VOLUMINOUS

CEP 6-21 Attachment 1 is a VOLUMINOUS attachment.

SOAH DOCKET NO. 473-21-2606
DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

CONFIDENTIALITY STATEMENT UNDER SECTION 4 OF THE PROTECTIVE ORDER

The undersigned attorney for El Paso Electric Company (EPE) submits this statement under the section 4 of the Protective Order entered in this case. Materials provided in the responses to CEP 6-14 (Attachment 1 – Confidential Voluminous), CEP 6-19 (Attachment 1 – Confidential Voluminous), and CEP 6-19 (Attachment 2 - Confidential) are exempt from public disclosure pursuant to sections 552.101 and 552.110 of the Public Information Act (PIA) and section 418.181 of the Texas Government Code.

The responses contain information on business operations and financial information that is commercially sensitive and not otherwise readily available to the public. Moreover, the documents contained within the responses include information that qualifies as trade secrets, as the information is not generally known and provides a commercial advantage to its owner. Public release of this information would also cause substantial competitive harm to EPE and the other companies that are owners in the Palo Verde Generating Station. Additionally, some of the documents contained within the response contain information on highly sensitive, confidential critical infrastructure that EPE is required to keep confidential and the public release of which could jeopardize the security of EPE's system. Finally, some of the documents contain sensitive customer information.

The undersigned counsel for EPE has reviewed the information described above sufficiently to state in good faith that the information is exempt from disclosure under the PIA and merits the confidential designation given to it.

Respectfully submitted,

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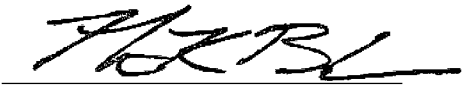
By: 
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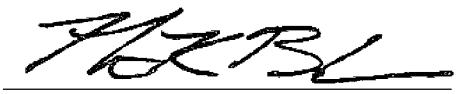
ATTORNEYS FOR EL PASO ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I certify that a true and correct copy of this document was served by email on all parties of record on July 29, 2021.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CEP 06-01_Attachment 01.xlsx
CEP 06-01_Attachment 02.xlsx
CEP 06-01_Attachment 03.xlsx
CEP 06-01_Attachment 04.xlsx
CEP 06-02_Attachment 01.xlsx
CEP 06-02_Attachment 02.xlsx
CEP 06-03_Attachment 01.xlsx
CEP 06-03_Attachment 02.xlsx
CEP 06-04_Attachment 01.xlsx
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CEP 06-09_Attachment 01.xlsx
CEP 06-11_Attachment 01.xlsx
CEP 06-12_Attachment 01.xlsx
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CEP 06-13_Attachment 02.xlsx
CEP 06-13_Attachment 03.xlsx
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Contact centralrecords@puc.texas.gov if you have any questions.

CEP 6-17 Attachment 2

Utilicast

EIM Gap Assessment Report

Proprietary and Confidential

Prepared For:

El Paso Electric

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El Paso Electric

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August 2019

Utilicast | *El Paso Electric*

EIM Gap Assessment

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1 Executive Summary

Joining the Western Energy Imbalance Market (EIM) will bring significant changes to the way in which El Paso Electric (EPE) does business and the systems and people needed. A significant project will be necessary to put in place the required processes and systems. These impacts and costs are described in detail in this report.

1.1 EIM Implementation Project

Based on an anticipated project schedule for integration in April 2023, EPE will be joining EIM after most Investor Owned Utilities in WECC. Though there are always participant-specific variations, many of the combinations of generation fleet, IT systems, physical equipment, modeling conditions and required project activities have precedent at this point. Utilicast has assisted most current and in-progress EIM participants over the past four years and has developed this Gap Assessment for EPE based on those experiences, EPE's responses during our workshops, and to other data gathering efforts.

Table 1 shows the estimated Project Costs for EPE to join the EIM for an April 2023 Go-Live, as described in more detail in this report.[1] Major cost categories include internal labor, external labor, software and hardware required to close the identified gaps. Cost elements are broken down by Capital and O&M based on EPE budget designations and estimated by quarter based on high-level assumptions about the duration of the major phases of work. Cost estimates are budgetary estimates and 15% contingency should be applied.

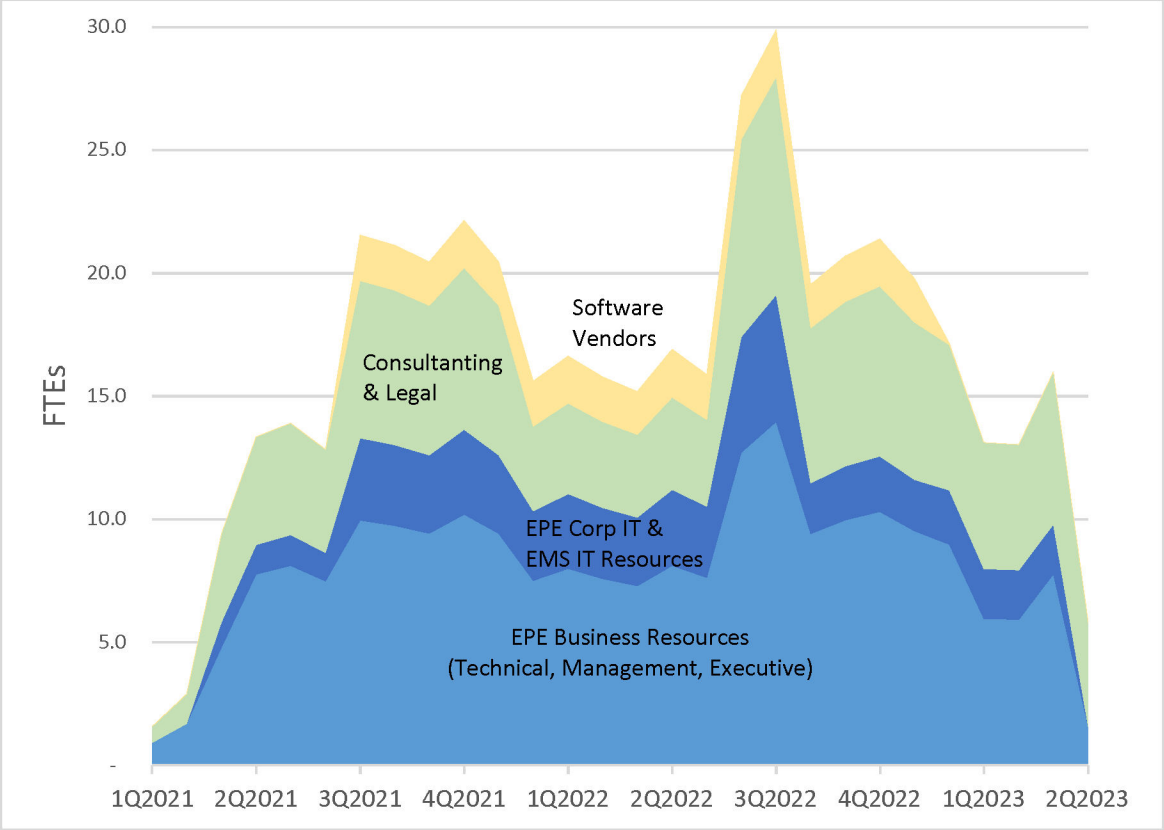
Table 1 – Estimated EIM Implementation Project Costs

Quarter / Year	2021	2022	2023	Total
Capital	$1,690,000	$4,530,000	$860,000	$7,080,000
O&M	$3,130,000	$4,040,000	$410,000	$7,580,000
Subtotal Cost	$4,820,000	$8,570,000	$1,270,000	$14,660,000
15% Contingency	$720,000	$1,290,000	$190,000	
Total Cost	**$5,540,000**	**$9,860,000**	**$1,460,000**	**$16,860,000**

In planning the project, EPE will also need to consider how the effort required to deliver the EIM project will align with other initiatives underway. Figure 1 shows an estimate of the effort by different groups which will be needed over the course of the EIM project.

[1] Figures are rounded to the nearest $10,000.

Figure 1 – Estimated EIM Implementation Project Effort Over Time



At the outset, primarily business and consulting resources begin to define and organize the project. As the project moves into design, IT and software vendor resources begin to play a bigger role starting around 3Q2022.[2]

As the new systems are delivered in later 2022, EPE's participation begins to ramp up substantially. During this time, a significant effort is anticipated on testing the new systems, refining business processes and training the EPE team who will execute EIM tasks on a daily basis.

A period of joint testing with the CAISO will begin in the 4Q2022 and culminate in intensive efforts during Parallel Operations and cutover. During this period, it is anticipated that EPE's team will take the lead – both the business units and IT support – and support from consulting and software staff will decline as knowledge transfer is completed and EPE prepares for daily EIM operations.

[2] The estimate of software vendor effort is probably understated as it is based on only services which those vendors have represented as supplemental implementation costs and is based on a high blended rate.

1.2 On-Going Costs & Impacts

Once in Production, several new responsibilities will become permanent. The most notable are the increased responsibilities on System Operations and Settlements staff.

The EIM design requires significant participation from the BAA, which serves as the EIM Entity, to aggregate and validate data for use in the market runs and review and approve market results on an hourly basis. Based on the current responsibilities and staffing of EPE's System Operations team, new EIM responsibilities and EIM Entity BAA staffing at peer entities, EPE should anticipate the need for a new EIM Real-Time Desk in System Operations and a new Supervisor.

The Resource Management team will also take on new hourly, Real-Time and ATF analysis responsibilities. These responsibilities should be able to be absorbed without adding a full 24x7 Real-Time Trading desk. However, an incremental one to two FTEs is anticipated.

The settlement of EIM charges, and the analysis of those results will be new and complex. This has been one of the largest impacts at other new EIM members. New staff will be needed to perform these functions. There is an important organizational decision to make about how these staff will be aligned. The primary approach is to create a centralized group or adapt an existing centralized group, such as an existing Settlements or Accounting group. An alternative is to distribute the functions between Resource Management and System Operations or hybrid approaches which divide the responsibilities. Regardless, new FTEs are anticipated.

In addition, the CAISO and EIM markets are constantly evolving. Keeping up with the proposed enhancements, advocating for EPE's interests and identifying impacts to EPE systems and operations will require attention. Some participants have added a new role for this function but others have not. At this time, no budget has been included for a new FTE to meet this need.

The ongoing personnel cost associated with these functions is presented in Table 2. The impacts and assumptions are described further in the body of this report.

In addition to new ongoing staff, EPE will be paying maintenance and hosting fees for several new software applications.[3] EPE will also pay ongoing fees to CAISO for administering the market through Grid Management Charges (GMC).

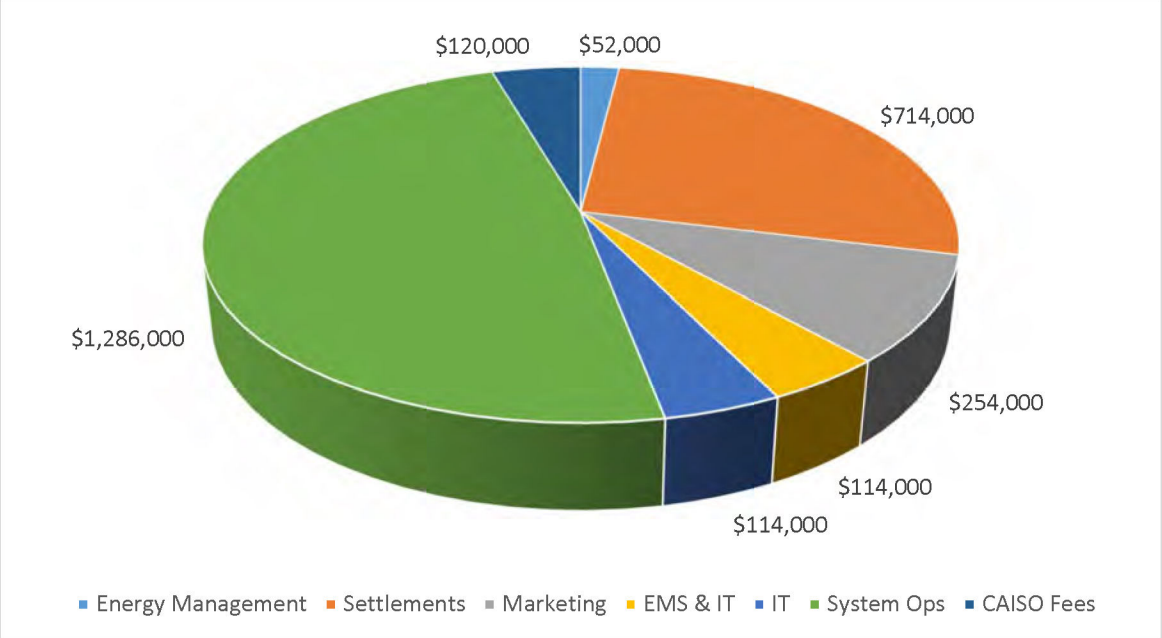
[3] This report assumes EIM software systems are vendor-hosted in lieu of estimating EPE on-premise hardware procurement and maintenance

Table 2 – Estimated Ongoing EIM Costs

New EIM Function	FTE	Annual Cost
Bidding Support	0.5	$52,000
PRSC Settlements	1.5	$157,000
Sys Ops EIM Desk	7.0	$880,000
Sys Ops EIM Desk Sup	1.0	$154,000
Results Analysis	1.0	$154,000
Meter Data Management	0.5	$52,000
EESC Settlements	1.5	$157,000
EMS & IT Support	1.0	$104,000
Corp IT Support	1.0	$104,000
Software Fees	N/A	$720,000
CAISO Fees	N/A	$120,000
Total Incremental FTE	15.0	$2,654,000

The breakdown of these estimated costs by department is show in Figure 2.

Figure 2 – Estimated Ongoing Costs by Department



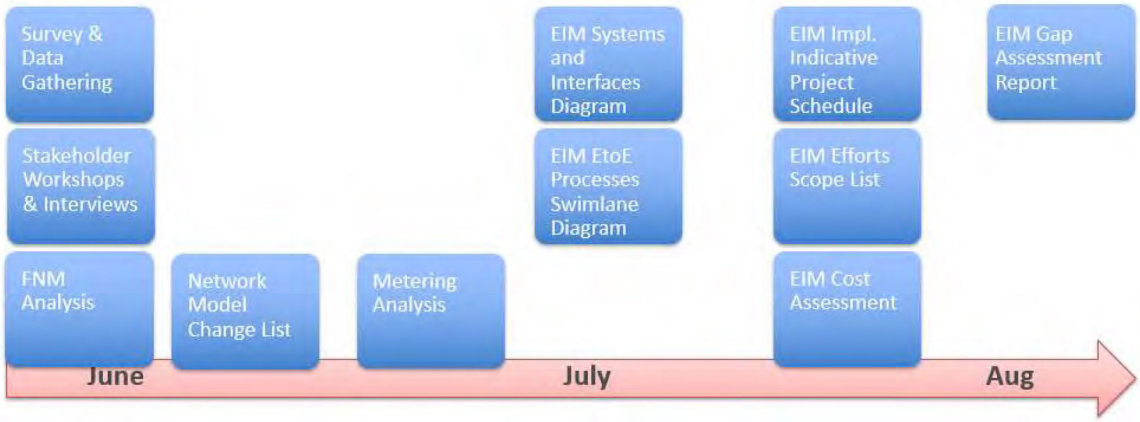
2 Organization of the EIM Gap Assessment Report

El Paso Electric (EPE) requested an assessment of the costs and efforts required for potential EIM membership, currently targeting April 2023. This EIM Gap Assessment Report (and Appendixes) represents the culmination of the following sequence of deliverables in this effort:

- Survey and Data Gathering.
- Stakeholder Workshops & Interviews.
- Full Network Model (FNM) Analysis.
- Network Model Change List.
- Metering Analysis.
- EIM End to End (EtoE) Processes Swimlane Diagram.
- EIM Systems and Interfaces Diagram.
- EIM Efforts Scope List.
- EIM Implementation Indicative Project Schedule.
- EIM Cost Assessment.
- EIM Gap Presentation.

Each of the above identified efforts and deliverables included collaborations, iterations, draft reviews and content confirmation with EPE Stakeholders over the four-month period from May to August, 2019.

Figure 3: EIM Gap Assessment project efforts and deliverables



2.1.1 Organization of Gap Assessment Information

This report provides budgetary level estimates of costs and schedule of efforts, to use in conjunction with a separate benefits study which EPE is undertaking with E3, to inform expectations of what EPE joining EIM would entail. Assumptions were made about the type of systems EPE will need to procure, process requiring translations, systems' configuration changes, project and ongoing efforts as well as an indicative timing of expenditures. It is anticipated that as part of an implementation project, EPE will conduct RFPs, develop a resource-specific staffing plan and define a detailed project schedule.

This report is intended to summarize EPE's Gaps for EIM Entry to an audience aware of EIM. To aid those absent past contexts, provided below are brief descriptions of the preceding deliverables' intent and obtainability:

Survey and Data Gathering. And **Stakeholder Workshops & Interviews**. The Organizational, Process and Data Questionnaires, Interviews and Working Sessions Notes and correspondences are not explicitly provided as part of this report's production. The content and information gathered from these efforts were the inputs to the resulting suggestions, quantifications, and conclusions. These efforts were also used to inform and educate the EPE stakeholders in EIM concepts and principles in order to effectively contribute to the discussions, efforts and requests.

Full Network Model (FNM) Analysis and **Network Model Change List**. Included as Appendix 3 and summarized in Section 6. This is EPE's current network modeling state and conventions as compared to EIM requirements, with identified issues and errors to be corrected before joining.

Metering Analysis. Included as Appendix 4 and summarized in Section 8. This addresses the metering aspects that need to be met for EIM, and attempts to provide the variable-representation to enable EPE to quantify their current state as comparison.

EIM End to End (EtoE) Processes Swimlane Diagram (and Working Sessions). Included as Appendix 1 and referenced in many sections of this document. This diagram helps visualize the sequence of processes, actions and responsibilities of the Entity (System Operations), Merchant (Resource Mngt), and The EIM Market (CAISO), across a timeline relative to the Trade Hour (T).

EIM Systems and Interfaces Diagram. Included as Appendix 2, referenced in sections of this document, and summarized in Section 10. This diagram helps visualize how the needed EIM systems will interface with the market and each other. Additionally, there are references relating back to the EtoE diagram.

EIM Efforts Scope List. The Scope List is included as part of the EIM Cost Assessment (further addresses in Appendix 6). A list of efforts that are required to join EIM, which drive the cost assessment and inform the implementation schedule.

EIM Implementation Indicative Project Schedule. Included as Appendix 5 and summarized in Section 9. A high-level project schedule, addressing EIM/CAISO interactions as well as EPE specific considerations. Provided as both a single-page visual, as well as a Gantt chart representation.

EIM Cost Assessment. A multi-tab excel workbook addressed further in Appendix 6 and summarized in Section 12. Estimation of costs to implement solutions based on the gaps identified. Developed collaboratively with EPE to reflect EPE budgeting practices.

EIM Gap Presentation. Executive Presentation reviewing assessment findings and next steps. Presentation retained by EPE Project Team, and available from them by request.

EIM Gap Assessment Report. This document, summarizing the identified gaps, anticipated project scope, cost estimates and assumptions. Provides background and context into the efforts necessary to join EIM.

2.1.2 EIM Gap Assessment Report Navigation

Sections

Brief descriptions of Sections of this document are:

1. **Executive Summary**. Budgeting results, and major decisions to address.
2. **Organization of the EIM Gap Analysis Report**. Provides a brief primer of document, project, and market conventions. Intended to aid the reading audience in interpretation the Gap Analysis Report.
3. **Entity / System Operations**. Focus on the changes and impacts for EPE's System Operations area.
4. **Merchant / Resource Planning and Management**. Focus on the changes and impacts for EPE's Marketing area.
5. **EIM Settlements and Invoicing**. Addresses changes involving EIM settlements and aspects currently performed by EPE accounting teams.
6. **Network Model & EMS**. Section addressing the changes that will need to happen on modeling and affecting the Energy Management System.
7. **EIM Outage Management**. Addresses EIM's 'availability' interpretation of Outage Management, and the associated impacts.
8. **EIM Metering**. Addresses the Metering Processes, Testing, Documentation, and Technology aspects needed to align with EIM Standards.
9. **Implementation & Market Readiness**. Sequences the efforts needed for EIM Implementation.
10. **Technology Summary**. Expectation setting around impacts to technology. A holistic view of the associated category aspects embedded in individual sections of this document.
11. **Additional EIM Aspects**. Aspects identified during the Gap project which are specific to EPE. Items that may not have a precedent from a previous EIM entrant.
12. **Cost Assessment**. Explanation of Cost estimation.
13. **Glossary of Terms and Acronyms**. Alphabetical list of associated terms to aid EIM understanding.
14. **Appendixes**. Providing more detailed versions of:
    - 1st **Full End to End Process Swimlane Diagram** used in working sessions.
    - 2nd **Systems and Interface Diagram** for new systems, in relation to persisting systems (some needing upgrades).
    - 3rd Written **Full Network Model Analysis** with abridged version of results table.
    - 4th Written **Metering Analysis**.
    - 5th Navigation instructions and supporting context for **Implementation Schedule** Swimlane and Gantt Chart representations.
    - 6th Descriptions for interpreting the **EIM Cost Assessment**.

Categories

Sections 3 – 8, and 10 use a format of shared categories. These are the Sections that most directly map existing EPE areas to their EIM future-state translations, and as such are organized into categories of:

- ***Process.*** Addresses what functions and actions change with EIM for the responsible EPE area.
- ***Technology.*** Addresses what applications, interfaces or other technological aspects change with EIM for the responsible EPE area.
- ***People.*** Addresses human capital aspects related to EIM. Often including hiring, training and organizational arrangement centric criteria.

There are also Subcategories, aligned to the content being addressed. The most common of which is a juxtaposition of "Current State" (ie Pre-EIM) and "Gaps for EIM Participation".

Terminology Conventions

Section 13 of this document is a Glossary of Terms and Acronyms to help with EIM Terms and references. Of particular interest are three aspects that have the lion's share of responsibilities in an EIM world.

- Most Commonly referred to as "**Entity**" in this document, with synonyms that encompass "EIM Entity Scheduling Coordinator (EESC)", and "System Operations (Sys Ops)". The Entity is a "Balancing Area Authority (BAA)" that determines the resources and transmission services required to participate.
- Most Commonly referred to as "**Merchant**" in this document, and alternately as "Participating Resources Scheduling Coordinator (PRSC)", the side of EPE which represents the generation participating in EIM and has non-public information constrained by Standards of Conduct (SOC). Sometimes called "Marketing" or the "Resource Planning & Management" team, inclusive of Day-Ahead Trading, Real-Time Trading, Real-Time Marketing.
- Most Commonly referred to in this document as "**EIM**" (typically when referencing software and procedures) or "**CAISO**" (typically when referencing people), is the Market Operator. Alternatively, also called "The Market".

There are nuances throughout the document where the synonyms are used for a variety of reasons, including pre- and post- EIM organization of resources, personnel 'wearing different hats at different times', and to distinguish between processes/applications/personnel. Hopefully this stated correlation will help the audience better understand common macro groupings.

3 Entity / System Operations

EIM is reliant on the member Balancing Area Authority (BAA) performing a key role in administering the Market. These functions are performed by the "EIM Entity". EPE's current System Operations team is likely to be significantly impacted by EIM. As Entity, System Operations will be responsible for providing Base Schedule information to the CAISO and for performing the BAA and Outage Management functions (Outage Management is addressed in Section 7). This section describes the System Operations current state and potential EIM future state as EIM Entity, and provides supporting information for the cost estimates.

The EIM Entity functions in EIM include Transmission Scheduling, Generation and Interchange Base Schedule Creation, Generation and Interchange Base Schedule Sufficiency Tests, Managing Generation and Transmission Outages and Availability Limits, submission of Real-Time Interchange Schedules, management of ETSR limits, managing Contingency Events in the Market, Conforming Transmission elements, and Determining and Sending Dispatch Signals to Generation Units. In general, the activities covered lead up to and through the Operating Hour.

Many functions which the System Operations team performs today will continue in EIM, generally referred to in this report as EIM Entity functions. Functions which are not related to EIM impacts are not discussed.

For additional detail on the costs for the EIM Entity, please refer to the Estimating Model. Appendix 6 contains information on using and interpreting the model.

3.1 Entity – Process

3.1.1 Current State

Day-ahead or pre-schedule day, Marketing submits a Unit Commitment plan to System Dispatch, for analysis of internal transmission constraints, RMR, and other system conditions, either approving the Unit Commitment plan or modifying if necessary, based on the analysis. Transmission Planning provides System Operations with the RMR table based on different load levels and number of generating units required for voltage support. Marketing also creates a contingency reserve plan, but System Operations plans and manages in real-time the BA contingency reserve obligation independent of the Marketing plan.

Prior to the Operating Hour, System Operations determines and posts ATC for each Interchange location. The team monitors for transmission or generation outages which impact ATC on an ongoing basis and posts updated values to OASIS. Transmission Service Requests are received and evaluated.

Leading up to Operating Hour, System Operations receives and processes eTags. Tags are submitted for all interchange transactions as well as for generation which sinks to load within the EPE BA. Marketing is currently the only EPE transmission customer with generation or load in the EPE BA, with Marketing providing all transmission services to Rio Grande Co-op as a full requirements customer of Marketing, so they already have visibility of the net BA short/long position. At T-20, the final Net Scheduled Interchange for the BA is determined and provided to System Operations.

The majority of EPE's gas-fired generation is able to be placed on AGC, while none of the solar generation is AGC-able, due to the PPA contractual constraints on dispatching. Unit Commitment and duct firing instructions are communicated to gas-fired generation by phone.

System Operations has a Generation Overview PI display which shows generation-related parameters, including unit outputs, ACE, NSI, reserve requirements, flow margins, BAAL statuses, and frequency.

In the event that schedule curtailments are needed, these are processed through OATI software solutions.

3.1.2 Gaps for EIM Participation

3.1.2.1 Base Schedule Management

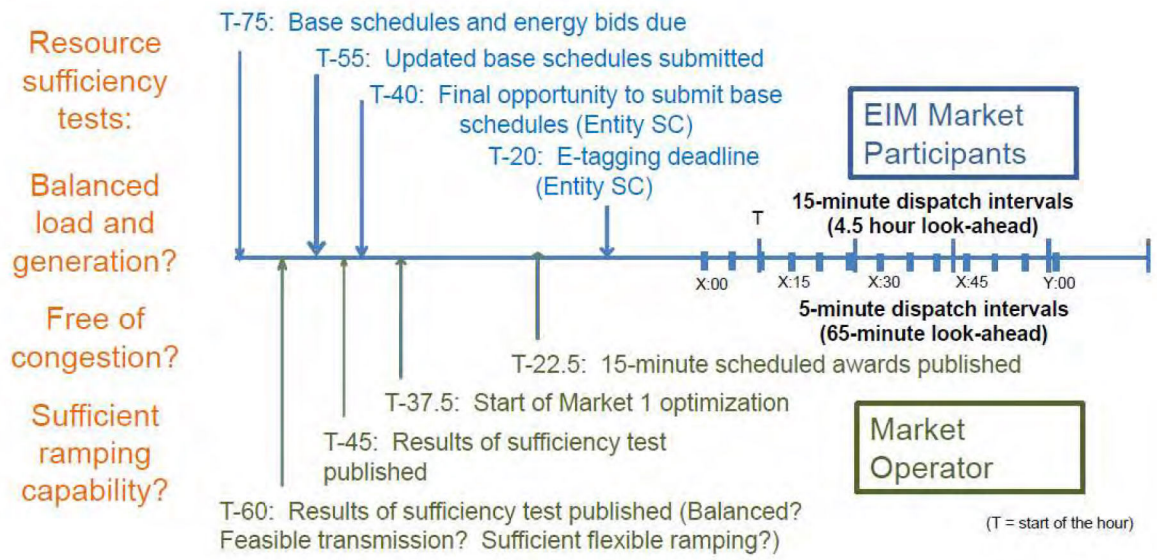
Prior to the T-75 Base Schedule submission deadline, it is expected that Marketing will create and submit to BSAP Generation Base Schedules for all EPE owned and managed Participating Resources. Technically, the EIM Entity is responsible for the submission of Base Schedules for Non-Participating Resources but it is likely that Marketing will have a significant role in determining the schedules for EPE-owned Non-Participating Resources (or designate no NPRs). EPE does not currently have any 3rd Party generation resources that are not contracted with EPE. Should a 3rd Party generation resource not contract with EPE in the future, the 3rd Party Generation Operator, could create and submit base schedules directly to BSAP by T-75, or the EIM Entity might provide a Base Scheduling service for them. The EIM Entity will then need to create Interchange Base Schedules for every interchange location prior to T-75.

Following T-75, the CAISO will run four sufficiency tests and provide the results. It is anticipated that Marketing and 3rd Parties would make adjustments to generation Base Schedules and submit them by T-57 (a deadline which will be set by EPE in the OATT, but which all other EIM Entities have set at T-57) in preparation for the T-55 sufficiency tests. Similarly, the EIM Entity would make adjustments (included for any new tags) and submit Interchange Base Schedules to BSAP for all interchange points by T-55.[4]

Following T-55, the CAISO will again run the four sufficiency tests and provide the results. At this point, Marketing and 3rd Party generation operators will be locked out of BSAP and it is the EIM Entity's responsibility to balance for both generation and interchange. The deadline for the EIM Entity to update any Generation or Interchange Base Schedules is T-40 minutes. It may be possible to coordinate with Marketing (e.g. by phone) if Generation Base Schedule require adjustments, but this is not required by EIM. The EIM Entity will need the Load Forecast, VER Forecast and Generation Operating Limits (ambient derates and outages) for the creation of T-40 Generation Base Schedules, even if Marketing is consulted. Following the T-40 submission to BSAP, Base Schedules are fixed for the purposes of settlements.

[4] The timing and adjustments can be confusing T-57 is the financial deadline for a Tag to participate in the Base Schedule that will likely be established by the EPE OATT However, CAISO will continue to accept Interchange Base Schedules up to T-40 and it is up to the EIM Entity to ensure that only Tags which comply with the OATT are submitted EPE will continue to accept tags up to the WECC tagging deadline of T-20 However, those tags will not participate in the Base Schedule Instead they will update the Real-Time Interchange Schedule (RTIS) Similarly, curtailments will update RTIS ATF Dynamic Tag adjustments affect another related process, called ATF RTIS All applicable tag types (e g excluding Dynamic Wheels) are processed in one or another process

Figure 4 – EIM Real-Time Submission and Sufficiency Test Timeline



There are several variations on how the Interchange Base Schedules are created depending on the Balancing Areas involved. Prior to EIM participation, System Operations will need to identify each interchange location and some properties of that location. Logic will need to be defined to automatically aggregate tag data for each interchange location. For Base Schedules, the aggregation process is performed prior to each Operating Hour, as described above (as well as continuously in Real-Time as part of the Real-Time Interchange Schedule (RTIS) process). Some of the key considerations for different types of interchange are outlined below:

- EPE as an EIM Entity – to/from a Non-EIM Entity – Pending and Approved Schedules are aggregated to Transaction IDs. Transaction IDs group interchange Base Schedules by import or export at the Interchange (defined by a Scheduling Tie ID that maps to the Network Model). They can be further divided by appending a distinguishing PSE code. There are variations for this situation as well:
    - Dynamically Scheduled Imports – If dynamically scheduled imports from a non-EIM BA exist, there are two options: A Registered Import Tie System Resource or a Tie Generator. If EPE were to have any dispatchable resources in adjacent BAs, it might be useful to model them as Tie Generators so that they could be dispatched by EIM.
    - Dynamically Scheduled Exports – If there are exports dynamically scheduled to a Non-EIM BA, these are mapped to Registered Export Tie System Resources.

  The EIM treats interchange at these locations similarly to interchange schedules today. For static imports/exports, the schedule is held constant throughout the hour (unless EPE submits tag curtailments). For dynamics, actual energy is updated after the fact (with settlement consequences).

- EPE as an EIM Entity – to/from an EIM Entity – Pending and Approved Schedules are aggregated to Base EIM Transfer System Resources (Base ETSRs). Similar to above, this creates aggregated scheduled interchange on a scheduling tie specific basis. The tagged schedules are not modified by the EIM. If other participants who are not currently anticipated to be EIM Entities at Go-Live subsequently join the market, revisions will be needed. Dynamic ETSRs will also be defined for Market transfers, but typically they carry no Base Schedules.
- EPE as an EIM Entity – to/from CAISO – Transactions which involve CAISO are created as Mirror Transactions. This approach is used to avoid double counting since CAISO already has representation of this schedule in their systems. This concept is similar to creating aggregated schedules but for the Mirror resource. While this situation is not anticipated to apply to EPE at Go-Live, Marketing may submit CAISO intertie bids in the future, such that EPE would need to implement additional capabilities at that time.

For each of these scenarios, EPE will need to map each tag which crosses a BA boundary to one of the interchange locations for each hour. Marketing is currently the only EPE transmission customer, so they already have visibility of the net BA short/long position. If other transmission customers begin transacting within the EPE BA, impacting the BA position, the EIM Entity will need to determine the net BA position and communicate it to Marketing. Further investigation of the modeling framework for the TEP exchange, Afton generation, and Luna generation should be conducted during the early stages of the EIM implementation, due to the multi-BAA and EIM Entity interactions with the scheduling and dispatch for these generation and transmission arrangements.

As it does today, the EIM Entity will continue processing Tags up to T-20 minutes, which is after the conclusion of the Base Scheduling process. These "late" Tags are created as "Ghost" schedules or modifications to Base ETSRs in the creation of Real-Time Interchange Schedules, which is described below.

3.1.2.2 Real-Time Interchange Schedule and Limit Management

On an on-going basis, the EIM Entity will be calculating and providing Real-Time Interchange Schedules (RTIS) to BAAOP for use in the Real-Time Market (RTM). The process for creating RTIS is similar to the process for creating Interchange Base Schedules described in the previous section in that tags are aggregated for each interchange location. A few distinctions between RTIS and Interchange Base Schedules are notable:

- Interchange Base Schedules are calculated for the hour and submitted up to 40 minutes before the hour begins (T-40). RTIS is calculated on a 5-minute granularity and is submitted every 5-minutes for a rolling 5-hour window.
- Interchange Base Schedules are based on the hourly energy profile at the time of Base Schedule submission. RTIS is ramped to account for schedule changes during and between hours.
- Tie Generators are included in Base Schedules but they are excluded from RTIS calculations.

Interchange curtailments will be immediately communicated to the market and incorporated into the next market optimization run. The next 5-minute market run, or real-time dispatch (RTD) will rebalance,

re-dispatching generation across the EIM footprint (internal and external generation) and adjusting ETSR transfers between EIM Entities. Small curtailments can be absorbed easily, but large curtailments (i.e., MW impact is greater than available ramping capacity) can cause issues in the market which result in price spikes.

Note that while RTIS is updated for schedule changes, it is not updated for changes in flows on ETSRs due to EIM dispatches.

Prior to EIM participation, the EIM Entity will need to establish the logic for creating the ETSR Limit for each ETSR. There are actually three ETSR limits for each ETSR. The first is a "Transfer Limit" which is a single value for the hour. The second is a "Static Limit" which is for the Fifteen Minute Market (FMM). The third limit is a "Dynamic Limit", which is used in the 5-minute Real-Time Dispatch. It is likely EPE will use the same value for all three limits, as some EIM Entities do, unless EPE transfer paths have restrictions on the magnitude of variation in dynamic transfers. Typically, all three limits are related to either the available transmission on related scheduling paths or scheduling rights offered by Marketing.

Throughout the Operating Day, each ETSR Limit must be updated based on the RTIS. This can be done on an hourly basis for an hourly granularity.

RTIS must also be updated after the fact with actual values.

3.1.2.3 Dispatch and Real-Time Operations

Up to five hours in advance of the Operating Interval, CAISO will provide advisory and binding unit commitments and advisory Dispatches via ADS. This information should be monitored by System Operations and Marketing.

The 15-minute market (FMM) is executed by the Real-Time Pre-Dispatch (RTPD) process and will issue commitment instructions (unit starts, stops and transitions) every fifteen minutes. Each run starts at 37.5 minutes before the start of the interval and publishes within 15 minutes.

The 5-minute market (RTM) is executed by the Real-Time Dispatch (RTD) process and will issue Dispatch Operating Targets (DOTs) every five minutes. Beginning just prior to the Operating Hour and every five minutes through the Operating Hour, the CAISO will provide DOTs for every EIM Registered Resource. Typically, only Participating Resources will receive dispatches other than their Base Schedules. Non-Participating Resources are not optimized by the market and are typically dispatched at their base schedule. However, sometimes they are manually dispatched by the EIM Entity, limited by an outage, or dispatched to deploy Available Balancing Capacity when a market infeasibility occurs.

The EIM Entity will have the opportunity to review these unit commitment instructions and DOTs in the BAAOP and block or modify them for each unit. In this way, the EIM Entity is essentially administering the EIM Market within its BA footprint. Once instructions and DOTs are reviewed and any actions are taken, they become binding and are distributed by the CAISO via ADS.

EIM does not include dispatch of Regulation or Operating Reserves. Therefore, the EIM Entity, potentially in conjunction with Marketing, needs to combine the DOTs provided by ADS with any other deployments which may be needed and create a single set point for each Unit. To manage the volume of

set point changes, the set point needs to be provided directly to the Unit for automatic response. The most conventional approach is to have at least the Participating Resources on AGC to automatically respond to DOT changes.

Throughout the Operating Hour, the EIM Entity will also be observing which critical transmission elements are binding within the BAAOP. When an EPE transmission element is on the critical list, System Operations should review the state-estimated flows which were used to bind that element and ensure they are accurate. Likewise, if flows are approaching limits in real-time, System Operations should locate the elements in BAAOP to ensure the state-estimated flows are correct in the market. If adjustments are needed, they can be made through the Transmission Conformance process. This is another way in which EPE administers EIM for its BA.

If a generation resource in the EPE BA experiences a Forced Outage, the outage must be reported to the market as soon as possible. For small losses, System Operations can let the market rebalance. For larger loses, System Operations will respond by deploying Operating Reserves, as it does today. It may also request reserve deployment from the Southwest Reserve Sharing Group (SRSG). To prevent EIM from compensating for the lost generation, the EIM Entity will need to flag in BAAOP that a contingency is in progress, which freezes EIM transfers at their advisory level, and conform its load within BAAOP by the amount of the SRSG response. As reserves are deployed and dynamic reserve sharing adjusted, the EIM Entity will adjust load conforming to keep the market aligned.

3.2 Entity – Technology

3.2.1 Current State

System Operations currently uses OATI WebTrans for transmission scheduling. The system receives and processes tagged schedules, and determines NSI.

System Operations also uses WebTrans to calculate Total Transfer Capability (TTC) and Available Transfer Capability (ATC) for each path for public posting. The calculations are affected by generation and transmission outages which are logged in iTOA but there is no programmatic interface between iTOA and WebTrans. TTC and ATC are posted on OATI OASIS.

EPE does not currently have a VER forecasting application, rather an in-house application aggregates individual PPA solar and community solar forecasts.

EPE utilizes a third-party vendor, TESLA Forecasting Solutions, to forecast its load. TESLA provides a short-range forecast for a maximum 14-day horizon and hourly forecasts. Actual, hourly midpoint load data is uploaded to TESLA on an hourly basis. The load forecast from TESLA is sent to WebTrans and onto webSmartBid by APIs, providing the forecast to System Operations and Marketing, respectively. The TESLA forecast runs each hour and the EPE BAA load excluding Station Service. EPE adds in the Station Service separately. Dispatch and AGC control are performed in the GE EMS. The EMS impacts are discussed in Section 6.2.

3.2.2 Gaps for EIM Participation

For Scheduling, there are four major technology gaps for EIM participation: Interchange Base Schedule Creation and Validation, Generation Base Schedule Creation and Validation, Real-Time Interchange Schedule creation and submission, and ETSR limit determination and submission. These functions can be performed by an EIM Entity Scheduling system. OATI, MCG and PCI are implementing or have implemented solutions which provide these functions.

An EIM Entity Settlement system will perform several key functions required for EIM participation. Specifically, Meter Data submission, Shadow Settlements, Settlement Allocations, Imbalance Invoicing and ISO communications. These processes are described in the Settlements Functions section of this report based on how EPE is organized and the personnel likely to perform the tasks. To avoid repetition, the description of the EIM Entity Settlement system capabilities and integration is in Section 5.

CAISO requires a five-minute granularity VER Forecast for each defined VER Resource in the FNM. Aggregates are acceptable if they are electrically similar but a system level aggregation will likely not work. Additional considerations for the VER Forecast are included in Section 4.2.

An EIM Entity can choose to use either an internal Forecast or the CAISO-provided BAA Demand forecast for Balancing in EIM. However, if an internal Forecast is used, the Entity is subject to much stricter tolerances for accuracy which can result in penalties. All EIM Entities have decided to use the CAISO EIM Forecast and EPE anticipates doing so as well.

Many Entities have kept their own Demand Forecast active as a comparison. EPE should consider keeping TESLA for some time until it is comfortable with the CAISO Demand Forecast. However, no costs have been estimated for integrating the TESLA forecast as a long-term comparison since it is anticipated to be deprecated.

In some cases, EIM Entities have decided to supply their internal Forecast to CAISO to support the ongoing training of the CASIO Forecasting algorithm (ALFS). For this submission to add value, the submitted Forecast needs to be at a 5-minute granularity, solved as close as possible to the T-7.5 snapshot to the 5-minute interval and submitted with very little API lag relative to the snapshot (e.g. T-8). The TESLA Forecast did not seem to meet these requirements and no costs are included to perform this integration.

EPE has no visualization capabilities associated with operating in EIM or a Market. Visualization displays are not mandatory for participation in EIM. The vendor solutions described elsewhere provide some capabilities and CAISO Portals also provide some. However, System Operations may want to consider adding some PI displays or custom displays to the Scheduling and Settlement system. Displays to consider include:

1. Unit Details – Add a new display or enhance the existing Generation Overview display to show the current operational parameters (market rated mins, maxes, etc.), loading (energy, A/S), dispatches and operating levels. Integrate operational, economic and actual information in one place with color coding and other logic. Fleet-wide summary and individual unit breakouts should both be considered.

2. Driving Lanes – A display that shows the upper and lower ranges that can be reached from the currently committed resources. Integrates updated operational ratings with current operating conditions over time.
3. EIM Enhanced NSI – A display that shows NSI, EIM transfers and EIM-adjusted NSI on a rolling 5-minute basis.
4. Transfer and Price Bubbles – Show the potential and actual ETSR flow and prices for each Node. This provides a view of how the market is utilizing EIM transfer capabilities in Real-Time.
5. DOT Comparison – Displays unit EIM DOT, EMS Set Point and actual performance over time. Allows real-time awareness and analysis of differential EIM and EMS instructions and unit performance relative to these.

Some of these concepts may be more associated with the EMS section but we have included them in one place to keep them together. Budget has been included for additional visualization.

3.3 Entity – People

3.3.1 Current State

EPE System Operations currently has a 4-desk Real-Time Operations team. The current roles include:

- Two Real-Time Transmission Operator Desks and one Supervisor
- One Real-Time Scheduler Desk
- One Real-Time System Dispatcher Desk

Each of the four desks are staffed 24/7. While each desk is allotted seven FTEs, none of the desks are currently fully staffed, varying between five and six staff.

3.3.2 Gaps for EIM Participation

The EIM design requires significant participation from the BAA, which serves as the EIM Entity, to aggregate and validate data for use in the market runs and review and approve market results on an hourly basis as well as manage the market in Real Time.

After the implementation is complete, the key new work for EPE's System Operations is anticipated to be:

- Create and Submit Base Schedules
- Manage Sufficiency Tests
- Create and Submit Real-Time Interchange Schedules
- Create and Update Dynamic ETSR Limits
- Receive and Follow Market Commitments and Dispatches
- Manage the Market through Outages, Load Bias and Manual Dispatch
- Manage the Market through Transmission Limits
- Respond to Contingency Events in the Market

Almost all EIM Entities have added a new 24x7 Real-Time Desk to manage EIM.[5] This appears to be needed for EPE as well. A rotation of seven new FTEs is included in the budget. For budgeting purposes, the mix of the team is assumed to be four new FTEs at a Junior / Trainee level and three at a Senior / Experienced level. EPE has stated a preference for a new Supervisor position to manage the new EIM Desk as opposed to rolling the EIM Desk under an existing Supervisor. A Senior / Experience position is budgeted for this role.

The new EIM Desk team will be NERC certified which entails a significant lead time. Additionally, to provide a good mix of experienced team members to the project and to anchor the new Desk, it is anticipated that EPE will draw at least some of the positions from existing System Operations Desks and backfill existing positions with new Resources. It is expected that the new EIM Desk Operators will provide significant support to the project after they are backfilled in their current roles.

EIM responsibilities are intertwined with existing responsibilities in such a way that the split of duties will require further analysis. EPE will need to evaluate the specific distribution of responsibilities during the project, through a preliminary distribution is shown in Table 4. Note that some of the tasks identified in Table 4 are normally automated. However, when that automation fails, it becomes the responsibility of that Desk to troubleshoot or take mitigating actions. These are denoted with Grey Highlighted text. The main considerations are:

- Alignment of subject matter knowledge to EIM responsibilities
- Alignment of non-EIM and EIM responsibilities
- Alignment of hourly and Real-Time tasks in a way that don't conflict
- Distribution of effort among the team

In addition to the Real-Time responsibilities, new market result analysis and additional IT support is needed. The budget currently assumes an additional 0.5 FTE in the EIM Entity for analyzing market results, though some of this effort could be taken on by the new EIM Desk Supervisor. An additional 0.5 FTE for EIM Entity IT support is also included. As discussed in the Network Model and EMS section, an additional 0.5 IT EMS FTE is also allocated. The approach to providing on-call IT support for the new EIM Entity applications and how these FTEs will be divided needs more analysis.

[5] PacifiCorp, NVE, APS, PGE and SMUD added a new System Operations Desk SCL, SRP, NWE, PNM, and LADWP plan to add new desks IPC did not add a new System Operations desk, however, they automated additional existing functionality to free up time to take on the EIM responsibilities BC Hydro did not add a new desk as PowerEx is not a traditional EIM Implementation

Table 3 – Potential Alignment of EIM Responsibilities to System Operations

Desk	Current Responsibilities	Major EIM Responsibilities
EIM Operations Real-Time Desk	• RT Generation Outage creation in iTOA and analyze for reliability impacts (planned outages would continue to be managed by the Outage Management Planning Engineer) • RT Transmission Outage creation in iTOA and analyze for reliability impacts (planned outages would continue to be managed by the Outage Management Planning Engineer)	• Coordinate with RT Trader to Review / Respond to Sufficiency Test Failures (Balancing, Capacity, Flex Ramp after T-75 and T-55) • Create and Submit Non-Participating Resource Base Schedules (in coordination with RT Trader at T-75 and T-55) • Modify, if necessary, and Submit all final Balanced Generation Resource Base Schedules prior to T-40 • Coordinate with System Dispatch to Review / Respond to Sufficiency Test Failures (Balancing, Capacity, Flex Ramp after T-40) • Determine EIM Transfer limits for each Intertie to another EIM participant – Automated under normal circumstances with manual override capability • Coordinate with System Dispatch to create Manual Dispatches in BAAOP for Reliability, Testing, Reserves Dispatch, etc. • Coordinate with System Dispatch to Load Bias in BAAOP as necessary • Manage Contingency Events in BAAOP • Coordinate with System Dispatch and/or RT Trading to modify Participating Resource availability range in BAAOP or iTOA

Desk	Current Responsibilities	Major EIM Responsibilities
System / Generation Dispatch Desk	• Allocate required Contingency Reserves and Regulation Reserves to Resources • Monitor and Maintain Contingency Reserve Levels • Ensure Contingency Reserves are responding to events to meet required response times • Activate Reserve Sharing Processes • Adjust Generation in Real Time to Balance, respond to Contingency Evens and schedule curtailments • Monitor Generation performance, Manage ACE/BAAL • Coordinate with Transmission System Management for generation movement to address transmission system overloads • Coordinating with Plants on issues	• Monitor Market Unit Commitments and Dispatches and take appropriate actions to ensure the Market and dispatches are aligned • Ensure Market Commitments and Dispatches are translated through EMS correctly and passed to Plants • Monitor and reconcile AGC / Regulation Response with Market Dispatches • Update EMS NSI to account for EIM Dynamic ETSR flows – Fully Automated
Scheduling Desk	• Review and approve short-term transmission service • Review and approve e-tags for the BA/TP • Calculate operational NSI for AGC (excluding EIM Dynamic ETSR Transfers) – Fully Automated • Check out Scheduled Interchange with neighboring BAs.	• Create and Submit aggregated Intertie Base Schedules for each Intertie Location (T-75, T-55, T-40) – Fully Automated • Provide a rolling five hour forecast or ramped interchange for each Intertie at a 5-minute granularity, refreshed every 5 minutes – Fully Automated • Provide after-the-fact Intertie Resource schedules with 5-minute un-ramped profile – Fully Automated • Update EIM Transfer Tags with Net Hourly transfers – Potentially Automated

Desk	Current Responsibilities	Major EIM Responsibilities
Transmission Operations Desks (2)	• Create or Review and Approve Switching Orders • Transmission Switching and tag out management • Enter Forced Transmission Outages into EPE iTOA OMS • Perform Contingency Analysis studies • Coordinate with System Dispatch to address transmission system overloads through generation and/or transmission switching • RAS scheme arming and implementation	• Review / Respond to Sufficiency Test Failures (Expected Congestion) • Manage EIM Binding Constraints / violations of RTCA in Market dispatch and Conform Transmission Limits in Market as needed

4 Merchant / Resource Planning and Management

In EIM, the BAA begins from a financially balanced position of generation and load. The Market then optimizes the short-term commitment and dispatch of all EIM Generation to serve all EIM Load. This includes commitment and dispatch of EPE generation as well as that of all other Participating Resources in other EIM BAAs, subject to the Dynamic ETSR Transfer capability and physical constraints.

The economic information provided to EIM for optimization is supplied by the Participating Resource Scheduling Coordinator (PRSC). The majority of the functions required of the PRSC will be performed by the Day-Ahead and Real-Time Trading teams. This section describes the current state and potential EIM future state for these groups and provides supporting information for the cost estimates.[6]

For additional detail on the costs, please refer to the Estimating Model. Please see the Appendix for information on using and interpreting the model.

4.1 Merchant – Process

4.1.1 Current State

Currently, EPE determined Unit Commitment in EDUC. However, prior to the EIM project, it is anticipated that this function will be implemented in OATI's webSmartBid (WSB) where EPE's Trading team will define Generation and Generation Costs.

The WSB output is hourly Resource schedules for Energy and Ancillary Services. This information is provided to System Operations (Sys Ops) for review via spreadsheet. After Sys Ops approval, it is communicated to Real-Time. It is unclear if the financial information for Startup, Min Load and Energy Bid creation is exported or exportable from WSB, and may need to be an enhancement.

Once WSB is fully rolled out, the expectation is that the Real-Time Trading team will continue to tweak assumptions in WSB (e.g. actual SRSG reserve targets) to support the identification of bilateral purchase and sale opportunities. The Real-Time team continues to transact to balance and optimize the portfolio on a bilateral basis.

EPE is not currently a Scheduling Coordinator for the MRTU Market and does not transact directly with the CAISO. EPE does not bilaterally import power to California and has no California Air Resources Board (CARB) Green House Gas (GHG) compliance program.

The Real-Time team has visibility into Resource movement controlled by Sys Ops via a replicated set of EMS / PI Displays. Real Time takes an active, secondary role in generation dispatch and unit commitment, managing unit outages, and meeting contingency/operating reserves.

The Resource Planning and Management team plays a primary role in the planning of and monitoring of generation outages and their termination. Resource Management records all key performance indicators (KPI) from all generation plants, including unit outages and de-rates. Anticipated outages / outage windows are provided to the Resource Planning and Management team by Sys Ops. Real-Time

[6] Note that "current state" in some cases is the state anticipated at the start of an EIM project For example, the webSmartBid implementation is assumed to be completed and the planned capabilities implemented

sees Forced Outages via their EMS screens. The Real-Time team is responsible for purchasing replacement power when needed following an outage.

4.1.2 Gaps for EIM Participation

EPE will need to define the physical and economic parameters of its Generation Resources in a way that is consistent with CASIO requirements and definitions. There are several aspects to this and it is a major project effort.

- The first step is to define the Generation Resource Data Template (GRDT) which establishes the base physical properties of all EPE Resources. This effort must be coordinated with Network Modeling, System Operations, Outage Management and Metering to ensure consistency of information (e.g. that every Generator in the Full Network Model (FNM) is accounted for in all other processes in a consistent way, that the location of measurement of schedule, bid, dispatch and meter are all at the same point). This will include details on the startup, ramping, min, max, fuel type, GHG properties and many other characteristics as well as heat rate and O&M cost information.
- Once the base GRDT is defined, the Resource Planning and Management team will need to define Major Maintenance Adders (MMAs) and Default Energy Bids (DEBs) / Fuel Regions to be used in the Mitigation Process. It appears that EPE has some information like this within WSB but it will likely need to be updated in coordination with the Plant operations team.
- As part of these processes, but also with distinct elements, EPE will also need to create a participation strategy for each Resource. This is the approach that EPE will use to combine Schedule, Bid, Outage, Modeling, Process and other techniques to ensure that EPE resources are treated correctly in the Market.

Once defined, a process should be created to periodically (e.g. annual) review and refresh the information, file updates with CAISO and update EPE systems to reflect updated modeling parameters. Additionally, this process will apply to each new Resource added to the system.

The general Day-Ahead process can be much the same in EIM. While there will be some changes to Resource definition, cost modeling and other WSB inputs, which are discussed in the Technology section, the main process of creating Energy and Ancillary Service schedules appears sufficient. EPE will then submit this information as Base Schedules for a future 7 Day Ahead (7DA) horizon to CAISO. The Base Schedule submission is a Tariff requirement but is not currently used in the Market. EPE's existing needs and RC obligations are the main drivers for the Day-Ahead process. The Marketing team will submit bid curves for each Participating Resource for each Operating Hour to CAISO. Bid curves are due to the Market by T-75 minutes to the Operating Hour. These curves are the economic input the CAISO uses to determine the dispatch of Participating Resources in Real-Time. Typically, the Day-Ahead team has some role in setting up the Bids for the next day but the final submissions are performed by the Real-Time team.

EPE must submit Energy and Ancillary Services Base Schedules (including VER forecasts) for each hour for the Participating Resources. There are three Energy and Ancillary Service Base Schedule submission

timelines – T-75 minutes to the start of the Operating Hour, T-55 and T-40. It is likely that the Real-Time Marketing team / the Participating Resource SC will be responsible for the T-75 submission and the T-55 submission to CAISO while the System Operations team / EIM Entity will be responsible for the T-40 submission to CAISO. The CAISO will provide results to EPE indicating whether it detects imbalances, capacity shortages, ramping insufficiency or transmission infeasibility following each submission, with the results of the T-40 submission becoming financially binding for the Operating Hour.[7] Anticipating the Sufficiency Test Results, and responding to Sufficiency Test failures, is a key process for Real-Time Marketing that happens each hour.

During Real-Time, the CAISO will issue start-up instructions for Participating Resources which can start within about five hours. Startup instructions will be advisory until the last interval in which the unit could start based on the Start Up Times in the Master File. The CAISO will issue Fifteen Minute Market (FMM) Awards and 5-Minute dispatch signals for all EPE Participating and Non-Participating Resources via the Automated Dispatch System (ADS). The FMM awards are financially binding but don't require a physical response. The 5-Minute dispatches are issued about 30-60 seconds before resources should begin ramping to achieve the 5-minute Dispatch Operating Target (DOT). Real-Time Marketing can view this information in the ADS terminal to monitor for potential issues (e.g. resources which systematically are not achieving their DOT).

Managing generation outages and availability is an important process in EIM. Generation ambient derates are considered "outages" in the EIM and EPE will need to provide hourly updates to minimum and maximum output capabilities and ramp rates. Similarly, the precise start and end time of outages can have a bigger effect on results than in traditional operations. The use of Generation Outages is also the only way for the Real-Time Marketing team to provide information to the market that is faster than 75 to 135 minutes from 'now'. These tasks could also be performed by System Operations but during this project it was discussed that more analysis was needed to see how the Real-Time Marketing team could best support these requirements given that Real-Time Marketing does not currently have direct access to the Outage Management System.

EIM introduces a new level of after-the-fact analysis. The CAISO publishes a wealth of data. In addition to the awards and dispatches which are published for each FMM and Real-Time interval, Locational Marginal Prices (LMPs) are published for each Pricing Node on the system. Several other interesting pieces of data are also available from CAISO (load and VER forecasts and actuals, transmission availability, shadow prices on specific constraints, and dozens of others). In the past couple years, the CAISO has been publishing a set of participant-specific charts, and reviewing those with the participant (daily at first and then weekly about 6 months after the start of operations). Resource Management will need to develop processes and tools to review Market results and make changes to scheduling, bidding, cost, modeling and other Market-facing inputs. This effort will likely be shared between the Market Results analyst, the Real-Time team by reporting unusual events and Resource Management leadership.

Finally, EPE does not currently participate in the CARB GHG market. Initial discussion during this project was that EPE would continue to opt-out of participation. This is easily accomplished through EIM submissions but does carry a potential opportunity cost of not receiving dispatches when EPE units are

[7] Transmission Feasibility results are only provided to System Operations

in the money.[8] If EPE participates in the GHG market as part of EIM, tools and processes would be needed. In general, this report only includes GHG functionality when it might be bundled with other services in a way that has no marginal cost (e.g. in the PRSC Settlement System). No costs have been estimated for the GHG compliance process.

4.2 Merchant – Technology

4.2.1 Current State

EPE Forecasts VER using an aggregation of VER Forecasts provided by the project owners.

EPE utilizes a third-party vendor, TESLA Forecasting Solutions, to forecast its load. TESLA provides a short-range forecast for a maximum 14-day horizon and hourly forecasts. Actual, hourly midpoint load data is uploaded to TESLA on an hourly basis.

The Day-Ahead Trading team performs an optimization to determine the Day-Ahead generation plan for the BAA using EDUC, and in the future OATI webSmartBid (WSB), applications. Key features of the optimization include:

- Generation Resources are represented at an individual Unit or Combined Cycle level in WSB.
- System Operations provides a Reliability Must Run (RMR) schedule based on transmission system studies, load and the SNMIC import constraint. The Day-Ahead team self-schedules those resources in the optimization.
- The optimization is aware of the EPE transfer capability, including the PV exchange agreement with TEP, to import energy into the El Paso BAA as well as opportunities to make off system sales.[9]
- The Load Forecast is provided by Tesla and is for the full BAA requirements excluding Station Service. The Merchant team is responsible for serving the Rio Grande Cooperative Load and it is included in the Forecast.
- Ancillary Service targets are defined in WSB. A fixed 7% is used for Operating Reserve (i.e. unadjusted by SWRSG diversity benefits) and 35 MWs for Reg Up/Dn is defined.[10]
- The VER Forecast is an aggregation of solar project supplied forecasts using an in-house developed aggregation tool.
- Generation Derates are manually entered into WSB based on a daily report provided by System Operations.
- Gas Prices are supplied from Gas Review and Management System (GRAMS), an internally developed tool which has gas costs by source location, transportation and blending logic. This data is copy/paste into WSB.
- Forward bilateral prices are input for Palo Verde to allow recommendations for off system sales.

[8] The opportunity cost is described here as "potential" because there appear to be some errors in the way that CAISO has implemented the settlements for EIM GHG Awards Until this is corrected, it would make EPE participation in GHG unlikely

[9] During the project we will need to understand the approach to derates

[10] During the project, we will need to discuss Regulation v Load Following

- Adjustments for bilateral transactions are made manually in WSB. In addition to general Purchases and Sales, the Freeport McMoran exchange and Station Service are provided to WSB this way.
- Incremental Startup, Min Load and Energy Bid functionality. The primary inputs are the fuel consumption for each of these but there are some adders available as well. It was unclear how flexible this model was to include other costs and this will need to be explored during the project.
- WSB appears to have some functionality for modeling resource "phases" which appears to be similar to combined cycle modeling as well as defining "flexibility" products these have not been explored in detail or setup as of this evaluation.

4.2.2 Gaps for EIM Participation

A new VER Forecasting application will be needed. EPE VER will likely be modeled as individual Resources within the GRDT rather than an aggregate. EPE will be directly settled by the CAISO for deviations between the VER Forecast at T-40 and actual VER output. EPE's existing VER forecasting approach is likely to become more problematic as additional VER is added to the system. Additionally, the use of in-house VER Forecasting application can be challenging to maintain given the requirements of EIM. This gap is split between Resource Planning and Management and System Operations but is accounted for in the Resource Planning and Management costs.

EPE could continue with the TESLA forecast but during the project it was discussed that EPE would like to move to using the CAISO Demand Forecast directly. This will provide benefits in terms of alignment to EIM obligations. It might make sense to continue TESLA for some time as a backup or a way to measure the quality of the CAISO Demand Forecast before deprecating it.

webSmartBid will need to be updated to reflect the EIM Modeling. This is likely to have the following elements:

- Update Resource definition and parameters to match GRDT as well as potential updates to model combined cycle resources consistent with the CAISO Multi-Stage Generation modeling.
- Update cost definitions and parameters to match those desired for Bidding and calculate CAISO formatted Bids (this may also be done in the PRSC Scheduling System).
- Integration updates to receive CAISO's Demand Forecast, receive OMS derates, receive VER Forecasts, publish Base Schedules and Bids to the PRSC Scheduling System.
- Potential update to the RMR processing to ensure they are created as Self-Schedules rather than Base Schedules when a required minimum operating level other than Pmin in required.
- Potential updates to the way gas costs are defined. This is not a major issue for EPE based on proximity to the basins and pipeline capacity. However, it should be noted that the incremental fuel cost applicable to CAISO commitment and dispatch is likely not WACOG in at least some instances.
- Potential updates to model Flexible Ramping targets, Resource capability and reservation of rampable range on Resources to meet the Flex Ramp Sufficiency Tests.

A new PRSC Bidding and Scheduling application will be needed to coordinate the hourly CAISO submissions, manage Sufficiency Test results and all the Real-Time Marketing team to perform analysis. The capabilities of these systems vary and EPE will need to understand which calculations will be performed in WSB in a future state and how that impacts the capabilities needed in a PRSC Bidding and Scheduling System.

As noted in the Process section, minimal consideration has been given to the technology requirements of tracking GHG positions in this analysis because EPE is anticipated to opt-out. If EPE chooses to opt-in to GHG participation, that will require system to support it. At a minimum, EPE would need to record allowance purchases in the Deal Capture System (probably webTrader), record GHG obligations in the PRSC Settlement System, combine those values, mark that position to market, perform the "lesser of" analysis, compute the annual GHG obligations and update the position in webTrader when certificates are retired. These costs are not included in this analysis.

There is also an expected change to allow Merchant personnel user access roles to the OMS to submit availability tickets for generation. The driving factor is OMS is the most time-effective way to provide the Market some signals for which Merchant is anticipated to be responsible for. This is addressed further in Section 7.

4.3 Merchant – People

4.3.1 Current State

The portion of EPE's Resource Planning and Management team that participated in the evaluation and is anticipated to have significant EIM responsibilities.

- Day-Ahead – The team has a Supervisor, three Day Ahead traders and two energy schedulers.
- Real-Time – The team has a Supervisor and one 24x7 Real-Time shift of seven Real-Time operators.
- Resource Planning – Provides no Resource Management Real Time Desk support

4.3.2 Gaps for EIM Participation

After the implementation is complete, the key new work for EPE's Resource Management team is anticipated to be:

- Maintenance of Generation Cost Parameters
- Submission of Base Schedules
- Creation and Submission of Bids
- Management of the Sufficiency Test Results
- Management of Real-Time Generation Outage
- Monitoring Real-Time Dispatches
- GHG Trading, if applicable
- Analyze Market Results

There are a few options to organize the team that EPE can consider.

Maintenance of Generation Cost Parameters is typically assigned to a Supervisor or Engineer rather than a Real-Time Operator. From a Marketing perspective, it can be managed by Day-Ahead, Real-Time or an appropriate Engineer and is anticipated to include input of Sys Ops and the Plants. This tends to be a decision based on existing skills, availability and relationships with plants. Depending on how well this is maintained currently, there may be a small amount of incremental work spread out over the year.

Five of the major hourly tasks are grouped together below for staffing considerations:

- Creation and Submission of Bids – This task is often thought of as a Real-Time task because the submission deadline is a rolling Real-Time window. At some participants with complex hydro fleets or very constrained gas pipeline operations there can be important on-going Bid management throughout the day. However, with EPE's fleet, it is unlikely that Bids will change significantly during the day (gas price changes would be the main candidate for updating bids).
- Submission of Base Schedules – This is primarily a Real-Time task but is similar to the existing hourly responsibilities of the existing Real-Time Operator.
- Management of the Sufficiency Test Results – This is a Real-Time task and is new relative to existing responsibilities. Managing the submission deadlines and results each hour takes some time.
- Management of Real-Time Generation Outages – This is a Real-Time task and is new relative to existing responsibilities. Depending on how this function is split with System Operations, and how much automation is implemented for ambient derates will affect how much incremental effort is associated with this task.
- Monitoring of Real-Time Dispatches – This is a Real-Time task and is new relative to existing responsibilities. However, this is not a significant role at EPE.

Some participants have added (or tried to add) a new 24x7 Real-Time Marketing shift to manage Bids, Base Schedules, Sufficiency Tests and Generation Outage Management but the majority have not. Those that have tended to have either significant responsibilities for gas management, Real-Time unit commitment and dispatch, or large and complex fleets. Often there is a reduction in bilateral hourly trading responsibilities, existing slack in responsibilities, and new tools and automation of processes that offsets the incremental work in Real-Time.

Additionally, with EPE's fleet, it is likely possible to move the majority of the Bid creation, submission and management to a daily / Day-Ahead person, though this is complicated by two important factors. The first is that the ideal time to create Bids is no earlier than 2pm daily (when the CAISO Day-Ahead Market publishes and opens the Real-Time Bidding window) and likely after the 4pm pre-schedule process is completed. This tends to be late in the day for someone with Day-Ahead responsibilities, though this might be addressed with staggered schedules, though this is not preferred by EPE. The second is that Bids must be submitted 7 days a week. This means that either EPE needs to pre-create the Bids for Saturday through Monday based on what is known on Friday or needs to have a person assigned (or rotating assignments) to support the weekend. Overall, the Bid creation process should be manageable in 2-4 hours per day.

The other main process is analyzing the Market Results. This is a weekday only process but is significant, likely consuming 4 hours per day. It also usually requires a significant amount of uninterrupted thought, analysis and cross-checking of results and is therefore not well suited to a Real-Time Operator. This is typically assigned to a daily / Day-Ahead person and/or Supervisor but it might be possible to make a portion of this analysis part of the responsibilities of the Real-Time person on relief, depending on existing relief shift responsibilities. This is likely a team effort with the Supervisors also being involved.

Overall, the cost estimates assume [11]one new FTE, 50% on Bid support and 50% on Market Result Analysis with no incremental Real-Time shift. For cost estimating purposes, the new Resource level was split between the lower cost for Bid support and higher cost for Market Result Analysis. The Real-Time Operator takes on the Outage Management, Base Schedule and Sufficiency Test management responsibilities, along with minor tweaks to Bids.

The final new process of significance would be GHG participation, if applicable. This would become part of the Day-Ahead responsibilities to purchase offsets and track the position.

[11] The analysis in this report is based on a review of EPE's team and comparison to other utilities that have joined EIM. However, there is some uncertainty in tools, scope, market or regulatory changes, and how the new responsibilities will be integrated into the Marketing team. EPE may choose to participate in the GHG market, Real-Time trading activity may not decline as much as anticipated, market or regulatory changes may increase the burden on the Marketing team, analysis responsibilities could be greater than anticipated, EPE's fleet may become more complex, the weekend assumption may not hold, or other factors may increase the required effort. If so, a second FTE it may be considered.

5 EIM Settlements and Invoicing

EIM Settlements and Invoicing will be a significant change for EPE. New responsibilities, stakeholders, processes, applications and timelines will need to be navigated.

EIM consists of one timeline for two Settlement audiences, Entity and Merchant. Because of this shared timeline this Section of the document will be written from that shared perspective, and deviations particular to Entity or Merchant settlements will be called out.

5.1 EIM Settlements and Invoicing – Process

5.1.1 Current State

Currently EPE is not a CAISO SC (Scheduling Coordinator), has no direct CAISO transactions and hence no CAISO Settlements processes, though some counterparties (e.g. APS) have passed through EIM related charges to EPE.

EPE's settlement and cash management with counterparties for bilateral purchases and sales and transmission purchase is currently monthly, which differs from the EIM weekly invoicing timeline. Responsibilities associated with ISO CCs (Charge Codes) will be new for EPE. A downstream new responsibility associated with EIM will be the TC (Transmission Customers) Allocation of ISO CCs.

While EPE currently collects meter data for interchange check-outs and revenue billing, EPE does not currently collect and process meter data in the context of a wholesale market, such as the CAISO market.

With EPE's footprint bridging two states, Texas and New Mexico, there are accounting procedures in place to account for percentage of cost responsibilities assigned to the customer in each State. In addition, EPE has an off-system sales revenue sharing agreement in New Mexico.

5.1.2 Gaps for EIM Participation

Following the Operating Day, EPE must submit meter data for Generation and Load resources. This will be a new responsibility for EPE. There are still some decisions to be made on addressing this aspect. For the purposes of this report it is assumed that EE Settlements will ultimately be responsible for the submission of Meter Data, an approach driven by the Applications involved. In this model the webAccounting application receives MV90 and PI Meter Data, and applies correction factors as needed. webAccounting then passes the data to the EE Settlement System which has an OOTB interface with MRI-S to provide the ISO the values. This is the preferred approach based on understanding the owners for these Applications.

With Generation meter data anticipated to be submitted by EE Settlements, Marketing Operations will obtain Generation meter data from CAISO MRI-M after EE Settlements has completed the submission. Marketing Operations will likely need to obtain EPE Supply Load separately, as EE Settlements will be submitting BA-level load.

Following the Operating Day, the CAISO will issue a Settlement Statement. Settlement Statements are composed of CCs (Charge Codes) which are essentially the algebraic equations used to calculate each

payment. There are currently 21 CCs which apply to the PRSC and 27 that apply to the EESC.[12] The Charge Code data ("Billing Determinants") contains a very granular breakdown of all the inputs (e.g. 5-minute DOTs, 5-minute meter data, 5-minute prices) and the equations defining the Charge Codes can cover several pages. A given Operating Day can be settled 3 or more times over the course of a year when there are changes to one or more inputs.[13] Most companies have a "shadow settlements" function which validates the charges which is a significant new process for EPE. If issues are discovered with the CAISO calculated settlements, Disputes may be filed with the CAISO to request an adjustment on a future "resettlement".

To demonstrate the CAISO publishes a "California ISO Payments Calendar" on their website at http://www.caiso.com/market/Pages/Settlements/Default.aspx

Figure 5 – Excerpt from CAISO Payments Calendar

California ISO

Timelines are PT (Pacific Time) except as noted

Calendar Date	Day	Publish Initial Statement Publish Day-Ahead Price Corrections T+3B	Publish Real-Time Price Corrections T+5B	Receive End-Use Meter Data, Manual Submission of non PTO Wheeling Data T+8B	Publish Recalculation Statement T+12B	End of SC Review Period T+26B	Receive End-Use Meter Data (to include non-PTO load) T+48B	Publish Recalculation Statement T+55B	Publish Weekly Invoice (by bill period)	Weekly Invoice Due by 10:00am for Disbursement at 2:00pm T+4B
18-Nov-19	Monday	11/13/2019	11/11/2019	11/06/2019	10/31/2019, Oct 2019 Monthly	10/11-10/13/2019	09/11/2019	08/30-09/02/2019, Aug 2019 Monthly		
19-Nov-19	Tuesday	11/14/2019	11/12/2019	11/07/2019	11/01-11/03/2019	10/14/2019	09/12/2019	09/03/2019		T+3B Initial: 11/04-11/10/2019, T+12B Recalc: 10/21-10/27/2019
20-Nov-19	Wednesday	11/15-11/17/2019	11/13/2019	11/08-11/10/2019	11/04/2019	10/15/2019	09/13-09/15/2019	09/04/2019	T+3B Initial: 11/11-11/17/2019, T+12B Recalc: 11/01-11/03/2019, T+12B Recalc: 10/01-10/31/2019, T+55B Recalc: 08/01-08/31/2019	
21-Nov-19	Thursday	11/18/2019	11/14/2019	11/11/2019	11/05/2019	10/16/2019	09/16/2019	09/05/2019		
22-Nov-19	Friday	11/19/2019	11/15-11/17/2019	11/12/2019	11/06/2019	10/17/2019	09/17/2019	09/06-09/08/2019		
23-Nov-19	Saturday									
24-Nov-19	Sunday									
25-Nov-19	Monday	11/20/2019	11/18/2019	11/13/2019	11/07/2019	10/18-10/20/2019	09/18/2019	09/09/2019		
26-Nov-19	Tuesday	11/21/2019	11/19/2019	11/14/2019	11/08-11/10/2019	10/21/2019	09/19/2019	09/10/2019		T+3B Initial: 11/11-11/17/2019, T+12B Recalc: 11/01-11/03/2019, T+12B Recalc: 10/01-10/31/2019, T+55B Recalc: 08/01-08/31/2019
27-Nov-19	Wednesday	11/22-11/24/2019	11/20/2019	11/15-11/17/2019	11/11/2019	10/22/2019	09/20-09/22/2019	09/11/2019	T+3B Initial: 11/18-11/24/2019, T+12B Recalc: 11/04-11/10/2019, T+33M Recalc: 02/01-02/28/2017	
28-Nov-19	Thursday									
29-Nov-19	Friday									
30-Nov-19	Saturday									

With the new responsibilities of EIM Settlements also come TC Allocations, which consists of allocating the EIM CC dollar amounts to the TC (Transmission Customer) that caused the charge according to an updated EPE OATT. This new functionality is major implementation effort where the methods of allocation will need to be determined and defined. There will be an on-going component where the EESC Settlements group will be responsible for calculating the values and sending statements to TCs.

Some companies have the shadow settlement function included in "back office" while others view this function as more analytical and want it to be closer to the teams which are participating in the Market.

The CAISO then groups Settlement Statements onto Invoices for financial reconciliations and payment once a week (in contrast to bilateral settlements which are traditionally done monthly). Keeping up with this new cycle, and determining whether to apply it to EPE TCs, will be new.

[12] This count is continually changing as changes are made to the market.
[13] The cycle is currently the subject of an ongoing market initiative.

At some point a handoff to the Accounting group will take place. With EPE's current Cash Management operating on a Monthly interval, some effort will need to be put toward reconciling the Weekly CAISO timeline. There are tradeoffs with adjusting either timeline, and downstream stakeholders should contribute to the conversation. The standard Accounting associated with bilateral and transmission invoices, receiving/paying funds, and other basic aspects will continue in EIM as currently executed.

New responsibilities around posting and managing Credit with the CAISO will be part of EIM, though these efforts are not anticipated to be significant on an ongoing basis as long as EPE is investment grade.

California has Greenhouse Gas (GHG) regulations which will influence the pricing and dispatch of generation resources. EPE is currently evaluating the exclusion of scenarios which will need to account for energy from GHG producing resources which is sold to California. This may need to be investigated to a greater level of detail, and may have a corresponding CARB/GHG-type constraint from other States.

There should be some additional investigation to reconcile the EIM Resettlement timeline with EPE's Rate Department. Uncover if there are incongruities with the 3-yr horizon on EPE's ability to claw back.

Another element that will require detailed analysis is accounting for the pass-through of EIM costs and benefit to customers. With two state jurisdictions and differential treatment of wholesale margins between Texas and New Mexico, detailed design will be required to understand how to treat EIM Costs. The current method of "stacking" the resources to determine "deal margin" will need to be adjusted.

EIM Settlements will be assigned to either the PRSC or the EESC, and, more specifically to individual resources on both 15-minute and 5-minute basis. For generation resources, these revenues and charges are computed relative to the submitted Bids (Startup, Min Load and Energy) and may represent economic sales, economic buy-backs or uneconomic sales.[14] In addition, charges are not only for energy. They may settle flexible capacity payments or charges and will also include some significant "offset" charges.

Further, it will not be straightforward to determine whether a given charge or credit was assessed in support of EPE Load service, 3rd Party Load service (e.g. Rio Grande) or for EIM import / export. There are options to address these conditions, but they are not entirely straightforward and involve some tradeoffs and assumptions. EPE will need to make both software and policy / regulatory decisions on how to perform this split.

Beyond validating EIM CC's and invoicing 3rd parties, the Settlements Team(s) may play a bigger role in the Analysis of EPE's performance in the market. This may consist of providing reports on the operation of units, "what-if" comparison evaluations, and KPI (key performance indicators) measurements of benefits from the market.

[14] In the case of uneconomic sales, Bid Cost Recovery can come into play

5.2 EIM Settlements and Invoicing – Technology

5.2.1 Current State

For System Ops, the webAccounting application does all the Transmission Billing, including the Loss Billing. After a difficult implementation, the application is now running well and expected to persist. webAccounting is used to create the bills, and collect Meter Data from MV90 and PI.

The Power Plant application is used as a tool in the AP/AR processes.

5.2.2 Gaps for EIM Participation

For EIM there will be at least two major systems added, a PRSC Settlements & Analytics System, and an EESC Settlements & Allocation System. These systems will provide the interfaces needed with EIM Systems, provide the functionality needed to perform Settlement Validations, aid in disputing with CAISO, help with workflow, and other functions.

Due to the previously described quantities of data and new responsibilities it is infeasible for a Participant to adequately perform EIM Settlements functions without an application. From specifics that were uncovered during this Gap Assessment, EPE may have unique requirements which will require Vendors to propose custom development in order to solve.

The timeline for an Application is covered in Section 10. The main vendors for Settlements Systems will have enough OOTB User Permission Management to allow for different organizational structures to be supported.

The persisting webAccounting application will also require project efforts and has been included in the budget.

Downstream applications, such as Power Plant, are expected to be minimally affected with no new interfaces identified. Minimal regression testing may still be required, and any timeline changes could affect this assumption.

5.3 EIM Settlements and Invoicing – People

5.3.1 Current State

Currently there are separately defined areas for Merchant and System Operations accounting functions. The Merchant aspects are the responsibility of Ana Boisselier's team, and the System Operations are the responsibility of Brenda Delgado's. The workload for these teams has been described as being fully loaded with current responsibilities.

5.3.2 Gaps for EIM Participation

The settlement of EIM charges, and the analysis of those results will be new and complex. This has been one of the largest impacts at other new EIM members. New staff will be needed to perform these functions.

Broadly, the key "settlement" functions can be classified into five groups.

1. Market Analytics – Analysis of market and financial results for the purposes of changing strategies or operations. This often involves scrutinizing settlement data.
2. Merchant Shadow Settlements – Analysis of CAISO settlement data for the purposes of validating that bills are correct. Includes disputing errors and tracking disputes.
3. TC Allocations & Billing – Processing of CAISO settlements which were assigned to EPE but which belong to a Transmission Customer. Involves validating CAISO results, calculating and validating TC statements and invoices, and receiving and responding to disputes / questions from TCs.
4. Invoice Payment & Reconciliation – Validating invoice match settlement results, recording AR/AP and reconciling cash transactions.
5. Overall Financial Reporting – Identifying how market results impact EPE's overall costs and how those costs are allocated among customers.

Table 5 contains some of the key tasks for EIM which fall into the five groups identified above and attempts to split them between PRSC and EESC facing responsibilities. Most tasks are required in some way or another but the amount of effort needed can vary by EPE's objectives.

Table 4 – Potential Alignment of EIM Settlement Responsibilities

Function	PRSC / Marketing Responsibilities	EESC / Sys Ops Responsibilities
Market Analytics	Analyze Market Results for Bidding & Scheduling Issues (some potential items are listed as examples, but a final list of analysis topics and reports has not been developed yet – the level of effort will be partially dependent on these choices) • Feasibility Test Performance • Infeasibilities / Market Deployment of "Regulation" • EIM "Late" Tags • Logical Resource Commitment / Dispatch • Impact of Mitigation • Impact of EIM on Gas / Fuel Activities • Impact of EIM on O&M Costs • Dispatch Following / Ramping / UIE • Bid Cost Recovery Payments • Bid Cost / Parameter Analysis • Implications of Physical Parameters • Costs of Generation Outages	Analyze Market Results for EPE Operational & Transmission Issues (some potential items are listed as examples, but a final list of analysis topics and reports has not been developed yet – the level of effort will be partially dependent on these choices) • Use of Load Bias • Impact of Congestion / Transmission Limit Conformance • Impact of ETSR Limits • ETSR Swings • ACE Performance • Analyze/Trend components of Congestion, Loss and Energy Offsets • UFE Analysis

Function	PRSC / Marketing Responsibilities	EESC / Sys Ops Responsibilities
Shadow Settlements	• Process PRSC Market Results and EIM Settlement Statements • Identify CAISO data errors in PRSC Settlements and file / manage disputes (e.g due to Meter Data issue, Prices Corrections, CAISO System or Calculation failures)	• Process EESC Market Results and EIM Settlement Statements • Identify CAISO data errors in EESC Settlements and file / manage disputes (e.g. due to Meter Data issues, Schedule / Tag issues, CAISO System or Calculation failures)
TC Allocations & Billing	• Receive Settlement Statements from EESC • Dispute EESC Charges	• Calculate EIM Settlements for Transmission Customers • Receive/Analyze/Process TC disputes and post disputes to OASIS • Issue Invoices for Transmission Customers
Invoice Payment & Reconciliation	• Process PRSC Invoices and Reconcile to Settlement Statements • Record CAISO Invoiced Amounts as AR/AP • Process Cash Transactions for CAISO	• Process EESC Invoices and Reconcile to Settlement Statements • Record CAISO Invoiced Amounts as AR/AP • Record Transmission Customers Invoiced Amounts as AR/AP • Process Cash Transactions for CAISO • Process Cash Transactions for Transmission Customers
Overall Financial Reporting	• CAISO Benefits Shadow Calculation / End-Customer Savings • Process Texas / New Mexico Margin analysis and EIM benefit split • Market value of VER Generation • Create EQR reflecting EIM Transactions, combine with bilateral EQR and upload to FERC	• CAISO Benefits Shadow Calculation / End-Customer Savings • Process Texas / New Mexico Margin analysis and EIM benefit split

There is an important organizational decision to make about how these staff will be aligned. Two "book-end" options with some pros/cons have now been provided below. There are additional options in-between these options and that can be part of the discussion. Some major principles to consider:

1. Alignment of the work with skills and responsibilities
2. Cost of staff and tools and how they will be shared
3. Backup / Training / Share responsibilities
4. Developing enough expertise to do the tasks effectively

Option 1 is to create or adapt an existing centralized group to take on the responsibilities for both the PRSC and EESC.

1. Pros

a. A single supervisor over the EIM-facing functions will allow greater specialization in the supervisor and more attention to EIM-facing issues.
b. Most of the work could use a common software platform and have some overlap in skills / techniques / processes, making cross-training / backup easier and possibly reducing the number of tools.
c. Company-level performance may be more easily analyzed / tracked with a centralized team.
d. If the assigned group performs both the EIM TC Allocations & Billing and Transmission Service Billing functions, there may be long run opportunities for more efficiency

2. Cons
   a. Direct financial consequences of Scheduling, Bidding and Operations is one of the main aspects of the market. It is critical to establish a settlement results feedback loop to the Resource Management and System Operations teams and distancing this function may cause issues with that feedback.
   b. If the outcome of centralizing settlements is that Resource Management and System Operations teams need their own research and analysis teams / tools then it may duplicate efforts / costs.
3. Notes
   a. The TC Allocations & Billing functions cannot be staffed with Merchant Function employees or where SOC concerns exist.
   b. As companies move to a full market, more dollars will be at stake in settlements (about 15-20x the EIM dollar value). Though the TC Allocation function is eliminated in a full market, it is not clear that will be true for eDAM. Also, both eDAM and full market settlements would involve additional charges requiring analysis and processing.
   c. CAISO invoices are payable/receivable regardless of the outcomes, amounts, disputes, etc.

Option 2 is to assign the analytics function to Resource Management and System Operations separately, Merchant settlement and analytics resides with Resource Management, TC Allocations & Billing resides with System Operations and Invoice Payment & Reconciliation resides with Accounting.

1. Pros
   a. Most aligned with existing organization tasks / responsibilities / skills making this the easiest organizational / project participation / training option.
   b. Maximum specialization will focus each area on the work most important to that area / best suited to take on those tasks.
   c. Best feedback loop to Resource Management and System Operations on implications of decisions on financial performance.
2. Cons

a. Will likely limit "natural" cross training / backup support as spreading the responsibility over several individuals may be difficult, especially if some tasks only warrant partial FTEs.
b. This will be an add-on to supervisory resource duties which will likely make building functional and technical knowledge in the supervisor more difficult. It is unlikely that new supervisor positions would be viable.
c. Shared systems with multiple owners with different needs may make IT support more difficult and will consume more total time for ongoing testing for changes.
d. May duplicate vendor management responsibilities.

3. Notes
   a. If common vendors / tools are selected, SOC controls must be put in place, but this is fairly straightforward as the data is naturally divided by PRSC/EESC.
   b. The overall financial reporting cannot (or cannot easily) be a Merchant function since it will require EESC data

Overall, the budget assumes 3 new Settlement FTEs. These Settlement FTEs are in addition to the 0.5 Resource Management Market Results Analysis FTE, the 0.5 Sys Ops Resource Management Market Results Analysis FTE and an additional 0.25 FTE for Meter Data processing and submission. In addition to business side staff, 0.25 FTE is anticipated to support the new PRSC Settlement System and similarly, 0.25 FTE for the EESC Settlement System. In total, 4.75 new FTEs are anticipated to support the ATF EIM efforts. This is more than peer entities have initially budgeted but more in line with what they have ultimately needed.

Training

The EIM responsibilities will require a significant amount of training for the Settlements resources. Content will include:

- Understanding CAISO CCs. Variables, Determinates, BPMs (Business Process Manuals), etc.
- Navigating CAISO Timelines. For Settlements Validation, Disputes, Resettlements, Invoices, Credit Posting, etc.
- EPE Business Processes. Addressing the changes from pre-EIM processes and stakeholders.
- Tools (Systems and Applications).
- Analysis and Reporting.
- Front Office. To better aid in the investigation of Settlement discrepancies, the settlements team(s) should understand the front office concepts and mechanisms.
- Stakeholder outreach. Communicate changes and expectation management for EIM aspects, such as invoicing timelines.

Design and Testing

Associated with the acquisition of new Applications, the Settlements Team(s) will need to be able to articulate EPE needs into requirements and work with Vendors to translate into designs. After development of the stated functionality is completed the Settlements Team(s) will conduct testing of

the applications to ensure they are correct. This testing may include scripting scenarios, and mocking data to trigger the necessary test conditions.

6 Network Model & EMS

The EIM requires a detailed and accurate Network Model. The network applications and modeling requirements described in this section are based on similar projects performed by other electrical utilities of a similar size and provides budgetary level cost estimates for this work.

Furthermore, this section is based on the detailed analysis of the GE's network model for the EPE footprint and CAISO CIM model requirements, and discussions with EPE on plans for joining the EIM.

6.1 Network Model & EMS – Process

6.1.1 Current State

EPE currently maintains a Network Model of its transmission footprint and nearby facilities, providing modeling updates to the RC for incorporation in the RC Network Model. EPE may wait to incorporate system changes in its Network Model or submit model updates to the RC until shortly before energization.

6.1.2 Gaps for EIM Participation

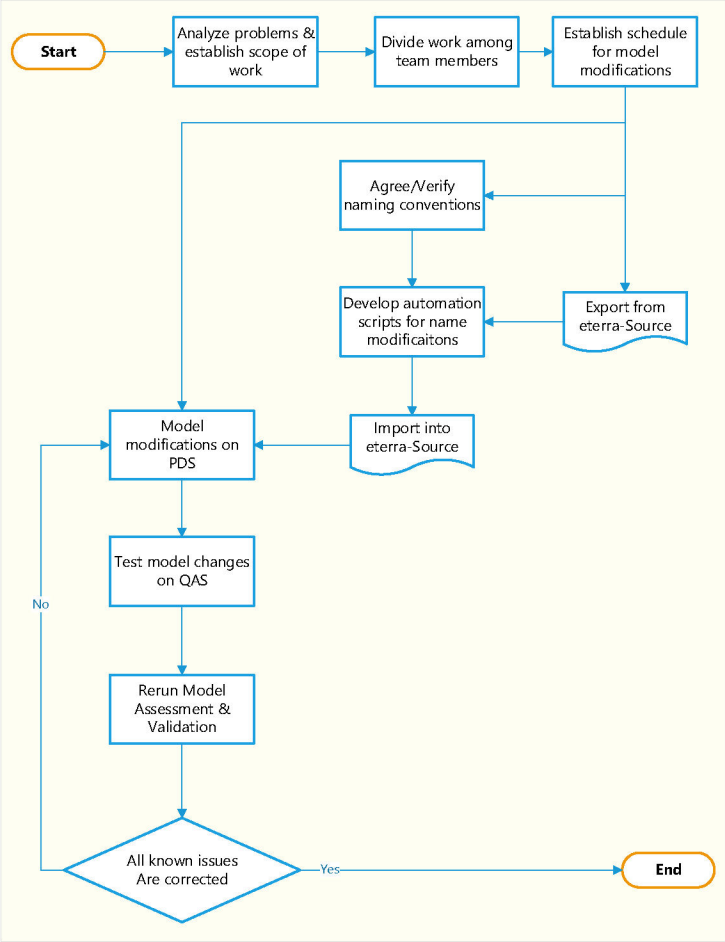
In the EIM, EPE must provide a Network Model that is consistent across its footprint, consistent with EPE's neighbors, and consistent with the CAISO's Network Model. EPE will need to update its Network Model to ensure that:

- Point naming convention meets CAISO requirements, including:
  - Station names unique and no longer than eight characters;
  - Branch names which are unique;
  - No spaces in names of network components;
  - SCADA measurement names which are unique, without special characters and do not exceed 24 characters; and
  - Generator names which match AGC names.
- Each interchange location included in measuring NAI maps one-for-one in the network model.
- Scheduling interchange ties conform to Company from/to specification.
- Transmission lines are modeled down to 69kV. Each generation unit / aggregation is configured in the Network model as it will be used in EIM.
- Each load which is being measured is within the boundaries of the BA in the Network Model.
- Each type of limit required by the CAISO is specified in the Network model.
- Non-conforming loads are identified.
- Quality of telemetry measurements scaled, modeled and tuned to provide reliable state estimator solution.

Coordinating with CAISO during EIM Implementation will require EPE to be familiar with exporting CIM files, CAISO Network Model conventions as summarized in the list above, and adhering to CAISO model submission timeframes. CAISO requires Network Model updates to be submitted and successfully incorporated into the CAISO Network Model six to nine months in advance of energization.

The future process flow for Network Model tasks is illustrated in Figure 5 for illustration purposes, while the actual coordination of work and process flow can be different. The process diagram illustrates that the model modification work should be properly planned, name changes automated where appropriate, and model validation periodically monitored through re-running of model problem assessment.

Figure 6: Proposed process flow for model modifications



6.2 Network Model & EMS – Technology

6.2.1 CIM Model – Network Model Export

EPE will need to procure CIMSpy or similar GE tools to export and validate EPE's network model for submission to CAISO during EIM implementation and on an ongoing basis once in the market. EPE will have to provide a network model and associated data to CAISO that meets the requirements specified in the CAISO's document "CIM Model Requirements". The document outlines the requirements for the network model in CIM/XML, network model related data, SCADA requirements, data related to market

applications, the CAISO model update process and other related market data. The CIM Model data is an export from the EMS database, and therefore, includes some of the issues already identified in the native database format (summarized in the previous section) as well as additional ones specific only to CIM model format.

The CIM Model analysis, detailed in the Network Model Assessment Appendix, showed that most of the EPE's network modelling approaches are compliant, and there only 9 requirements that have been identified as definitely not compliant which will require correction. There are 8 requirements that need to be discussed and verified with CAISO, but most of those are to get the common understanding of details on the network data submission.

The review of compliance with CAISO's CIM Requirements is preliminary and based on analysis and discussions with EPE. A comprehensive compliance analysis will need to be performed on the exported CIM model using specialized tools with embedded validation capability (e.g. GE's validation tools or CimSpy) after EPE has corrected the issues identified in the Network Model Assessment Appendix, implemented a naming convention adjustment, and completed the network model build in GE's EMS.

It should also be noted that after completion of the identified Network Model work, some iteration with CAISO to correct additional issues is expected. Typically, CAISO will identify some additional issues as it integrates EPE's network model into the full CAISO network model and tunes the CAISO State Estimator.

6.2.2 Network Model

The EPE network model was assessed in GE's EMS native format. The information was extracted from the GE EMS database provided by EPE. Various scripts were developed and executed to validate the model for the compliance with CAISO requirements and some additional reasonability checks. The supporting details are enclosed in the Network Model Assessment Appendix.

The analysis of the EPE's network model yielded 971 detected issues. The count of detected errors and warnings is in line with the average for similar electrical utilities joining the EIM. Thus, the current EPE network model is considered to be in a reasonably good state, but will still require some modifications. The level of required corrections is deemed to be low-to-medium in terms of the effort required to comply with CAISO's modeling requirements.

6.2.3 Generation Control and Telemetry

To participate in EIM, EPE will need to provide Telemetry data to CAISO via ICCP so that CAISO can execute their State Estimator. EPE has ICCP architecture and the current configuration is expandable to duplicate the feeds and provide data to CAISO, in addition to the RC. The firewalls and other IT infrastructure appear to meet the needs. Communications via two vendors and two separate routes to both Folsom and Alhambra would need to be established. Budget has been included to create a parallel ICCP feed to CAISO, including redundancy for that feed and a small amount of testing support.

EPE would likely have about 15 Participating Resources. Every 5-minutes a DOT is received for each Participating Resource via an ADS XML data feed. It is likely not possible to manage the 5-minute dispatches manually. The most common approach is to automatically pull the ADS DOT into the EMS, combine the EIM DOT with any other needed deployments of Regulation or Operating Reserves and

generate a single set point for each unit. That set point is then passed automatically to each Participating Resource Plant Controller. For estimating purposes, the cost of these changes has been included in the EMS section.

In order to integrate the EIM provided DOT and any Regulation of Operating Reserve deployment, the EMS must be capable of running in a Market / Mixed operating mode. GE has previously delivered solutions that provide this capability. It is not anticipated that EPE would conduct an RFP for an EMS replacement, but rather would need to acquire the additional capabilities from GE.

Some additional visualization concepts are identified in Section 3.2.

6.3 Network Model & EMS – People

EPE staff currently maintain a Network Model of its transmission footprint, which is utilized for situational awareness, real-time contingency analysis, and submission to the RC. Many of these activities prepare EPE well for EIM participation, with some additional tasks and planning processes to consider in EIM. The team's aptitude, responsiveness and collaboration during the Gap Assessment give high confidence for successfully incorporating EIM responsibilities.

There will be some training for EPE staff to understand the EIM Timeline for communicating Network model changes, with significantly more lead time than previous. The CAISO updates Network models about quarterly with submission of updates due about 6 months in advance of the effective date. Currently, EPE makes model changes much closer to the time of the physical change than this. It is possible to manage some uncertainty using outages (e.g. include an upgrade in the network model based on its projected or aggressive go-live and then submit a derate / outage if the facility is not ready by the date). However, some change management is likely to be required to change the way EPE does business today as well.

This assessment estimates EPE will require one-half of an FTE to address the EIM-related maintenance tasks for Network Model, Real-Time Contingency Analysis, State Estimator functions. These functions could be combined with other operations analyst or engineer duties for a full FTE position, or distributed across existing staff as appropriate.

7 EIM Outage Management

Outage Management is an area which will undergo significant changes for EIM participation. The core of the changes relate to the Outage Management System, the need to actively manage generation availability in EIM, and the EPE groups responsible for timely communication to EIM.

7.1 EIM Outage Management – Processes

7.1.1 Current State

The drivers for outage reporting are outage planning and satisfying RC requirements. EPE has selected SPP for RC services. Most other EIM participants selected CAISO for RC Services, though TEP is currently in the process of moving to SPP RC Services and EIM with a 2022 EIM Go-Live, so there will be some precedent for this model by the time the EPE joins EIM. Currently, submission of Outages to the RC is the responsibility of System Operations.

7.1.2 Gaps for EIM Participation

On an on-going basis, the EIM Entity will be managing outages and submitting transmission and generation availability limits to the CAISO OMS. Managing outages requires considerably more effort and precision than current outage management. The main functional gap for EIM participation is the submission of outages to CAISO.

For Generation Outages, Planned and Forced outages over 10 MWs must be logged in CAISO's OMS. Additionally, EPE is expected to submit Ambient derates for all Participating Resources. Inaccurate modeling of generation availability has two consequences. First, if derates are not accurate (e.g. a unit's Pmax is 100 MWs but it is only capable of 95 MWs) it may receive a dispatch with which it cannot comply. In this case, the generator could be charged for not meeting its dispatch target. This is not a major financial impact if the deviations are small. Second, the Base Schedule and Bid creation process must use limits which match the availability which has been logged with CAISO or the Base Schedule or Bids may be rejected or modified by CAISO.

One consideration for Generation outage management is the role Resource Management should have for submitting or managing outages. Some EIM participants have placed a portion of the responsibility for determining generation limits and logging generation outages and ambient derates on the Resource Management group, with the System Operations team having final approval for outages. This is an option, but not required. CAISO considers the EIM Entity the single point of contact for outages, though participation by the Marketing team can be addressed through system configuration.

For Transmission outages, EPE must submit outages on any modeled equipment that affects system topology. There are two consequences to not accurately managing transmission outages in EIM. The first is that the CAISO State Estimator will be inaccurate. The second, related, consequence is that the Market solution may see congestion when it does not actually exist or not see congestion when there are actually transmission overloads.

All outages are submitted with planned start and end dates/times. CAISO OMS automatically transitions EIM Entity outages to OUT and IN-SERVICE (i.e., actual start and actual end, respectively) when the

planned start and end date/time arrives. This means that an outage scheduled to start at 08:00 is assumed to have started at 08:00 unless it is modified before that time. In addition, the market optimization is forward looking and will make decisions based on anticipated start and end of outages. For example, the 15-minute market that runs at 07:20 will issue commitment instructions to relieve congestion it anticipates as a result of an outage that is *scheduled* to start at 08:00. Thus, the importance of accurate outage schedules is greatly increased in EIM.

There are a number of rules and complications on the way that CAISO manages outages. For example, once an outage starts, it cannot be canceled, it must be end dated; once an outage ends, it cannot be extended, a new outage needs to be created. There are numerous rules like this which make learning to actively managing outages and availability within EIM significantly different than current processes.

7.2 EIM Outage Management – Technology

7.2.1 Current State

System Operations has the iTOA system for managing transmission and generation outages.

iTOA has an API to report planned outages to the RC. Unplanned outages which require submission to the RC are manually entered in the RC outage reporting interface. iTOA is not integrated with OATI WebTrans for the update of ATC. Please see the System diagram for additional information.

7.2.2 Gaps for EIM Participation

It is anticipated that EPE will continue using the iTOA system for both Generation and Transmission Outage Management. It is likely that iTOA will need to be upgraded to synchronize outages between SPP's Outage Management process and the CAISO webOMS.

The split between CAISO as a Market provider and SPP as an RC provider is likely to present some data modeling challenges. It is likely that the two entities will have different naming conventions for generation and transmission elements, different required submission fields / codes, different submission APIs, etc. This is not a new challenge, as it existed with Peak and EIM prior to the change in the RC landscape, but it has presented difficulties in the past and EPE should anticipate some effort and cost required to work through these challenges.

EIM manages generation with an availability concept where the ambient dependent Pmin and Pmax are import in the market solution. Regarding ambient derates, iTOA could automatically obtain weather data and determine ambient derates for each unit, or obtain ambient derates for each unit form another EPE supplied source, and keep the derated amounts fresh in the CAISO OMS. For example, this could be configured to automatically refresh on a rolling hourly basis to decrease the workload associated with managing ambient generation availability. As of Q3 2019, this is not functionality that iTOA has. A budget estimate has been included for creating ambient derate functionality.

Another EIM requirement is the processing of "overlapping" outages with the more restrictive always talking priority, but when it is removed, programmatically understanding the next most restrictive constraint as well as restringing availability for the vacated period. As of Q3 2019, this is not currently

part of the iTOA product, and will be assumed to be covered by a process as no budget has been included for custom development.

Another iTOA change, if Resource Management is to participate in the managing of Generation availability in EIM, is the management of User Roles, as responsibilities will likely change due to joining EIM. There will be permission considerations (visibility into Transmission outages, etc). While it is anticipated that iTOA has this capability, it will require updating of the permission modeling.

It is possible to integrate the PRSC Scheduling System and EESC Scheduling System with the iTOA outage system or pull successfully logged outages from CAISO OMS to support Bid and Schedule creation. Having the PRSC Scheduling and EESC Scheduling Systems obtain derates and outages directly from CAISO may be preferred, as this ensures that the valid Market outages are used. No budget has been included for custom interfaces.

iTOA has a strong solution for Transmission Outage Management but is still developing its solution for Generation Outage Management as well as its CAISO integration capabilities. While iTOA has some anticipated 2021 and 2022 EIM clients which may result in additional development and upgrades, at least one 2021 EIM switched OMS vendors due to iTOA's proposed costs for adding required generation functionality and one of the 2017 participants purchased a supplemental OMS to manage outages with CAISO. There is also the possibility to perform a System Selection process if EPE is not satisfied with iTOA functionality / upgrade costs after the 2021 implementations. For the purposes of this assessment it was established that EPE would stick with the current vendor, and that is what is reflected.

Budget has been included to upgrade this system to meet the EIM requirements while also satisfying SPP RC requirements as well as the implementation and testing. Since there is no current precedent for the EIM / SPP RC split, these costs are hard to judge.

7.3 EIM Outage Management – People

7.3.1 Current State

While the optimal time to take outages is determined collaboratively, submission of Outages to the RC is the responsibility of System Operations. The Marketing team monitors and manages resource availability in Real-Time but does not report this to the RC.

7.3.2 Furture State

There is likely to be a good deal of change associated with Outage Management responsibilities. These changes will require Training and Testing Efforts.

While no new FTEs are budgeted specifically for Outage Management, it is anticipated to become part of the responsibilities of both the Resource Management Real-Time Trader and the new System Operations EIM Desk. Additionally, with the more precise timing required for the Market, more coordination on the start / end times of outages and derates will become important. To the extent that EPE field personnel are more relaxed on the specific timing and notification on in/out of service designations, there will be some change.

This is an area EPE should consider a focus area for Change Management efforts.

8 EIM Metering

An overview of EIM Metering requirements are provided in this section of the report. Additional details are included in the Metering Appendix

8.1 EIM Metering – Process

8.1.1 Current State

EPE currently collects meter data from most EPE generation, all EPE interchange, and all imbedded loads. EPE owns the metering equipment for all generation and imbedded loads in its BAA, while the interchange metering equipment ownership is either by EPE or the adjacent BAA. Meters utilized for revenue billing, such as contracted generation, and all interchange and imbedded loads, are generally revenue quality and have data collected in MV-90. However, the specific accuracy and burden ratings of the underlying metering equipment is not fully documented.

8.1.2 Gaps for EIM Participation

EIM participation requires the collection and submission of Settlement Quality Meter Data (SQMD) on an approximately daily basis. For every generation resource included in the FNM, all intertie locations between EPE and other BAAs and the EIM Load Aggregation Point (ELAP) Load, EPE will submit SQMD for each defined interval.

It is anticipated that EPE will collect meter data on an approximately daily basis for the previous operating day. The meters will communicate meter data into MV-90, EPE's meter head-end system for revenue meters. EPE's team will then perform Validation, Editing, and Estimating (VEE) on the meter data in MV90. Once validated, meter data is passed to webAccounting to apply correction factors, as necessary, profile selected meter data to the appropriate granularity, and calculate the ELAP load to produce SQMD for submission to CAISO. The SQMD will be sent from webAccounting to the EESC Settlement System, which will submit the SQMD to CAISO. Meter data errors are a key source of settlement errors and these processes will need to be defined carefully.

Before any of the daily processes can take place, there are some modeling and registration steps that are needed. The first key decision to establish the EPE EIM metering program will be to register as either a Scheduling Coordinator Metered Entity (SCME) or an Independent System Operator Metered Entity (ISOME). This is a choice between retaining ownership and responsibility over EPE's generation and interchange metering or turning over metering ownership and responsibilities to CAISO, respectively. Assuming EPE chooses to register as a Scheduling Coordinator Metered Entity, as other EIM participants have, the second key decision is for EPE to choose to meet either the CAISO metering requirements or Texas and New Mexico state metering requirements.

EIM participation will require EPE to certify to the accuracy of installed metering equipment at generation and interchange sites in its BA, with the EPE EIM metering program subject to annual self-audits. EPE may establish the procedures of its annual self-audit plan at its own discretion, although CAISO must approve the audit plan.

Additionally, CAISO retains the right to audit the EPE EIM metering program, including its self-audit records. As part of the metering program, EPE will establish and document test plans, meter equipment ratings, data collection, and validation processes in the CAISO template Settlement Quality Meter Data (SQMDs) Plan for each EIM meter installation and submit the completed SQMDs for CAISO review and approval. These final, approved SQMDs will be a commitment by EPE to follow the stated processes and test plans, including meter test schedules according to the stated plan.

8.2 EIM Metering – Technology & Infrastructure

8.2.1 Current State

EPE staff provided an inventory of existing meters in scope of the EIM meter program, including generation within the EPE BA greater than 1 MW, interchange, and imbedded loads. For generation and interchange meters, the inventory provided meter IDs, locations, accuracy, interval granularity, metered facility description, and communications to MV-90. Due to staff time constraints and the lack of available data, metering instrument accuracy and burden ratings were not obtained, and Validation, Editing, and Estimating (VEE) processes were not discussed. Lacking metering instrument accuracy and burden ratings, the gap assessment provides an EIM compliance probability-weighted cost estimate with stated assumptions for each meter installation. However, EPE staff did identify meters currently utilized for revenue billing and therefore subject to accuracy requirements and VEE processes, increasing the probability of sufficient accuracy ratings at those sites.

8.2.2 Gaps for EIM Participation

The Metering Appendix summarizes the inventoried characteristics and configurations of existing meters, current transformers (CTs), and potential transformers (PTs) at generation and interchange sites in the EPE BA. The metering equipment was evaluated relative to the CAISO metering requirements rather than the Texas and New Mexico state Local Regulatory Authority (LRA) metering requirements, based on the assumption that EPE will utilize CAISO rather than LRA requirements, as is typical of EIM entrants. Therefore, these equipment characteristics and configurations were compared to the CAISO metering requirements stated in the current version of the CAISO Metering Business Practice Manual[15] as well as past experience with undocumented CAISO exemptions.

The core CAISO requirements and recommendations for metering equipment are:

- Meter
  - 0.2 Accuracy class
  - Recommended 60 days storage for meter data[16]

[15] CAISO Metering Business Practice Manual Version 18, Revised May 24, 2018 https://bpmcm.caiso.com/BPM%20Document%20Library/Metering/BPM%20for%20Metering_v18_Clean.docx

[16] Not specifically a CAISO requirement, but EPE needs to have a plan to recover from meter communication errors. This is a good target to start with.

- 5 or 15-minute interval granularity for Participating Resources, 5-minute recommended[17]
- 5-minute interval granularity for Interchange meter data
- 5, 15, or 60-minute interval granularity for Non-Participating Resources
- 5, 15, or 60-minute interval granularity for ELAP Load

- CT
  - +/- 0.3% accuracy at burden of 0.1 - 1.8 ohms, 10% - 100% rated current
- PT
  - +/- 0.3% accuracy through burden rating ZZ (400 Volt-Amperes secondary at 0.85 power factor) at 90% through 110% of nominal voltage

EPE may use equipment which does not meet the accuracy requirements but doing so will require EPE to calculate a "correction factor" to apply to the meter data. The correction factor does not increase accuracy – it is a penalty which reduces the observed readings to ensure that the metered output is not overstated.

Any gaps in adherence to these requirements and unknown equipment ratings are identified in the Metering Appendix, along with proposed steps to address these gaps and determine unknowns through metering projects, equipment tests, or requests to CAISO for requirement exemptions. While many requirements are identified in the Metering Appendix, it is not intended to be exhaustive in listing all applicable requirements. In addition to these stated requirements, there are several considerations for metering configuration that are key to EPE's successful EIM participation, which are described in the Metering Appendix.

For any meters that are not currently communicating with MV-90, new communication channels will need to be created. In doing so, EPE should be aware of communication gaps that may not be EIM related such the pending prohibition on dial-up connections to BES sites. According to the EPE-provided meter inventory, it appears that all EPE meter sites in scope of the EIM meter program except Newman have MV-90 connectivity.

New integration between MV90 and webAccounting, PI and webAccounting, and webAccounting and the EESC Settlement System will be needed. It is likely that some additional webAccounting logic will also be required. If OATI is selected for the EESC Settlement System, this distinction may not be apparent. However, if EPE selects another Settlement vendor, some stand-alone webAccounting work will likely be required and budget has been included for this work.

[17] Technically, EIM standards permit 15-minute metering on Participating Resources. However, this is not a good approach from a business perspective as the dispatch / meter data misalignment will have a significant effect on financial outcomes.

8.3 EIM Metering – People

8.3.1 Current State

EPE generation and interchange meters are currently managed by three teams: 1) the Meter Test team for revenue meters, 2) the Power Generation team for EPE-owned gross metered generation, and 3) the Transmission Substation Relaying (TSR) team for all other meters, including non-revenue meters, EPE-owned net metered generation, non-EPE owned metered generation, and non-revenue interchange meters. Additionally, the Meter Test team is currently responsible for meter data collection in MV-90.

8.3.2 Gaps for EIM Participation

These teams will be responsible for drafting and submitting SQMD Plans to CAISO, establishing internal test plans and EIM metering program compliance processes to support EIM participation. These meter teams will require training on the metering requirements, meter submission deadlines, settlement timeframes, and monitor requirements for changes on an ongoing basis.

This assessment estimates EPE will require one-half of an FTE to address the EIM metering program, combined with other responsibilities the half FTE would be an EIM meter data analyst and meter technician, with existing staff taking on some EIM responsibilities. While it is typical for EIM participants to split EIM metering responsibilities between existing teams, EPE should review the organization and division of responsibilities of these teams in consideration of the added EIM responsibilities.

To the extent meter equipment testing or upgrades are necessary to comply with the EIM metering requirements, EPE will need to plan for generator outages to test or install metering equipment, and ensure sufficient planning time to engineer, procure equipment, and coordinate generation outages to complete the work prior to entering the EIM.

9 Implementation & Market Readiness

Some of the most direct takeaways from this Gap Assessment effort are, 1) to informing decision making, and 2) set expectations around the effort, organization and undertaking EPE will experience to join the EIM. Implementing the content identified in the Process, Technology and People categories of each section of this document will require a strong Program Structure overseen by an experienced team.

9.1 Implementation Project/Program

Joining the EIM will be a major effort on many levels. EPE will need to centrally coordinate, plan and monitor the process and technology implementations described in this assessment. Additionally, there are other registration activities and fees, procurement activities, regulatory and outreach efforts, and physical infrastructure which are not accounted for elsewhere.

9.1.1 EPE Program Management

A centralized Program Management function is needed for a coordinated planning and implementation of required EIM processes and systems and to ensure overall readiness. It is likely that EPE will define eight to twelve workstreams (highly corelated with the EPE "Groups" detailed further in section 9.2.1.2) which will have both resource and milestone interdependencies. For projects of this magnitude, it is useful to partner a strong internal leader / project manager who understands the organization and relationships with a consulting resource who has expertise in project management and EIM subject matter. Additionally, a part time EPE analyst has been included to assist in status reporting, time tracking, program communications and other similar activities. Budget estimates for this arrangement have been included.

The EIM Program will need to facilitate buy-in, engagement, cooperation, and coordination from a variety of Stakeholders:

- CAISO / EIM
- EPE Internal Stakeholders
- Vendors of EIM Application and Services
- Integrator
- EPE 3rd Parties

An effective EIM project will require input and direction from EPE's executives and key managers which does not directly contribute to the development of deliverables. These resources will help identify and resolve issues and risks, review status and provide direction, supply resources and coordinate across the organization. Budget estimates for these functions are included.

9.1.2 EIM / CAISO Program Coordination Aspects

CAISO Tracks

The CAISO organizes their internal resources around six (6) "Tracks". More can be learned about these tracks by reviewing CAISO publicly available materials referenced below. When engaging with the CAISO EIM Implementation Team, these tracks are the organization of efforts and resources.

The following are more detailed overviews, each focusing on the CAISO's perspective for performing the efforts within the individual "Tracks".

- Track 1 Overview – Project Management https://www.westerneim.com/Documents/EIMTrack1Overview-ProjectManagement_Planning.pdf
- Track 2 Overview – Agreements https://www.westerneim.com/Documents/EIMTrack2Overview-Agreements.pdf
- Track 3 Overview – FNM https://www.westerneim.com/Documents/EIMTrack3Overview-FullNetworkModel.pdf
- Track 4 Overview – Integration and Testing https://www.westerneim.com/Documents/EIMTrack4Overview-Integration_Testing.pdf
- Track 5 Overview – Metering and Settlements https://www.westerneim.com/Documents/EIMTrack5Overview-Metering.pdf
- Track 6 Overview – Training https://www.westerneim.com/Documents/EIMTrack6Overview-Training.pdf

Significant efforts requiring CAISO Coordination include:

Modeling

The EIM is a very literal market, requiring Participants to model aspects unambiguously for the Master File (MF). Populating the GRDT (Generation Resource Data Template), IRDT (Interchange Resource Data Template) and Network Model require multiple iterations and coordination with CAISO counterparts.

Metering

Metering is typically a long lead time aspect of a project to complete the steps needed for EIM. Early project aspects include identifying Meter Accuracy Testing availability, information collection and Documentation creation (Test Plan, SQMDs). There are also decisions and attestations to navigate.

CAISO Testing

An aspect to point out from the CAISO's arrangement is that of Testing (Integration Test, Day in the Live Testing, Market Simulation, and Parallel Operations. These are further defined in the Track 4 Overview). Because the CAISO is coordinating multiple participants joining for a Go-Live date, these Testing aspects become a rigid timing aspect of planning that EPE will need to accommodate.

CAISO Training

Training is defined in greater detail in the Track 6 Overview Document. Worth highlighting here are that CAISO encourages Project Stakeholders to engage in the CBTs (Computer Based Trainings) early in the Implementation to benefit understanding and participation. There will also be travel (to Folsom CA) logistics to work out, and for some participants this has had a longer than expected lead time.

Registration and Agreements

In addition to the Network Model and Master File efforts described above, a number of agreements and other efforts are needed to register with the CAISO. There are several agreements which must be executed. Additionally, EPE will need to register roles and obtain certificates for interacting with CAISO's systems.

9.1.3 EIM Participant Coordination

Outside of CAISO aspects, a typical EIM Participant shares certain project aspects such as Core Project Team Staffing, Coordinating Workstreams, Change Management, System Selections, Personnel Preparation, Communication, and a mirid of other project aspects.

As apply to EPE, these shared aspects have been built into the Project Schedule. Some highlights are:

System Selection / RFP. For EIM solutions, EPE will need to identify potential vendors, develop a solicitation, create an evaluation methodology and evaluate the response, select a solution and negotiate terms and conditions. Cost estimates have been included for these activities. (Addressed more in Section 10, Technology Summary of this assessment)

Staffing and Hiring. Achieving project goals while sharing team members with day jobs is often a challenge. Filling and preparing identified new EIM roles (such as operators) often have a significant lead time to consider.

Communication. To Coordinate as varied and as many stakeholders as this effort will require it is advisable to get a clear communication plan established.

Participant Trainings

In addition to the Trainings identified and concerning the CAISO, there will be additional trainings for Vendor Applications, Market Readiness, Business Process Changes and Stakeholder Outreach.

Participant Testing

In addition to the Testing efforts defined and driven by the CAISO, there will be additional efforts which EPE will be required to contribute significant efforts towards. These include Vendor Application Testing, (Test Conditions' Scripting, Base Product SAT/UAT, Upgrades and Custom Development Testing, Persisting Systems Regressions testing). There will also be testing tied to EPE's Business processes and portfolio, such as Scenario Creation and Testing.

9.1.4 EPE Specifics

The previous two sections covered relatively typical implementation content shared by all EIM Participants (from a CAISO and Participant perspective). All EIM Participants also have some aspects that are particular to their specific circumstances. Section 11 of this document addresses these aspects in more detail. These aspects will need to be accounted for in EPE's Implementation.

9.1.5 EIM Implementation Indicative Project Schedule

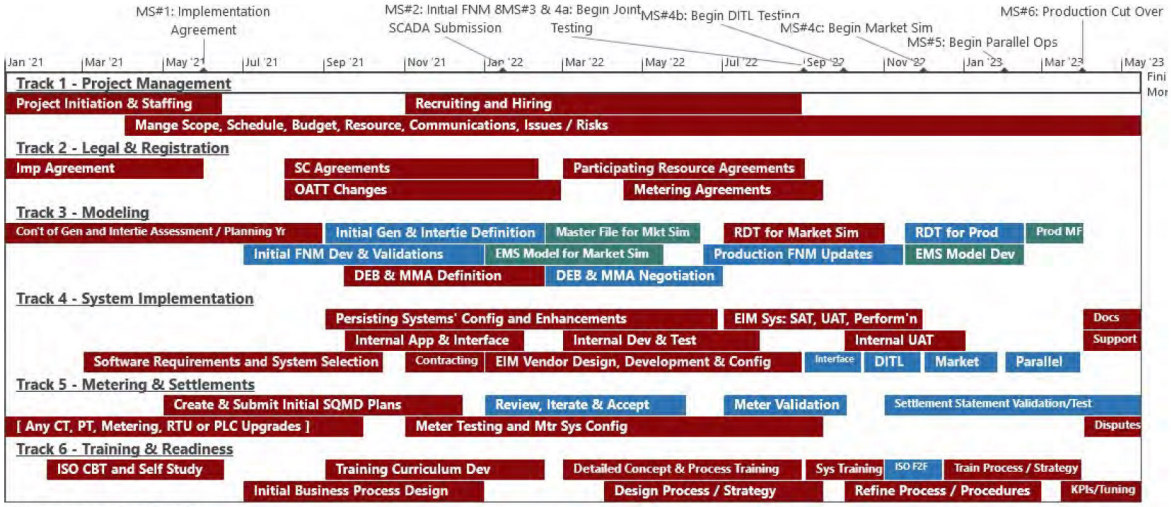
The CAISO Implementation planning efforts (i.e. "Tracks") do not account for all aspects of EIM Readiness that El Paso Electric will need to complete in order to be successful. There are many

components of readiness that are "behind the curtain" from CAISO's perspective, and therefore not accounted for in CAISO planning. An organization and sequencing of EPE's EIM efforts have been collected in a MS Project Plan. To aid in communication with CAISO Project Team the efforts have been aligned with corresponding CAISO's Track aspects.

The EIM Implementation Indicative Project Schedule has been included as Appendix 5.

9.1.5.1 High Level Project Effort by Track

Figure 7 – High Level Project Effort by Track

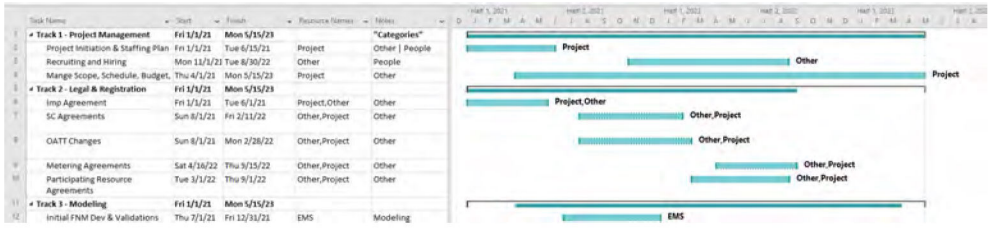


EIM Implementation Timeline

The Swimlane Diagram is a version of the Implementation plan intended to give a high-level representation, which can be conveyed with a single visual. This is derived from a MS Project File "Timeline" View, using color coding to map the CAISO/EPE division of efforts.

The payment Milestone points with CAISO ("MS#"), have been approximated at the top of the timeline based on previous implementations. This is partially to demonstrate that the CAISO milestones are not equally spaced across the duration and should not exclusively be major project measurement criteria. There will be other payment milestones with Vendors and Contractors which are more variable than these.

9.1.5.2 Gannt Chart Representation



The Gannt Chart representation are the efforts/records which roll-up to the level displayed in the Swim Lane Diagram. In addition to the Task Name and Dates, two addition columns of Resource Name

(representing EPE "Group") and Notes (representing "Category") have been provided to aid viewing in conjuncture with the Scope and Cost Assessment.

The Resource Name represent the EPE "Group". EPE Dept(s)/Area(s) significantly contributing to the effort. Below are the designations (and "owner") discussed in the walk-through:

- Marketing (Omar Gallegos)
- IT (Lourdes Tapia)
- Marketing Settlements (Ana Boisselier)
- System Operations (Ernie Martinez)
- EMS (Tracy Van Slyke)
- EE Settlements (Brenda Delgado)
- Power Gen (Kyle Olson)
- Meter Testing (Ray Morelock)
- TSR – Transmission Substation Relaying (TBD)
- Project (Project Mngr assigned by Gary Bruner or David Hawkins)

The Notes column is used to identify "Categories" of Efforts that are associated with a given Gantt row.

9.1.6 Planning Year

There are some efforts anticipated for EIM that can be begun prior to the Implementation Project. Some of these are prerequisites, others tangentially impactful on EIM but not specifically driven by joining the market. Some are aspect with long lead times. These efforts are not included in the Implementation Project Plan above. The timeline for these is Q4 2019 through Q4 of 2020. They are elaborated on more in Section 11 of this report.

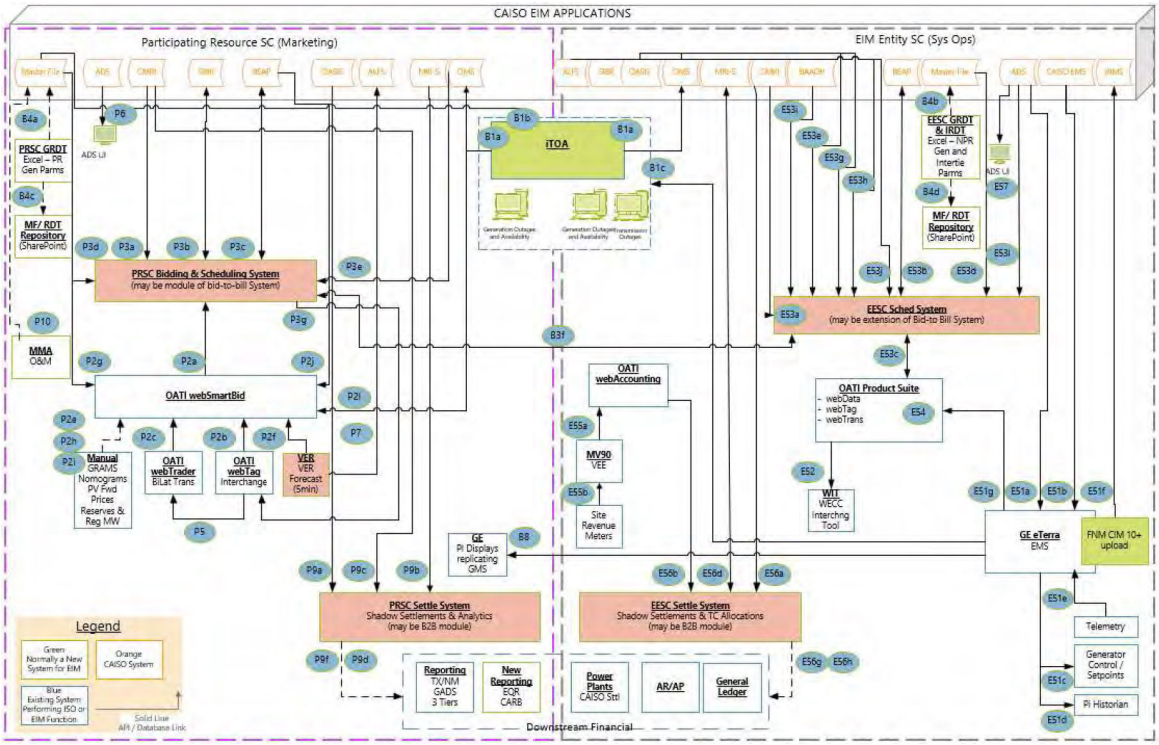
- Benefits Study
- Business Case
- Capital and O&M Planning Budgets
- Additionally, EPE will likely conduct a solicitation for a consultant Project Management and Solution Implementation support.
- Organizational Structure, Staffing & OCM
- Regulatory Impacts
- Future Agreements Impacts (PPAs)
- Metering Assessment Details; Potential Metering Infrastructure Upgrades
- Navigate Merger
- No Additional Option Evaluations Anticipated (Other EIM Providers; Changing RCs)

10 Technology Summary

10.1 Technology Summary – Applications and Interfaces

Attachment 2 is a diagram of the anticipated Systems and Interfaces required for EIM. These are quantified further in the Interface spreadsheet and inputs to the Cost Model.

Figure 8: High Level Applications and Interface Diagram



New EIM Applications/Services:

- PRSC Bidding and Scheduling System.
- EESC Scheduling System.
- PRSC Settlement System.
- EESC Settlement and TC Allocation System.
- VER Forecast Service.
- ICCP Link to CAISO.

EIM Upgrades Needed:

- EMS – GE eTerra. EIM Module and CIM export Functionality
- OMS – Sun-Net iTOA. CAISO Interface, User Roles Functionality, Ambient Derate Functionality, Layered Outage Logic Functionality.
- OATI webSmartBid. Interfaces for webOMS, Demand Forecast, VER Forecast, Flex Test Results.

The System Diagram also identifies the anticipated Interfaces, both with EIM Systems and Internally to other EPE applications. The interfaces with EIM Systems should be OOTB (out of the box) if an experienced Vendor is chosen, as these have been applied for previous clients. The internal interfaces can potentially require more efforts depending on the solutions selected. For this Gap Assessment the new interfaces have been categorized and estimated based on complexity. The list of interfaces is provided as part of Appendix 2, and the associated cost expectations are in the budget model.

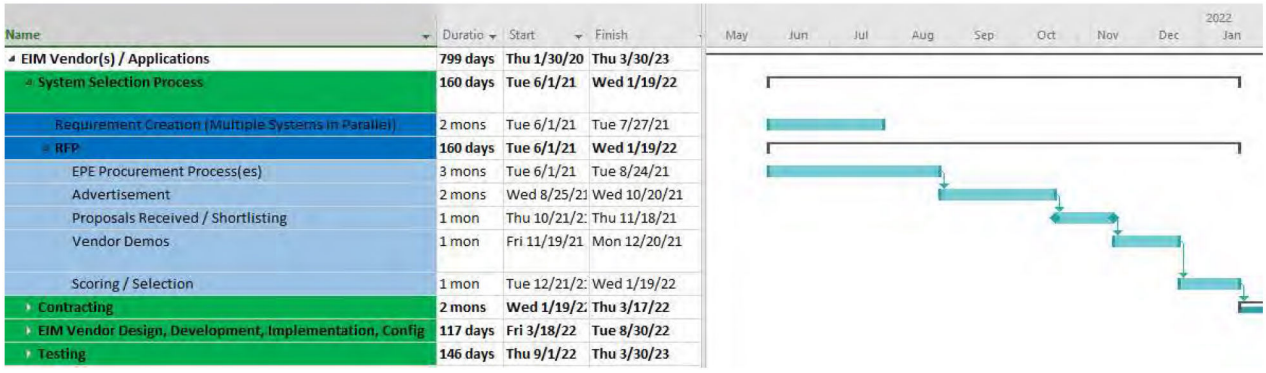
Table 5: List of Anticipated EIM Application Interfaces

Interface #	SC	System A	System B	Direction	Interface Effort	Data/Purpose
B1a	PR/EE (Both)	OMS (iTOA)	CAISO OMS	BiDir	OOTB	PR Gen Outage/Derates/Availability (Assuming Merch ownership)
B1b	PR/EE (Both)	OMS (iTOA)	Master File	B>A	TBD	Sync Resource IDs & Parameters
P2a	PR	webSmartBid (OATI)	PRSC Sched	A>B	Dev*	Energy and A/S Schedules
P2b	PR	webSmartBid (OATI)	webTag (OATI)	B>A	Existing	Hrly Gen Schedules
P2c	PR	webSmartBid (OATI)	webTrader (OATI)	B>A	Existing	Bilateral Transactions, Station Service
P2d	PR	webSmartBid (OATI)	Internal Load Forecast	B>A	Sunset	Have Tesla, but would like to replace with CAISO Load Forecast
P2e	PR	webSmartBid (OATI)	GRAMS	B>A	Manual	WACOG with Incremental Transport by Fuel Location
P2f	PR	webSmartBid (OATI)	VER Forecast	B>A	Dev	Create Hourly VER Forecast for Rolling 7 Days
P2g	PR	webSmartBid (OATI)	Master File	B>A	OOTB	Sync Resource IDs & Parameters
P2h	PR	webSmartBid (OATI)	Nomograms	B>A	Manual	Provide PMR Schedule based on Load, SNMIC and Start Times
P2i	PR	webSmartBid (OATI)	(Other Manual Inupts)	B>A	Manual	PV Forward Prices; 7% Reserves and 35MWs Reg Up/Dn
P2j	PR	webSmartBid (OATI)	BSAP (CAISO)	B>A	TBD	7 Day-Ahead EPE BAA Demand Forecast inc Station Service (updated daily)
B53k	PR/EE (Both)	EESC Sched	webSmartBid (OATI)	A>B	Dev*	Estimated Flex Ramp Obligations
P2l	PR	webSmartBid (OATI)	CAISO OMS	B>A	TBD	Validate Outages
P3a	PR	PRSC Sched	OMRI (CAISO)	B>A	OOTB	Market Results
P3b	PR	PRSC Sched	SIBR (CAISO)	BiDir	OOTB	Submit/Validate/Sync 3-pt PR Gen Bids
P3c	PR	PRSC Sched	BSAP (CAISO)	BiDir	OOTB	Receive / Validate PR Energy and A/S Base Schedules
P3d	PR	PRSC Sched	Master File	B>A	OOTB	Sync Resource IDs & Parameters
P3e	PR	PRSC Sched	OMS	B>A	OOTB	Outages Sync
B3f	PR/EE (Both)	PRSC Sched	EESC Sched	BiDir	Dev*	Estimated Flex Ramp Obligations
P3g	PR	PRSC Sched	webTag (OATI)	A>B	Dev*	Hrly Gen Schedules
B4a	PR/EE (Both)	PR GRDT (excel)	Master File	A>B	Manual	RDT Updates sent to CAISO
B4c	PR/EE (Both)	PR GRDT (excel)	EPE Repository	A>B	Manual	Store historical changes of submitted RDTs (Separate from IRDT & NPR GRDT)
P5	PR	webTag (OATI)	webTrader (OATI)	A>B	Existing	Hrly Gen Schedules
P6	PR	ADS UI	ADS (CAISO)	B>A	OOTB	Read-only visability
P7	PR	VER Forecast	ALFS	A>B	Dev	Submit VER Forecast directly to CAISO
B8	PR/EE (Both)	PI Display (from GE)	EMS (GE)	B>A	Existing	Read-only visability
P9a	PR	PRSC Settlements	OASIS (CAISO)	B>A	OOTB	Public Market Data
P9b	PR	PRSC Settlements	MRHS (CAISO)	B>A	OOTB	CAISO Settlement Statements

10.2 Technology Summary – Process

10.2.1 System Selection Process and Indicative TimeLine

Figure 9: System Selection Process and Indicative TimeLine



Name	Duratio	Start	Finish
EIM Vendor(s) / Applications	799 days	Thu 1/30/20	Thu 3/30/23
System Selection Process	160 days	Tue 6/1/21	Wed 1/19/22
Requirement Creation (Multiple Systems in Parallel)	2 mons	Tue 6/1/21	Tue 7/27/21
RFP	160 days	Tue 6/1/21	Wed 1/19/22
EPE Procurement Process(es)	3 mons	Tue 6/1/21	Tue 8/24/21
Advertisement	2 mons	Wed 8/25/21	Wed 10/20/21
Proposals Received / Shortlisting	1 mon	Thu 10/21/2:	Thu 11/18/21
Vendor Demos	1 mon	Fri 11/19/21	Mon 12/20/21
Scoring / Selection	1 mon	Tue 12/21/2:	Wed 1/19/22
Contracting	2 mons	Wed 1/19/2:	Thu 3/17/22
EIM Vendor Design, Development, Implementation, Config	117 days	Fri 3/18/22	Tue 8/30/22
Testing	146 days	Thu 9/1/22	Thu 3/30/23

For EPE anything over $50,000 will require a competitive bid, or RFP (Request For Proposal), process. Nearly all of the identified Application and Services will exceed this threshold, and the duration of System selections are often significant enough to define a project schedule's critical path. Multiple System / Service selections can be run in parallel, with the typical aspects and effects on a project schedule being:

- **Requirements Creation**. Working with End Users, Technical Resources and Market SMEs to define the functionality EPE desires for an application. The requirements will require some internal iterations before finally being documented in a format that can be presented with the RFP. This differs depending on system and is represented in the plan by a two (2) month duration.
- **EPE Procurement Process(es)**. This varies per organization and is usually defined by a Procurement or Purchasing office. Within this phase of System Selection there are usually forms to populate, approval gates, defining evaluation criteria, establishing an evaluation team, and other internal documentation. These can typically happen in parallel with Requirement Creation efforts. A three (3) month duration has been used to represent this aspect.
- **Advertisement**. Once the RFP is created, and merged with the Requirements, it is put out to potential Vendors. The amount of time the Vendors have to review and respond will be adjustable based on EPE policies and variables. A two (2) month duration is used to represent a typical advertisement period.
- **Proposals Received / Shortlisting**. Depending on the quantity of respondents, EPE may want to use a shortlist to trim down the number of Vendors that will be presenting Demos. Shortlisting typically takes between two (2) and four (4) weeks, as each received proposal has to be evaluated. Even if a short list is not performed, scheduling Vendors to travel on-site for Demos

requires some time. A one (1) month duration is used to represent the time between Proposals Received and performing the Vendor Demos.

- **Vendor Demos**. Bringing the RFP Respondents on-site to demonstrate their applications concerning EPE's specific functionality requirements and scenarios. A Vendor's demo can last between hours and days and will have to be coordinated for all Vendors that advance to this stage (shortlisted or otherwise). The window for demos is usually between two (2) and four (4) weeks. The more conservative end of this spectrum is used in this representation.
- **Scoring / Selection**. To select the winning Vendor involves applying the (previously established) evaluation criteria to the written proposals and demos, then comparing and documenting the results between vendors. The window for scoring is usually between two (2) and four (4) weeks. The more conservative end of this spectrum is used in this representation.
- **Contracting**. Once a Vendor has been determined the winner, a contracting and negotiation period will commence. These can last from four (4) to ten (10) weeks. For the purposes here, eight (8) weeks are represented.
- **Design, Development, Implementation, Config**. As part of the Contracting, the Vendor will provide a project schedule that includes Designing any custom functionality EPE requires, Developing that functionality, implementing the base product and configuring the system with EPE data. This can take different amounts of time for different applications, and what is represented here is the time available between Contracting completing, and the Testing Phases beginning.
- **Testing**. CAISO enforces some rigid timeline constraints on testing, to support their Test Environment availability for all participants joining on the same EIM Go Live date. These tests begin in September, and in order to be prepared for them the applications should complete the Vendor specific testing criteria by the end of August (preceding EIM Go Live date). More details about testing are provided in Section 12.

10.3 Technology Summary – People

For each System requiring upgrade modules or functionality there will be training. Vendor Testing. Market Testing. Time spent updating and documenting associated business processes.

For each Persisting System there will still be efforts required related to interfaces and regression testing.

11 Additional EIM Aspects

The focus of this document has been primarily to address the gaps, obstacles and challenges associated with EPE Implementing EIM. There are some peripheral aspects that have potential impacts or the potential for implementation acceleration. This section highlights EPE aspects that fall into this definition, and which may prove beneficial to act upon during the approximate year long duration before starting an Implementation Endeavor. This is referenced in Section 9.2.2 as a "Planning Year".

EIM Project Budgeting Process

Preceding the efforts in this report, EPE will need to navigate steps to fund an implementation Project. This is anticipated to include:

- *Complete Benefits Analysis & Business Case*. Benefits Analysis is expected to complete Q4'19 or Q1'20. A Business Case effort is expected between the completion of the Benefits Analysis and EPE's Capital Planning Committee (Aug 2020) and Operational Expense Planning (Sept 2020).
- *Complete the Metering Assessment, Testing & Conducting Upgrades.* As part of the Gap Analysis, Metering Personnel were informed on what CAISO will be looking for as part of the EIM Metering criteria. Metering has often turned out to be a significant duration which defines an EIM Implementation Critical Path. (One aspect that influences this is the need to navigate scheduled outages to perform some of the testing.) If EPE can perform the needed evaluations ahead of time, it would aid Implementation. The Gap Report has provided the cost estimated based on the best available information, and having more complete information could affect the estimated dollars.
- *Understand Impacts of JPMorgan Merger*. There may be aspects to the impending JPMorgan deal which impacts the EIM Implementation budgeting.

Project Initiation

These project aspects could be pulled forward in the timeline, and accomplished before competing for attention with all the other moving parts of EIM Implementation. Once the project begins, there will be a lot of coordination which would benefit from a clear and documented planning effort.

- *Site Visits to Neighboring EIM Participants*. It is common for potential new EIM entrants to survey existing EIM Participants to aid with expectation setting. These have a great deal of latitude in execution, but are typically beneficial.
- *Consider Organizational Alignment*. There are known changes that EIM will have on some of the organization EPE has pre-EIM. Since most organizations perform alignment changes infrequently (yearly), it may be beneficial to transition to new arrangements on an EPE schedule that does not fall mid-project.

- *Cyber Security Policy Excerpt Preparation*. Not having clearly defined and shareable cyber security policies have hampered pervious EIM entrants. In conversations with stakeholders, it appears that EPE is in solid shape with regards to the policies (both current, and with scheduled iteration). Since there will be new application procurements during Implementation, it would be useful to have a subset or excerpt of the EPE policies in a format that can be easily be sent to vendors, in order for Vendors to evaluate how they will comply.
- *Define a Project Charter and Create the Project Team*. The Gap Report has used broad strokes to identify personnel resourcing needed for Implementation, and completing these aspects ahead of time could also provide more detailed resources' cost estimating.

Additional Options

Briefly addressed in concert with EIM efforts are some aspects EPE could use to be in a more advantageous position.

- *Consider EIM Implications for new PPAs*. Specifically, the terms around dispatch down / curtailment rights in contracts.
- *Gage Interest in Becoming CAISO Full-Market Scheduling Coordinator*. There is a learning curve that could be ascended early, along with connectivity, training and other EIM prerequisites. Could be an avenue for PV to California that doesn't exist today.
- *Actively Monitor for Market Changes*. Several important initiatives are underway at CAISO in public forums, including the Extended Day-Ahead Market (eDAM). Additionally, once EPE executes an implementation agreement, certain member-only forums where EIM participants discuss enhancements will be available.

12 Cost Assessment

Nearly all of the preceding content presented in this Gap report has been building toward a cost estimate for El Paso Electric to join EIM. As part of this EIM Gap Project, the cost assessment has been provided to EPE in the form of an Excel file. This provided greater level of insight into component variables that build up to final values. It also allows for some latitude for EPE to see the impacts of updates to inputs and assumptions.

12.1 Estimating Model Notes

The provided model has been created to estimate the potential cost of EIM. The workbook is organized in a series of tabs. Key values which can be edited are in blue text.

- Input Assumptions – Allows modification of key global assumptions, including the dates for each major phase of the project, rates for labor, effort for interfaces by complexity type and several lists of meta data used in the model.
- Project Cost and Effort Est – The main estimating model. Each row is a cost element with meta data describing it. This is the most detailed view of the data. A single "task", such as Project Management, may be split over several rows to spread the cost over designated time periods. The columns are quite wide with several formula driven columns for reporting to the right. If you insert new rows, it makes sense to copy an entire existing row and past it in, then adjust the meta data and efforts. Use the group +/- buttons at the top to show/hide additional detail.
- Ongoing FTE Est – Estimates of ongoing staffing costs described in the report.
- Ongoing Non-FTE Est – Estimates of recurring costs other than incremental staff.
- Green Tabs – A variety of reports / pivot tables sourced from the Project Cost and Effort Est tab. Don't forget to refresh the pivot tables to ensure they are drawing on the current data set.
- Yellow tabs – Additional detail for certain cost estimate categories.

12.2 Cost Estimates & Assumptions

The cost analysis prepared by Utilicast and described in this report covers the direct costs of the project to register with the CAISO, procure and implement new systems, design new business processes, train employees, make changes to EPE's Tariff and directly identified upgrades to physical infrastructure such as meter replacements, IT hardware, telecommunication and network connections and similar costs. Incremental on-going costs for personnel are also included. This model has not estimated potential changes in fuel costs, major infrastructure projects (such as new generation or transmission capacity) or other similar costs.

The hiring of new permanent Staff is a key component of the project. New resources will need to be onboarded throughout the project so that they can be adequately trained on both EIM and non-EIM functions as well as be integrated into the EPE teams. In some cases, this will include hiring up to a year in advance of EIM Go-Live. When first hired, the new resources are likely to be contributing little to the project deliverables as they are trained on EPE's assets, processes, systems, etc. However, after some

period of time, they will need to either backfill existing EPE staff or participate in project deliverables. To balance these considerations, a 3-month overhead charge has been assigned to the project for all new Staff.

This section describes some of the key assumptions which were used in the creation of the cost estimate.

12.3 Project Assumptions

The assumed Go-Live date is April 2023. The implementation project will run from January 2021 through just after the Go-Live date. This translates roughly to have the initial requirements gathering / system selection phase in early 2021 and the bulk of the implementation effort in 2022.

To join EIM, EPE will incur implementation costs (e.g. procuring new systems, designing new business processes) and will also incur some on-going costs (e.g. grid management charges, potential additional personnel). Project costs are estimated through June 2023 to cover immediate post-Go-Live support. However, a relatively small amount of consulting support is included after the Go-Live date. Different entrants have had different approaches to contracting for post Go-Live support.

Attempts have been made to assign costs roughly to the time period in which they will be incurred. The approach used spreads the cost of a line item evenly over the roughly anticipated duration but does not attempt to create a detailed implementation plan, identify potential milestone payments or other refinements which will likely be performed as part of the implementation project and during procurement negotiations.

12.4 Rate Assumptions

The costs information in this report includes high-level estimates of EPE employee and contractor labor. The rate assumptions are included in the Estimating model.

12.5 Cost Categorization

In addition to categorization by the probable EPE Organization and Groups, costs are grouped in several other ways.

12.5.1 Process, Technology and People

Cost Estimates for the Process category include:

- Development of new business processes
- Development of Strategies for maximizing the benefits of EIM for EPE customers
- Developing reports to track EIM results

Cost Estimates for the Technology category include:

- Development of functional and technical requirements for new applications and interfaces
- Development of functional and technical designs for new applications and interfaces
- Development of new applications and software license and maintenance fees
- Procurement, Configuration and maintenance of new applications for use in EIM

- Hardware for new EIM applications

Cost Estimates for the People category include:

- Project Management
- Training to prepare EPE's designated SME staff for participating in all phase of the project
- Training to prepare EPE testing resources for test execution and market simulation
- Training to prepare EPE end users for executing EIM in production
- Execution of testing and Market Simulation
- Incremental permanent staff required for new EIM responsibilities
- Registration activities, network and commercial modeling and participation fees
- Other project support

12.5.2 Other Groupings

- Costs are designated as Internal (e.g. Staff Time) or External (e.g. Consulting Support, Vendor Software).
- Costs are designated as Capital or O&M based on the Cost Name. There are likely to be a few tasks which do not follow this convention during the actual project, but designations are likely sufficient for budget purposes.

12.6 Training & OCM

Based on current knowledge of EIM and the fact that new processes, software applications and strategies will be necessary for EIM participation, significant training will be needed. Training is anticipated to be developed and delivered throughout the project as illustrated in the Track 6 portion of Figure 6.

Joining EIM will cause major changes to the way that many departments at EPE work. Based on discussions with EPE, a dedicated Organizational Change Management (OCM) effort will be required.

12.7 Testing and Market Simulation

A significant amount of testing of new applications and integration points is anticipated. Internal testing costs have been estimated in four categories: Site Acceptance Test (SAT), System Integration Test (SIT) and Functional Integration Test (FIT), User Acceptance Test (UAT). The focus of SAT is proving that any new of modified applications, custom displays or workflows perform as required in a standalone manner. The focus of SIT and FIT is proving that the interfaces connecting applications work as expected and allow users to perform their jobs using the applications in an integrated manner. The focus of UAT is ensuring that end users who may not have been involved in the project on a day-to-day basis confirm that the integrated systems perform as required.

Testing is a significant effort for a project like joining EIM and is expected to last for several months. One of the most effective ways to learn the market and the capabilities of the new systems is to be involved in testing. While consulting support can help to define the testing strategy, create complex test cases

and test data required to flex the systems, as well as share the burden of working through test cases, it is recommended that EPE dedicate resources to the testing effort.

Following EPE's testing, there will be a lengthy period of joint testing with CAISO to ensure that EPE's systems function as expected in an integrated manner with CAISO's systems. There are three phases of joint testing: Day-in-the-Life (DITL), Market Simulation and Parallel Operations. Each phase is progressively more intense. DITL is mostly about working through a standard Operating Day and ensuring all basic functionality is present. Market Simulation is about proving that the correct market outcomes are achieved in more complex Structure Scenarios. Parallel Operations is about proving that the EPE system can be operated correctly and continuously in EIM while simultaneously executing as a stand-alone BAA.

12.8 Other Costs

This section includes a description of some of the other overall EPE costs that may be incurred to join EIM and which are found in the cost model.

12.8.1 Membership Fee

Joining EIM requires payment of a membership fee. The fee is based on total load and is payable to the CAISO in installments based on completed milestones. EPE's fee has been estimated based on a 0.8% annual increase in 2018 load between 2018 and 2023. The fee has been spread over six milestone payments.

12.8.2 Grid Management Charges (GMC)

Once EPE joins EIM, it will pay GMC as part of the settlement process. There are three GMC charge codes which apply to EPE.

- EIM Transaction Fee – Assessed per EIM cleared MWh.
- Bid Submission Fee – A half cent charge assessed per submitted bid segment.
- Settlements, Metering and Client Relations Fee – A $1,000 per month fixed charge per SC.

Estimates have been created for each charge. The EIM transaction fee may be a significant cost and has been estimated based on assumed imbalance energy of 4% of total load.

12.8.3 OATT Changes

To participate in EIM, EPE will need to revise its OATT to detail how EPE Transmission Customers will be handled and settled under EIM. Budget, including support from outside counsel has been included.

12.8.4 Market Based Rate Study

EPE will apply for EIM Market Based Rates (MBR) as part of its EIM project. This is distinct from the bilateral MBR authority EPE currently has but the analysis leverages similar data and concepts. A study which assesses EPE's Market Power within its BAA will be required. Budget, including support for a study and support from outside counsel for the filing has been included.

12.8.5 Third Party Engagement

EPE has no embedded load or generation that is not part of the EPE portfolio and few Transmission Customers. Additionally, the New Mexico and Texas Public Service Commissions may require some communication. However, in general, EPE does not have a large burden for external communications and 3rd party education and management. A small budget has been included for TC and Commission communications and additional time for participating in CAISO forums.

12.9 Updateability

There is the ability to revise the Cost Assessment, with relatively little effort, should inputs be updated / improved.

13 Glossary of Terms and Acronyms

(Also provided in the Cost Assessment File)

EPE EIM Gap Assessment - EIM Terminology		
Term	Literal Meaning	Function
ADS	Automatic Dispatch System	CAISO system communicating market dispatch, start-up, shutdown, and MSG transition instructions
ALFS	Automatic Load Forecast System	CAISO system for automatically forecasting load for each BAA in the EIM footprint
ATC	Available Transmission Capacity	For EIM Transfer purposes, the non-firm transfer capability which is not scheduled, or scheduling availability. One way to provide EIM with transfer limits
ATF	After The Fact	Final e-Tagged energy schedules, trued up to actual delivered volumes following the end of an operating hour.
BAAOP	Balancing Authority Area Operations Portal	CAISO UI for transmission and BA operators to view and control their EIM Entity market results and instructions
BCR	Bid Cost Recovery	Make whole payment to resources instructed by market and lacking sufficient market revenues over a full operating day to recover their operating costs. Typically occurs for market committed resources to recover start-up and minimum load costs.
BSAP	Base Schedule Aggregation Portal	Receive and process Base Schedules and perform sufficiency tests
CCA	California Carbon Allowance	California state financial instrumental required for the emission of GHG to serve electric load inside California.
CIDI	Customer Inquiry Dispute & Information	CAISO system for submitting settlement disputes or IT ticket.
CMRI	Customer Market Results Interface	CAISO system for retrieving customer-specific market results
DEB	Default Energy Bid	Cost-based bid approved by Department of Market Monitoring (DMM). Energy cost DEB utilized when model predicts market power, while start-up, minimum load, and GHG bids are always capped relative to cost.
DOT	Dispatch Operating Target	Market dispatch instruction, indicating resource setpoint for the midpoint of the next market interval
EESC	EIM Entity Scheduling Coordinator	CAISO registered representative for the BA and Transmission functions of an EIM Entity

ELAP	EIM Load Aggregation Point	A CAISO-defined load area, typically a BAA. Also the energy settlement price for the ELAP, which is calculated as the load-weighted average of the LMPs for each load bus in the ELAP.
EMS	Energy Management System	Real time system used for transmission, generation, and BA operations.
ETSR	Energy Transfer System Resource	Also referred to as EIM Transfer. A mechanism to account for EIM BAA to EIM BAA scheduled flow.
FNM	Full Network Model	Transmission system model utilized by CAISO market engine to model transmission flows and perform Security Constrained Economic Dispatch (SCED).
GRDT	Generator Resource Data Template	Registered PR or NPR operating characteristics utilized by market model to dispatch resources.
LMP	Locational Marginal Price	Location-specific, incremental market price of energy
MDM	Meter Data Management	System for gathering, performing VEE, and submitting meter data
MMA	Major Maintenance Adder	Registered costs for major maintenance by resource ID.
MRI-S	Market Results Interface - Settlements	CAISO system for submitting meter data, and retrieving meter data, settlement statements, and invoices.
MSG	Multi Stage Generator	Hybrid of single resource ID and aggregate resource, allowing for multiple operating regions with transition time and costs between regions. Typically utilized to model combined cycle gas plants with multiple CTs or duct firing and occasionally utilized for complex hydro resource modeling.
NPR	Non Participating Resource	CAISO registered generator in an EIM BAA that does not bid or follow market dispatch except under limited circumstances
OASIS	Open Access Same-Time Information System	CAISO system for retrieving public market results
OMS	Outage Management System	Manages coordination and scheduling of transmission and/or generation outages, mapped to the FNM for incorporation in market engine.
PR	Participating Resource	CAISO registered generator in an EIM BAA that may bid and must follow market dispatch
PRSC	Participating Resource Scheduling Coordinator	CAISO registered representative scheduling and bidding EIM participating resources, including the EPE Merchant function

RTCA	Real Time Contingency Analysis	Model of credible transmission outages mapped to FNM, run with market engine to ensure reliability and inform congestion prices.
RTIS	Real Time Interchange Schedules	Aggregation of interchange schedules into various CAISO-defined categories and EPE scheduling paths, and submission to CAISO every 5-minutes for incorporation in market engine, affecting optimal solution for BAA balancing.
SE	State Estimator	Real time model of transmission system conditions utilizing the FNM and telemetry throughout the grid.
SIBR	Scheduling Infrastructure Business Rules	CAISO system for submitting resource bids
TC	Transmission Customer	Entity contracted to reserve and schedule transmission contractual rights on a Transmission Service Provider's transmission system, subject to the provider's Open Access Transmission Tariff (OATT).
VEE	Validation Estimation & Editing	Meter data process to review raw meter data prior to submission for use in settlements.
VER	Variable Energy Resource	Typically wind or solar

14 Appendix

14.1 Appendix 1 – EIM End to End (EtoE) Process Swimlane Diagram

14.2 Appendix 2 – EIM Systems and Interfaces Diagram

14.3 Appendix 3 – Full Network Model (FNM) Analysis

14.4 Appendix 4 – Metering Analysis

14.5 Appendix 5 – EIM Implementation Indicative Project Schedule

14.6 Appendix 6 – EIM Cost Assessment

CEP 6-17 Attachment 2

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EIM Gap Assessment Report – Appendixes

Proprietary and Confidential

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August 2019

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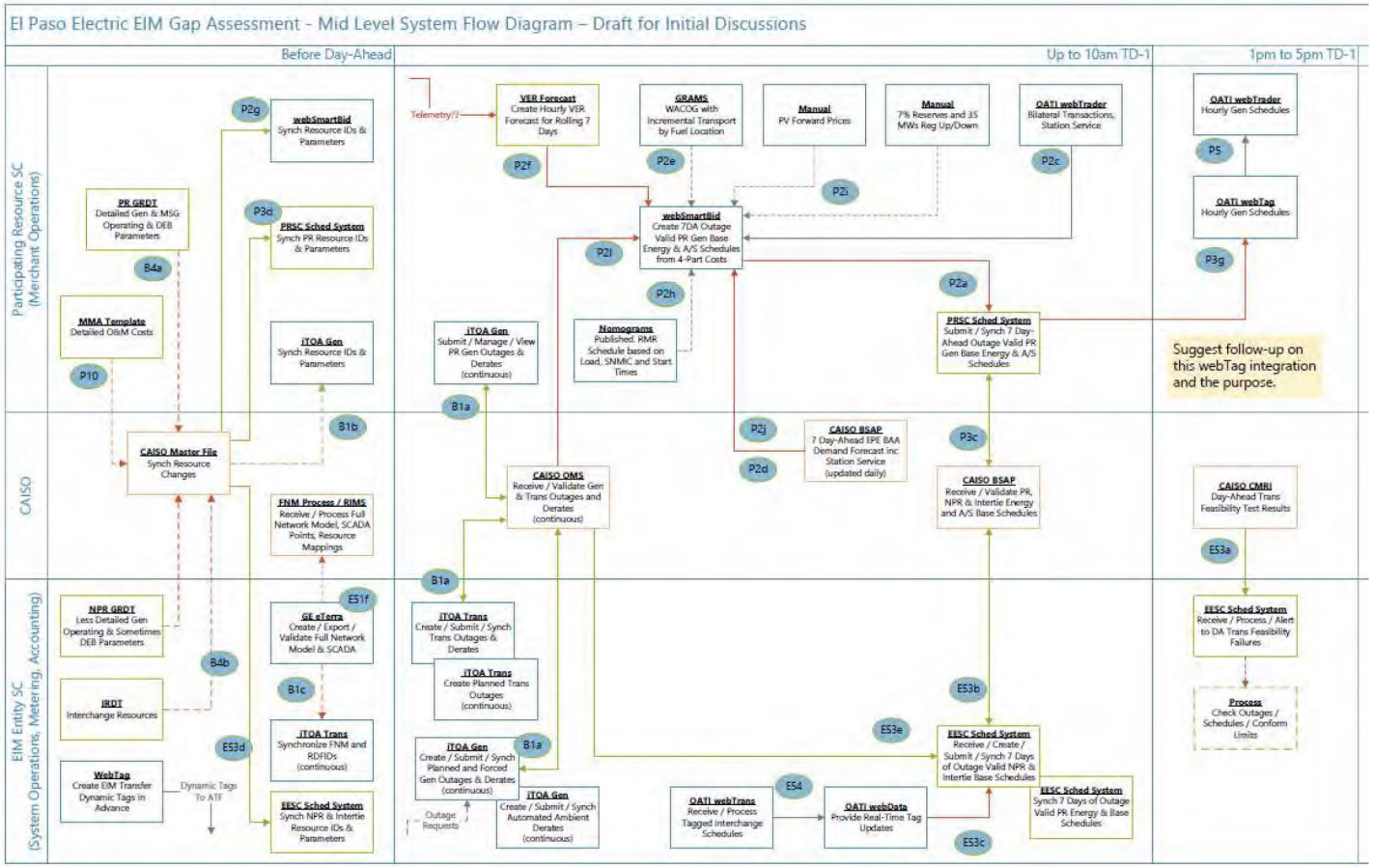
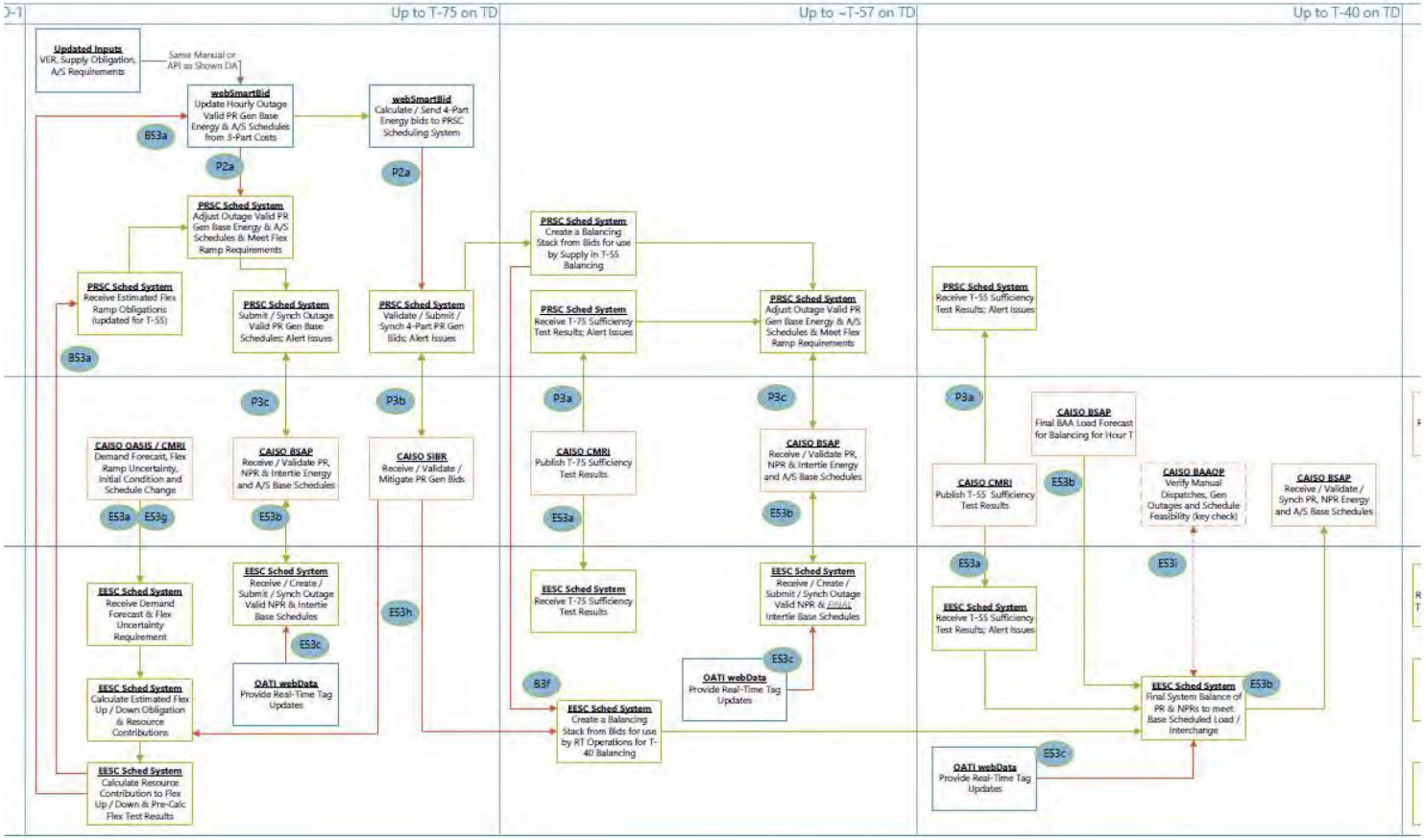
14.1 Appendix 1 – EIM End to End (EtoE) Processes Swimlane Diagram





CEP 6-17 Attachment 2

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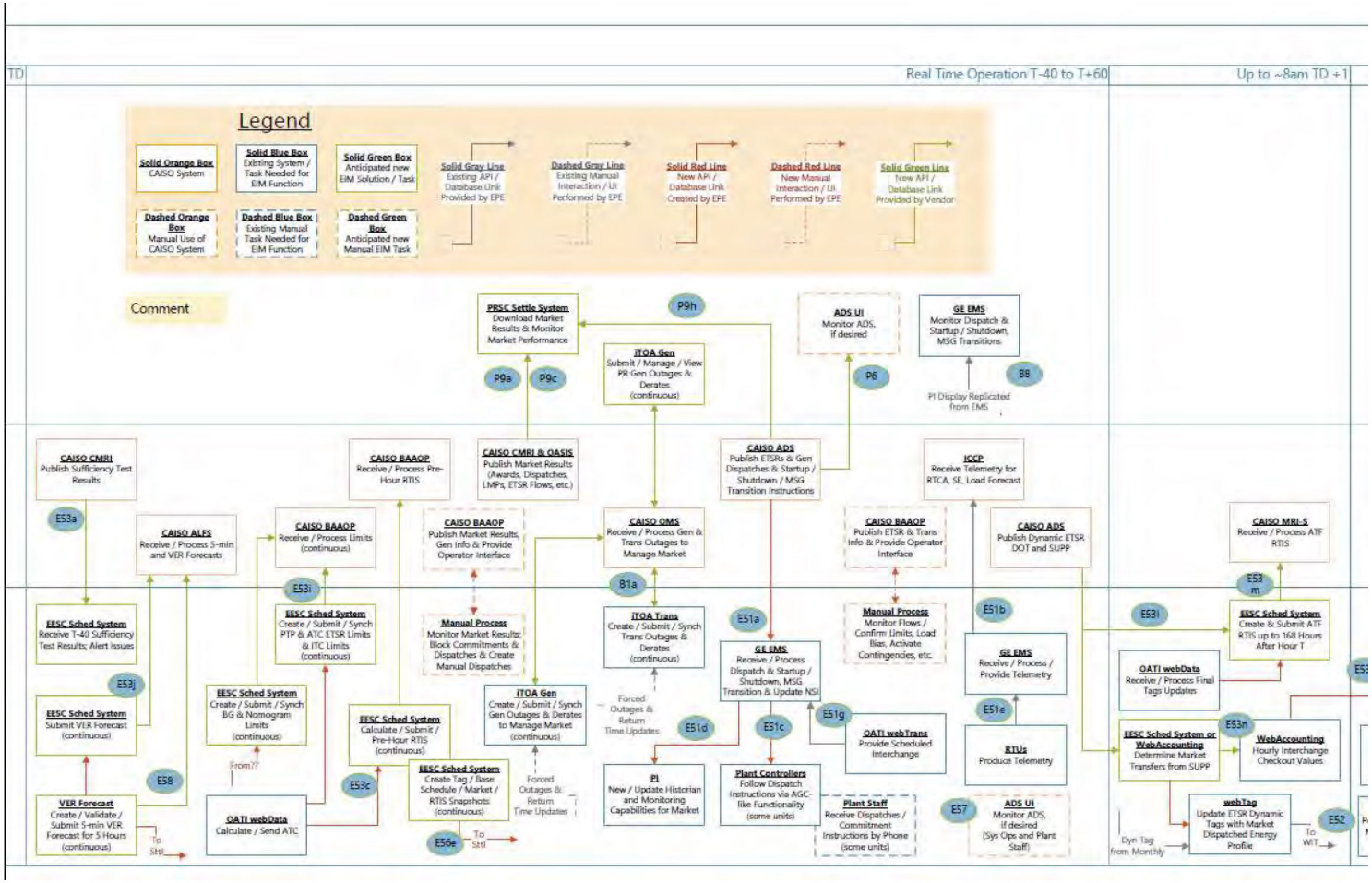
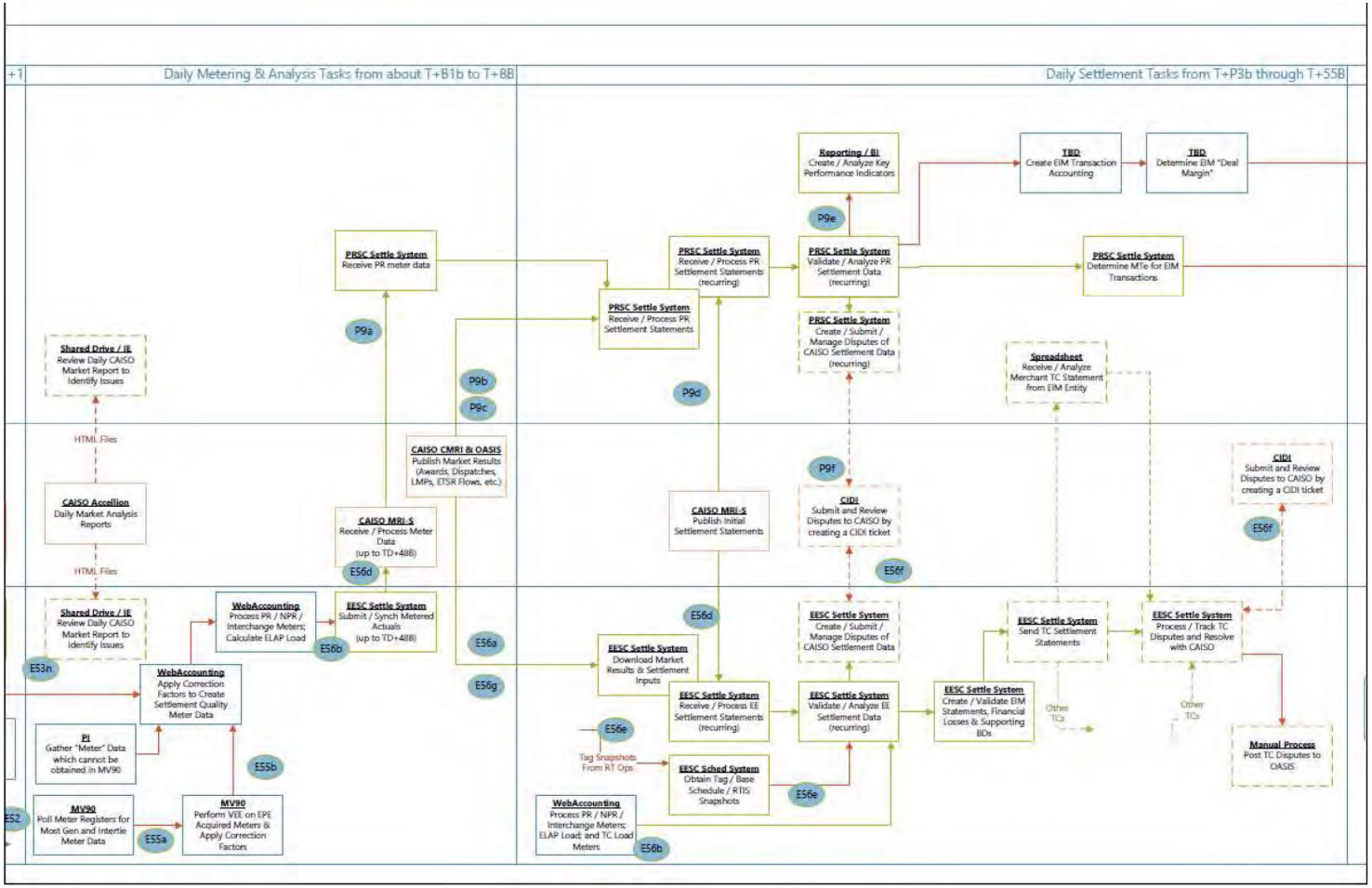
El Paso Electric

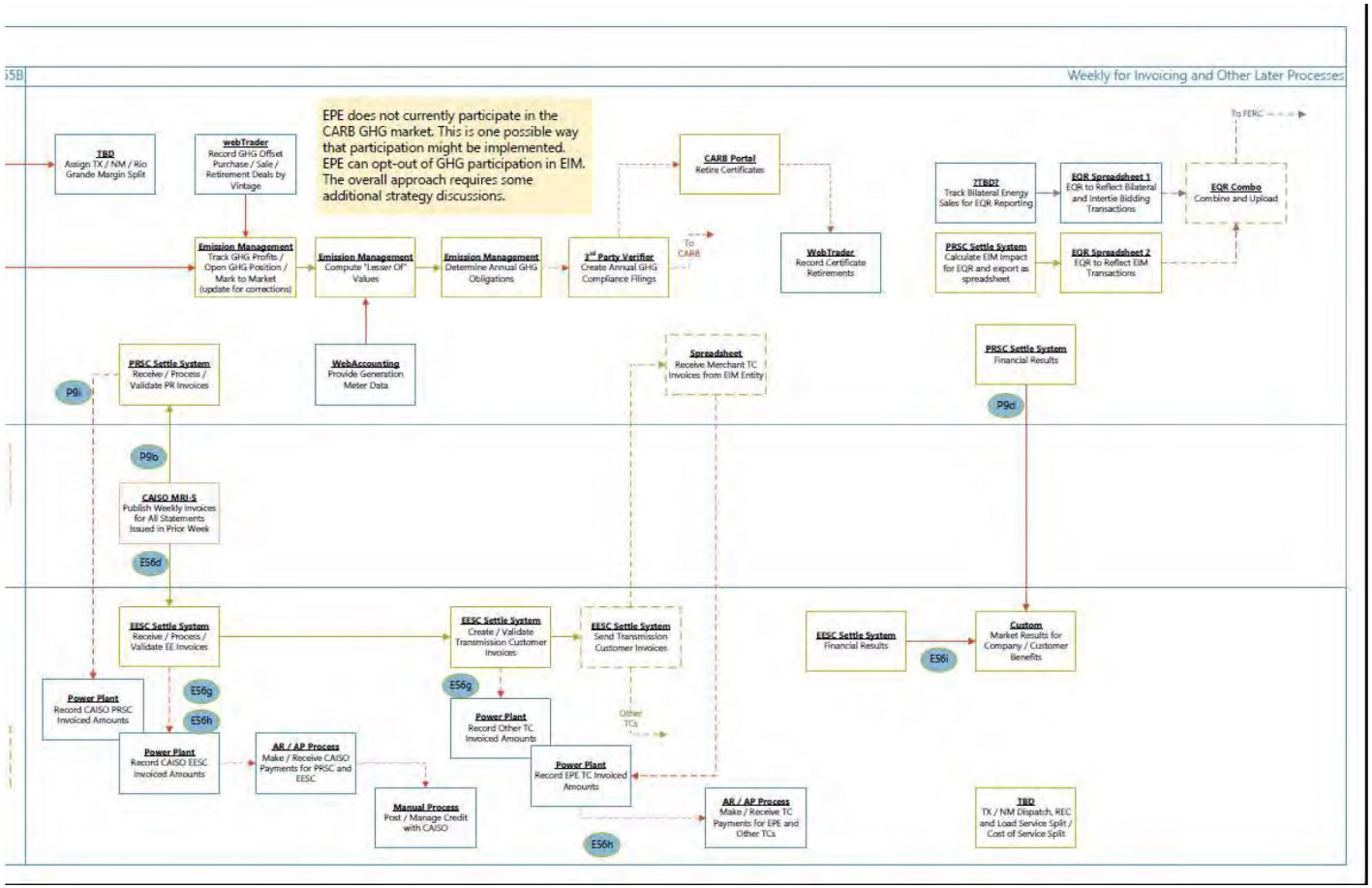
EIM Gap Assessment



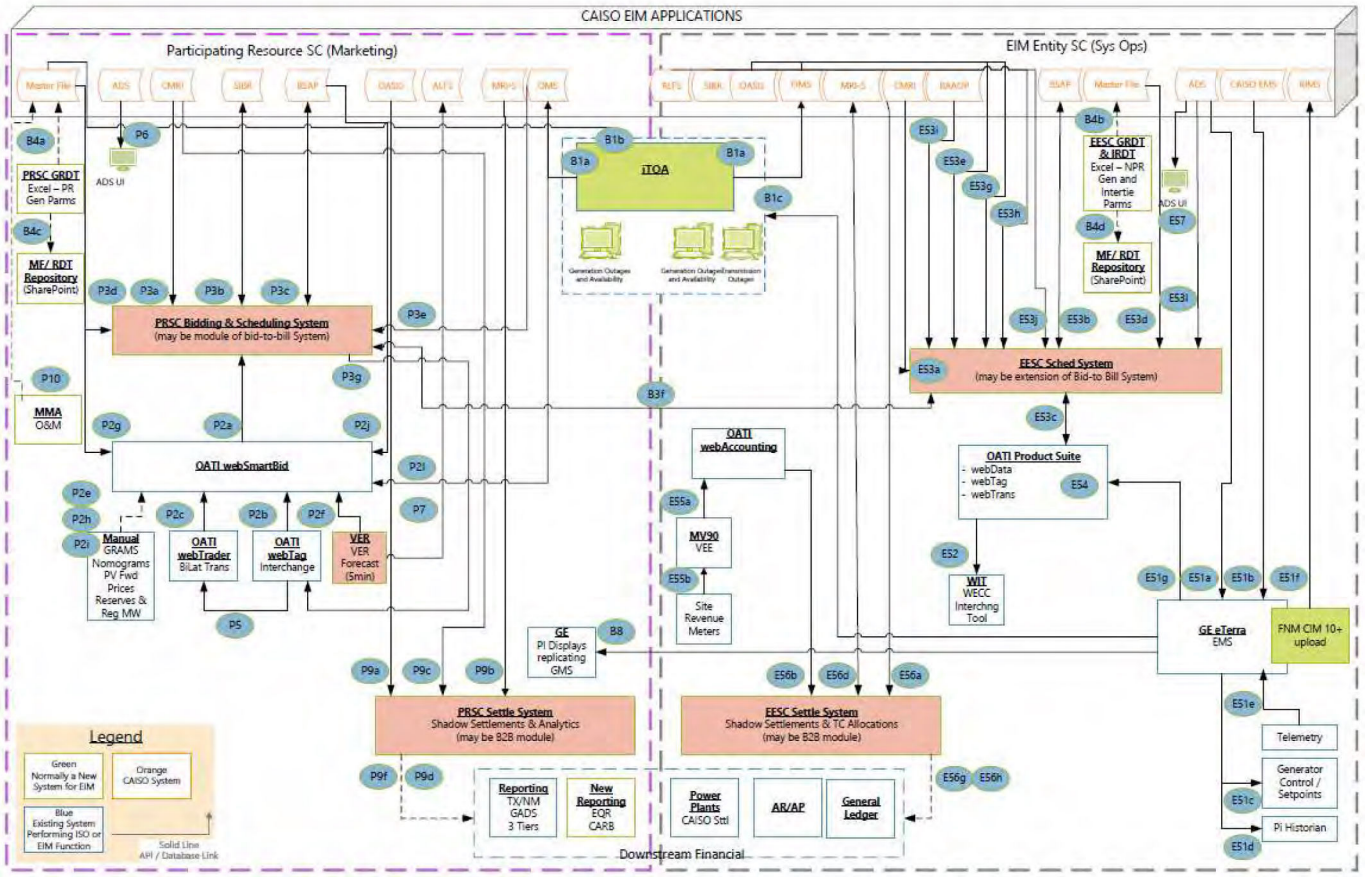
CEP 6-17 Attachment 2



CEP 6-17 Attachment 2



14.2 Appendix 2 – EIM Systems and Interfaces Diagram



EIM Interface List

Interface #	SC	System A	System B	Direction (1->2)/BiDir	Interface Effort	Data/Purpose
B1a	PR/EE (Both)	OMS (iTOA)	CAISO OMS	BiDir	OOTB	PR Gen Outage/Derates/Availability (Assuming Merch ownership)
B1b	PR/EE (Both)	OMS (iTOA)	Master File	B>A	TBD	Sync Resource IDs & Parameters
P2a	PR	webSmartBid (OATI)	PRSC Sched	A>B	Dev*	Energy and A/S Schedules
P2b	PR	webSmartBid (OATI)	webTag (OATI)	B>A	Existing	Hrly Gen Schedules
P2c	PR	webSmartBid (OATI)	webTrader (OATI)	B>A	Existing	Bilateral Transactions, Station Service
P2d	PR	webSmartBid (OATI)	Internal Load Forecast	B>A	Sunset	Have Tesla, but would like to replace with CAISO Load Forecast
P2e	PR	webSmartBid (OATI)	GRAMS	B>A	Manual	WACOG with Incremental Transport by Fuel Location
P2f	PR	webSmartBid (OATI)	VER Forecast	B>A	Dev	Create Hourly VER Forecast for Rolling 7 Days
P2g	PR	webSmartBid (OATI)	Master File	B>A	OOTB	Sync Resource IDs & Parameters
P2h	PR	webSmartBid (OATI)	Nomograms	B>A	Manual	Provide RMR Schedule based on Load, SNMIC and Start Times
P2i	PR	webSmartBid (OATI)	(Other Manual Inupts)	B>A	Manual	PV Forward Prices; 7% Reserves and 35MWs Reg Up/Dn
P2j	PR	webSmartBid (OATI)	BSAP (CAISO)	B>A	TBD	7 Day-Ahead EPE BAA Demand Forecast inc Station Service (updated daily)
B53k	PR/EE (Both)	EESC Sched	webSmartBid (OATI)	A>B	Dev*	Estimated Flex Ramp Obligations
P2l	PR	webSmartBid (OATI)	CAISO OMS	B>A	TBD	Validate Outages

P3a	PR	PRSC Sched	CMRI (CAISO)	B>A	OOTB	Market Results
P3b	PR	PRSC Sched	SIBR (CAISO)	BiDir	OOTB	Submit/Validate/Sync 3-pt PR Gen Bids
P3c	PR	PRSC Sched	BSAP (CAISO)	BiDir	OOTB	Receive / Validate PR Energy and A/S Base Schedules
P3d	PR	PRSC Sched	Master File	B>A	OOTB	Sync Resource IDs & Parameters
P3e	PR	PRSC Sched	OMS	B>A	OOTB	Outages Sync
B3f	PR/EE (Both)	PRSC Sched	EESC Sched	BiDir	Dev*	Estimated Flex Ramp Obligations
P3g	PR	PRSC Sched	webTag (OATI)	A>B	Dev*	Hrly Gen Schedules
B4a	PR/EE (Both)	PR GRDT (excel)	Master File	A>B	Manual	RDT Updates sent to CAISO
B4c	PR/EE (Both)	PR GRDT (excel)	EPE Repository	A>B	Manual	Store historical changes of submitted RDTs (Separate from IRDT & NPR GRDT)
P5	PR	webTag (OATI)	webTrader (OATI)	A>B	Existing	Hrly Gen Schedules
P6	PR	ADS UI	ADS (CAISO)	B>A	OOTB	Read-only visability
P7	PR	VER Forecast	ALFS	A>B	Dev	Submit VER Forecast directly to CAISO
B8	PR/EE (Both)	PI Display (from GE)	EMS (GE)	B>A	Existing	Read-only visability
P9a	PR	PRSC Settlements	OASIS (CAISO)	B>A	OOTB	Public Market Data
P9b	PR	PRSC Settlements	MRI-S (CAISO)	B>A	OOTB	CAISO Settlement Statements
P9c	PR	PRSC Settlements	CMRI (CAISO)	B>A	OOTB	SC Specific Data, Market Results
P9d	PR	PRSC Settlements	Custom Reporting	A>B	Manual	Downstream Financial & Reporting
P9e	PR	PRSC Settlements	CIDI (CAISO)	A>B	Manual	CAISO Settlement Disputes
P9f	PR	PRSC Settlements	Power Plants	A>B	Manual	CAISO PRSC Invoice Amts
P10	PR	MMA	Master File	A>B	Manual	Detailed O&M Costs
B1a	PR/EE (Both)	OMS (iTOA)	CAISO OMS	BiDir	OOTB	NPR Gen Outage/Derates/Availability; Trans Outage

B1c	PR/EE (Both)	OMS (iTOA)	EMS (GE)		Existing	FNM RDFIDs stay in Sync
B4b	PR/EE (Both)	NPR GRDT & IRDT (excel)	Master File	A>B	Manual	Sync Resource IDs & Parameters
B4d	PR/EE (Both)	NPR GRDT & IRDT (excel)	EPE Repository	A>B	Manual	Store historical changes to submitted RDT (Separate from PR GRDT)
E51a	EE	EMS (GE)	ADS (CAISO)	B>A	OOTB	Dispatch Instructions
E51b	EE	EMS (GE)	EMS (CAISO)	A>B	Dev	ICCP Link
E51c	EE	EMS (GE)	Plant Generation Control	A>B	Existing	Plant Instructions
E51d	EE	EMS (GE)	Pi Historian	A>B	Existing	PI Data
E51e	EE	EMS (GE)	Telemetry	B>A	Existing	Telemetry
E51f	EE	EMS (GE)	FNM / RIMS	A>B	Manual	Full Network Model
E51g	EE	EMS (GE)	webTrans (OATI)	B>A	Existing	Scheduled Interchange
E52	EE	webTag (OATI)	WIT	A>B	Existing	Dynamic Tags
E53a	EE	EESC Sched	CMRI (CAISO)	B>A	OOTB	
E53b	EE	EESC Sched	BSAP (CAISO)	BiDir	OOTB	Receive / Validate NPR & Intertie Energy and A/S Base Schedules
E53c	EE	EESC Sched	webData (OATI)	B>A	Dev*	Exchanging Data with OATI Suite
E53d	EE	EESC Sched	Master File	B>A	OOTB	Sync Resource IDs & Parameters
E53e	EE	EESC Sched	CAISO OMS	B>A	OOTB	Sync 7 Days of Outage
B3f	PR/EE (Both)	PRSC Sched	EESC Sched	BiDir	Dev*	Estimated Flex Ramp Obligations
E53g	EE	EESC Sched	OASIS (CAISO)	B>A	OOTB	Public Market Data
E53h	EE	EESC Sched	SIBR (CAISO)	B>A	OOTB	Schedules
E53i	EE	EESC Sched	BAAOP (CAISO)	-	OOTB	BAA portal
E53j	EE	EESC Sched	ALFS (CAISO)	A>B	OOTB	VER Forecast

B53k	PR/EE (Both)	EESC Sched	webSmartBid (OATI)	A>B	Dev*	Estimated Flex Ramp Obligations
E53l	EE	EESC Sched	ADS (CAISO)	B>A	OOTB	Dynamic ETSR DOT and SUPP
E53m	EE	EESC Sched	MRI-S (CAISO)	A>B	OOTB	ATF RTIS
E53n	EE	EESC Sched	webAccounting	BiDir	Dev*	Metering
E54	EE	webTrans (OATI)	webData (OATI)	B>A	Existing	Tagged Interchange Schedules
E55a	EE	MV90	webAccounting	A>B	Existing	VEE is performed in MV90, passed thru webAccounting to a sleeve to MRI-S (CAISO)
E55b	EE	MV90	Site Meters	B>A	Existing	Metering
E56a	EE	EESC Settlements	CMRI (CAISO)	B>A	OOTB	SC Specific Data, Market Results
E56b	EE	EESC Settlements	webAccounting	B>A	Dev*	Meter Data values
E56c	EE	EESC Settlements	OASIS (CAISO)	B>A	OOTB	Public Market Data
E56d	EE	EESC Settlements	MRI-S (CAISO)	BiDir	OOTB	CAISO Settlement Statements, and Mtr Data Submission
E56e	EE	EESC Settlements	EESC Sched	B>A	Dev*	Shaddow Sttl Inputs
E56f	EE	EESC Settlements	CIDI (CAISO)	A>B	Manual	Disputes
E56g	EE	EESC Settlements	Power Plants	A>B	Manual	CAISO EESC Invoice Amts
E56h	EE	EESC Settlements	AR/AP	A>B	Manual	CAISO Payments for PRSC and EESC
E56i	EE	EESC Settlements	Custom Reporting	A>B	Manual	Cost of Service Split, etc.
E57	EE	ADS UI	ADS (CAISO)	B>A	OOTB	CAISO Dispatch Visability
E58	EE	ALFS (CAISO)	VER Forecast	B>A	OOTB	ATC

14.3 Appendix 3 – Full Network Model (FNM) Analysis (Abridged)

14.3.1 Detailed Analysis of Network Model – EPE area only

The following two tables provide a summary of the results grouped by categories and detailed analysis on Network Model, respectively.

Summary of EPE's FNM Analysis – GE Native Format

Severity	Category Description	Problems Count
ERROR	Capability Curve Min/Max mismatch	36
ERROR	Device name has more than 16 char	0
ERROR	Devices connected to the same node	1
ERROR	Duplicate	0
ERROR	Generator without measurement	0
ERROR	Generator without switch	8
ERROR	Load without switch	10
ERROR	Missing Capability Curve	8
ERROR	Negative or zero load	24
ERROR	No individual Capability Curve	18
ERROR	Shunt without Switch	2
ERROR	Special character in device name	692
ERROR	Stranded Station without lines	2
ERROR	Substation name has more than 8 char	0
ERROR	Switch Between Stations	0
ERROR	Unit is Missing Voltage Schedule	8
WARNING	Dangling Line	0
WARNING	Incorrect Limit Order	0
WARNING	Line Rating Load Shed is missing	124

Severity	Category Description	Problems Count
WARNING	Line Rating Set is Undefined	6
WARNING	Line Voltage is different on From/To	0
WARNING	Load without measurement	54
WARNING	Missing Information	0
WARNING	Station without devices	0
WARNING	Unreasonable voltage regulation target	0
WARNING	Verify Charging	3
WARNING	Verify Impedance	4
WARNING	Verify Resistance	2
WARNING	Verify XFMR voltage class on high/low side	1
WARNING	Very small load	4
	TOTAL	**971**

An "Error" identifies an issue which must be corrected for minimum compliance with the CAISO standards. A "Warning" identifies an issue that requires further investigation and which may, if unaddressed, impact the quality of the solution from the model.

As it can be seen from the previous table**Error! Reference source not found.**, most of the identified issues are related to the violation of naming convention rules (special character presence in the name) required by CAISO, e.g. number of characters used in the name over the acceptable limit, unacceptable special characters in the name. It is recommended to address the large number of detected naming issues through automated scripts. Similar scripts have already been developed and can be adapted to EPE needs. However, the logic for name modification needs to be established and agreed upon with EPE operations and engineering to ensure that the new names are recognizable and usable. EPE should take this opportunity to assess the feasibility of establishing a comprehensive naming convention appropriate for EPE's operations.

There are other problem areas (e.g. capability curves) that can be corrected using script automations. However, a general rule is that for issues below 200 count is usually recommended to make manual modifications, for issues over 500 count, script automation usually provides a cost-

effective benefit of time saving, reducing labor intensive work, and eliminating human errors of manual model adjustments. Thus, it is recommended to manually make all necessary modifications except for naming convention modifications.

Excerpt of Detail from EPE's FNM Analysis – GE Native Format

Severity	ProblemCategory	TableSource	DiagnosticMessage
ERROR	Capability Curve Min/Max mismatch	UN	Station=RGD, Unit=RIO_GRANDE_9 Verify Pmax for capability curve, Pmax_un-Pmax_cc=-56.35
ERROR	Devices connected to the same node	UN & LD	Station=CAL, UN=CAL_TX_SLRLoad=CAL-12 are connected to the same bus
ERROR	Generator without switch	UN	Station=RGD; Unit= RIO_GRANDE_8has no associated switch
ERROR	Load without switch	LD	Station=ZZ_AGC; Load= WSA_USBRhas no associated switch
ERROR	Missing Capability Curve	UN	Missing MVar Capability Curve at Station=CHA, Unit = CHA_SUNED_SLR
ERROR	Negative or zero load	LD	Station=MPS;Load= MPS4_AUX_LD is negative or equal 0
ERROR	No individual Capability Curve	UN	Individual MVar Capability Curve Required at Station=NWM, Unit = NEWMAN_4GT2
ERROR	Shunt without switch	CP	Station=ZZ_AGC; ShuntCompensator= SHUNT2_C2_4has no associated switch
ERROR	Special character in device name	CB	Station=PIC; Breaker= PIC-22C has special character
ERROR	Stranded Station without lines	ST & LN	Station= ZZ_AGC is a substation without Lines in/out
ERROR	Unit is Missing Voltage Schedule	UN	Missing Regulation schedule/target at Station=HAT, Unit = HAT_NXTERA_SLR
WARNING	Line Rating Load Shed is missing	LNLIM	Line Rating Load Shed is missingfor LINE=12200_PEL_HOR
WARNING	Line Rating Set is Undefined	LNLIM	Limit is not defined for LINE=ORO_JAR_115
WARNING	Load without measurement	LD	Station=CHA;Load= CHA-OL no measurements
WARNING	Verify Charging	LN	BCH=0, No Charging on line MSPT_MSP_345, High Voltage KV=345 Verify the value with planning model

WARNING	Verify Impedance	LN	Very large Impedance X=58.25% on line 09100_NES_FAR Verify the value with planning model
WARNING	Verify resistance	LN	Very large resistance R=39.876% on line 09100_NES_FAR Verify the value with planning model
WARNING	Verify XFMR voltage class on high/low side	XF	Station=ARR, Transformer= T3 connects same voltage class = 345 KV
WARNING	Very small load	LD	Station=SUN;Load= SUN-8 is very small - verify

14.3.2 CAISO CIM Requirements

EPE reviewed the CIM Model Requirements document in order to get a preliminary assessment of the existing network model's compliance with the CAISO requirements. The results are classified into the following categories:

1. "Yes" - Existing EPE network model already meets the CAISO requirement. No further actions required.
2. "No" - Existing EPE network model does not meet the CAISO requirement. The model needs to be modified or expanded in order to meet CAISO requirement.
3. "TBD" - The CAISO requirement requires further analysis (the requirement may need to be verified in the model or requires discussion with CAISO).
4. "N/A" - The CAISO requirement is not applicable to EPE network model

The above categories established the effort estimate, providing a baseline for initiating discussions with CAISO, and a work breakdown for assigning internal tasks. The following two tables summarize the results of the analysis and detail the assessment, respectively.

Summary of Compliance with CAISO CIM Requirements – Preliminary Assessment

Compliance Category	Count of items
Yes	**37**
No	**9**
N/A	**5**
TBD	**8**

Detail of Compliance with CAISO CIM Requirements – Preliminary Assessment

# in "EIM CIM Model Requirement" Document, ver.1.3, Date: 11/21/2018	EPE Assessed Compliance	EPE COMMENT	EPE Assessed Effort Assessment
Network Model in CIM/XML			
1	yes		
2	yes	Upgrade will ensure they remain the same	
3	yes		
4	yes	To be verified	
5	yes		
6	no	Curves need to be separate, no schedules	1
7	TBD	Needs to be checked	
8	yes		
9	yes		

10	N/A	No LTC	
11	N/A	Generators regulating voltage at their terminal	
12	YES		
13	NO	No regulated schedule or bus defined	1
14	no		TBD
15	yes		
16	yes		
17	yes		
18	TBD		
19	TBD		
20	YES		
21	N/A	CIM15	
22	yes		
23	NO		1
24	YES		
25	YES		
26	yes		
27	yes		
28	TBD		
29	yes		
30	yes		
31	yes		
32	TBD		
33	TBD		
34	TBD	Discuss breaker and a half configuration	
35	TBD		
36	yes		
37	no	add kV to feeders, XFMRS, etc	2
38	yes		
39	yes		
40	yes		
41	no	MW, MV from redundant sources	
42	no	MW, MV from redundant sources	
43	yes		
44	yes		
45	n/a	CIM15	

46	n/a	PV uses dynamic schedule	
47	yes		
48	no	Discuss breaker and a half configuration	1
49	yes		
50	yes		
51	yes	Extra measurements can be ignored (PF,Hz)	
52	yes		
53	no	have status associated with generic equipment, need to discuss with CAISO	2
54	yes		
55	yes		
56	yes		
57	yes		
58	yes		
59	yes		

NETWORK RELATED DATA			
10	TBD	need to check with peak RC, need to get their sub names and create mapping	

SCADA RELATED DATA			
2	TBD	need to create calculations	2

14.4 Appendix 4 – Metering Analysis

14.4.1 CAISO Metering Requirements

14.4.1.1 Metered Entity Registration

CAISO provides the option for EIM Entities to choose between two metered entity registration types, ISO Metered Entity (ISOME) and Scheduling Coordinator Metered Entity (SCME). Utilicast recommends EPE register as a SCME, as this allows EPE to continue engineering, installing, testing, and gathering data for meters in scope for EIM participation. Selecting the ISOME option would relinquish these roles to CAISO-certified personnel and require EPE to pay for the metering services and provide site access to these external personnel. It is also notable that all EIM Entities to date have registered as SCMEs. Therefore, the metering assessment was performed with the assumption that EPE will be a SCME.

As part of this SCME registration, EPE will need to execute a registration agreement, requiring the EPE signee to attest to the accuracy of its submitted Settlement Quality Meter Data (SQMD) Plans.

14.4.1.2 Applicable Metering Requirements

CAISO allows EIM SCMEs to choose between adhering to CAISO metering requirements and LRA metering requirements. EPE's applicable LRAs are state utility commissions. This assessment evaluated the equipment relative to the CAISO metering requirements.

14.4.1.3 Generation Registration and Size Threshold

CAISO allows EIM participants some discretion on which generation capacity to be registered in the EIM. Very small resources may be excluded from all EIM involvement, including resource registration, the Full Network Model (FNM), base schedules, and meter submission. CAISO requires this threshold be set between 1 MW and 10 MWs.

During the metering assessment, EPE indicated it would likely set the minimum capacity threshold for resource registration at 1 MW. This threshold was chosen since it corresponds to the specified threshold for requiring Supervisory Control And Data Acquisition (SCADA) in the EPE Small Generator Interconnection Procedures (SGIP).

The exclusion of these generators from resource registration will be appear as negative load in the EPE load forecast and real-time operations for the EIM. Therefore, EPE should subtract these resources' historical output from the EPE historical load actuals submitted to CAISO for its load forecast engine to ensure greater forecast accuracy.

All generation within the EPE BA above the 1 MW capacity threshold must be registered with submitted and approved SQMD Plans, regardless of ownership and EIM participation.

14.4.1.4 SQMD Plan

To join EIM, the Entity must complete a SQMD Plan and receive CAISO approval for each registered Resource ID. Each Participating Resource (PR), Non-Participating Resource (NPR), and scheduling tie will be assigned a Resource ID, with scheduling ties being comprised of physical interchange points

aggregated to EPE-defined locations. The EPE-completed SQMD Plans[1] will include information such as meter granularity, meter and instrumentation accuracy, loss compensation, meter audit and test plans, calculations, single line meter diagrams, and descriptions of data collection and Validation, Editing, and Estimating (VEE). The descriptions of data collection do not require detailed diagrams of the communication pathway, but should include a description of communication networks, meter data head-end and EESC Settlement systems leading to daily SQMD data submission to CAISO systems for settlement.

As part of the SQMD plan submission, EPE will need to provide a Single Line Diagram (SLD) that shows the station configuration and specifically the locations of all relevant transformers, meters and station service. The SLD must either be stamped by a Professional Engineer (PE) or, if modifications have been made since the original construction, an EPE PE may attest to the accuracy of the SLDs.

As part of the EIM implementation project, EPE should prioritize the early submission of the first SQMD Plan to allow for sufficient review and revision time between CAISO and EPE staff, which may take several months of revision and discussion to finalize[2]. Furthermore, CAISO staff may request clarification or modification of the plans in a manner that could impact all SQMD Plans and the underlying EIM meter program, requiring substantial project work to address. Once one SQMD Plan has been approved, much of the content may be utilized for all other plans, as the description of the audit plan, data collection, and VEE should be common to the majority of meters, easing the submission of subsequent plans. Any expected exemptions should also be discussed early in the implementation project to ensure acceptance or a change in project work as necessary.

14.4.1.5 Equipment Rating Data

The equipment ratings specified in the CAISO Metering BPM, such as accuracy and burden ratings, must be determined by EPE for EIM participation. The CAISO Metering BPM rating requirements are specified by accuracy and burden classes, as defined in the IEEE C57.13 Standard Requirements for Instrument Transformers. If the equipment ratings for any meters, CTs, or PTs used for EIM metering are unable to be found, then EPE must either replace the equipment having unknown attributes, or attest to the likely attributes based on known information, such as other installations of similar equipment having known attributes, test data, or other sources of engineering judgement.

EPE should undertake all reasonable measures to establish the accuracy of the equipment. At one time CAISO was aggressive in requiring nameplate information for all equipment. However, in more recent EIM implementations CAISO has been somewhat more willing to accept management attestation in a sworn affidavit that states the assumed accuracy "to the best of my knowledge" with a duty to update if

[1] CAISO's tutorial of SQMD Plan template is posted at https://www.caiso.com/Documents/SQMDResourceTemplateTutorial.pdf
The SQMD Plan template is posted at https://www.caiso.com/Documents/SQMDPlanTemplate.docx

[2] To begin the SQMD process, El Paso Electric must obtain a New Resource Implementation (NRI) number. To obtain this number, El Paso Electric must have an assigned Resource IDs. However, EIM Entities DO NOT have to follow the full NRI process if they are SCMEs.

new information becomes available. The assessment of validated equipment ratings and equipment lacking the necessary rating data are provided in section **Error! Reference source not found.**.

The core requirements for metering equipment are:

- Meter
  - 0.2 Accuracy class
  - 60 days storage for meter data
  - 5-minute interval granularity for Participating Resources and Interchange
- CT
  - +/- 0.3% accuracy at burden of 0.1 - 1.8 ohms, 10% - 100% rated current, or
  - Optional +/- 0.15% accuracy at burden of 0.1 - 1.8 ohms, 5% - 100% rated current
- PT
  - +/- 0.3% accuracy through burden rating ZZ (400 Volt-Amperes secondary at 0.85 power factor) at 90% through 110% of nominal voltage, or
  - Optional +/- 0.15% accuracy through burden rating Y (75 Volt-Amperes secondary at 0.85 power factor) at 90% through 110% of nominal voltage

EPE may use equipment which does not meet the requirements but doing so will require EPE to calculate a "correction factor" to apply to the meter data. The correction factor does not increase accuracy – it is a penalty which reduces the observed readings to ensure that the metered output is not overstated. See section 14.4.2.3 for more detail on correction factors. EPE may also utilize meters with less than 60 days storage for meter data and may utilize interchange meters with 15- or 60-minute granularity by requesting exemptions from CAISO. See sections 14.4.1.7 and 14.4.1.8 for more detail on meter data storage and granularity, respectively.

14.4.1.6 Equipment Burden Ratings

EPE may have installed CTs and PTs with burden ratings less than the CAISO requirements of B1.8 and ZZ, respectively. However, this equipment may have sufficiently low burden connected to their circuits to retain their rated accuracy, pending further validation by EPE engineers. While the CAISO-stated burden ratings may exceed these installations, EPE should be able to utilize this equipment with low connected burden in accordance with item b of the following excerpt from Attachment B Section A6 of the CAISO Metering BPM:

> Where the connected burden of a metering circuit exceeds the burden rating of a CT or [PT] or if an existing instrument transformer does not meet the minimum CAISO accuracy requirements, then one of the actions listed below must be taken:
>
> a. Replace the instrument transformer(s) with higher burden rated revenue class units; or
>
> b. Reduce the burden on the circuit to comply with the name plate of existing instrument transformer(s); or

c. Apply correction factors to the meter to adjust the meter's registration to compensate for inaccuracies.

In accordance with item b of the above excerpt, if EPE can document in the SQMD plan that the connected burden of these CTs and PTs and demonstrate it is less than the equipment burden rating, then the installed equipment can be utilized without replacement or correction factors.

14.4.1.7 Meter Memory Requirements

EPE may have installed meters with memory storage less than the CAISO requirement of 60 days storage. EPE should consider either replacing these meters, upgrading their memory, or utilize the existing memory and applying for an exemption from the CAISO requirement.

If EPE chooses to retain these meters with insufficient memory, an exemption should be submitted for CAISO's review early in the implementation project, to ensure sufficient time to adjust project work if CAISO rejects the request. The exemption request should describe the rationale for the decision and proposed mitigation plan. For example, EPE could describe its plan to replace these meters as associated site work occurs, and in the meantime, a process for sending field technicians for a local meter read in a timely fashion prior to reaching the memory limitation, should communications fail to read the meter.

14.4.1.8 Metering Granularity

Generation registered as a Participating Resource (PR) and BAA Interchange metering must be submitted to CAISO at a 5-minute granularity, while Non-Participating Resource (NPR) metering may be recorded at a 5-minute, 15-minute, or 60-minute granularity. BAA load metering, termed EIM Load Aggregation Point (ELAP) load, is determined as the net summation of all generation and interchange meter values and cannot be submitted to CAISO at a more granular level than the least granular meter data. For example, if all PR, NPR, and interchange meters record at 5-minute granularity except one NPR meter that records at 15-minute granularity, then the CAISO would require the ELAP meter be submitted at 15-minute granularity. See section 14.4.2.2 for a description of meter granularity impact on EIM participation.

In the EIM, the CAISO deems the Merchant largely responsible for PRs and the Transmission Operator, termed the EIM Entity, responsible for NPRs. One possible generation Resource registration strategy that simplifies scheduling and analysis is to register all EPE owned generation as Participating Resources. To do so would require EPE to satisfy the granularity requirements of Participating Resources for all generation.

In some cases, the CAISO has permitted profiling of a Revenue Quality value at a greater granularity to be profiled to a 5-minute granularity using other data (e.g. SCADA). The only cases we know of involve resources which have some other pre-existing revenue quality checkout process, such as Palo Verde. However, this is a commonly granted exemption for interchange metering, utilizing the process described in section 14.4.2.4.

14.4.1.9 Meter Submission at Resource ID Level

CAISO requires meter data to be submitted at the registered Resource ID level.

To the extent EPE records multiple meters for one Resource ID, these values will need to be netted to a single meter data set for submission to CAISO. For example, if two physical generators are metered individually at their gross output, have a separately metered station service onsite, and are registered as a single Resource ID, then all three meters will be combined into a single meter value recording the two generators' output net of station service.[3]

A revenue quality meter provides data to the VEE process. Once VEE has been performed, the data is deemed settlement quality, will be submitted to CAISO for settlement, and is subject to an approved SQMD plan. Other non-revenue quality meter reads may be used to allocate or distribute settlement quality data but are not provided to CAISO directly.

Similar to the requirement to submit generation meter data by Resource ID, EPE interchange metering must be aggregated to a scheduling tie. These scheduling ties will be registered with CAISO as a System Resource ID, typically corresponding to EPE's OASIS posted paths[4]. Careful review of these scheduling tie aggregations should be performed to ensure the net of submitted interchange metering for EIM includes all El Paso Electric points of interchange and equals Net Actual Interchange energy accounting records.

14.4.1.10 Pseudo-Tie Meters and Load Meter Calculation

Pseudo-tie generators modeled in the FNM will be registered as type Gen, whereas any generators not modeled, typically those electrically distant from the CAISO FNM footprint, will be registered as type Tie

[3] Netting of station service is permitted but only certain categories of use which are deemed "required" for the operation of the station are approved for this treatment (e.g. pumps, excitation). Other categories of use that might be tied to a generator (e.g. fish hatcheries at a hydro facility) do not qualify for station service netting and would need to be excluded from the netting, unless the generator is classified as behind-the-meter generation in its interconnection agreement. Onsite load for behind-the-meter generation may be netted from generation.
[4] EPE's OASIS posted paths, are described at http://www.oatioasis.com/epe/

Gen (TG). Given EPE's BAA adjacency to existing and planned EIM participants, it is likely that all EPE BA generators will be registered as type Gen. However, this assumption should be revisited for Palo Verde generation, given the complexity of the delivery arrangements.

Any pseudo-tie generators registered as type Gen, as opposed to type TG, require a corresponding scheduling tie registration to submit a counterflow to the physical interchange meter. Pseudo-tie generation meters will be submitted twice, once for the generator resource ID and again as a counterflow for the scheduling tie ID. As depicted in the pseudo-tie meter figure, internal generation and pseudo-tie generation will be metered and the generation production values submitted to CAISO. Additionally, pseudo-tie meters function as interchange meters, measuring the generation production as a BAA export, as the generation physically wheels through external BAAs before returning to the EPE BAA as a metered import at the contiguous boundary.

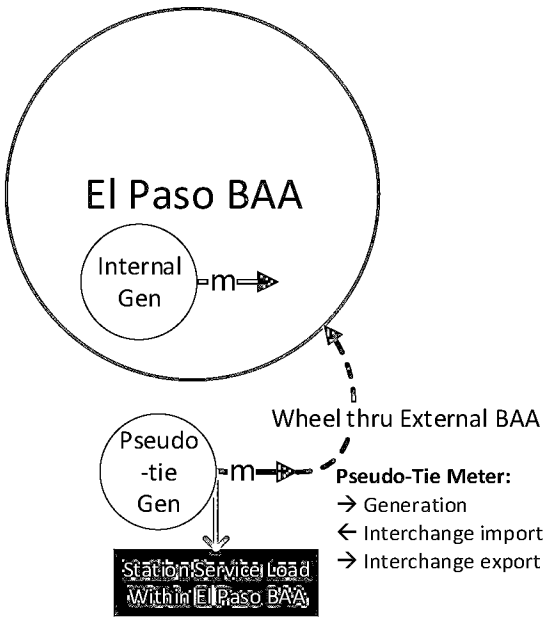


Figure: Pseudo-Tie Meter

For example, given CAISO's definition of BAA load as generation minus exports plus imports, a pseudo-tie generator value of 5 MW is accounted in load as 5 MW generation plus 5 MW metered import at the contiguous boundary minus 5 MW pseudo-tie meter export (counterflow), equaling 5 MW once this netting in the load calculation occurs. CAISO recalculates BAA load independent of the EIM Entity load meter submission, and thus requires the submission of pseudo-tie meters as both generation and interchange to net correctly.

Finally, EPE BA load must be calculated as the net of all generation and interchange metering, equal to generation plus imports minus exports. CAISO defines this BA load meter as the ELAP and requires its submission in two forms, once as the net of generation and interchange without any loss factor applied and again as the net of generation and interchange divided by the number one plus a transmission system loss factor, likely defined as one of the loss factors stated in EPE's OATT[5]. Existing EIM participants have also utilized their respective OATT-stated loss factor for this calculation.

14.4.1.11 Meter Channels

CAISO does not require the submission of Volt Ampere Reactive (VARs) for EIM participation, only active power, measured as kilowatt hours (kWh) or megawatt hours (MWh). Meters record these values on

[5] EPE Open Access Transmission Tariff (OATT) summary of rates
http://www.oasis.oati.com/woa/docs/EPE/EPEdocs/transmission_rates_WebTrans_Posting.pdf