California ISO
Shaping a Renewed Future

Energy Imbalance Market

Design Straw Proposal

and Issue Paper

April 4, 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 every hour 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 (CAISO) provides this energy imbalance market service today to its existing customers through advanced systems that automatically balance deviations every five minutes. The CAISO's real-time market and 5-minute dispatch systems have been tested and proven to be effective over four years, and now the CAISO offers to extend this service to other balancing authorities in the west. By extending its existing infrastructure, the CAISO can offer the EIM services to other balancing authorities at low cost and low risk to new participants. The CAISO approach is also highly scalable, meaning that new entities can be added incrementally when they are ready. Added participation brings economic benefits to both the new customers and existing customers of the CAISO.

Industry leaders in the west have explored and promoted the energy imbalance market 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 CAISO 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 CAISO proposal, leading to a memorandum of understanding early in 2013. In March of 2013 the CAISO 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 anyone in the west to take advantage of this important service.

The EIM provided by the CAISO allows other Balancing Authorities to leverage the benefits of real-time balancing while also maintaining all of their existing authority. Balancing Authorities remain responsible for procurement or self-provision of reserves and other ancillary services. The EIM does not change National Electric Energy Reliability Corporation (NERC) and WECC responsibilities for resource adequacy, reserves, or other balancing authority area reliability-based functions for the EIM Entity.

EIM does, however, change how participating balancing authorities deal with imbalances in real time. All Balancing Authorities start the hour with matched generation and forecasted load. Imbalances occur within the hour because load and generation typically vary slightly from what is forecasted. Resources within the EIM area can voluntarily provide bids to dispatch their facilities to manage these imbalances. The EIM will automatically look across the expanded EIM region and dispatch the most economical bids available to meet these imbalances. The real-time optimization determines the least cost mix of resources and dispatches them to resolve these imbalances while also respecting limits on the transmission system to alleviate 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 dispatching every five minutes using a security constrained economic dispatch. The CAISO EIM model:

a) Leverages the CAISO's existing five-minute market so the resources within the EIM Entity can be economically and automatically dispatched in real time. The EIM dispatches 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) Enhances reliability through real-time visibility and situational awareness of resources and transmission across the CAISO and EIM footprints.

c) 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) Potentially reduces the quantity of reserves required, by accessing a wider portfolio of resources to ensure electricity is available where and when it is needed.

e) Provides easy and economical entry/exit. New EIM participants will pay for set-up costs based upon the size of their system and will pay ongoing fees depending upon their participation level. Over the long term as volumes increase, EIM participation is expected to put downward pressure on existing administrative charges for all participants.

As new Balancing Authorities join the EIM, additional annual benefits will accrue to both the new customers and the existing CAISO customers, as well as EIM customerss that are already participating.

The stakeholder process initiated with this paper will address issues in two categories – detailed implementation issues in Section 3 and high level policy issues in Section 4. The detailed implementation issues include, for example, scheduling processes, outage management, and settlement/accounting. The high level policy issues include a range of matters including a process for new entities to join the market, the role of EIM participants in market design and oversight, and how to manage transmission usage charges.

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

2. Introduction

2.1. Structure of the Paper

This paper is organized into three substantive sections:

Section 2 provides the plan for stakeholder engagement associated with developing the EIM design.

Section 3 outlines the EIM design straw proposal. The design straw proposal details the existing CAISO real-time market processes which will be leveraged to implement EIM. In addition, the straw proposal incorporates the CAISO real-time market changes being contemplated for compliance with FERC Order No. 764.

Section 4 describes portions of the EIM design and policy that require additional input from stakeholders to develop a straw proposal. As a result this section guiding describes principles or current thinking regarding such EIM policy elements.

The paper also uses two new terms:

EIM Entity is a balancing authority area that is enabling EIM to occur in their area. By enabling EIM, load and generation imbalances within the balancing authority will settled through the EIM.

EIM Participant is a resource within the EIM Entity represented by a Scheduling Coordinator that has voluntarily elected to economically participate in the EIM.

2.2. Plan for Stakeholder Engagement

Stakeholder input is essential and often critical for the success of new initiatives from policy development to implementation. The CAISO 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 straw proposals, meetings and written stakeholder comments. Stakeholders should submit written comments to EIM@caiso.com.

Table 1 below lists the planned schedule for the EIM stakeholder initiative.

Item	Date
Post Straw Proposal	April 4, 2013
Stakeholder Meeting (Folsom)	April 11, 2013
Stakeholder Comments Due	April 19, 2013
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 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 five-minute dispatch in the combined network of CAISO 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. If necessary prior to economic dispatch through EIM, the base schedules for the generating units that the EIM Entity has provided will be adjusted by Market Operator (i.e., CAISO) prior to the start of the imbalance energy market optimization to alleviate transmission congestion in the EIM Entities’ network that is caused by base schedules. The 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. CAISO role as Balancing Authority

There is no impact to the current NERC functional entity (e.g., BA, GOP, LSE, TOP) responsibilities of the CAISO. Current functions (e.g., ancillary services, operating reserve management, AGC balancing of load and resources, SOL and IROL management, DCS recovery, voltage control, etc.) will be handled by the CAISO.

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

3.1.2. CAISO as Market Operator of EIM

The EIM provides the majority of the energy imbalance needs of multiple balancing authority areas (BAAs). As the Market Operator, the CAISO will only dispatch resources that are online and for which the EIM Participant has provided energy bids for EIM dispatch. The Market Operator will not commit, start-up or shut down any resource in the EIM Entity’s area.

If a market run indicates congestion in the future time intervals, the Market Operator will notify the EIM Entity through dispatch instructions to 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., BA, GOP, LSE, TOP) responsibilities of an EIM Entity. Current functions (e.g., ancillary services, operating reserve management, AGC balancing of load and resources, SOL and IROL management, DCS recovery, voltage control, etc.) 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 BA, 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 interchange schedules are below the associated inter-tie limits and make any reliability curtailments as required. The EIM Entity will also be responsible for 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 is correct for the real-time market optimization. This includes scheduled outages, forced outages, and lack of telemetry (no telemetry, telemetry failure, modeling of outages in outage system).
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. Meeting established criteria for submission of "balanced schedules" consistent with the EIM rules.
i. Communicating any changes to interchange schedules (real-time curtailments) to the Market Operator, as updates to its base schedule 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 may be an impact on the EIM Entity's interaction with entities within its BAA, such as definition of an Hourly Pricing Proxy used to settle energy imbalance under Schedule 4 and generator imbalance under Schedule 9 of its open access transmission tariff (OATT). With the activation of the EIM, the locational marginal price (LMP) at the corresponding resources and load will provide a basis that could be directly used to settle energy imbalances. The Market Operator will settle with the scheduling coordinators (SCs) that represent resources in the EIM, and the SCs will have all details needed about the MW deviation and settlement charges for their resources. The EIM Entity may choose to pass these charges to the resources/load causing the energy imbalance, or continue to use their existing Hourly Pricing Proxy.

3.1.4. Role as EIM Participant

The EIM Participant can voluntarily submit economic bids to the EIM through their scheduling coordinator. The EIM Participant will submit outages electronically into the designated outage reporting system using mutually agreed format. The CAISO currently uses a system referred to as SLIC which will be upgraded in the future to the Outage Management System (OMS). The EIM Participant will manage all of their 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.

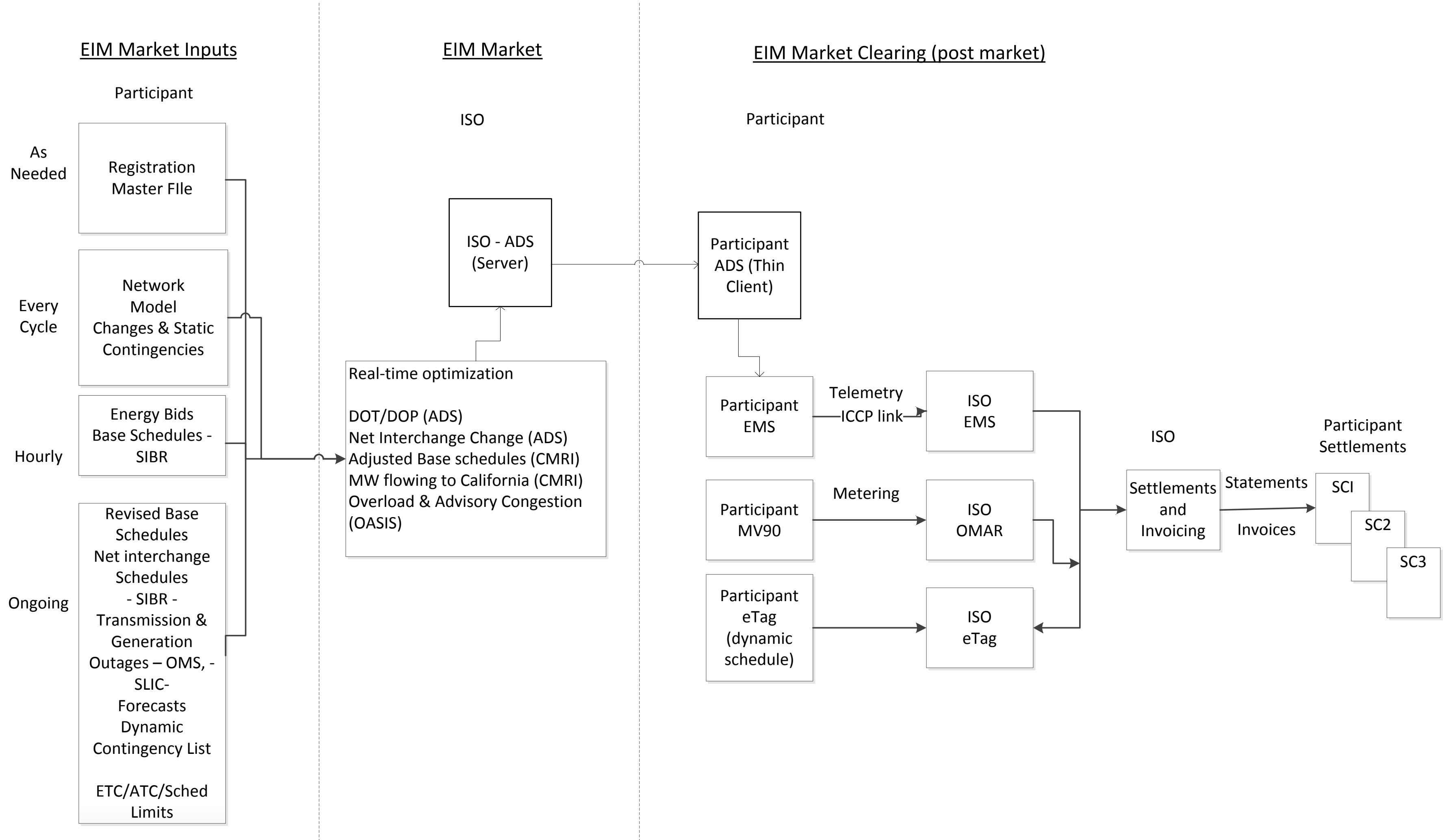

Figure 1 – Energy Imbalance Market Processes

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[1] 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 market requires the exchange of a variety of information between the systems of the Market Operator, EIM Entity and EIM Participants. The timeline shown in Figure 1 highlights the key activities of the Market Operator and EIM Participant. EIM Participants 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 is by 10:00 seven days preceding the operating day.

Energy bids may be submitted or revised as early as 7 days prior to the operating day; however, final energy bids must be submitted by 75 minutes prior to the operating hour. The EIM Participant indicates that a resource is available for dispatch through EIM by submission of an energy bid as part of its resource plan.

Base schedules, with a granularity of 15 minutes, must also be submitted by 75 minutes prior to the beginning of that hour, and may be updated in real-time, as frequently as every 5 minutes, until 40 minutes before the start of the relevant 15-minute market.

In the real-time horizon, 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 and interchange scheduling points. Interchange schedules with the CAISO BAA are arranged currently in the Hour-Ahead Scheduling Process, and will occur instead in RTUC once the CAISO's implementation of FERC Order No. 764 occurs. EIM Participants may make their bids available for consideration in RTUC. If the EIM Entity is using 15-minute base schedules, no unit commitment decisions are made by market optimization in the EIM Entity, nor is unit commitment made in the CAISO area for unbalanced base schedules or unresolved congestion in the EIM Entity because the base schedules are adjusted for balancing and feasibility; and
2) The Real-Time Dispatch (RTD), which runs every 5 minutes and produces 5-minute dispatch instructions and 5-minute LMPs within the EIM and interchange scheduling points.

[1] 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

Load forecasts and resource plans (including ancillary service plans) will be submitted via the SIBR system. RTUC contains a pre-process before the joint market optimization to ensure that 15-minute base schedules are balanced and feasible, considering transmission losses and any congestion within the EIM Entity. 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 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 to this condition. The RTD starts from the calculated 15-minute adjusted base schedules, which were validated prior to the 15-minute RTUC to ensure balancing and congestion free schedules in the EIM Entity.

Both RTUC and RTD have multi-interval time horizons where the outcome for the first interval in the horizon is physically and 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 adjusted 15-minute base schedules.

The Market Operator shall calculate, and EIM Entity shall 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. Reserve sharing schedules identifying resources may be updated until three days after the operating day.

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 Participant Action**	**Market Operator Action**
OD-7 by 10:00, to OD-1 by 10:00 By OH-75 minutes: updates to energy bids (OD is operating day. OH is start of operating hour.)	EIM Participant submit load forecasts, resource plans, and ancillary service plans. 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.

Activities Prior to Operating Hour		
Timeline (Pacific Prevailing Time)	**EIM Participant Action**	**Market Operator Action**
OD-7 by 18:00, to OD-1 by 18:00		For the next 7 days, the Market Operator will post hourly load forecasts by load aggregation point. The Market Operator will continue to update load forecasts during OD.
By 10:00 of OD-1	EIM Participant update submit load forecasts, resource plans, and ancillary service plans	Review EIM Participant load forecasts, resource plans, and ancillary service plans upon submission, and notify EIM Entities and EIM Participants when they do not balance and/or mismatched.
By 13:00 of OD-1		Notify applicable EIM Entities and EIM Participants of anticipated congestion based on submitted resource plans, to allow adjustments to resource plans prior to real-time to mitigate congestion.
By OH–75 minutes	Submission of bids, base schedules, and resource plans for OH.	Bid validation and processing. Base schedule adjustment after OH–75 minutes.
By T–40 minutes	Submission of base schedule update for 15min interval starting at T.	Base schedule adjustment after T–37.5 minutes.

Operating Hour Activities		
Timeline	**EIM Participant 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).	Approve tags.
Beginning of dispatch interval –7.5 minutes		1. Update load forecast for dispatch interval 2. Transfer latest state estimator solution to market system 3. Process updated self-schedules 4. Calculate Security Constrained Economic Dispatch (SCED)
Beginning of dispatch interval -2.5 minutes		Send dispatch instructions for the middle of the dispatch interval via ADS and ICCP, and publish LMPs for the dispatch interval via ADS and OASIS.
Beginning of dispatch interval -2.5 minutes	Begin ramp to achieve dispatch instructions for middle of dispatch interval	MO-calculated NSI reflects the ramp in 4-second values, including the impact of congestion management and reserve sharing events.
Middle of dispatch interval	Resources at instructed levels	
Within OH + 15 minutes		LMP for hourly settlement interval for net interchange available, including meter settlement locations.

Operating Hour Activities		
Timeline	**EIM Participant Action**	**Market Operator Action**
Approximately every 4 seconds		Net Scheduled Interchange (NSI) is modified and sent out to balancing authorities to support the ramp to achieve the dispatch instructions. The NSI accounts for the impacts of congestion management and reserve sharing events.
Within OH + 60 minutes	Estimated dynamic schedules may be updated	Checkouts among balancing authorities, including dynamic schedules

Post-Operating Day Activities		
Timeline	**EIM Participant Action**	**Market Operator Action**
3 days after the OD		Initial settlement statements by settlement location, hour, and EIM Participant
By 48 days after the OD	Submit 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 Participant

Updates to Operating Day Data		
Timeline	**EIM Participant Action**	**Market Operator Action**
Immediately following a reserve sharing event	Deploy energy in response to the reserve sharing event. Submit Assisting Balancing Authority Area Load to Contingent Balancing Authority Area Load schedules, for each participant involved in the reserve sharing event. One schedule is created from the Contingent Balancing Authority Area Load to the Contingent Resource for the amount lost.	Receive schedule for the amount lost, as created by reserve sharing from the Contingent Balancing Authority Area's load settlement location to the Contingent Generator Resource's settlement location, for the resources expected to be deployed in response to an event, pursuant to the reserve sharing group's criteria.
0100 following the OD+3 containing the reserve sharing event	EIM Participants have 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 for use in Settlement.	

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 accept static intertie imports and exports.

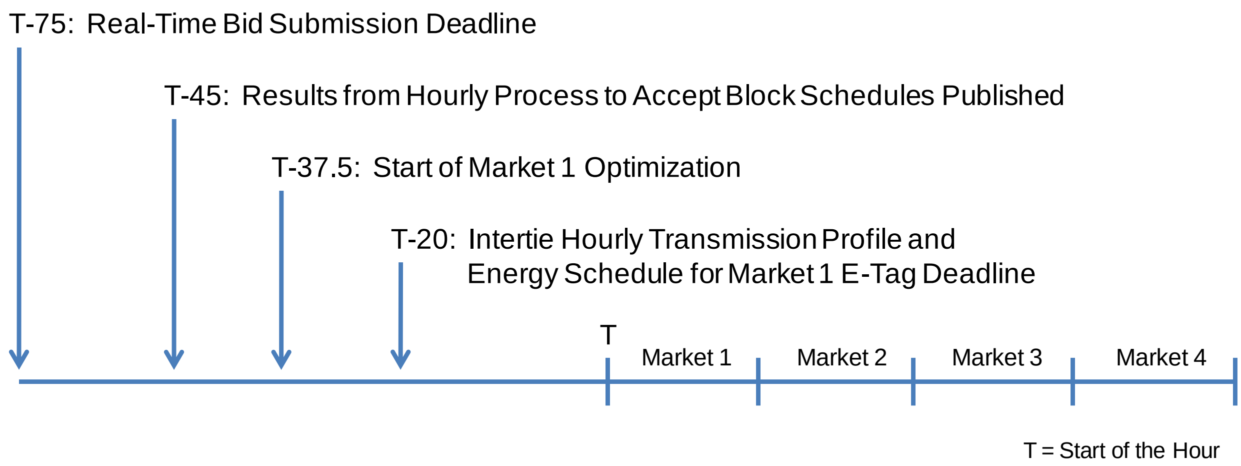

Figure 2. *Timeline of Hour-Ahead Scheduling Process*

The hour-ahead schedules produced by the T-75 run for the four 15-minute markets shown in 2 above are advisory; nevertheless, the hourly static intertie schedules across these intervals, as determined by the hour-ahead process, will be held fixed (price taker) 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 CAISO direction for implementation of FERC Order No. 764.

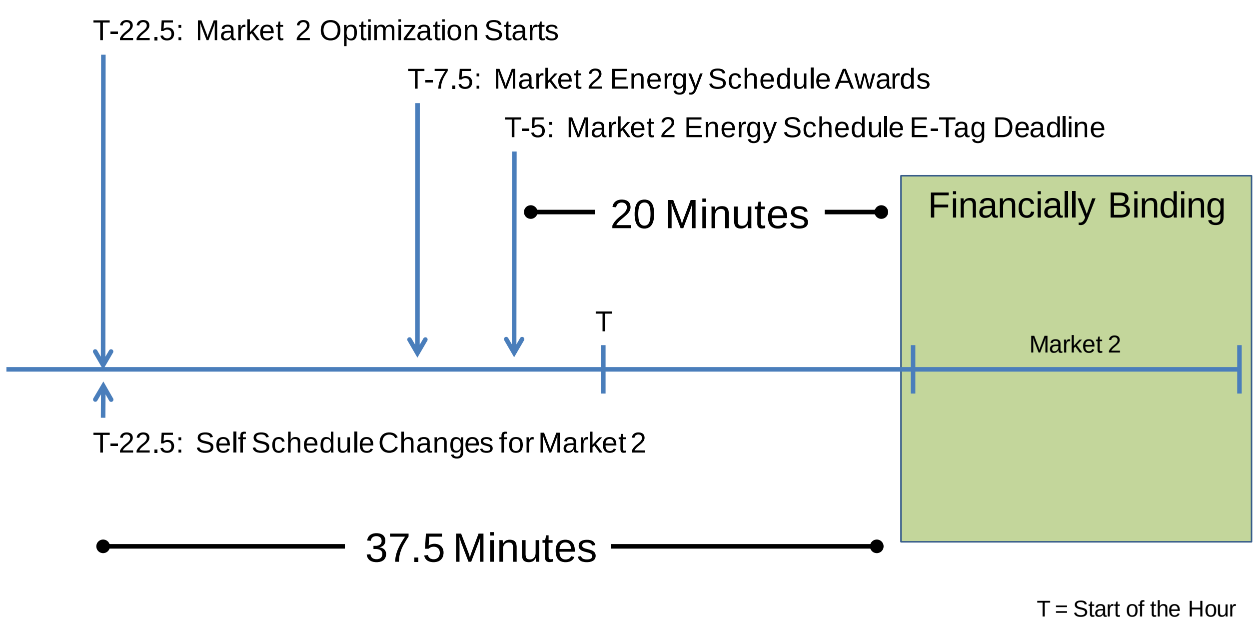

Figure 3. *Timeline of 15-Minute Real-Time Market*

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

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

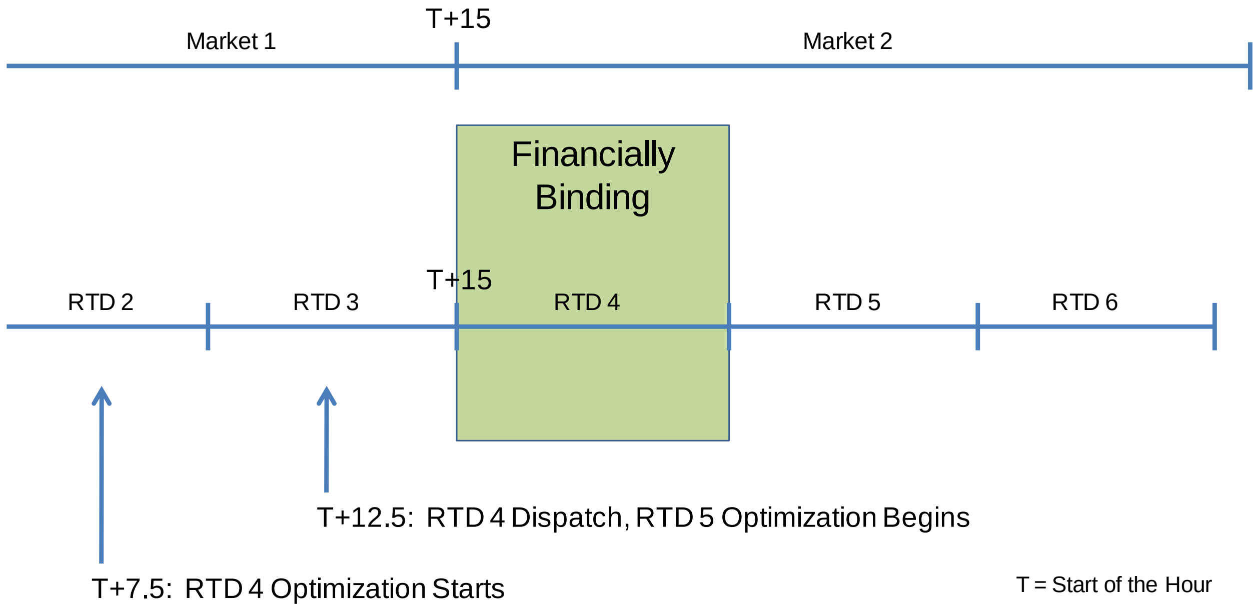

Figure 4. *Timeline of 5-Minute Real-Time Market*

3.3. EIM Input Data

3.3.1. Registration of Market Resources (Master File)

The EIM Participant will use a resource data template (RDT) to submit resource characteristics (such as ramp rates, start up times) into the Market Operator's Master File. EIM Participant unit bids will be treated as Dynamic Resource Specific System Resources. There will be an EIM service agreement, still to be defined; however, there is no certification requirement anticipated for an EIM Participant.

Mill points for coal fired generating units will be handled manually unless it fits into the CAISO's "forbidden operating region" definition or "multi state generation" model.

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). If provided using 5-minute intervals, the 5-minute base schedules may be flat across 15-minute intervals, or even the entire hour, as applicable. The 5-minute base schedules would be averaged to yield 15-minute base schedules for use in RTUC. 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 must submit base schedules for all EIM Entity resources and external system resources outside the EIM footprint with import/export schedules between the EIM Entity and other BAAs, which must have balanced supply and demand (including estimated losses). These base schedules should balance day-ahead import/export schedules with CAISO and the EIM Entity demand forecast; they should reflect all forward market schedules, bilateral contracts, variable energy resource (VER) forecasts, and estimated transmission losses.

Generation schedules used to create the EIM Entity's base schedule must be submitted at individual generating resources for all resources including third-party generators, and must include disaggregation of day-ahead import/export schedules between the EIM Entity and CAISO, and disaggregation of forward export schedules to other BAAs. Base import schedules from BAAs other than CAISO must be submitted at the relevant BAA scheduling points with EIM Entity. The EIM Entity may choose not to submit base load schedules prior to day-ahead, because these can be derived from the Market Operator's demand forecast for the EIM Entity, estimated transmission losses, and an assumed distribution of generation. However, for more accurate loop flow calculations in day-ahead, the Market Operator requests that EIM entity submits its expected actual distribution of its balanced generation and demand forecast, prior to 10:00 the day before the operating day. The Market Operator performs preliminary runs for two additional future days following its execution of the CAISO day-ahead market, and would be able to advise EIM Entities of congestion within their BAAs that would result from the base schedules. If submitted in day-ahead, the Market Operator will use the submitted demand forecast as a starting point for the balancing the base schedules with transmission losses in day-ahead and to calculate the base flows and loop flows in the network before starting the CAISO day-ahead market. For real-time market, the Market Operator will use its demand forecast for the EIM Entity. The Market Operator also encourages the EIM Entity to update the balanced demand and generation base schedule in real-time prior to 40 minutes before each 15-minute interval as a backup measure in case Market Operator's RTUC results are not available or usable.

3.3.3. Load Forecast

The Market Operator uses load forecast information for the following EIM purposes:

- Determine amount of resources necessary to be dispatched by the market
- Estimate the amount of market flow on flow gates for the next-hour
- Perform simultaneous feasibility studies
- Determine supply adequacy for submitted base schedules

3.3.4. EIM Participant Load Forecasting

By 10:00 on the day prior to the operating day, each EIM Participant that has registered a load settlement location must submit to the Market Operator the amount of load it expects to serve, by settlement location, for each hour of the next operating day. The EIM Participant must update its forecast for each operating hour by 75 minutes prior to that operating hour, as part of its base schedule in the SIBR system. The Market Operator uses the load forecasts provided by the EIM Participants to evaluate their resource plans, and to compare with load forecasts submitted by balancing authorities and load aggregation point forecasts developed by Market Operator. The EIM Participants' load 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 total load will be calculated by summing the load meter and the generator meter.

The Market Operator will use the load forecasts submitted by the EIM Participants to verify that each EIM Entity has committed sufficient capacity to supply its demand. To ensure that the EIM Participant load forecasts are reasonable for this purpose, the Market Operator will aggregate the load forecasts submitted by EIM Participants by balancing authority area and compare to the forecasts developed by the Market Operator and EIM Entity. The Market Operator will investigate and analyze where significant differences exist.

3.3.5. Market Operator Load Forecasting

The Market Operator develops short-term and mid-term forecasts by load aggregation point within EIM Entities. The short-term forecast produces a value every 5 minutes for the duration of the Market Operator's dispatch horizon, which extends from 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 load forecasts along with self-schedules within base schedules, including interchange schedules into and out of the EIM footprint (EIM Entity and CAISO), to determine the amount of supply to be dispatched by the market for the upcoming dispatch interval. The mid-term forecast is an input used to estimate the amount of market flow on flow gates for the next-hour and to perform simultaneous feasibility studies. To ensure that the Market Operator's forecasts are reasonable for these purposes, the Market Operator will compare its forecasts with the forecasts submitted by EIM Participants and EIM Entities. The Market Operator may use a combination of the available forecasts, combined with its current state estimator solution, to produce the forecast used for EIM dispatch.

3.3.6. Load Scheduling Requirements

The demand included in EIM Participants' base schedules is not required to match their actual firm demand at each settlement location in each dispatch interval, but EIM Participants that do not schedule load accurately may be subject to adjustment disgorgement off imbalance energy payments attributable to inaccurate scheduling profits. As described in other sections, the Market Operator will provide an hourly load forecast for all load aggregation points within the EIM footprint by 10:00 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 Participants may choose to submit their resource plans to match the Market Operator's forecast, and by doing so, 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. In addition, the availability of virtual bidding in the CAISO'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 CAISO's BAA.

If the EIM Entity does not use the Market Operator load forecast to set balanced base schedule prior to the start of the EIM optimization, under- and over-scheduling charges may apply to EIM Participants whose resource plans do not match the Market Operator's load forecast. In the Southwest Power Pool, determination of the revenue subject to potential disgorgement for failure to schedule load accurately is based on the following principles. These principles will be reviewed in the CAISO's EIM stakeholder process:

3.3.6.1. Charges for Under-Scheduling

During any hour, if LMPs diverge and a EIM Participant's load imbalance is more than 4% (but at least 2 MW) at an applicable settlement location in that hour, that EIM Participant 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), under-scheduling charges will be determined as follows:

a) For resource settlement locations, the Market Operator shall sort the Market Participant's negative imbalance energy amounts in ascending order according to each resource's LMP.

b) For load settlement locations at which scheduled load is less than 96% of reported load and the imbalance is at least 2 MW, the Market Operator shall sort the EIM Participant's positive imbalance energy amounts in ascending order according to each load's LMP.

c) Utilizing the sorted lists above, and starting with the resource with the lowest LMP, the Market Operator shall match each resource's imbalance energy against that EIM Participant's load imbalance energy, starting with the load imbalance energy with the lowest associated LMP, until all of the load imbalance energy has been accounted for or until no additional resources remain.

d) The following calculation is performed only for resources that have a LMP greater than the LMP for the associated load settlement location. An EIM Participant's under-scheduling charge, for each resource identified as being required to match that Market Participant's load imbalance energy, shall be calculated as follows:

   Resource Under-Scheduling Charge = (LLMP – RLMP) * Resource Imbalance Energy,

   where

   RLMP = LMP of the resource settlement location,

   LLMP = LMP of the associated load settlement location,

   Resource Imbalance Energy = the amount of that resource's imbalance energy required to offset the EIM Participant's load imbalance energy.

3.3.6.2. Charges for Over-Scheduling

During any hour, if LMPs diverge and a EIM Participant's Load imbalance is more than 4% (but at least 2 MW) at an applicable settlement location in that hour, that EIM Participant 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), over-scheduling charges will be determined as follows:

a) For resource settlement locations, the Market Operator shall sort the EIM Participant's positive imbalance energy amounts in descending order according to each resource's LMP.

b) For load settlement locations at which scheduled load is greater than 104% of reported load and the absolute value of the imbalance is at least 2 MW, the Market Operator shall sort the EIM Participant's negative imbalance energy amounts in descending order according to each load's LMP.

c) Utilizing the sorted lists developed above, and starting with the resource with the highest LMP, the Market Operator shall match each resource's imbalance energy against that EIM Participant's load imbalance energy, starting with the load imbalance energy with the highest associated LMP, until all of the load imbalance energy has been accounted for or until no additional resources remain.

d) The following calculation is performed only for resources that have a LMP less than the LMP for the associated load settlement location. A EIM Participant's over-scheduling charge, for each resource identified as being required to match that EIM Participant's load imbalance energy, shall be calculated as follows:

   Resource Over-Scheduling Charge = (LLMP-RLMP) * Resource Imbalance Energy,

   where

   RLMP = LMP of the resource settlement location,

   LLMP = LMP of the associated load settlement location,

   Resource Imbalance Energy = the amount of that resource's imbalance energy required to offset the EIM Participant's load imbalance energy.

3.3.7. 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, load forecasts, and the Market Operator's state estimator to determine the dispatch instructions for EIM resources, the resulting market area NSI calculations, and the calculation of EIM charges. Resource plans include ancillary service plans, which the Market Operator uses to ensure that EIM deployment does not consume unloaded capacity that is reserved for ancillary services. Resource plans may designate operating reserves and regulation in excess of their obligations for reliability purposes. This data will be submitted via the SIBR system.

Base schedules are not required to match forecasted demand, but (1) EIM Participants will not be paid for providing counterflow through EIM dispatches that are required due to under-scheduling of native load plus net interchange, and (2) EIM Participants will not be allowed to profit from scheduling supply in excess of their native load plus net interchange.

If the EIM Participant submits both a schedule for a resource as part of its base schedule, and a bid for EIM dispatch, the base-scheduled output will affect its settlement, but dispatch instructions will be based on the bid price as well as the information in the resource plan.

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

- Resource ID - Unique identifier for resource in EIM
- Resource Type - Generation or Controllable Load
- Operating Day
- Operating Hour
- Planned Megawatts – Initial operating point of resource, as part of the base schedule, prior to EIM dispatch
- Regulation Reserve MW – Up/Down[2]
- Operating Reserve MW – Spinning
- Operating Reserve MW – Supplemental
- Minimum Capacity Operating Limit – Resource's physical minimum sustainable output for each operating hour ("Pmin")
- Minimum Economic Capacity Operating Limit – Resource's economic minimum output for each operating hour, equal to or greater than Minimum Capacity Operating Limit.
- Maximum Capacity Operating Limit – Resource's physical maximum sustainable output for each operating hour ("Pmax")
- Maximum Economic Capacity Operating Limit – Resource's economic maximum output for each operating hour, equal to or less than value provided for Maximum Capacity Operating Limit.
- Ramp Rate - Rate at which the resource can change output, in MW/min

[2] In principle, imbalance energy bid limits could be used to indicate the available range of MW for EIM, without knowing whether the unavailable capacity is reserved for regulation or operating reserve for satisfying reliability functions by the EIM entity. However, the information about type of reserve can inform the Market Operator anticipate how the reserved capacity will respond in real-time operations: regulation capacity can be expected to have frequent variation under the EIM Entity's AGC control, spinning reserve would remain reserved except when contingencies occur, and non-spinning reserve could similarly be dispatched by the EIM Entity in contingencies even if telemetry shows it is off-line at a particular moment.

- Breakpoint Limit 1– Resource MW output at which segment 1 Ramp Rates will apply. If the value is not less or equal to actual measured MW during deployment, the values in segment 1 will apply back to the actual measured MW.
- Block 1 Rate – Rate at which Resource can change output upward in MW/min at output levels greater than or equal to Breakpoint Limit 1.
- Breakpoint Limit *n*– Resource MW output at which Ramp Rate changes from previous segment values to segment *n* values.
- Block *n* Rate - Rate at which Resource can change output upward in MW/min at output levels greater than or equal to the Breakpoint Limit *n*

EIM Participants will submit their ramp rates through a segmented profile. The profile will require at least one segment and may have up to *n* segments where *n* will be defined by Market Operator, currently set to 2. For multi-stage generating resources (e.g., combined cycle generation), this number applies separately to each resource configuration. For example, a combined cycle generator with four configurations may have 8 ramp rate segments in total.

Resources are considered self-committed in a particular hour if they submit a self-schedule for energy greater than zero. To the extent that resources have characteristics that do not vary from day to day (e.g., being quick-start, being variable energy resources that cannot be dispatched, or serving cogeneration), the Market Operator records these characteristics in its master file, and it is not necessary to submit these characteristics in market bids. If a resource is unavailable due to an outage or derates, the Market Operator's outage tracking system provides more detailed information than could be provided in market bids. The Market Operator's market system automatically and continuously tracks resources' status such as: being on-line or off-line, in startup or shutdown processes, or being subject to minimum run times or off-line times, as well as other limits including maximum starts per day and daily energy limitations.

EIM Participants are required to keep the resource plan data up-to-date during the operating day. In the event of a required change in the resource plan due to physical resource changes, the EIM Participant is responsible for notifying the Market Operator of required changes through the Market Operator's outage reporting system, to allow the Market Operator reflect the change within its dispatch horizon, as well as updating its resource plan to accurately reflect their resource plan for subsequent hours.

3.3.8. Supply Adequacy and Resource Scheduling Requirements

For interchange transactions included in a resource plan, the EIM Participant shall create and process e-Tags for bilateral schedules between balancing authority areas 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 balancing authority areas by the transmission providers' business practices. These e-Tags are managed by the WECC Interchange Tool (WIT). However, e-Tags 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 of zero MW at the beginning of an operating hour and updates after the operating hour to reflect EIM dispatches for purposes of inadvertent energy accounting and tracking greenhouse gas obligations.

The planned megawatts for each resource must be within the range between the Minimum Economic Capacity Operating Limit and the Maximum Economic Capacity Operating Limit for each operating hour. For each resource, the sum of the Maximum Economic Capacity Operating Limit, Regulation Reserve MW – Up, Operating Reserve MW – Spinning, and Operating Reserve MW - Supplemental shall not exceed the Maximum Capacity Operating Limit, and the sum of the Minimum Economic Capacity Operating Limit, Regulation Reserve MW – Down shall not exceed the Minimum Capacity Operating Limit, for each operating hour.

Each EIM Participant's resource plan is required to offer sufficient energy to serve its obligations at all times. EIM Participants must satisfy their energy obligations by scheduling energy from third parties, causing its self-dispatched resource to operate at scheduled MW levels, and/or submitting bids for its resources for dispatch by EIM with sufficient dispatchable operating range, such that in aggregate they are capable of producing sufficient energy to be capable of serving the EIM Participants obligations reflecting the forecasted load in each 15-minute interval.

By 13:00 on the day before the operating day, and 45 minutes before each operating hour (e.g., at 10:15 for hour ending 13:00), the Market Operator will provide results of a supply adequacy analysis for the next operating day or operating hour, respectively. The supply adequacy analysis will be based on load forecast information, resource plans, ancillary service plans, and energy bids received from EIM Participants. The Market Operator will compute each EIM Participant's Energy Obligation:

Energy Obligation = load forecast (including both end-use demand and system losses within participating balancing authority areas[3]) + scheduled sales – scheduled purchases

The Market Operator will compare the EIM Participant's Energy Obligation against the sum of its Maximum Economic Capacity Operating Limit and the sum of its Minimum Economic Capacity Operating Limit provided in its resource plan. An EIM Participant shall be deemed as having insufficient energy supply if:

Sum of Maximum Economic Capacity Operating Limit < Energy Obligation

A EIM Participant shall be deemed as having too much energy supply if:

Sum of Minimum Economic Capacity Operating Limit > Energy Obligation

In either case, the EIM Participant is deemed to have inadequate supply. The Market Operator will also compare the sum of the EIM Participants' supply adequacy analyses within each balancing authority area with Market Operator's load forecast for each balancing authority area.

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[3] A result of including marginal losses in LMP calculations is that marginal loss revenues paid by loads generally exceed the marginal loss payments to supply resources, and no additional payments for transmission losses are necessary for dispatches within the EIM. This marginal loss surplus is credited back to loads.

The Market Operator will notify the EIM Entities of the results of the supply adequacy analyses, and will notify EIM Participants that are deemed inadequate. The EIM Participants with inadequate supply in the day-ahead analysis shall resolve this energy supply inadequacy by modifying its resource plan prior to 17:00 of the day prior to the operating day. The EIM Participants with inadequate supply in the hour-ahead analysis shall make the appropriate modifications no later than 20 minutes prior to the operating hour. The Market Operator shall provide a copy of any modified resource plans to the affected balancing authorities.

In the event that this review by the Market Operator has identified an inadequacy to the EIM Entity, the affected EIM Participants do not resolve the issue, and it contributes to a reliability problem within the affected EIM Entity at or prior to real-time, the EIM Entity and WECC may take appropriate actions regarding the EIM Participant including interruption of load or resources, curtailment of schedules, and/or manual deployment of resources, if deemed necessary.

3.3.9. Reserve Sharing Schedules

EIM Entities remain responsible for their DCS compliance, or their share of DCS 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.

EIM Entities, and reserve sharing groups of which EIM Entities are members, will continue to deploy operating reserves and regulation in conformance with NERC and WECC policies. The energy schedules implemented for deployment of reserves are settled in EIM as bilateral (self-scheduled) transactions. 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.

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 participating balancing authority areas. To the extent a EIM Participant’s actual response differs from the resource plan adjustment, the EIM Participant is expected to supply a resource plan update showing the actual resources that have deployed during the event by no later than 01:00 three days after the operating day in which the event occurred, for settlement purposes. Each EIM Participant retains obligations to update e-Tags that may be required for reserve deployment, in accordance with NERC and WECC standards and business practices.

3.3.10. Base Schedule Adjustment

The submission of schedules prior to the operating day and concurrent with the CAISO's day-ahead market allows EIM Participants 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, considering transmission losses, and must be free from congestion within the EIM Entity. The Market Operator will adjust base schedules with an AC optimal power flow (ACOPF) while fixing the EIM Entity's net scheduled interchange and alleviate any network constraint violations within EIM Entity and distribute transmission loss deviation to the EIM Entity 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 details of the base schedule adjustment are subject to stakeholder discussion, but the key point here is that the Market Operator will ensure that only the base schedules in EIM Entity, or the revised base schedules if updated by EIM Entity, are used to alleviate any congestion within the EIM Entity 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 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 ensure conformance of schedules to demand forecast, the market optimization process, which includes both CAISO and the EIM Entity commences. The steps for the base schedule adjustments for the different markets are as follows:

- Day-ahead: The EIM Entity provides balanced base schedules including demand forecast, generation and net schedule interchange. The Market Operator will run ACOPF using the EIM Entity's demand forecast while fixing the net scheduled interchange and calculate the adjusted day-ahead base schedules. The day-ahead 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 congestion management in the EIM Entity, but Market Operator will report the overloads in that area on OASIS.

- 15-minute RTUC: The revised base schedules are required at least T-75 minutes for two hours' worth of data. The data can be flat for the whole hour or it can be submitted on 15-minute or 5 minute granularity. The submission is not restricted by T-75 minutes. It can be updated any time as long as at least one submission is making it before T-75 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. 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 congestion management in the EIM Entity, and 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 CAISO 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, the 15-minute adjusted base schedules while enforcing congestion management in EIM Entity, 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.

3.3.11. Intertie Schedules with Other Balancing Authorities

The EIM Entity must submit intertie schedules with other BAAs at the relevant BAA 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 electronic tags and for managing schedule curtailments at these interties. Furthermore, EIM Entity must update these intertie schedules, when applicable, as part of the base schedule revision.

3.3.12. Energy Bids (submitted via SIBR)

Energy bids must be submitted hourly by 75 minutes before the start of each hour for each EIM Participant resource that would participate explicitly in EIM. The same energy bids would be 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. Assuming that the energy bids are not used in RTUC and assuming for simplicity that imbalance energy is zero for both EIM Entity and CAISO BAA, the fact that the energy bids are not used in the 15-minute RTUC but are used in the 5-minute RTD would cause shifts movement of energy in the 5-minute interval that would be settled based on the 5-minute LMP prices. This would not be a good market design because it creates divergence between the 15-minute and 5-minute prices even when no changes in system conditions occurred. 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 would be submitted through the SIBR system. 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 shall 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 for the relevant resource so that it is incorporated in the EIM schedules dispatch instructions.

3.3.13. Load Aggregation Points (LAPs)

Traditionally Load Aggregation Points (LAPs) were constructed around retail load service areas. Ultimately, this is up to the EIM Entity to decide the definition of the LAPs with their balancing. 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 CAISO are the same as the utility service territories. The mapping of loads to the nodes is done in the network model. Market Operator validates to ensure no missing load locations so that the sum of all LDFs 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 on the EIM Entity and how the Market Operator calculates them is determined by the network model.

CAISO recently started publishing 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. Market Operator is calculating LDFs for day ahead and hour ahead only. (Seasonal and annual LDFs are used for the CAISO's congestion revenue rights, which are not part of the EIM.) There will not be two way communication between the Market Operator and the EIM Entity 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 is encouraged to review and verify LDF accuracy.

The calculation of LDF/GDF will automatically accommodate changes in transmission and generation due to outages. GDFs are used for where there are several units in a plant metered together as a single unit, where there are no transmission constraints between the units.

3.3.14. Demand (Load) Forecast

The Market Operator will produce a demand forecast every 5 minutes separately for CAISO and the EIM Entities. 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 EIM Entity will provide non-binding day-ahead forecasts by 10:00 AM for forward 7 days (informational only). The Market Operator may create forecasts in parallel, but they will not be used for settlements. The EIM Entity may provide hour-ahead demand forecasts by T-75 minute (which may be able to move closer to the operating hour when the CAISO makes changes due to FERC Order No. 764), for the forward 6 to 10 hours as a backup to the Market Operator demand forecast, which is generated for the EIM Entity'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. The forecasts are for load, wind, non-bid resources, and interchange (both static and dynamic, excluding dynamic schedules dispatched by EIM). If the EIM Entity does not provide updated forecasts, then the default base schedule will be a previous forecast or base schedule. EIM Entities may provide forecasts of non-bid resources (including wind) and interchange (but not necessarily load) every 15 minute at T-37.5 minutes for forward 2 hours with 15-minute granularity. FERC Order No. 764 15-minute market, to be implemented in Spring 2014, will still support hourly market schedules. The Market Operator will create 5 minute forecast for forward 2 hours for load and wind (using persistence).

3.3.15. Renewable Energy Production Forecast

The Market Operator will produce a renewable energy production forecast every 5 minutes separately for each VER in the EIM Entity 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 EIM Entity 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 CAISO market is 0.5 MW and netting load against generation at the PNode level is also acceptable.

3.3.16. Generation and Transmission Outages (OMS, SLIC)

The EIM Entity must submit planned generation and 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 Entity must also revise these planned outages whenever their timeline or conditions change. Additionally, EIM Entity must submit generation and transmission forced outages in the OMS within 30 minutes of their occurrence so that they are considered in the EIM dispatch.

3.3.17. Load Distribution Factors

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).

3.3.18. Resource Operating Characteristics

EIM Participants must register all generating resources in the Market Operator's Master File, whether they would explicitly participate in EIM by submitting energy bids or not. The resource registration includes operating characteristics like minimum/maximum capacity and ramp rate capability (see Appendix B of the Market Instruments Business Practice Manual). The operating characteristics are required for resources participating in EIM to produce feasible EIM dispatch instructions. Registration is still 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.

3.3.19. Resource Telemetry and State Estimator

Telemetry is required for all generating resources in the EIM Entity 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.

3.3.20. Network Constraint and Contingency Definition

The EIM Entity must specify the network constraints and associated limits that the EIM solution must observe in the EIM Entity'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 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 similar to CAISO's 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 CAISO-EIM Entity footprint. The unit commitment function of RTUC does not affect the EIM Entity resources because the commitment status of these resources is given and not optimized. Any EIM Entity 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 CAISO-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 in CAISO and the EIM Entities, CAISO and the EIM Entities' interties, and any external transmission corridor where CAISO or the EIM Entity have contractual rights. The EIM Entity must specify the network constraints, including contingencies, and the associated limits that Market Operator needs to enforce in EIM. Furthermore, the EIM Entity base schedules must not violate any of these constraints. Finally, EIM Entity 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 CAISO and EIM Entity) will include congestion contributions from binding network constraints within the CAISO-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.[4]

3.4.3. 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 system 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 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 Participant resources. The EIM Entity may do so for EIM Entity BAA purposes. These dispatches would still register as imbalance deviations, but they would be settled at the LMP with no specific Exceptional Dispatch settlement from Market Operator.

Exceptional dispatch from the EIM Entity to the EIM Entity's generating resources will be declared in the respective 15 minute and 5 minute base schedule updates provided by the EIM Entity to the Market Operator to coordinate the movement of the resource in the EIM and the actual reliability need of EIM Entity in real-time.

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[4] The current allocation determinant for the Real-Time Offset is measured demand (metered demand plus exports). However, the allocation determinant for an EIM Entity merits discussion since EIM does not include the Day-Ahead Market. A possible allocation determinant can be the gross imbalance energy.

3.5. EIM Output Results

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

3.5.1. 15-Minute Energy Schedules

The financially binding 15-minute Energy schedules calculated by RTUC will be available for the Scheduling Coordinator (SC) that would represent EIM Participants 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 Participant receives a market award through the CAISO's intra-hour (15-minute) energy market that will be implemented for compliance with FERC Order No. 764, 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 Entity's Energy Management System (EMS) through an interface to the Market Operator's Automated Dispatch System (ADS). 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 every 5-minute. The net schedule interchange variation shall be modeled as a dynamic schedule between the CAISO 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 balancing authority area.

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 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 CAISO-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 CMRI, which are protected and require a Non-Disclosure Agreement (NDA) for a SC to access it. Protected data that relates to the EIM and may be of interest to EIM Participants 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. 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 applicable constraint's limit in EIM to the value 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 for which flows exceed 85% of their capacity. 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 balancing authorities to conditions that EIM cannot resolve, which may require them to initiate the UFMP under WECC procedures.

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 BAs' 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 and other balancing authority areas. 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 CAISO 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 CAISO is equivalent to hourly firm.
- Loads in CAISO depend more on imports from other parts of WECC. Imports to CAISO use transmission for which entities sell their transmission rights through external BAAs to CAISO 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 areas 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 EIM or another area has insufficient resources itself (including dynamic transfers with other areas) 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:

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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 full the WECC network, define external constraints in their models, and prepare to enforce constraints in step 4.
2. Exchange load & generation forecasts and other data at 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 to UFMP.

If a balancing authority initiates the UFMP, EIM and the WECC UFMP will work with each other to manage congestion on constrained flowgates and handle curtailments of energy schedules as appropriate. The UFMP will prescribe curtailments of those tags that are not included in market flows, while the Market Operator will prescribe curtailment of market flows in the event that EIM 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 less than 85% of its capacity. 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 tags for schedules with external parties that are sourced or sunk in the EIM footprint and 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 Participants 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.

3.6.3. Contingency Dispatch

The current EIM framework does not include the procurement or dispatch of ancillary services in EIM Entity BAAs. Each BA is responsible for meeting NERC and WECC reliability standards in its respective BAA. Specifically, each BAA 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 to produce a dynamic net interchange schedule for AGC purposes.

Regarding contingency dispatch, each BAA is responsible for dispatching contingency reserves in their BAA to recover from contingencies that involve loss of generation or interties. Furthermore, BAs 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 Participant resources from the top and bottom of their energy bid to be used for ancillary services or exceptional dispatch. The EIM Entity 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.

3.6.4. 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.

3.6.5. Load Curtailment

The EIM can dispatch price-responsive demand, such as pump load or exports from the EIM footprint, based on submitted energy bids. The EIM will not dispatch price-inelastic demand; demand management and load shedding would be coordinated between the BAA system operators 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 affects a BAA in the EIM footprint, the Market Operator would maintain the EIM for unaffected BAAs by enforcing a net interchange constraint for the affected BAA to decouple it from the rest. A similar approach would be employed for contingency dispatch in the CAISO. Although contingency dispatch is not a market disruption because the CAISO uses a special market application (RTCD) for it, contingency dispatch is currently not in the scope of EIM, as mentioned in §3.6.3. Therefore, if the CAISO suffers a contingency within its BAA, the RTCD would only dispatch resources in CAISO to recover from the disturbance. Resources in EIM Entities would not be dispatched to assist in that recovery; similarly a contingency in an EIM Entity would not affect CAISO resources. Nevertheless, RTUC and RTD would continue to run during a CAISO contingency and produce dispatch instructions for resources in EIM Entities to balance the remaining EIM footprint by excluding the CAISO, for which dispatch instructions would be produced by RTCD. This can be achieved by isolating the CAISO from the rest of the EIM footprint by enforcing a net interchange constraint in RTUC and RTD for the CAISO, 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. Instructed Imbalance Energy

Instructed imbalance energy is calculated as the algebraic difference between the 5-minute 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.

3.7.2. Uninstructed Imbalance Energy

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 CAISO or an EIM Entity, 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 extreme LMP in the population. The load forecast deviation in a 15-minute market is measured with reference the corresponding adjusted base load schedule. The load forecast deviation in a 5-minute market is measured with reference 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.

3.7.3. 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 Utility Distribution Company (UDC). Note that UDC role is separate from the EIM entity which is enabling EIM to occur in its BAA. 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.

3.7.4. Inadvertent Energy Accounting

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

All deviations from schedules with EIM Participants as a result of EIM operations will be settled financially. To assist balancing authority areas within the EIM with accounting for inadvertent energy within balancing authority areas, the Market Operator will maintain a dynamic schedule with resources in each participating balancing authority area. Because each balancing authority area 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. 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 balancing authority area, 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.

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]

It should be noted that the imbalance breaks the advertent energy down by generator and load customers because the inadvertent = [sum (Gen^{act} – Gen^{sched})] – [$Load^{act}$ – $Load^{sched}$]

3.7.5. Settlement Metering

Settlement metering is required for all Generators within an EIM Entity 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 CAISO Metered Entity (ISOME). Generation values associated with SCME must be submitted according to current submittal formats and time periods captured within CAISO Metering Business Practice Manual (BPM). Those electing to be an ISOME must meet current Tariff and Metering BPM requirements related to CAISO 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 CAISO if no local authority standards exist.

Concurrent with its compliance with FERC Order No. 764, CAISO is proposing a 5- minute metering requirement for generation resources. This 5-minute requirement will also apply to generating resources of the EIM Entity. 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.

3.7.6. Interchange Meter Data

Settlement metering is not required for interchange points between EIM Entity and CAISO if they are tagged. The Market Operator will utilize e-Tag information used for interchange checkout between the CAISO and the EIM Entity. The e-Tag is deemed delivered thus equivalent to metering. The dynamic interchange capacity between CAISO 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 CAISO 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 meter data for interchange locations of the EIM Entity with other BAAs than the CAISO's BAA as well as e-Tag information (schedule and originating/receiving BAA).

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[6] The CAISO does not currently use an Uninstructed Deviation Charge other than settlement of real-time at the resource location's LMP. The CAISO has proposed limitations on bid cost recovery payments and possibly other payments based on deviations. The need for and structure of an Uninstructed Deviation Charge is among the implementation details that may be considered further in EIM stakeholder discussions.

3.7.6.1.1. e-Tagging

All scheduled energy must be e-Tagged including the awarded imbalance energy 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's interchange points with other BAAs that are not CAISO.

CAISO will maintain a dynamic schedule with resources in each EIM Entity. Because each BAA 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. 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.

3.7.7. Forecasting

The Market Operator will utilize available information to derive forecasts for demand within the EIM Entity. The costs associated with the gathering and processing of required information will be recovered by the Market Operator and be recovered through the EIM administrative rate.

The Market Operator will utilize available information to derive forecasts for VERs. The cost for the CAISO to provide this service is currently $0.10 per MWh.

3.7.8. 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 CAISO payment calendar) will be followed for the purposes of issuing settlement statements, exchanging invoiced funds, submitting meter data and submitting settlement disputes.

3.7.9. Neutrality

As the Market Operator conducts a revenue neutral market, applicable MW and fiscal neutrality or rounding adjustments will apply. These adjustments occur on a 10-minute level of granularity. Additional discussion is needed to determine if Unaccounted For Energy, otherwise known as MW neutrality, will be calculated based on the EIM Entity as a whole or performed at lower levels of granularity. The real-time loss calculation needed to calculate UFE will be performed by the market application based on the power flows in the network model. In addition, the EIM Entity's LMP differences will be allocated to the EIM Entity's measured demand. Measured demand includes loads and exports. If there were no transfers between EIM Entity and the CAISO, the neutrality adjustment will ensure there is no net settlement payment to or from CAISO for LMP differences. If there were exports to CAISO, some of the LMP basis difference will follow the export out to CAISO. If there are imports from CAISO, some of the LMP differences will come over with the import because the import will be included in the measured demand of CAISO customers.

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 CAISO 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 CAISO will commence a stakeholder process in late 2013 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 CAISO's BAA and the EIM footprint.

3.7.10.1. EIM Initial Fee

The CAISO has established an initial fee of $0.03 times the total annual energy usage of the EIM participant. 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 CAISO energy usage. The project costs were linearly related to the amount of load that would be participating in EIM. 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 CAISO through specific payment milestones that are consistent with the implementation agreement.

3.7.10.2. EIM Administrative Rate

Currently, the CAISO's overall administrative charge is made up of three components or services: (1) Market Services, (2) System Operations and (3) CRR Services. Market services encompass all activities in issuing bids to schedules in both the Day Ahead Market and Real Time Market. System operations encompass all activities in dispatching energy on the grid and balancing area activities such as transmission planning, CRR Services encompass activities surrounding Congestion Revenue Rights. The CAISO 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[7] 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 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

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

- 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 load. This EIM administrative cost covers staff and portions of CAISO systems used to support EIM functionality. EIM revenue will be applied to the CAISO GMC components which reduces the costs that need to be recovered from CAISO market participants. The following examples illustrates the administrative cost:

Example 1 – Imbalance Energy Exceed Minimum Threshold

Base Schedule:	Generation = 100 MW	Load = 100 MW
Imbalance Energy	Generation = (20 MW)	Load = 30 MW
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 MW	Load = 100 MW
Imbalance Energy	Generation = 4 MW	Load = 30 MW
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 CAISO 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 CAISO 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. Other Items

3.8.1. Market Monitoring

The EIM shall include market monitoring, which services shall be provided by the CAISO Department of Market Monitoring (DMM) and included in the EIM administrative charges. DMM monitors markets administered by the CAISO 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 CAISO business units that review and monitoring the performance and quality of the CAISO markets. DMM provides recommendations about potential market design flaws or ineffective market rules to the CAISO 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 CAISO market rules has occurred, the issue will be referred to FERC for further review.

3.8.2. Third Party Arrangements

EIM Entities may engage in discussions with third parties, including EIM Participants, 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.

3.8.3. Compliance

Each EIM Entity and EIM Participant 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. Each EIM Entity's and EIM Participant's current functional responsibilities associated with compliance with reliability standards are not intended to be modified, changed or otherwise amended as a result of participation in the EIM.

3.8.4. Enforcement Protocol

EIM Participants 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 CAISO 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. EIM Issue Paper

In this section we will explore some of the policy questions associated with EIM implementation. These areas will require additional stakeholder input and discussion to further develop a straw proposal. In addition, the market design straw proposal discussed in Section 3 above will influence the policies needed to address the issues outlined below. The issues presented below are not intended to be exhaustive. The CAISO believes that additional issues may be identified through the stakeholder process.

4.1. Market Rule Oversight

EIM rule oversight shall be consistent with existing CAISO governance, allow for voluntary participation and expansion of participants and market activities, and evolve based on stakeholder feedback.

The CAISO's concept of EIM market rule oversight allows EIM participants to realize the benefits of the CAISO proposal. EIM participants should have a meaningful and formal role in fostering a market that meets their needs, reviewing its operation, and influencing future changes or revisions. In particular, this oversight role should have the objective of preserving for EIM participants – both at the outset and in the future – the significant and tangible benefits of EIM.

CAISO will work with EIM Entities and EIM Participants to implement its proposal recognizing that market rule oversight is a matter that must be resolved among interested EIM Entities and EIM Participants through the stakeholder process. Indeed, there may not be consensus on this issue among the diversity of interests in an EIM.

Here the CAISO presents two basic conceptual models – a market administrator model and a market operator model – as well as a hybrid of these two models. These models have been discussed in the various forums considering EIM in the west. Other models and variations on these models are certainly possible but these are sufficient for purposes of this discussion.

1. Market Administrator Model

The market administrator model places oversight of EIM rules under the CAISO Board of Governors.

The market administrator model was the basis for proposal submitted by the CAISO to the PUC-EIM Task Force on March 29, 2012. It preserves the costs and benefits identified in the CAISO's proposal, and is the model being presented by the CAISO in this stakeholder process. The model can accommodate enhanced participation by EIM Entities and EIM Participants but involves decision-making consistent with the current CAISO governance structure.

Participation under this model would enhance stakeholders' role in EIM oversight and development of changes to EIM market rules. For example, EIM Entities and EIM Participants may believe an EIM advisory committee chartered under the CAISO bylaws would be useful. This EIM committee could directly engage with the CAISO board on issues affecting the EIM consistent with its charter. The EIM committee could also serve as a forum for consideration of

EIM market rule changes and provide regular reports to stakeholders, among other related duties and responsibilities as chartered.

In addition, EIM Entities and EIM Participants could recommend changes to the EIM market rules for consideration by the CAISO Board of Governors. In the event all EIM Entities and EIM Participants, including the existing CAISO market participants, benefit from the changes and the Board approves them, related implementation costs would be shared among EIM and CAISO market participants. In the event the changes increase costs to the CAISO, the Board could still approve them but could elect to apply the changes only to EIM Entities and EIM Participants outside the CAISO and/or allocate the associated costs directly to EIM Entities and EIM Participants and not to CAISO market participants.

EIM Entities and EIM Participants in the EIM also could decide to form their own separate stakeholder body under principles agreed to among themselves similar to those established for corporate consortiums, for example, but this would be up to such persons. This stakeholder body could have a role in EIM market rule oversight as a stakeholder in the CAISO process but would be external to the CAISO.

In any event, each potential EIM Participant and EIM Entity is free to make an independent choice to participate in the EIM, which it would ultimately implement by executing a service agreement under the CAISO EIM rules. Each EIM Participant and EIM Entity would also be able to select individually whether it desired to utilize any additional market features offered by the CAISO.

2. Market Operator Model

Note that the term market operator above should not be confused with the use of Market Operator to describe the EIM design in Section 3. The market operator model for oversight is an independent body from the current CAISO Board of Governors.

The governance memorandum posted on the PUC-EIM Task Force Website envisions a new market administrator that would develop EIM market rules and execute a contract with the market operator. This model, the market operator model, presents a number of challenges that the participants need to consider carefully and is not part of the CAISO proposal. This option presents fundamental risks to the CAISO's ability to operate the EIM at a low incremental cost using the same market platform and software it has developed for its own real-time energy markets. While these sorts of risks could possibly be mitigated through appropriate contractual provisions between the CAISO and EIM Entities and EIM Participants, the challenge would be compounded by California participation in an EIM overseen by an entity other than the CAISO, particularly if its governing body is not independent.

3. Hybrid Model

An organization of EIM Entities and EIM Participants could seek to negotiate a contract with the CAISO that lays out the responsibilities to operate the EIM. An example of this might be a group of EIM Entities who prefer the CAISO operate an EIM for their sub-region without transfers with other balancing authority areas also participating in the EIM. This contractual vehicle would need to be compatible with the market administrator model and would effectively result in an EIM sub-region. However, it is not currently being considered in this stakeholder process due to the associated implementation timelines. After EIM commencement, the CAISO could consider such an arrangement if that is the direction a group of EIM Entities are interested in considering this approach further.

Above all, CAISO believes there are opportunities to maintain the costs and benefits of its proposal and achieve the objectives of interested EIM Entities and EIM Participants. CAISO recognizes that some participants interested in an EIM may prefer the market operator model, perhaps due to the enhanced opportunity to develop EIM market rules different from the CAISO's real time market rules. At the same time, others may not view the additional complexity, uncertainty, and costs associated with the market operator model as necessary to meet their needs.

CAISO believes the market administrator model discussed above most appropriately balances these interests. In any event, the CAISO recognizes the importance of reaching consensus and looks forward to working with interested EIM Entities and EIM participants to resolve these questions to the satisfaction of those interested in pursuing the benefits presented by the EIM.

4.2. Market Rule Structure

The CAISO proposes that the EIM rules shall be contained in a discrete part of the CAISO tariff to the extent this structure provides additional clarity to all EIM Entities and EIM Participants; however, provisions generally applicable to the relationship between the CAISO and market participants may be provided for by reference and applicable to EIM Entities and EIM Participants.

4.3. Transmission Service

Since the transfer capability between the CAISO and initial EIM entities may be limited, the CAISO proposes no charge for EIM use of as-available transmission occur for initial EIM implementation. Further consideration of transmission service could be informed by actual EIM operational experience or if additional entities consider entities participate in EIM. In any event, the EIM transmission service rate should be the same across all EIM Entities.

Under FERC goals that include elimination of rate pancaking and the use of single system access charges, the CAISO uses a transmission access charge within its controlled grid that uses a two-tiered structure. A single grid-wide "postage stamp" rate recovers the costs of "high voltage" transmission facilities (at or above 200 kV) from all transmission customers (loads and exports), while the individual participating transmission owners recover the transmission revenue requirements of local "low voltage" transmission facilities (below 200 kV) from the customers in their own service areas. Placing responsibility for the access charge on withdrawals from the CAISO 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 CAISO controlled grid, which reduces the transmission capacity that the CAISO 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 CAISO's transmission access charge does not preclude a utility that pays the grid-wide access charge from adopting different retail rate designs within its service area. A transition mechanism applied over a 10-year period from the original utility-specific rates to the single grid-wide rates.

EIM Entities and EIM Participants who are not CAISO participating transmission owners may adopt transmission rates for EIM transfers within their region, subject to certain agreed upon limits established by the EIM design (which may be zero), separate from the EIM rule oversight and approval processes.

4.4. Process for New EIM Entities Joining

New entities 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 CAISO as part of the EIM market rules on a going forward basis.

The CAISO encourages entities interested in participating in the EIM to engage with the CAISO as early as possible. Implementation requires sufficient time for the associated network model and other system changes to be accomplished. Accordingly, the opportunity for entities 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 CAISO 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 entity's system. Implementation of an EIM Entity following any particular annual commitment cycle would be aligned with the CAISO's spring and fall software release cycles. Details concerning this process will be further considered with stakeholders and established in the EIM market rules.

4.5. Uplift Allocations

Due to the nature of the EIM and the structure of various Market Operator settlement charge codes, the Measured Demand allocation base for EIM Entity will need to be determined. The determination may be on a charge code by charge code basis or as an overarching application to all associated charge codes. This determination will be this stakeholder process based upon input of stakeholders and be influenced based upon the EIM design outline in Section 3.

For example, the CAISO has sought to minimize uplift costs moving between an EIM Entity and the CAISO Balancing Authority by ensuring a balanced schedule, including transmission losses, which results in no transmission constraint violations in the EIM Entity's system prior to the start of the real-time market optimization. With this adjusted base schedule as the reference for EIM dispatch instructions, any imbalance energy procurement in EIM would only be due to demand or other uninstructed deviations and congestion or system condition changes occurring in real time. Therefore, the EIM would make full use of the diversity throughout the EIM footprint to address real-time conditions without any BAA leaning on EIM to resolve pre-EIM conditions. Furthermore, if the EIM Entity adopts the Market Operator demand forecast for their BAA in constructing the base schedules prior to EIM without violating any network constraints in their BAA, the base schedule adjustment would only be a minimal transmission loss adjustment.

Bid Cost Recovery is another potential market uplift whose allocation will depend on the EIM design in Section 3. In the straw proposal, the EIM will not make commitment decisions for the EIM Entity and will simply utilize on-line resources to meet demand, the main components driving Bid Cost Recovery of Start-Up Costs and Minimum Load Costs will not be applicable. For the energy component of the bid cost recovery, EIM Participant resources will be made whole based on bid cost recovery rules that are anticipated to be similar to the existing CAISO settlements.

4.6. Greenhouse Gas Emission Costs for Imports into California

The CAISO 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 CAISO'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 Participants 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 Cap compliance obligation. To properly account for costs of Greenhouse Gas Cap compliance instruments, the portion of the net export imbalance deviation of an EIM Entity's resources that will be imported into California would be assigned a greenhouse gas emission cost within the RTUC and RTD objective function. This greenhouse gas emission cost adder in the objective function will result in an efficient EIM dispatch with full consideration of the additional costs of the output energy from EIM Participant resources that has a Greenhouse Gas Cap compliance obligation.

The net export imbalance deviation from the EIM Entity into the California would be derived from the dynamic schedule interchange deviation between the EIM Entity and CAISO, based on the EIM dispatch instructions and the demand forecast deviation in each BAA. This would be recorded in the e-Tag for the dynamic resource interchange between the EIM Entity and the CAISO. (Imported energy amounts listed in e-tags serve as the basis for the compliance obligation under CARB's regulations)

The EIM settlement will ensure recovery of greenhouse gas emission costs by EIM resources and imports that clear RTUC and RTD. Details of this settlement mechanism will be reviewed during the stakeholder process, but the likely resolution appears to be for the CAISO to recover this cost by uplift to metered load (not including exports) in the CAISO. The net export imbalance deviation from the EIM Entity into the CAISO California would be derived from the dynamic schedule interchange deviation between the EIM Entity and CAISO, based on the EIM dispatch instructions and the demand forecast deviation in each BAA. This would be recorded in the e-Tag for the dynamic resource interchange between the EIM Entity and the CAISO. (Imported energy amounts listed in e-tags serve as the basis for the compliance obligation under CARB's regulations). The portion of the net export imbalance deviation that would be assigned the greenhouse gas emission cost would be derived pro rata based on the composition of the positive EIM imbalance instructions between non-green and green energy. Green energy is produced by generating resources registered as a green energy resource or provided by imports from other BAAs when the corresponding e-Tag identifies a green energy resource.

5. 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 CAISO'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
CAISO	California Independent System Operator Corporation
CARB	California Air Resources Board
CMP	Congestion Management Process
CMRI	CAISO 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

Acronym	Term
FOR	Forbidden Operating Region
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 ME	CAISO 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 CAISO
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