schedules, bilateral contracts, variable energy resource (VER) forecasts, and estimated transmission losses.

Base schedules must be submitted (they may be 0MW) 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 may choose not to submit base load schedules because these can be derived from the Market Operator's demand forecast for the EIM Entity BAA, estimated transmission losses, and an assumed load distribution. 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 base schedules. The Market Operator encourages the EIM Entity Scheduling Coordinator to update the base schedules in real-time prior to 40 minutes before each 15-minute interval to reflect any changes in real-time conditions such as demand forecast or resource outages.

3.3.3. EIM Entity Scheduling Coordinator Demand Forecasting

The EIM Entity Scheduling Coordinator may elect the option to provide their own demand forecast as part of the base schedules or adopt the Market Operator's demand forecast for the EIM Entity BAA. In the former case, the EIM Entity Scheduling Coordinator must update its forecast for each operating hour by at least 75 minutes prior to that operating hour, as part of its 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.

3.3.4. Market Operator Demand Forecasting

The Market Operator develops short-term and mid-term forecasts by load aggregation point (LAP) within EIM Entity BAA. The short-term forecast produces a value every 5 minutes for the duration of the Market Operator's dispatch horizon, which 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 self-schedules and 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.

3.3.5. Load Scheduling Requirements

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 may be subject to adjustment of imbalance energy payments attributable to inaccurate scheduling profits. As described in other sections of this paper, the Market Operator will provide an hourly demand forecast for all LAPs within the EIM Entity BAA by 10:00 PPT daily for a 7-day horizon, and will update this forecast during the operating day, using a granularity down to 5-minutes as the operating hour approaches. EIM Entity Scheduling Coordinators may choose to submit base schedules for their resources to match the Market Operator's forecast, and by doing so, they would not be subject to charges for under- or over-scheduling. For example, if the under- and over-scheduling charges are based on a tolerance band of ±4%, and the Market Operator's forecast for a load aggregation point 75 minutes before the operating hour differs from actual demand by 5% due to unexpected changes in weather, the under- or over-scheduling charges would not apply. 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.

If the EIM Entity Scheduling Coordinator does not use the Market Operator demand forecast to balance base schedules prior to the start of the EIM optimization, under- and over-scheduling charges may apply to EIM Entity Scheduling Coordinators whose resource plans do not match the Market Operator's demand forecast. The determination of the revenue subject to potential adjustment for failure to schedule load accurately is based on the following principles. If the EIM Entity Scheduling Coordinator uses the Market Operator demand forecast and provides sufficient base schedules to meet the Market Operators demand forecast then under and over-scheduling charges shall not apply.

3.3.5.1. Charges for Under-Scheduling

During any hour, if an EIM Entity Scheduling Coordinator's load imbalance is more than 4% (but at least 2 MW) at an applicable settlement location in that hour, that EIM Entity Scheduling Coordinator may be subject to an under-scheduling charge. If the reported load is greater than the scheduled load by more than 4% of reported load (but at least 2 MW), an initial concept discussed in the EIM Design Straw Proposal and Issue paper would follow steps used by the Southwest Power Pool, by matching 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 that would be multiplied by the resource imbalance energy required to offset its load imbalance energy. This process may be more complex than necessary, and discussion in the upcoming stakeholder meeting will explore possible simplifications.

3.3.5.2. Charges for Over-Scheduling

During any hour, if an EIM Entity Scheduling Coordinator's Load imbalance is more than 4% (but at least 2 MW) at an applicable settlement location in that hour, that EIM Entity Scheduling Coordinator may be subject to an over-scheduling charge. If the scheduled load is greater than the reported load by more than 4% of reported load (but at least 2 MW), the initial concept would follow similar steps to those above, by 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, discussion in the upcoming stakeholder meeting will explore possible simplifications to this process.

3.3.6. Resource Plans

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 plus losses. The Market Operator utilizes resource plan data along with the energy bid curves, demand 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
- Regulation Reserve MW – Up/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. 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.

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.

3.3.7. Supply Adequacy and Resource Scheduling Requirements

For interchange transactions included in a resource plan, the EIM Entity Scheduling Coordinators create and process e-Tags for bilateral schedules between BAAs that are arranged prior to the real-time horizon 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 the EIM footprint when issued by the Market Operator, until the end of an operating hour. The Market Operator will manage dynamic schedules with resources that bid in EIM, with initial values that may be 0 MW at the beginning of an operating hour if these e-Tags represent only imbalance energy dispatched in 5-minute intervals (or may be non-zero if they also include schedules for hourly or 15-minute intervals), and updates after the operating hour to reflect EIM dispatches for purposes of inadvertent energy accounting and tracking greenhouse gas obligations. The Market Operator will issue an aggregate dynamic schedule with each EIM Entity BAA.

The 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 should provide 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.

After the submission of base schedules by the EIM Entity Scheduling Coordinator and energy bids by the EIM Participating Resource Scheduling Coordinators by 75 minutes before each operating hour, the Market Operator will provide results of a supply adequacy analysis for each EIM Entity for that operating hour. The supply adequacy analysis will be based on the EIM Entities or Market Operator's demand forecast information, 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. 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 each 15-minute period of the relevant 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.

3.3.8. 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 policies. The energy schedules implemented for deployment of reserves are either reflected in the 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 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 regulation requirements will be settled as instructed energy, rather than as uninstructed deviations 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.

3.3.9. Base Schedule Adjustment

The submission of schedules prior to the operating day and concurrent with the ISO’s day-ahead market allows EIM Entity Scheduling Coordinators to revise their schedules to avoid congestion coming into the operating hour. Base schedules must be balanced with the demand forecast for the EIM Entity BAA based on the agreed upon demand forecast values from the source elected by the EIM entity, considering transmission losses, and must be free from congestion within the EIM Entity BAA. The Market Operator will adjust base schedules with an AC optimal power flow (ACOPF) while fixing the EIM Entity BAA’s net scheduled interchange and alleviate any network constraint violations within EIM Entity BAA and distribute transmission loss deviation to the EIM Entity BAA load using applicable load distribution factors. The objective function of the ACOPF will minimize the MW re-dispatch, i.e., no economic bids will be used, but it will be limited in real-time to resources with energy bids, i.e., to resources explicitly participating in EIM. The Market Operator will ensure that only the base schedules in the EIM Entity BAA, or the revised base schedules if updated by EIM Entity Scheduling Coordinators, are used to alleviate any congestion within the EIM Entity BAA as a result of these base schedules. The adjustment process of the base schedules yields what is called adjusted base schedules, which form the reference point for calculating imbalance energy; hence, the adjusted base schedules themselves would not be subject to EIM settlement.

After the calculation of the adjusted base schedules which ensures conformance of schedules to the demand forecast, the market optimization process, which includes both ISO bid-in resources and the EIM Participating Resources commences. The steps for the base schedule adjustments for the different markets are as follows:

- **Day-ahead**: The EIM Entity Scheduling Coordinator provides balanced base schedules including demand forecast, generation and net schedule interchange. The Market Operator will run the ACOPF using the EIM Entity Scheduling Coordinator's demand forecast while fixing the net scheduled interchange and calculate the adjusted day-ahead base schedules. The day-ahead market is executed with the adjusted day-ahead base schedules as fixed reference injections for the corresponding time interval to establish the loop flows for which the day ahead market will use as base flows and the market will be solved without enforcing transmission constraints in the EIM Entity BAA, but the Market Operator will report any overloads in that BAA on OASIS.
- **15-minute RTUC**: The revised base schedules are required at least T-75 minutes prior to the operating hour for two hours' worth of data. The data can be flat for the whole hour or it can be submitted in 15-minute granularity. The submission made by T-75 minutes in advance can be updated any time as long as at least one submission is provided before that deadline and extends for at least two hours. The revised base schedules are validated using ACOPF that keeps the base net interchange fixed and uses Market Operator's demand forecast for the EIM Entity BAA. Adjusted base schedules will be generated as a result of the ACOPF. The 15-minute market is executed with the adjusted 15-minute base schedules to reflect the 15-minute base flow in the network. The 15-minute market will be solved using the 15-minute adjusted base schedules, enforcing transmission constraints in the EIM Entity BAA, and using the EIM energy bids on top of the 15-minute adjusted base schedules. Any extra energy cleared in the 15-minute market (15-minute final schedule) above the adjusted base schedule is settled using the 15-minute LMP price.
- **5-minute RTD**: RTD does not have an initial process like the 15-minute and day-ahead markets to balance base schedules. The market design is flexible enough to add such a process but the current ISO market design doesn't anticipate major topology and system changes within the 15-minute time frame between the execution of the 15-minute process and the 5-minute process for the same binding time interval. Therefore, for efficiency purposes, the 5-minute RTD inherits its adjusted base schedules from 15-minute RTUC for the corresponding time horizon. The 5-minute market will use the up-to-date Market Operator demand forecast for the EIM Entity BAA, the 15-minute adjusted base schedules while enforcing transmission congestion in EIM Entity BAA, and the EIM energy bids. Any extra MW cleared in the 5-minute market above the 15-minute final schedule is settled using the 5-minute LMP price. Any uninstructed deviation from the 5-minute final schedule is settled based on the 5-minute RTD LMP prices at the

corresponding location. If the EIM Participating Resource Scheduling Coordinator submits an energy bid for EIM dispatch of an EIM Participating Resource, the adjusted base schedule for that resource will affect its settlement, but the dispatch instructions will be based on the resource telemetry and its energy bid.

3.3.9.1.Minimum Shift Optimization Detail

The Market Operator will use a minimum shift, also known as minimum redispatch, optimization method to adjust submitted base schedules from each EIM Entity Scheduling Coordinator for balancing and feasibility. The minimum redispatch optimization method is a constraint least-squares minimization where deviations from a base are minimized subject to constraints. In this application, deviations from the submitted base schedules are minimized so that the adjusted base schedules balance the demand forecast for the EIM Entity BAA without violating transmission constraints. Subject to sufficient bid range being offered, only the base schedules for resources and intertie transactions with energy bids would be adjusted, and only as little as possible and if necessary. The adjustments would not be economic; the energy bids are used only as an indication of EIM participation and the amount of that participation in terms of the energy bid range. Any financial considerations regarding the base schedule adjustments would not be settled in EIM, but they will be the responsibility of the EIM Entity Scheduling Coordinator with its participants. The minimum redispatch optimization will not adjust resources outside of their submitted energy bid range. If the method exhausts all available capacity under the submitted energy bid and the adjusted base schedules are still not balanced with the demand forecast, the distributed base load net of transmission losses would be adjusted next as needed. On the other hand, if the method is unable to remove all transmission constraint violations, the offending transmission constraints would be relaxed for the amount of any remaining violations and the relaxed limits would be enforced in EIM. In both cases, the Market Operator will inform the relevant EIM Entity Scheduling Coordinator that the submitted energy bid ranges were not sufficient to fully adjust the submitted base schedules, which would result to either load imbalance or unresolved congestion, as the case may be.

3.3.10. Intertie Schedules with Other Balancing Authorities

The EIM Entity Scheduling Coordinator must submit intertie schedules with other BAAs at the relevant intertie scheduling points as part of the balanced base schedule submission. 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 base schedule revision.

3.3.11. Energy Bids (submitted via SIBR)

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 Trading Hour. 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.

3.3.12. 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.

3.3.13. Demand Forecast

The Market Operator will produce a demand forecast every 5 minutes separately for the ISO BAA and the EIM Entity BAA. The forecast will have a 5-minute granularity and will be produced for several hours to provide input data for RTUC and RTD time horizons. The 15-minute demand forecast for each of the intervals in RTUC will be derived based on the corresponding three 5-minute demand forecasts.

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 forecast zone and then aggregated for each BAA. The costs associated with the gathering and processing of required information will be recovered by the Market Operator through the EIM administrative rate.

The EIM Entity Scheduling Coordinator will provide non-binding day-ahead forecasts by 10:00 PPT for the next 7 days (informational only). The Market Operator may create forecasts in parallel, but they will not be used for settlements. The EIM Entity Scheduling Coordinator may provide hour-ahead demand forecasts by T-75 minute for the forward 6 to 10 hours as a backup to the Market Operator demand forecast, which is generated for the EIM Entity Scheduling Coordinator's real-time demand forecast. These forecasts will be used to balance the generation and net interchange base schedules that are required from the EIM Entity Scheduling Coordinator.

3.3.14. 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.

The cost for the ISO to provide the forecasting service is currently $0.10 per MWh. However, if the EIM Entity has an independent forecast for its variable resources and shares its forecast, the $0.10 per MWh service charge would be waived.

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. The Market Operator will consider this forecast in producing its own forecast on a case-by-case basis based on historical forecast accuracy.

The quality of the market solution and the prediction of congestion in look ahead intervals depend on the quality of the forecast among other things. Therefore, the better the forecast the better the EIM solution quality. It should be noted that the minimum nameplate capacity for becoming a participating generator in the ISO market is 0.5 MW and netting load against generation at the PNode level is also acceptable.

3.3.15. Generation and Transmission Outages (OMS, SLIC)

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.

3.3.16. Resource Operating Characteristics of Non Participating Resources

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). 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.

3.3.17. Resource Telemetry and State Estimator

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.

3.3.18. 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). There should also be an interface to update limits on transmission interfaces and scheduling limits, as occurs within the ISO using the ETCC system.

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. The unit commitment function of RTUC does not affect the EIM Participating Resources because the commitment status of these resources is given and not optimized. 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 adjusted 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 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.

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, would be allocated through the Real Time Congestion Offset.

3.4.3. Flexible Ramping Constraint and Future Product

On December 13, 2011, the ISO implemented a new flexible ramping constraint[3] 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 interval 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 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 where 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. The cost allocation allocated 75% to measured demand 25% to gross uninstructed negative supply deviations.

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.

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

When the ISO received Board approval of the flexible ramping constraint, the ISO committed to start a stakeholder process that would develop a flexible ramping product[4]. 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.

The flexible ramping constraint will be in effect when EIM goes in to production in Fall 2014. As a result resources across the EIM and ISO footprint will be eligible for compensation (as described above) if the resource is used to resolve the flexible ramping constraint. The flexible ramping constraint requirement will be based upon upward ramping needs across the EIM and ISO footprint. The constraint ensures sufficient upward ramping capabilities are available or committed in the RTUC. The constraint does not require commitment of resources prior to the start of the 15-minute market. For example, there is not a requirement for ISO load to have a day-ahead balanced position that includes unloaded capacity necessary to meet the flexible ramping constraint. Likewise, there will not be a requirement for an EIM Entity Scheduling Coordinator to submit a balanced schedule that includes additional unloaded capacity necessary to meet the flexible ramping constraint. The initial cost allocation split between ISO BAA and EIM Entities is discussed in this paper in Section 3.7.8.

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.

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.

---

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

3.5.1. 15-Minute Energy Schedules

The financially binding 15-minute 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 as the algebraic difference between the 15-minute Energy schedule and the 15-minute adjusted base schedule for the relevant resource would be settled at the 15-minute LMP.

If an EIM Participating Resource or 15-minute Import/Export receives a market award through the ISO's intra-hour 15-minute energy market, the market award will be incorporated into the base schedule that was submitted prior to the binding RTUC market run.

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). 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.

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.

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 base schedule update is received before the 15-minute market for the relevant interval, these exceptional dispatch instructions will not be part of the EIM; otherwise they will be settled at the applicable LMP. The Market Operator will reflect base schedule updates 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

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 base schedule update.

Exceptional dispatch from the EIM Entity Scheduling Coordinator to the EIM Entity BAA generating resources will be declared in the respective 15 minute base schedule updates provided 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. After T–40 minutes', which is the deadline for updating base schedules for the 15-minute interval starting at T, 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. 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 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 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 flowgate, 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. In particular, dynamic transfers to EIM Entities can effectively 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. The use of dynamic transfers in this way is encouraged for market-to-market or market-to-non-market coordination.

A presentation at the WECC Seams Issues Subcommittee's November 2010 meeting[5] 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 with other BAAs) to effectively manage congestion. WECC has established procedures for path ratings, and market operators and other system operators would use a similar process to agree on limits for coordinated flowgates and 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:

---

5 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)

1. Participating market or non-market system operators model the full WECC network, define external constraints in their models, 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 a market or non-market system operator forecasts real-time congestion, other market or non-market system operators determine their own firm market flows on the coordinated flowgate.
4. Each market or non-market system operator then enforces the coordinated flowgate to prevent further increases of its flow, allowing real-time redispatch to reduce flow.
5. Each market or non-market 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. 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 managed by the UFMP. Provided that the Market Operator is able to obtain flowgate 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 flowgate responsible for the curtailment will be available on OASIS.

3.6.5. Load Curtailment

The EIM can dispatch price-responsive demand, such as pump load or exports 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.

3.6.6. Market Disruption

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

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.

3.6.7. 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.

In addition, the establishment of the adjusted base schedule may result in schedule changes for resources prior to the start of the EIM. The changes to the base schedules would be settled by the EIM Entity based upon the EIM Entity's OATT.

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 adjusted 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 adjusted 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.[6]

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 adjusted 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

6 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.

extreme LMP in the population. The load forecast deviation in a 15-minute market is measured with reference to the corresponding adjusted 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.

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. 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.

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 within BAAs, the Market Operator will maintain a dynamic schedule with resources in each EIM Entity BAA. 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 economically participating and/or settling imbalance energy in the EIM. 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).

3.7.7.1.1. 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. Because each EIM Entity Scheduling Coordinator has a balanced schedule at the beginning of each operating hour, the initial energy profile for each of these dynamic schedules will show zero MW at the beginning of an operating hour if these e-Tags represent only imbalance energy dispatched in 5-minute intervals (or may be non-zero if they include schedules 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 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. Uplift Allocations

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

The cost allocation guiding principles have seven elements:

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 utilizes measured demand (metered demand plus exports) for real-time market uplifts. Under the combined EIM-ISO real-time market optimization a measure is needed to approximate the use of the real-time market by individual BAAs prior to applying the billing determinant for the uplift. This will allow the ISO and EIM Entities to develop their own allocation methodologies for their BAA share of the uplift.

The ISO proposes to calculate an hourly percentage split for the following real-time uplifts which are relevant to the EIM:

CC6477 Real Time Imbalance Energy Offset[7]

CC6774 Real Time Congestion Offset

CC6678 Real Time Bid Cost Recovery Allocation

CC7024 Flexible Ramp Up Cost Allocation

Since the EIM is an imbalance market, the ISO will use the gross absolute value of the changes from the initial state prior to the start of the EIM and the meter for all supply and demand regardless if the changes are instructed or uninstructed deviations. The usage will be calculated for each 15-minute interval in the hour. The usage for each 15-minute interval will be summed for the hour. An hourly percentage will be calculated the each BAA.

For ISO supply and load, the gross deviations for each resources will be calculated as the absolute value of the difference between the day-ahead schedule and the meter. For EIM Entities, the supply and load gross deviations will be the absolute value of the difference between

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

the adjusted base schedule and the meter.

The percentage hourly split will be calculated as follows:

Total RT Market Use = ISO Gross Deviations + EIM Entities Gross Deviations

ISO % = ISO Gross Deviations / Total RT Market Use

EIM Entity BAA % = EIM Entity Gross Deviations / Total RT Market Use

The following provides a numerical example for a single 15-minute interval in the hour:

	DA	Adjusted Baseline	Gross ABS Deviations	%
ISO	31,500 MWh	N/A	1,500 MWh	50%
EIM Entity A	N/A	10,000 MWh	1,000 MWh	33%
EIM Entity B	N/A	2,000 MWh	500 MWh	17%
		Total	3,000 MWh	100%

Assuming the same use in each 15-minute interval for the hour, 50% of the uplift cost is allocated to the ISO balancing authority, EIM Entity A receives 33%, and EIM Entity B receives 17% of the total hourly cost allocation. The ISO will not change the billing determinant to Scheduling Coordinators it its BAA, thus the 50% share of the costs will be allocated based upon the existing billing determinant established by the ISO tariff. For EIM Entity A and EIM Entity B, the total costs will be allocated to the EIM Entity Scheduling Coordinators. The EIM Entity will then allocate the costs within its BAA based upon the cost allocation rules of the EIM Entity. There is no requirement that the cost allocation within and EIM Entity is the same as used by the ISO in its BAA.

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 WECC by the total annual energy usage of WECC 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

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 encompass 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[8] 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 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

The EIM cost of $96M divided by the allocated volume of 500 TWh yielded a rate of $0.19 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

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

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. 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 anticipate engaging industry leaders and regulators from across the West to develop specific governance options that can be implemented on the same timeline as the new market. We will publish a proposal for stakeholder consideration in August, 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.

3.9. 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. 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.

3.10. 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 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 if additional balancing authorities consider participating in EIM. In any event, any EIM transmission service rate should be the same across all EIM Entities. 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 on an as-available basis,

- 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.

Further details of these alternatives are as follows:

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

Not charging for EIM use of transmission should either be considered at least 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 energy imbalance market 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. A question to be addressed is whether there are needs for an EIM Entity or EIM Participating Resource within an EIM Entity to have arranged transmission service (e.g., network service, point-to-point service, or non-firm service) to or through transmission systems in other EIM Entity Areas.

Alternative 2: EIM Transmission Access Charge:

The second 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 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, 90% of each transmission provider's revenue requirement could be recovered 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.. 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 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 BAAs. 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 BAA. A transition mechanism applied over a 10-year period from the original utility-specific rates to the single grid-wide rates. 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 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. 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. Indeed, in studies of the potential benefits of EIM implementation, using an hourly model, "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.

In considering what transmission cost recovery is appropriate, the following guiding principles should be considered:

> **Principle 1**: There should be no pancaking for transmission service,
>
> **Principle 2**: Each transmission owner should meet its transmission revenue requirement,
>
> **Principle 3**: Resource owners should not have to estimate or attempt to incorporate where their production is going, as part of their supply bids,
>
> **Principle 4**: The implementation cost of a transmission access charge approach should be consistent with the magnitude of the total transmission costs expected to be incurred through EIM operations and recovered in EIM-related rates, and
>
> **Principle 5**: The transmission charge should be consistent regardless of whether the EIM Participating Resource is operated by an EIM Entity. In other words, transmission cost recovery should not be affected by whether or not a load is the native load of the business entity that also is the transmission provider.

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 and 2 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 of Alternative 1, to have no transmission charge between the ISO and EIM Entities during the first year of EIM operation, as alternatives are considered further in the long-term.

3.11. Process for New EIM Entities Joining

New balancing authorities joining the EIM must pay the initial fee provided in this proposal. This payment would be established through an implementation agreement for commitments between now and the startup of the EIM, but may be established through a specific rate filed by the ISO as part of the EIM market rules on a going forward basis.

The ISO encourages balancing authorities interested in participating in the EIM to engage with the ISO as early as possible. Implementation requires sufficient time for the associated network model and other system changes to be accomplished. Accordingly, the opportunity for balancing authorities to participate as part of the initial EIM implementation will necessarily depend on the complexity of the entity's system and the timing of their commitment.

The ISO anticipates that later implementations will be established based on an annual commitment cycle with an associated 12-18 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 and fall software release cycles. Details concerning this process will be further considered with stakeholders and established in the EIM market rules.

3.12. Greenhouse Gas Emission Costs for Imports into California

The ISO is committed to working with CARB and all market participants through this stakeholder process to ensure that greenhouse gas (GHG) costs are accounted for properly.

Entities that import energy have an obligation to surrender compliance instruments to the California Air Resources Board (CARB) for greenhouse gas emissions under the California Greenhouse Gas Cap regulations for the emissions associated with the imported energy. In the ISO's existing day-ahead and real-time markets, import resources include the cost for acquiring these compliance instruments in their submitted energy bids. However, this practice 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 Greenhouse Gas compliance obligation.

In order to achieve an efficient dispatch of resources inside the EIM area, the dispatch algorithm will evaluate the differences in GHG costs that these resources incur so that the energy from a renewable resource may be differentiated from that of a non-renewable resource.

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 a similar fashion 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 different costs for GHG emissions that take into account the resources' individual emission properties when adding GHG costs to energy produced from those resources selected for import into California.

The Security Constrained Economic Dispatch (SCED) formulation in RTUC and RTD can be modified to address these requirements. In the following we will introduce a method for real-time optimal dispatch that accounts for the greenhouse gas emission costs of resources in EIM Entity BAAs.

3.12.1. Expanded SCED with GHG Emission Costs

The offer cost for generators at nodes inside California will include the cost of any necessary GHG emissions. 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 stay outside California, it will not be required to procure GHG allowances and so the cost can be excluded from its offer price. If it is deemed to flow into California, the EIM participant scheduling coordinator will be responsible for procuring adequate GHG allowances and so the GHG allowance 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 generators outside California for import into California and make the EIM participant scheduling coordinators of the generators responsible for any GHG allowances needed
- Include costs of necessary GHG emissions in the dispatch cost of generators outside California that produce energy deemed to be imported into California
    - Generators outside California that are clean resources and deemed to import energy into California will not be required to procure GHG allowances and so have GHG related costs of $0/MWh.
    - Generators outside California that are not clean resources and deemed to import energy into California will be required to procure GHG allowances to cover their emissions and 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.
    - Generators outside California that are deemed to import energy into California can be subject to the GHG costs that depend upon their emission characteristics.
    - EIM Participating Resources whose energy is deemed to serve load outside California would not be assessed greenhouse gas emission costs.
    - Load in EIM Entity BAAs outside California will not be assessed greenhouse gas 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.
e_j	greenhouse gas emission factor for generator at node j.
C_G	Greenhouse gas emission cost rate.
$S_{i,k}$	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.

A simplified mathematical formulation is as follows:

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

subject to:

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

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

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

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 greenhouse gas emission revenue is calculated as follows:

$$R_G = -\eta\ E$$

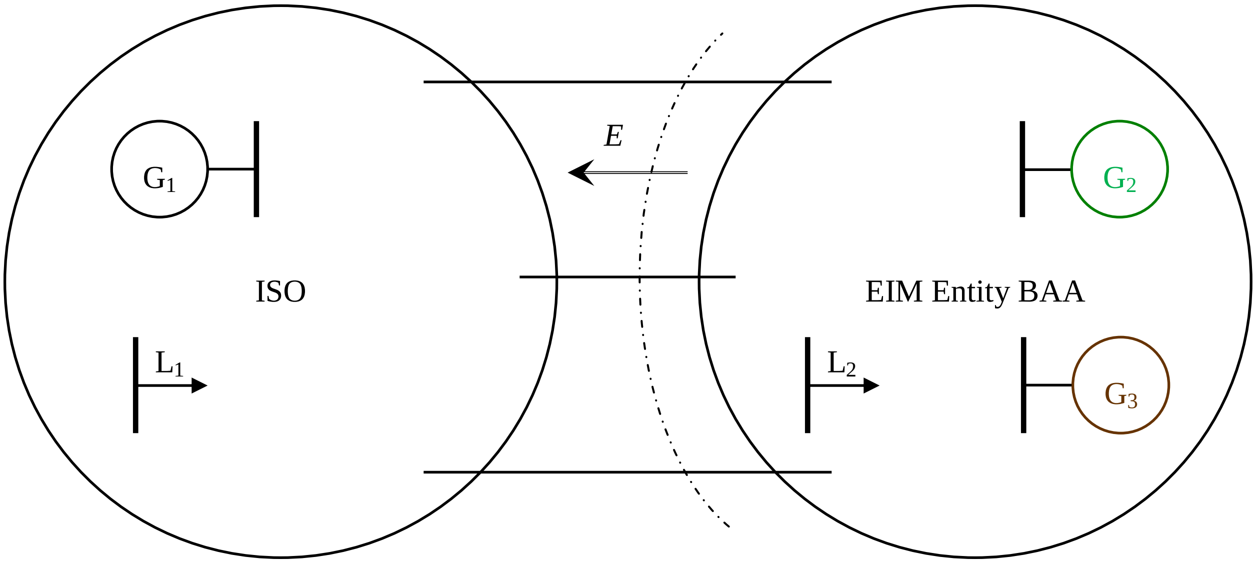
This revenue is then distributed to the optimal net imbalance energy export allocations as follows:

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

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

3.12.1.1. 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)	Bid ($/MWh)	Emission Factor	Emission Rate ($/MWh)
G_1	0	300	50	-	6
G_2	0	200	35	0.0	
G_3	0	200	30	1.0	

Generator G_2 is a non-emitting resource with an emission factor of zero, whereas G_3 is an emitting resource with an emission factor of one. 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: $\mu = -\$15/\text{MWh}$; $\eta = -\$5/\text{MWh}$

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 emission 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 emission 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 emission cost can be easily verified if the export allocation (which carries the emission 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 emission cost in the optimal solution even when all the exported energy is allocated to the “green” resource G_2. This is because the cost of that energy is $5/MWh higher than otherwise available energy from G_3.

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

Resource	Energy Cost	Emission Cost	Total Cost	Energy Payment	Export Allocation 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		
Emission Revenue				$500		

Where it is assumed that emission 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 emission costs.

3.12.1.2. Example 2

This is a variation on the first example where <u>G_3 reduces its bid price to $28</u> to become a more competitive exporter compared to G_2, taking into account the additional emission cost 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: μ = –$16/MWh; η = –$6/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 emission 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 emission 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 emission 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 emission cost of \$6/MWh on a 100MWh energy export result in a congestion revenue of \$1,600 and an emission revenue of \$600, respectively. Assuming that the emission revenue is distributed to the optimal export allocations, the settlement is as follows:

Resource	Energy Cost	Emission Cost	Total Cost	Energy Payment	Export Allocation 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.

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

Resource	Energy Cost	Emission Cost	Total Cost	Energy Payment	Export Allocation 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 emission costs.

3.12.1.4. Example 4

This is a variation on the third example where the available maximum capacity of G_3 is restored to 200MW while the power transfer capability is increased to 300MW. The purpose of this example is to show that the LMP in the ISO would include the greenhouse gas emission 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 and G_3 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	50	50	29
G_3	200	150	29

Example 4: μ = \$0/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 emission 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. G_2 is marginal for serving L_1 and sets the LMP in the CAISO to \$35/MWh.

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

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

Resource	Energy Cost	Emission Cost	Total Cost	Energy Payment	Export Allocation Payment	Total Payment
G_1	$0		$0	$0		$0
G_2	$1,750	$0	$1,750	$1,450	$300	$1,750
G_3	$4,200	$900	$5,100	$5,800	$900	$6,700
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 emission costs.

3.12.2. 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 emission costs, not in terms of their physical location.
- Each supply resource in an EIM Entity BAA is registered with a greenhouse gas emission factor that reflects greenhouse gas emissions per unit of generated power.
- The product of the greenhouse gas emission cost rate and the greenhouse gas emission factor for each supply resource in an EIM Entity BAA represents a cost to the respective EIM Participating Resource Scheduling Coordinator for acquiring the necessary greenhouse gas emission credits required by CARB for energy imports to California. This cost 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 greenhouse gas emission cost. Otherwise the net imbalance energy export allocation constraint is binding and it may have a nonzero shadow price.
- Greenhouse gas emission 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 can be seen as a cost adder to the marginal energy component to reflect the marginal cost of greenhouse gas emission credits in EIM Entity BAAs. 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 greenhouse gas emission credits 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 in no impact on existing Market Participants that would not have to modify their systems to account for this fourth component.
- As a result of the imbalance energy settlement, the ISO would collect greenhouse gas emission 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 greenhouse gas emission 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.

3.13. Other Items

3.13.1. Market Monitoring

The EIM shall include market monitoring, which services shall be provided by the ISO Department of Market Monitoring (DMM) and 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.

3.13.2. Third Party Arrangements

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.

3.13.3. 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.

3.13.4. 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.

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