Los Alamos County EIM Gap Analysis

Prepared For:

Los Alamos County

Department of Public Utilities

ATTACHMENT B

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1. Executive Summary

The *Los Alamos County Department of Public Utilities* (LAC) is joining the CAISO's *Western Energy Imbalance Market* (EIM) due to being a sub-entity of the Public Service of New Mexico (PNM). LAC has asked Utilicast to perform a gap assessment and costing estimate to join the EIM with the optionality of becoming a Participating or Non-Participating Scheduling Coordinator. This information will allow LAC to decide the best course of action with regards to joining the EIM.

Joining the EIM would bring changes to the way LAC does business. It would impact the systems needed to successfully execute that business. LAC recognizes that several systems and processes may need to be upgraded in order to participate successfully in the EIM. Additional human resources may also be required to execute EIM workflows. They have requested an analysis of the cost to participate in EIM. LAC has contracted with Utilicast to perform this analysis. This report is Utilicast's response to that request. This report is structured as an EIM Gap Assessment which compares the current state of LAC's resources, processes and technology (systems and infrastructure) with what would be necessary to operate in the EIM.

The assessment was delivered in phases as follows:

- *Phase 1: As-Is State of Operations Assessment*. The As-Is state was presented to LAC sponsors and a true-up was performed for accuracy.
- After completing the *As-Is State of Operations Assessment*, Utilicast and LAC collectively decided to accelerate the contractual component entitled *Phase 2.1.A.C EIM Participation Approach* to focus the EIM Gap Assessment on the decision to either become a Participating or Non-Participating Resource participant. The EIM Participation Approach was documented, and a slide deck was presented and delivered. LAC opted for the Non-Participating Resource designation, thereby greatly reducing technical, procedural, human resource, and cost hurdles.
- The *EIM Participation Gap Assessment* section was then delivered and reviewed with LAC.
- Finally, the *EIM Integration Cost Assessment* was delivered and reviewed with LAC.
- A final slide deck was created, and a board presentation was delivered. Remaining questions were answered as needed.

2. Introduction and Approach

This report is organized into sections. The *As-Is State of Operations* provides a high-level overview of LAC's existing processes and technology. The *EIM Participation Approach* section outlines reasons LAC should pursue either of those EIM options. The *EIM Participation Gap Assessment* section identifies the largest EIM gaps arranged by functional area. Following this summary, the *EIM Integration Cost Assessment* section is a cost analysis of each of the functional areas affected by EIM membership and details the capital and ongoing costs of participation in EIM.

The content of this report is a high-level assessment of the work LAC must undertake to join and successfully operate in the EIM.

Approach

Utilicast developed the two states (current state and required EIM state) via an interview, data collection, and analysis process. To develop the current state of the LAC systems and processes, Utilicast interviewed the staff utilizing those systems, and the key technical staff that support those systems. Additionally, Utilicast reviewed documentation and diagrams provided by LAC staff. To develop the desired EIM state of the systems Utilicast utilized its experience at other EIM clients, CAISO system and process documentation, and an extensive network of market subject matter experts inside and outside of Utilicast. This analysis allowed Utilicast to define the required EIM-enabled state of the systems, and additionally suggested 'desirable' extensions to the requirements that may enable more efficient data analysis, situational awareness, or other efficiencies.

This resulting report leverages the as-is/to-be analysis described above. For each functional area the report describes the required EIM functionality, the current state of that functionality, and the resulting system (or other) gap that must be addressed.

3. As-Is State of Operations Assessment

This section summarizes the current state of people, technology, and processes at LAC.

3.1 Merchant & System Operations

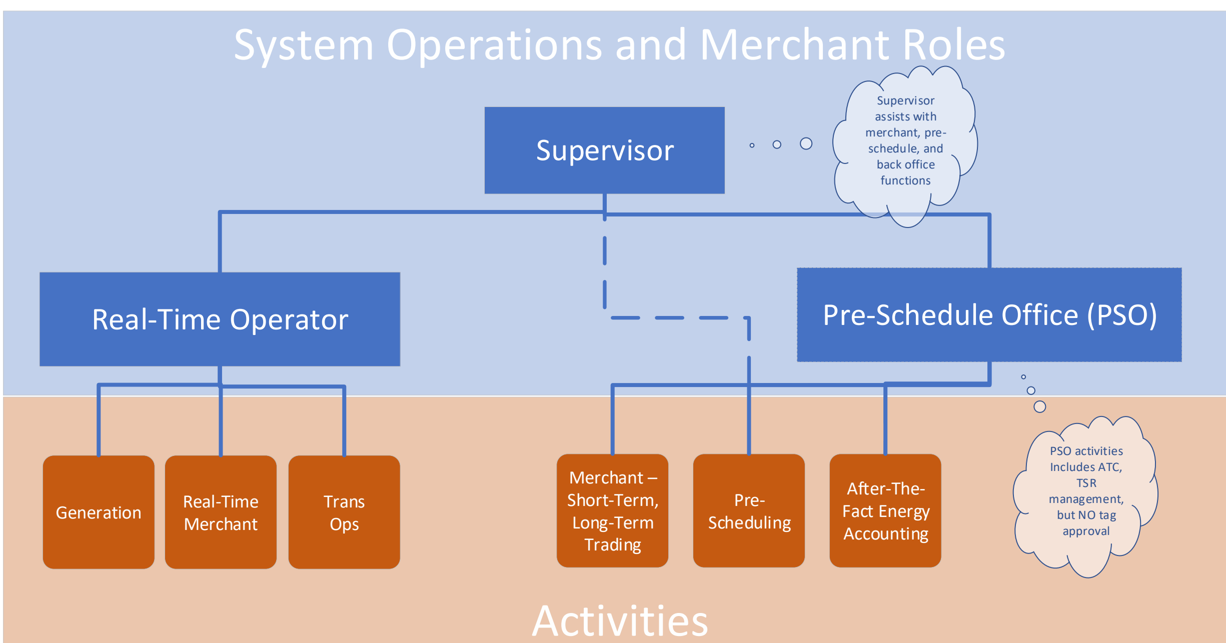
3.1.1 Organizational Structure

LAC operates their merchant and system operations functions under a single management umbrella. A supervisor manages both the system operations and merchant functions, while providing targeted operational assistance where required.

The System Operations function is performed by a Real-Time Operator, who covers operational tasks such as generation dispatch, transmission operations (limited), and Real-Time merchant activities.

The core merchant functions are centralized within the *Pre-Schedule Office* (PSO), covering activities such as short-term and long-term trading, prescheduling, and after-the-fact energy accounting. The PSO handles activities such as *Available Transfer Capacity* (ATC) management and *Transmission Service Request* (TSR) workflows. The supervisor who oversees both the system operations and merchant functions, also provides targeted assistance for merchant, preschedule, and back office activities.

Figure 1: System Operations and Merchant Roles



The Real-Time operators physically work in the Real-Time Operations area. The merchant function as part of the Pre-Schedule Office reside in a separate physical location from Real-Time operations.

3.1.2 Merchant As-Is Business Process

Load Forecasting

LAC produces a rolling one-month load forecast. Inputs into the load forecast include the previous year's actual load and energy-intensive scheduled activities at *Los Alamos National Laboratories* (LANL). In a 7 day to one-month outlook, the county's load is relatively stable and the previous year's actual load is very indicative of load forecast projections. LAC has a peak load of 91 MWs. There are no load areas outside of the LAC area (LAC is not a Balancing Authority).

Los Alamos National Laboratories Load

LAC provides load service to LANL and is a part of LAC's load forecast calculations. LANL load is heavily based on lab program funding and scheduling. Active and future projects are well documented in terms of scheduled use and electricity requirements. The LANL energy requirements and schedules are made available to the Pre-Schedule Office and Real-Time Operations more than a month into the future. There exists some significant seasonal load based on LANL's linear super computing requirements, but these are well scheduled at the hourly level. Between supercomputer batch jobs, there is some downtime, which would make a large energy consumption delta in the 5- and 15-minute markets. An ongoing effort is in progress to smooth out energy usage and forecasting (30 day forecast and 2-day forecast), with the goal of steady state operation during *duck curve* timings. The LAC energy scheduling function integrates LANL energy requirements into the overall LAC load forecast.

Sandia National Labs and Kirtland Airforce Base Load

LAC provides merchant service for Sandia National Labs and Kirtland Airforce Base; thus, these entities are a part of LAC's load and are accounted for in their overall load forecast.

Note: This forecasting approach has been successfully implemented for 35+ years, but there are concerns about future liquidity in bilateral trading markets.

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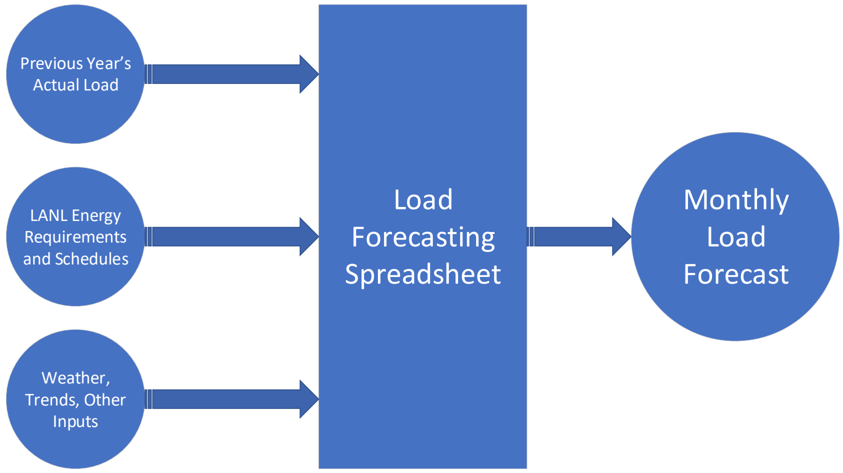
Figure 2. Load Forecast Inputs

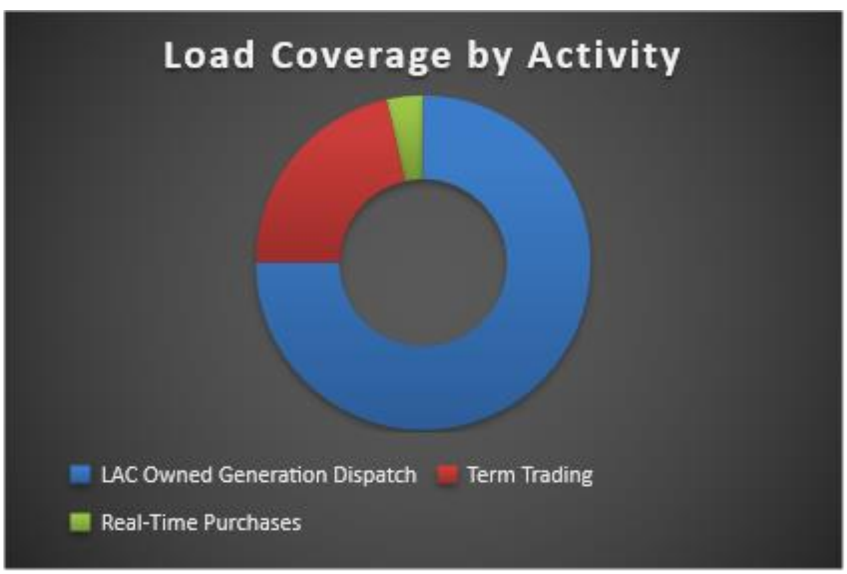


LAC provides *Public Service New Mexico* (PNM) with their load forecast at the beginning of each month for use in PNM's overall *Balancing Area* (BA) load forecast. Additionally, LAC sends updated load forecasts at T-3 (Three days prior to each trade date) via an Excel spreadsheet delivered by email. There is an effort underway to automate load forecast communication by utilizing a database to send PNM a 7-day load forecast, updated weekly.

Generation Scheduling

LAC covers about 75% of the county's load by dispatching their own resources, while the Pre-Scheduling Office (PSO) is responsible for purchasing a sizeable percentage (an additional 20%+) of the remaining load via bilateral trading with adjacent entities during the day-ahead time horizon. The last 2-5% is procured via real-time purchases and sales within the trading day or pre-hour.

Figure 3: Load Coverage – By Activity



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LAC's trading strategy to meet load requirements is to utilize most owned generation and *Purchase Power Agreements* (PPAs), and then make up the difference on the open market. Ancillary Services (Spin, Non-Spin, Regulation) for the LAC area are handled by PNM.

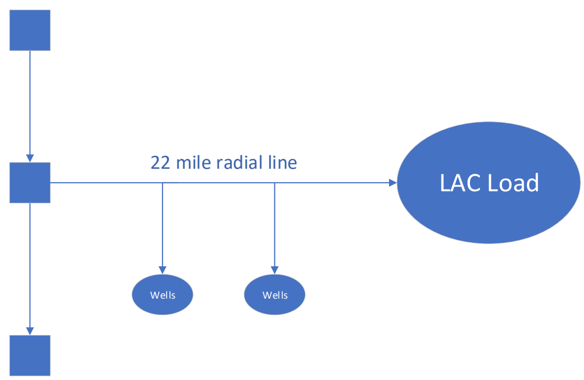
Generation forecasts are provided to PNM's Generation Department on a Day-Ahead basis, for use in their BA balancing workflows.

As a part of LAC Generation Scheduling, internal units as well as units outside their territory are scheduled, such as Laramie River Station and the hydro units.

Merchant Transmission Rights & Energy Scheduling

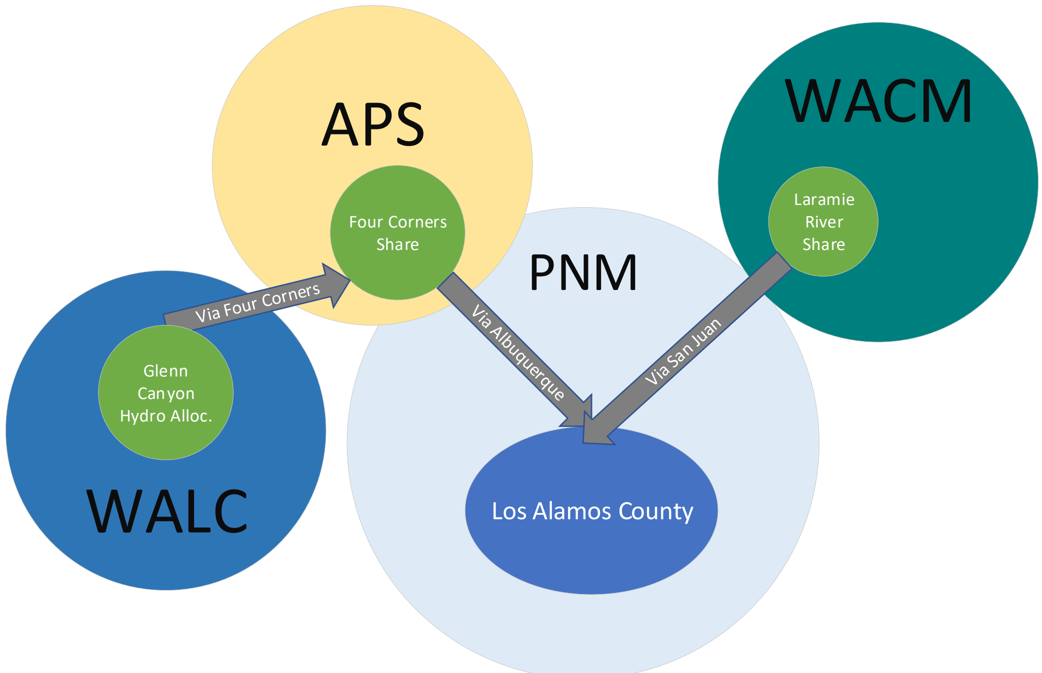
LANL owns twenty-two miles of transmission assets within the county to utilize internal, owned generation and bring home imported energy to load centers. The transmission consists of a radial line serving some water wells along the way with the LAC load center at the end of the line.

Figure 4: LAC High-Level Topology



LAC owns (and purchases additional) transmission rights from the *Western Area Power Administration, Colorado-Missouri Region* (WACM) Balancing Authority to bring their share of Laramie River Station (LRS) MWs to San Juan to Los Alamos County. LAC and LANL own transmission rights (via NITS agreements) on PNM's system to bring home energy from Four Corners Generation Station through Albuquerque to Los Alamos County. Additionally, LAC has transmission rights from Ault, Colorado. LAC collects it's WAPA-based (WALC BA) Glen Canyon Hydro allocation via the PNM transmission network (WAPA to Four Corners). LAC is a network customer of PNM and has rights at secondary points in PNM's system.

Figure 5: Major Transmission Rights and External Generation



As a policy, LAC aims to maximize usage of pre-purchased transmission rights, such as from Four Corners to Albuquerque, before purchasing additional capability in the Day-Ahead timeframe. All transmission access and provisioning is done in the Day-Ahead timeframe.

LAC does not list transmission on OASIS, and therefore does not perform tag approval. There is no transmission billing activity at LAC since they only utilize their transmission for themselves and do not sell capacity to transmission customers. The merchant function handles 60-75 tags per week including monthly tags. All tags are static in nature.

Figure 6: Energy Scheduling Capabilities

Capability	Applicability / Features	Comments
OASIS-listed Transmission	Not Applicable	LAC-owned transmission is not available for external use. No posts to OASIS, read-only
Tag Approval	Not Applicable	LAC-owned transmission is not available for external use. LAC is not a tagging authority.
Transmission Billing	Not Applicable	LAC does not sell owned transmission capability to transmission customers
Tag Volume	60 – 75 Tags per week	Monthly, daily (mostly daily) apply.
Tag Type	Static Schedules Only	No dynamic schedules, no Pseudo-ties are present.

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Grandfathered Agreements	Not Applicable	None

Hourly After-The-Fact Energy Accounting

The Real-Time Operator performs after-the-fact (ATF) checkouts with adjacents up to 50 minutes after the trade hour. Analog and Accumulator meter data collected from the Energy Management System (EMS) are used to perform hourly checkouts. There is a monthly ATF process.

Merchant Technologies

Deals and Energy Schedule Management

The Pre-Schedule Office primarily uses WebTrader to manage deals, the OATI E-Tagging system to track reservations and energy schedules, and WebOASIS to reserve the Ault to San Juan line (LAC does not post to OASIS). These applications are fully cloud hosted solutions. A set of monitors are available to track purchases and sales, and related tags.

Energy & Risk Management (ERM)

Energy & risk management functions are process rather than software-driven; thus, no formal energy & risk management software is in place. The software focus remains on energy trading.

Meter Data Management

LAC has a SCADA System to view analog and accumulator meters, and applicable generation resource attributes such as current MW output and limits. There are alerts in place to detect fluctuations in load and generation. Meter data accuracy and other meter attributes are known and handled by PNM and Tri-State. Intra-ties are managed via SCADA data.

Analysis and Reporting

For profitability analysis, the Real-Time operators track bids and asks in WebTrader to identify margins. WebTrader is the primary source of reporting and data warehousing. Reporting and financials are very manual and ad-hoc in nature. LAC does not operate a shadow settlements system. LAC does not use a separate data warehouse to collect information from disparate systems to perform automated reporting or trending analysis.

Load Forecast Technologies

No external vendors provide weather forecast data or proprietary load forecasts as an input into the LAC load forecast.

Outage Management

LAC does not currently use outage management software to track and communicate generation or transmission outages. The Real-Time Operators and the Merchant function monitors SCADA data from the EMS for odd fluctuations in generation. The Real-Time Operations personnel monitor SCADA data for transmission fluctuations. The PSO accounts for planned generation outages in the Day-Ahead timeframe.

Figure 7: Technology Overview

Technical Function	Technology Solution
Deal Management	OATI WebTrader
Energy Schedule Management	OATI E-Tagging
ATC/TTC Management	OATI WebOASIS
Meter Data Management	SCADA System
Generation Parameters	SCADA System
Load Forecasting	None
Weather Forecasting	None
Post Analysis	None
Variable Energy Resource (VER) Forecasting	None
Settlements	None
Outage Management	None – Manual Monitoring
Meter Data Management & Acquisition (MDMA)	None

Organized Market Participation

LAC does not participate in CAISO markets such as the MRTU intertie bidding market, nor other Western markets. LAC does not interface with CAISO for Reliability Coordination (RC) purposes because RC West serves as the reliability coordinator for the PNM BA, and LAC is inside the PNM BA. LAC and CAISO do not perform data exchange.

Third Party Merchant Operations – Bilateral Contract Provider

The Pre-Schedule Office is open weekdays, 7:30am until 5pm. The full day-ahead workflow is completed in this time horizon, as well as any near-term trading. LAC Real-Time Operations operates 24 x 7 x 365 including real-time merchant activities.

LAC partners with bilateral contracting providers such as Tenaska Power Services to procure Day-Ahead energy power marketing based on predicted needs (T-120 to T-75, where T is the start of the trade hour). Third party providers use their extensive networks to provide LAC access to additional trading counterparties to find lower cost energy deals. Incremental energy from bilateral contract providers is tagged by that entity on behalf of LAC. Providers charge LAC transaction fees for their services.

3.1.3 System Operations As-Is Business Process

System Operations are performed by the 24x7 Real-Time Operator. The LAC Real-Time Operator performs three main functions:

1. Generation Dispatch
2. Real-Time Merchant Functions
3. Limited Transmission Operations functions

Note: PNM acts as the Balancing Area Authority, thus most transmission operations and some generation & load balancing occur with PNM rather than within LAC. The RC West acts as the reliability coordinator for LAC's area so most contingency analysis, power flow, limit management, and planning happens at CAISO.

Generation Dispatch

Generation dispatch is performed against those plants which are controllable (El Vado Hydro, Abiquiu Hydro, Laramie River Station, LANL Combustion Turbine). The Real-Time Operator uses the generation schedule as a guidepost to perform dispatch. The Real-Time Operator can send SCADA signals via the EMS to ramp up or ramp down El Vado Hydro, Abiquiu Hydro, and Laramie River Station to an appropriate setpoint. The operator can call LANL to request an adjustment to the lab's combustion turbine. PNM generation operators can ramp up and down LAC's San Juan share as requested in the day-ahead and next hour.

Real-Time Merchant Function

The Real-Time Operator performs real-time market functions such as:

- Tagging for near-hour energy schedules, including adjustments and curtailments
- ATF energy checkouts on an hourly basisShort-term load forecast adjustments

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3.2 Transmission Operations

3.2.1 Transmission Operations As-Is Business Process

LAC and LANL are not a Balancing Authority Area, but do perform some transmission operations functions including:

- Network Model Management for the LANL/LAC system, and provide model input to PNM
    - Includes single line diagramming
- Process revenue quality meter data and perform Verification, Estimation, and Editing (VEE) functions
- Perform meter upgrades for LAC-owned meters

PNM and RC West handle most transmission functions for LAC. The following typical business processes are covered by PNM and RC West:

- Network Model Management
    - Includes single line diagramming for the bulk electric system
- BA Load Forecasting
- Perform meter upgrades for PNM-owned meters
- Perform Tag Authority functions such as tag approval
- Manage transfer capability
- Process revenue quality meter data and perform Verification, Estimation, and Editing (VEE) functions for bulk electric system
- Manage transmission billing and third-party transmission customer billing
- Manage open access transmission rights on the OASIS
- Collect historical BAA Load
- Manage BAA-level transmission and generation outages
- Manage non-conforming loads

The Real-Time Operator performs real-time transmission management such as:

- Coordinate and communication of transmission and generation outages
- Manage contingency events for reliability coordination (via PNM) such as load shedding when required, etc.
- Communicate with the reliability coordinator around emergency conditions
- Monitor facilities, power flow, and general status of the grid
- Monitor the energy management system (EMS) for reliable operation

3.3 Information Technology

3.3.1 Information Technology As-Is Business Process

Information technology as it relates to generation & transmission operations, system operations, and merchant functions can be divided into two major LAC departments, namely:

1. Energy Management System (EMS)
2. Merchant and System Operations

The Los Alamos National Laboratory (LANL) manages the EMS & SCADA communications. EMS and data acquisition components include:

- EMS (OSI Monarch) at primary and backup center
- RTUs at all LANL substations

The LAC Merchant & System Operations group manages all other trading and energy accounting related software including:

- Energy Trading software
- Energy Scheduling Software
- Path Management
- Load Forecasting
- RTUs at the hydro units including El Vado and Abiquiu

The LAC Merchant and System Operations team is responsible for all IT functions in their organization. The team performs system administration, WebTrader programming, system integration (if any), and reporting and analysis IT support. A separate IT team (Information Management help desk) handles general desktop support. As issues come up the team responds in an "everyone pitches in", ad hoc manner.

3.4 Generation

3.4.1 Generation Asset Overview

The LAC system operates a set of resources to meet about 75% of native load. The following table details high-level resource characteristics:

Figure 8: Generation Asset Overview

Resource Name	LANL CT	San Juan 4 (Share)	El Vado	Abiquiu 1, 2, 3	Laramie River	Glen Canyon CRSP Allocation
Ownership	Los Alamos National Lab	7.2% Partial Ownership	Los Alamos County	Los Alamos County	Basin Electric Power Coop	WAPA
PPA	No	No	No	No	Yes	Yes (Allocation)
AGC Control	No, phone call-based control	Yes, with PNM. Can be called to adjust SJ4 share	No, rampable via EMS controls	No, rampable via EMS controls	Yes to overall plant, rampable via EMS	Yes, fixed allocation on a monthly basis
Physical Location	Los Alamos National Lab	Waterflow, NM	Rio Arriba County, NM	Rio Arriba County, NM	Platt County, WY	Lake Powell, UT
Capability	20 MW for 5k hours/year	507 MW (36.0 MW LAC share)	8.8 MW	17 MW	10MW share	11 MW entitlement
Plant Operators on Site	Yes	Yes	Partial - week days, 40 hours/week	Partial - week days, 40 hours/week	Yes	Yes
Fuel Type	Natural Gas	Coal	Run of River Hydro	Run of River Hydro	Coal	Large Hydro
Multi-Stage Generator	No	Yes	No	No	Yes	No
EMS View of Plant Attributes	Yes	Yes	Yes	Yes	Yes	No
Operator	Los Alamos National Lab	PNM	Los Alamos County	Los Alamos County	Basin Electric	WALC
Notes		Retirement in June 2022	In TriState sub-BA, Tri State	In TriState sub-BA, Tri State	Long-Term PPA for life of	

			manages meters	manages meters	plant through 2040	

In addition to the set of resources above, LAC has 1 MW of utility grade solar on the load side (behind the meter). 800 kW of rooftop solar exists in the LAC footprint.

3.4.2 Planned Generation Assets (Future Horizon)

LAC is planning for new resources to interconnect to the grid.

Figure 9: Planned Generation Assets

Resource Name	(Additional) LANL CT	LANL Solar	Firm PPA
Owner	Los Alamos National Lab	TBD	Uniper
Integration Schedule	October 2024	2023	Spring 2022
Capability	20 MW	10 MW	15 MW
Fuel Type	Natural Gas	Solar	Wind, Solar, Firmed by merchant
Notes	Distribution system integration	Behind the meter	PNM System

3.5 Energy Accounting & Settlements

LAC has a small peak load and a handful of generation resources. Energy Accounting and Settlements require less rigor and oversight compared to many larger utilities.

3.5.1 Metering

The LAC Pre-Schedule Office (PSO) has visibility into analog and accumulator meters that are made available from EMS via SCADA data. Polling occurs at 15-minute intervals, and then integrated to an hourly value.

LAC currently has visibility to their meters via ICCP and can access billing quality meters via Tri-State's MV90 system. Tri-State has documented the accuracy and capabilities of the source meters, and LAC attests the calibration of the meters. LAC and PNM are working together to review the meter data quality, accuracy, capabilities.

The hydro units (El Vado and Abiquiu) meters are located at the Spills and Coyote substations respectively. Line losses are accounted for in the meter calibration.

3.5.2 Energy Accounting

The PSO performs after-the-fact (ATF) checkouts with adjacents up to 50 minutes after the trade hour. Analog and Accumulator meter data collected from the Energy Management System (EMS) are used to perform hourly checkouts. There is no daily or weekly ATF process. ATF Monthly workflows are performed by a combination of personnel in the PSO. No revenue quality meters are currently used for energy accounting. LAC does not operate a meter data management and acquisition (MDMA) system such as MV90.

3.5.3 Energy Settlements

Energy Settlements is performed based on views of the analog and accumulator meters and the energy tags. LAC does not employ a formal energy settlements software system today. Currently LAC does not use formal methods of energy settlements validation such as using complex spreadsheets. They do not formally shadow the PNM bill they receive for NITS service. They do not shadow Schedule 1 – 6, Redispatch Service, or WAPA Hydro Allocation.

3.6 Regulatory and Compliance

3.6.1 Regulatory and Compliance

LAC does not currently employ an OATT. There is a NITS service agreement in place between LAC and PNM. All LAC-internal transmission is owned by the LANL. LAC is non-FERC jurisdictional. The county's Department of Public Utilities performs a rate study to determine electricity costs. The Public Utility board approves rate increases as required and forwards to county council for adoption.

4. EIM Participation Approach

The Western EIM employs absolute separation of Participating Resources (PR) and Non-Participating Resources (NPR) in the commercial model. This bifurcation requires the EIM entrant to determine whether they wish for their resource(s) to participate or not participate in the market. Electing to include participating resource(s) in the market requires substantial adherence to PR requirements, business process, software, hardware, market modeling, standards of conduct, and human resource considerations. Generation resource participation capabilities must also be examined to decide on a participation approach.

The EIM Participation Approach section provides the following:

- Participating and Non-Participating resource definitions and differences
- Participating and Non-Participating resource requirements and business process
- LAC gaps to integrate PR resources in terms of automated generation control, bid submittal, human resources, market settlements, IT support capabilities, and metering
- A review of each generation resource, their capability of becoming a participating resource, and gaps that require resolution to allow for participation (where possible)
- PR/NPR recommendation

4.1 Participating and Non-Participating Resources Defined

The Western EIM allows the market participant to select, on a per-resource basis, participation in the market. By default, all non-participating resources (NPRs) are registered under the participant's EIM Entity Scheduling Coordinator (EESC). The EESC performs most EIM functions for reliability, balancing, and financial settlements. If any resource is deemed a PR, the market participant must register as a Participating Resource Scheduling Coordinator (PRSC), which is the commercial entity who acts on behalf PR(s). All PRs are then managed via the PRSC, including PR modeling (network and commercial), primary base schedule management, management of offers into the market (bidding), and PR financial settlement. The table below defines PRs and NPRs based on relevant attributes:

Figure 10: PR and NPR Processes defined

Attribute	NPR	PR
Definition	A generation resource that is used to meet entity's forecasted demand requirements & to achieve pre-hour power balance	A generation resource that is used to meet entity's forecasted demand requirements & to achieve pre-hour power balance. Resource makes itself available to the market for economic dispatch. <u>Submits bids (priced range of operation) to convey dispatch availability</u>

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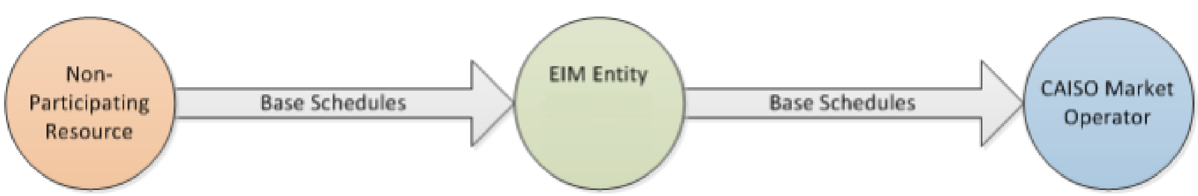
Scheduling Coordinator	EIM Entity Scheduling Coordinator (EESC)	Participating Resource Scheduling Coordinator (PRSC). If one or more resource(s) are deemed participating, the PRSC must be created and managed.
Accountability	Held accountable to deliver power according to the generation schedule (base schedule)	Held accountable to deliver power according to the base schedule plus bids
Market Signals	Market will send DOTs to mimic base schedule	Market will send Dispatch Operating Targets (DOTs) within bid range (lower or higher than base schedule)
Imbalance Mechanics	Deviations from base schedule result in imbalance charges; based on collection of accurate resource meter data	Deviations from DOTs result in imbalance charges; based on collection of accurate resource meter data
Modeling	Required to register general operating characteristics in the market model (GRDT/IRDT)	Required to register detailed operating characteristics in the market model (GRDT)
Settlements	Occurs with EESC	Occurs with PRSC. Requires analysis of both EESC and PRSC to determine overall cost and benefit

The operations business process diagrams below demonstrate the added operational complexity of integrating Participating Resources into the market. In addition to the Non-Participating Resource activities (base schedule management), the Participating Resource must submit bids to both the EIM Entity and the Participating Resource Scheduling Coordinator. The Participating Resource will receive commitment instructions (startup, shutdown, transition) up to every 15 minutes, and Dispatch Operating Targets (DOTs) every 5 minutes. The PR must be able to adhere to these instructions. Theoretically up to 96 commitment instructions can be sent each day, per participating resource. Each resource will receive 288 dispatch instructions per day.

Figure 11: PR and NPR Operations Business Process Workflow Overview



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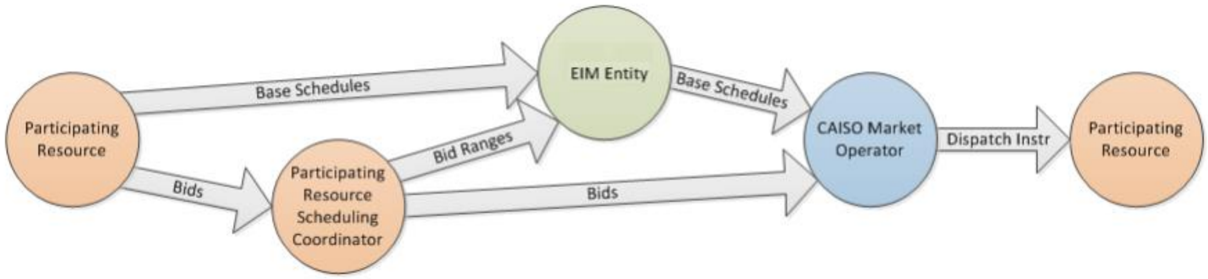


4.2 Participating and Non-Participating Resource Requirements

PRs and NPRs have major distinct requirements in terms of legal and contract, Meter Data Management, Bid Submittal, Automated Generation Control, Cost Modeling and Market Mitigation, Settlements, and Model Management.

Figure 11: PR and NPR Requirements Overview

Functional Area	NPR	PR
Legal & Contract	General	Per-resource contract required. Additional PRSC registration required.
Meter Time Granularity	60, 15, or 5-minute	15 or 5-minute minimum
Meter Data Accuracy	0.3% for CTs / PTs, and 0.2% for meter	0.3% for CTs / PTs, and 0.2% for meter
Bid Submittal	N/A	Bid calculation, submission required up to hourly by T-75 (Pre-hour)
Automated Generation Control	Not Required	Required; Must adhere to 5-min dispatches within bid range. Must adhere to startup/shutdown instructions
DEBs / MMAs / Fuel Regions	N/A	Definition required for Mitigation Process
Charge Codes and Shadow Settlements	Charge codes from EIM Entity (BA); Shadow settlements recommended	Charge codes from EIM Entity (BA) and CAISO; Shadow settlements required
Model / Market Data Management	Submitted by EESC (Physical Characteristics)	Submitted by PRSC (Physical and Commercial Characteristics)

ATTACHMENT B

4.2.1 Legal and Contract

NPRs are registered under the EIM Entity Scheduling Coordinator (EESC). Any resource deemed a PR must be registered under the Participating Resource Scheduling Coordinator (PRSC). If a single PR is defined, the PRSC must be implemented. Each PR requires its own contract to be submitted to the Western EIM and must be approved for market inclusion.

4.2.2 Meter Data Management

PR resources have more stringent meter data granularity requirements than NPRs. NPRs can be polled in 60, 15, or 5-minute intervals, at the most granular level the meter is capable of reporting. PRs must be polled at a 15- or 5-minute interval, at the most granular level the meter is capable of reporting. Most market entrants configure PR metering at 5-minute intervals to match the granularity of the real-time market. Selecting a resource as a PR may require meter reprogramming, physical upgrades, and meter data communication costs, which could increase EIM implementation capital costs.

Both PR and NPR require revenue quality meters with accuracy requirements as follows:

- For CTs and PTs: 0.3%
- For the generation meter: 0.2%

4.2.3 Bid Submittal

Participating Resources

PRs may submit bids to convey the resources' capabilities and costs to the market. A bid is a set of price and MW pairs and hourly costs that relay to the market the generator's ability to be economically committed and dispatched. A bid inherently reflects the resource's range of operation. A bid may be calculated and submitted up to every hour based on variable inputs such as fuel cost, actual output levels, startup and minimum generation costs, operating constraints etc. Bids must be submitted by 75 minutes prior to the operating hour.

Non-Participating Resources

NPRs do not require bid submittal because their operating level and configuration are generally not altered by the market for economic dispatch, rather their base schedules are echoed back to them as output signals. NPRs follow their generation schedule and protected limits for ancillary services.

4.2.4 Automated Generation Control

Automated Generation Control (AGC) is a module that adjusts the power output of multiple generators at different power plants in response to a change in load. In the EIM, the market operator sends Dispatch Operating Targets (DOTs) and commitment instructions to the AGC module and directs generation power output based on these instructions.

Participating Resources

Generators elected as PRs and plan to bid into the market must integrate 5-minute DOTs into their AGC system to dispatch resources. They may elect to allow DOTs to send commitment instructions to start, stop, and transition generators, or may perform unit commitments by monitoring an EIM screen that alerts grid and plant operators to directives. For Participating Resources, the DOT will consist of a scheduled component along with a supplemental component. The net of scheduled and supplemental values will be the unit output value. The AGC may still continue to perform regulation functions while honoring market dispatch.

4.2.5 Market Mitigation Cost Components

If LAC elects to integrate PRs, they must provide reference generator costing data to the EIM. Data such as Default Energy Bids (DEBs), Major Maintenance Adders (MMA), and Fuel regions must be defined for each resource.

A DEB is a mitigation measure that mirrors competitive outcomes in situations where participants may exhibit market power. It attempts to approximate the true cost of production and compensate the resource (and the market) for that amount rather the bid amount, which the market sees as inflated.

An MMA is a mechanism to capture variable generator costs that occur on an irregular basis, such as an overhaul on a generator or generator components. This provides the participant a way to capture costs that are otherwise not easily reflected in their bids.

4.2.6 Charge Codes

Non-Participating Resources

NPRs and tagged intertie resources are settled by the Balancing Area via the EIM Entity. Since LAC is embedded in the PNM BA, they will be settled via EIM charge code allocation by PNM. A shadow settlements system is a “very nice to have” but not required. Without a shadow settlements system, the analyst must sift through many invoices and must manually compare multiple settlements dates and trade dates. The volume of data is great, and includes the charge components (bill determinants, prices, global metrics) that make up the calculations. This voluminous data would need to be downloaded, stored, and archived. For any given trade date, resettlements can occur up to 18 months into the future.

If a shadow settlements system is not implemented, any existing spreadsheets will need to be updated for EIM participation thus increasing complexity.

Participating Resources

Participating Resources are settled via the PRSC. PRSC settlements will be performed by CAISO. If LAC elects to integrate PRs, they will need to be capable of consuming settlement statements from CAISO (in addition to consuming EIM charge code allocations from PNM for NPRs). A shadow settlement system is required to ensure CAISO financial settlements calculations are accurate and LAC is being charged and credited precisely.

4.3 Participating Resource Capability Evaluation and Gaps

In reviewing LAC's As-Is state and comparing it to PR requirements, Utilicast has developed a PR Capability Evaluation and identified gaps that must be overcome in order to successfully bid into the market, operate PR resources, perform related settlements validation, and implement appropriate metering. We have assigned a "PR Impact" value (High, Medium, Low) to illustrate the level of effort and complexity in overcoming barriers.

Figure 12: LAC PR Capability Evaluation and Gaps Overview

Capabilities	Evaluation	PR Impact	PR Integration Gaps
AGC	3 generators on AGC, not operated by LAC.	**High**	Requires extensive hardware upgrades to any LAC owned/operated generator deemed PR
Bid Submittal	New; Bid submittal system or extensive business process upgrade required.	**High**	Additional cost of PR system procurement, configuration, integration, training. PR Business process highly impactful
Human Resources	PR business process requires dedicated staff, up to 24 x 7 x 365	**High**	0.25 – 0.5 additional staff required for PR option. SOC standards may require more rigor
Settlements	Requires registration as PRSC, 16 additional charge codes.	**Medium**	Shadow Settlements system required. Post Analysis recommended
IT Support Capabilities	PR integration requires additional systems and workflows	**Medium**	Additional system monitoring required. PR requires additional modules
Metering	PNM and Tri-State will reprogram / update most LAC meters as a part of EIM upgrade.	**Low**	Meter Data Management system required. Upgrades already required for EIM, higher meter precision for PRs attainable

4.3.1 Automated Generation Control

Currently AGC exists on three units LAC uses to meet their demand namely, their share of Laramie River Station, San Juan 4, and Glen Canyon. None of these units are operated by LAC. These resources need to consume CAISO market commitment and dispatch instructions.

The remaining resources (LANL CT, El Vado, Abiquiu) are not on AGC control. For most generators there is a major barrier to entry in terms of AGC because they are either not on AGC control or it would be difficult to coordinate getting AGC-controlled resources to consume CAISO signals.

To place these resources on AGC and to integrate CAISO signals, LAC would need to work with each plant operator to add AGC software, CAISO market adapters to consume payloads. CAISO ADS computer terminals would be required at each plant. Additionally, Operators would need training to use the new software and CAISO screens. A plant operator would need to be physically present during times when the units are bid into market. Constant coordination between LAC Real-Time Operations and plant operators would be required.

3.3.1.1. ADS Integration Requirements

If LAC wishes to integrate AGC dispatch and the consumption of CAISO ADS instructions for Participating Resource integration, the following EMS requirements would need to be addressed and implemented:

- LAC would receive from CAISO, dispatch operation targets for all generating units registered with CAISO, and energy imbalance adjustment to NSI.
- CAISO ADS data would be provided with CAISO Resource ID plant/unit names. LAC must convert CAISO Resource ID names to EMS Plant/Unit names.
    - CAISO Resource ID names should be available to RT Operators in the EMS application.
- The EMS would calculate the desired generation for control area and units based on DOTs and NSI adjustments received from CAISO.
- An ability to switch between EIM market operation and conventional non-market mode of operation of AGC would be required.
- AGC would process only units defined in AGC data base, though DOTs are validated, DOT values are further processed for ramping the units only when the unit is participating in EIM.
- A new area control mode – EIM Market Mode should be added. In the EIM Market control mode:
    - Adjustment to interchange schedules due to energy Imbalance transfers would be included in determining the required regulation.
    - Generation dispatch instructions (for generators participating in the EIM market) would be based on the DOT values received from CAISO.
- When a generation resource is not participating in the EIM Market there is no change to existing EMS dispatch. The EMS should dispatch the resource using the existing functionality and processes. That said, if a non-Participating Resource is manually dispatched in the market, the dispatch obviously needs to be reflected in the EMS and sent to the resource.

- Regulation is allowed on all units that are defined on AGC Control. The EMS should continue to maintain AGC adjustments incorporating the 5-min DOTs and NSI adjustments provided by the ISO.
- DOTs received for generation resources and net interchange adjustments would be validated and if the validation fails, alarm messages could be generated.
    - DOT must fall within Gen Min/Max parameters.
    - Movement between two DOTs must not exceed a Gen's 5-min ramp rate.
    - Identify DOT instructions and NSI adjustments which are old or stale.

4.3.2 Bid Submittal

Currently LAC does not participate in an organized market and does not employ any local joint dispatch agreements within their BA, thus the process and implementation of bidding into a market is a new concept and effort. LAC could bid into the EIM either by using CAISO's SIBR platform to manually submit bids, or commission vendor software to automate the submission of bids. Manual entry is time consuming, error prone, and requires constant attention.

Vendor software-based bid submission is the recommended approach. The software allows the merchant to enter multi-segment price/MW pairs and daily bid components in an organized manner. When fuel prices or other bid calculation inputs change, the software can recalculate and resubmit economic bids. When outages occur, the software can easily cancel bids on outaged resources. Bidding history is retained for after-the-fact analysis. Bidding strategies can be customized to increase market sales and purchases.

4.3.3 Human Resources

In addition to base schedule submission, bids for PRs can be calculated and submitted up to every hour, 75 minutes prior to the trading hour. Most EIM market participants employ a 24x7x365 trading floor that may update bids based on real-time operating conditions such as plant derates, outages, fuel price changes, market prices, self-schedules, etc. The PRSC is generally operated by the merchant, and the merchant is at least partially responsible for settlements validation and post analysis functions. The Western EIM follows strict SOC standards to separate merchant activity and data from the EIM entity. Those standards may require certain work operational functions to be performed by the merchant in case of PR integration.

It is estimated that 0.25 to 0.5 additional resources may be required to perform PRSC functions if participating resources are integrated.

4.3.4 Settlements

Market settlements for PRs reside on the PRSC side. If participating resource participation is elected, the PRSC will receive their own settlement statement (in addition to the BA EIM charge code allocations) from CAISO. The statement will need to be evaluated for accuracy. Settlement statements and invoices are easier to analyze using vendor software; thus, a shadow settlements system is required. It may also be useful to employ a Post Analysis system to run "what-if" scenarios, and to compare actual operation with "perfect" operation.

4.4 PR Generation Evaluation and Gaps

In this section each resource in the LAC fleet is evaluated for their operating characteristics, PR capability, and PR integration impact. Operating characteristics evaluated include:

- Nameplate capability (MWs)
- As-Is Dispatchability via AGC
- Ownership and plant operator characteristics
- Location (in EIM Entity area or non-EIM Entity area)
- Operating Restrictions
- Estimated *operating capability factor* (percent of time the resource is capable of being dispatched in the market without restrictions)
- As-Is and To-Be Integration in markets, especially the Western EIM
- Expected longevity of the generating unit or contracted service life

PR capability is rated as:

- **High** – no major hurdles for the generator to become a Participating Resource, already a Participating Resource in another BA and connected to CAISO's Automated Dispatch System (ADS). High operating capability factor
- **Medium** – few major hurdles, requires CAISO ADS integration. Medium to high operating capability factor
- **Low** - major hurdles such as requiring AGC on plant, high cost resource, limited plant operator availability, operated by an entity that does not participate in an organized market
- **No** – The unit is not capable of becoming a Participating Resource, even with substantial investment

Figure 13: LAC PR Resource Capacity Overview

Resource (Max Output)	PR Characteristics	PR Capability	PR Integration Impact
Glen Canyon 11 MW	PPA, On AGC control via allocation. Dispatchable	**Medium**	Requires dynamic tag and CAISO ADS integration

San Juan 4 (Share) 36 MW	On AGC Control. PR-capable, but retires in June 2022	**Medium**	Could integrate as PR under PNM, but would only participate until retirement
LANL CT 20 MW	No AGC control, Only capable of participating 57% of the time. LAC/LANL required to upgrade meters and MDMA	**Low / No**	Requires AGC hardware and EMS upgrades to control resource. High cost resource.
El Vado 8.8 MW	No AGC control, Plant operators available 24% of the time. Environmental restrictions.	**Low**	Requires AGC hardware and EMS upgrades to control resource. Plant operators required onsite.
Abiquiu 17 MW	No AGC control, Plant operators available 24% of the time. Environmental restrictions.	**Low**	Requires AGC hardware and EMS upgrades to control resource. Plant operators required onsite.
Laramie River (Share) 10 MW	PPA, AGC control at the plant, but not by LAC. Located in Non-EIM Entity area	**Low**	Requires plant to accept DOTs

4.4.1 Glen Canyon

Glen Canyon is a PPA from WAPA DSW. There is a contractually arranged monthly allocation that must be utilized. The scheduling of the allocation is up to LAC, but the allocation must be utilized. These usage restrictions can require creative strategies to properly bid the resource into the market. The unit is currently on AGC control at WAPA DSW, but it does not currently consume market instructions via CAISO ADS. It is possible that WAPA DSW could become a part of the EIM footprint in the future and label this resource as a PR. A dynamic tag, Registered Tie, or Tie Generator modeling designation would be required to account for the energy schedule, requiring heavy modeling efforts for LAC, PNM, and CAISO. It is possible to integrate Glen Canyon as a Participating resource, but that would require the consumption of CAISO dispatch instructions and then the signal would need to move the share of the generator. Glen Canyon's PR capability is rated as MEDIUM.

4.4.2 San Juan 4 (Share)

San Juan 4 is operated by PNM who will join the Western EIM in April 2021. San Juan is already on AGC control, and PNM plans to integrate CAISO ADS dispatch signals into their EMS and therefore AGC to San

Juan 4 will be capable of market control. LAC owns a share of the resource and that share could be controlled by PNM and the market based on arrangements between LAC and PNM. PNM would need CAISO certificates that allow it to consume ADS instructions for the LAC share.

The planned retired for San Juan 4 is June 2022 so any LAC-based market participation is limited to that date. San Juan 4 share's PR capability is rated as MEDIUM.

4.4.3 LANL CT

The LANL combustion turbine, which is owned and operated by Los Alamos National Labs (a partner of Los Alamos County), is not on AGC control at this time. The resource is currently controlled via phone calls to the operator. For this resource to become a PR, it would need AGC control on the generator, and an EMS module capable of interpreting CAISO dispatch operating targets and dispatch operating points and feeding and massaging these market signals to create market-driven set points.

The resource is available to operate for up to 5,000 hours per year, which represents a 57% potential capacity factor. According to LAC experts, the resource has a high cost of operation, which may prevent it from getting dispatched often in the EIM as a PR. If it were to be deemed a PR, the meter must adhere to PR standards which include 5-minute granularity data, and the ability to send the meter data (up to 288 intervals per day) to CAISO for market settlements. LANL CT's PR capability is rated as LOW or NO based on its low PR capacity factor and the extensive AGC hardware and software requirements.

4.4.4 El Vado & Abiquiu

El Vado and Abiquiu are hydro generators owned and operated by the US Bureau of Reclamation and reside in the Tri-State Balancing Area. Tri-State owns and operates the meters. They are not on AGC control at this time but can be controlled via SCADA signals. For these resources to become PRs, they would need full AGC control on the generators, and an EMS module capable of interpreting CAISO dispatch operating targets and feeding and massaging these market signals to create market-driven set points.

Plant Operators are currently onsite weekdays for 40 hours. Generally, plant operators report and record derates, outages, ramp rate derates, and other plant conditions. Generation conditions are only reportable to the market during those 40 hours; thus, the biddable window is restricted to only those 40 hours. This represents a 24% potential capacity factor for these units. Additionally, there are environmental restrictions that could lower market availability further. El Vado and Abiquiu's PR capability are rates as LOW due to low PR capacity and extensive AGC hardware and software requirements.

4.4.5 Laramie River (Share)

The Laramie River share is a long-term PPA (through 2040) owned and operated by Basin Electric, a non-EIM BA. The share is on AGC control, but it does not currently consume EIM market instructions via CAISO ADS. Basin Electric Power Cooperative is not in the Western EIM and unlikely to join the market. It is unlikely that Laramie River could be integrated as a Participating resource because it would require Basin Electric to consume CAISO dispatch instructions and then the signal would need to move the share of the generator. Glen Canyon's PR capability is rated as LOW.

ATTACHMENT B

4.5 Participation Recommendation

In reviewing the participating resource requirements against LAC's system and business process status and generating resource capabilities, **Utilicast recommends LAC integrate all resources as Non-Participating**. Relevant factors include:

- Low Participating Resource capacity factor
- Establishing resource fixed and incremental costs, adders, default energy bids is a large effort
- High impact to PSO, Real-Time Operations, and IT business processes
- Registration as a PRSC creates additional legal, settlements, and business overhead
- PR Market settlement requires greater oversight and reconciliation
- PR integration requires incremental project capital expenditure

Note: Resource participation and the desire to become a Participating Resource Scheduling Coordinator (PRSC) need not be set in stone at the time of EIM Go-live. It is advantageous to decide on PR vs. NPR before implementing the capital project to take advantage of implementation synergies, but the decision may be reevaluated later again when greater market experience is achieved and/or a new generation resource mix is integrated.

5. EIM Participation Gap Assessment

The EIM Gap Assessment section identifies by functional area the gap in technology, process, or people that needs to be addressed in order to participate in the Western EIM. The assessment compares LAC's *Current State* to EIM requirements to derive the *Gaps for EIM Participation*. Each identified gap is an input into the cost assessment.

The gap assessment categorized into the following sections:

- Assumptions
- System Operations / Entity
- Merchant Operations and Resource Planning
- EIM Settlements and Invoicing
- Outage Management
- Load Forecasting
- Training and Testing
- EIM Program Management

5.1 Assumptions

The following assumptions about LAC's participation are made based on information gathered and decisions made. These assumptions narrow the EIM requirements LAC must address in their EIM implementation, business process changes, and staffing.

1. **This Gap Assessment focuses on providing the "least cost" approach to market integration.** Options for greater market participation, more robust technology packages, higher quality financial settlements tracking and disputes, higher quality auditing, and process efficiency are downplayed in favor of a lower cost of integration and lower ongoing operations and maintenance costs.
2. **LAC is an embedded entity (sub-BA) inside the PNM Balancing Area. PNM generally acts as an agent for LAC** to:
   a. balance LAC's BA-level supply and demand in the real-time
   b. maintain and manage ancillary services such as spin, non-spin, regulation, voltage support for the BA, including LAC
   c. Participate in the Southwest Reserve Sharing Group (SRSG) and create a contingency reserve plan and manage in real-time the BA contingency reserve obligation and provide support to the group on behalf of LAC's share of the BA
   d. Comply with RC West requirements, perform most or all data exchange with RC West including forecasts, generation schedules, and contingency requirements
   e. Perform other BA balancing functions

f. Collect base schedules and forecasts from LAC for submission into the EIM on behalf of LAC
g. Post ATC for each interchange location on the PNM OASIS site

3. **LAC has elected to join the Western EIM with no Participating Resources (PRs), only modeling Non-Participating Resources (NPRs).** Choosing the Non-Participating Approach is a key assumption because PRs would add a very large scope and cost that is not represented in this assessment. The following PR requirements are NOT in scope:
   a. Participating Resource modeling and related bidding reference data management such as PR MMAs, PR DEBs, etc.
   b. Developing a Participating Resource Scheduling Coordinator (PRSC) agent to manage participating resource bidding, base scheduling, and market settlements
   c. Developing hourly bids (offers into the market) for economic commitment and dispatch
   d. Performing PR market settlements and collecting settlement statements and related data from the Western EIM
   e. Providing 5-minute meter data for PRs (can be lower granularity if needed)
4. **LAC can enter each hour with balanced base schedules to meet forecasted demand.** This can include intertie base schedules that represent purchases and sales to meet demand.
5. **The Western EIM will not provide a specific load forecast for LAC.** LAC will provide monthly load forecasts, and a 7-day rolling forecast updated daily, and will adhere to CAISO's *PNM BAA Load Forecast*.
6. **The quality, granularity, and accuracy of intra-tie meter data between LAC and PNM is managed by PNM.** Any EESC charge code sub-allocation is based on these PNM-measured intra-ties.

5.2 System Operations / Entity

The Western EIM is reliant on the member Balancing Authority Area (BAA) performing key roles in administering the market. PNM performs many of these functions on behalf of LAC and is therefore the representative "EIM Entity". LAC's current System Operations team is likely to endure a medium impact of EIM integration.

The EIM Entity (PNM) functions in EIM include Transmission Scheduling, global Generation and Interchange Base Schedule Creation, Generation and Interchange Base Schedule Sufficiency Test management, Managing global Generation and Transmission Outages and Availability Limits, submission of global 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.

The LAC System Operations functions in EIM will include LAC Generation Schedule (Base Schedule) creation and LAC generation outage management, and adherence to their generation plan.

5.2.1 Current State

System Operations is responsible for Generation Dispatch, Real-Time merchant functions, and limited Transmission Operations functions. System Operations adheres to a unit commitment plan that is developed by the merchant. Incremental changes are made to the plan as the operating day evolves. As energy requirements change, the System Operator performs incremental purchases in the hour(s) ahead of the trade hour. The team monitors for generation or transmission outages which impact the LAC sub-BA. Leading up to Operating Hour, System Operations processes eTags. Tags are submitted for all interchange transactions as well as for generation which sinks to load within the WAPA BA. At T-20, the final Net Scheduled Interchange for the BA is determined by System Operations.

LAC currently uses OATI WebTrader for energy scheduling and OATI WebTrader for deal capture.

Please refer to the System Operations As-Is Business Process section for more of the as-is state.

5.2.2 System Operations EIM Participation Gaps

4.2.2.1. Base Schedule Management

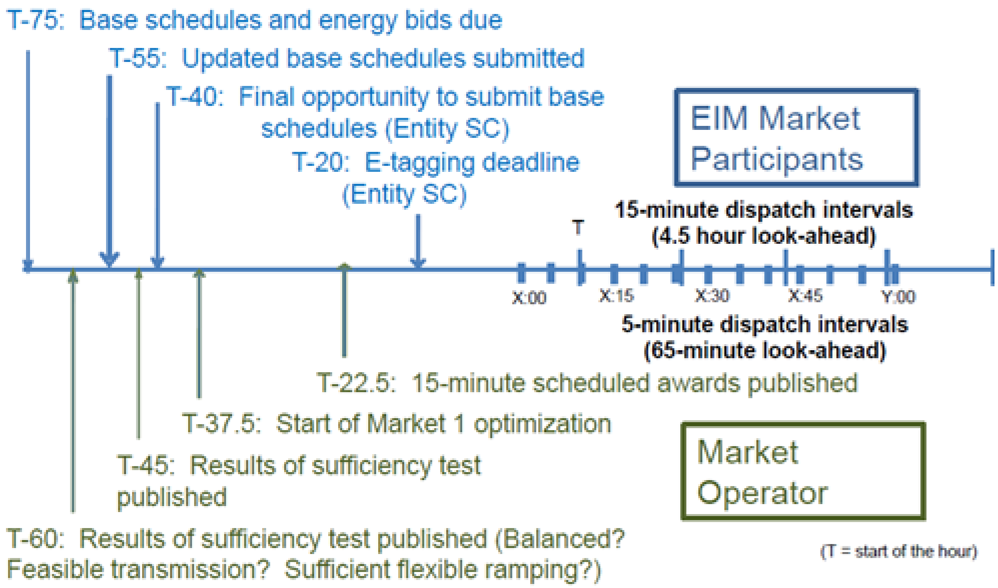
Business Process

LAC real-time merchant functions are handled by the System Operations group. Prior to the T-75 Base Schedule submission deadline, it is expected that LAC System Operations will create and submit LAC Generation Base Schedules for all LAC owned or managed resources (NPRs) to PNM.

Following T-75, the CAISO will run four sufficiency tests and provide the results. It is anticipated that LAC System Operations will adjust Generation Base Schedules and submit them by T-57 (a deadline which will be set by PNM in the OATT) in preparation for the T-55 sufficiency tests. Similarly, the EIM Entity (PNM) will adjust and submit Interchange Base Schedules to BSAP for all interchange points by T-55. **Note**: LAC will need to adjust their tagging deadline from T-20 to T-57.5 or earlier to align with PNM's requirement to calculate and submit interchange base schedules.

Following T-55, the CAISO will again run the four sufficiency tests and provide the results. At this point, LAC system operations will be locked out base schedule submissions to PNM and it is PNM'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 LAC (e.g. by phone) if Generation Base Schedule require adjustments, but this is not required by EIM. Following the T-40 submission to BSAP, Base Schedules are fixed for the purposes of settlements.

Figure 14: Pre-Hour Western EIM Timeline



The EIM Entity (PNM) will be responsible for integrating LAC's energy schedules into interchange base schedules to represent their purchases and sales. The Entity will be responsible for calculating and submitting Real-Time Schedule Interchange (RTSI) to CAISO on behalf of LAC. The EIM Entity will continue to process Tags up to T-20 minutes which is after the conclusion of the base schedule management process. Any tags that arrive between T-40 and T-20 will be considered "Late Tags" and will be categorized as "Ghost" schedules.

Gaps for EIM Participation

LAC must submit hourly generation base schedules for each managed resource. Generation schedules are represented by energy schedules for most resources. The two hydro resources (El Vado & Abiquiu) are currently tagged as a single element and will need to be split into two schedules.

All generators are required to submit a base schedule. They may be addressed in the following manner:

- **LANL CT**: The LANL CT generation schedule is known well in advance and the resource plan is generally followed. There are two options for generating a LANL CT Base schedule
    - 1. Use the PNM-provided PCI User Interface to manually enter hourly generation base schedules
    - 2. Commission OATI to create an XML interface (EIDE) to send the data to PNM's PCI system from WebTrader
    - 3. Work with PNM to create an internal tag (same POR / POD) that represents the energy schedule
- **El Vado & Abiquiu**: The single tag that represents El Vado and Abiquiu will need to be separated into two tags representing each resource. The tags will represent the energy schedule. PNM will convert the tags into base schedules

- **San Juan 4 Share**: PNM already calculates and knows the LAC share volume in any given hour. As long as the tag is implemented by T-57.5, the share will be counted in the total San Juan base schedule submission to CAISO.
- **Laramie River Station & Glen Canyon:** Tags represent the injection of MWs from these resources into the LAC footprint. PNM already accounts for this in their intertie base schedule calculations and NSI.

It is expected that the System Operations can add base schedule submission to their scope of work without increasing headcount. It is likely to add less than one hour per day of additional work.

4.2.2.2. Real-Time Interchange and Limit Management

Business Process

On an on-going basis, the EIM Entity (PNM) will, on behalf of LAC, calculate and provide Real-Time Schedule Interchange (RTSI) to CAISO BAAOP for use in the Real-Time Market (RTM). RTSI is calculated on a 5-minute granularity and is submitted every 5-minutes for a rolling 5-hour window. RTSI is ramped to account for schedule changes during and between hours. RTSI must also be updated after the fact with actual values.

LAC is responsible for updating energy schedules for interchange adjustments and curtailments that may occur on their paths. Interchange curtailments will be immediately communicated to the market and incorporated into the next market optimization run.

Prior to EIM participation, the EIM Entity (PNM) will, on behalf of LAC, calculate and provide an ETSR Limit for each defined ETSR, including any market transactions between the LAC sub-BA and EIM participants and CAISO.

Gaps for EIM Participation

LAC does not post path limits to OASIS thus there is no EIM participation impact.

4.2.2.3. Dispatch and Real-Time Operations

Business Process

CAISO provides dispatch instructions to Participating and Non-Participating resources in advance of the Operating Interval via their Automated Dispatch System (ADS). 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 for Participating Resources. 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 Dispatch Operating Targets (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 limited by an outage, and rarely dispatched to deploy Available Balancing Capacity (ABC) when a market infeasibility occurs. CAISO will generally echo back NPR generation base schedules via the resource DOT.

Conventionally only Participating Resources are subject to dispatch instructions and on AGC to automatically respond to DOT changes.

Gaps for EIM Participation

LAC has elected to only integrate Non-Participating Resources and are thus generally exempt from following commitment instructions and DOT movement away from the base schedule. Market controlled EMS/AGC integration and adherence is not required for LAC.

LAC is responsible for adhering to each NPR generation base schedule. It may be beneficial to monitor NPR DOTs via the CAISO ADS User Interface to manage the following use cases:

- Ensure CAISO DOTs properly align with generation base schedule
- ABC is deployed on LAC NPRs
- When a forced outage occurs and there is a need to true-up DOTs to avoid imbalance charges
- If PNM blocks a DOT on a LAC resource (will never happen or very rare for NPRs)
- If PNM issues a manual dispatch on a LAC resource (will never happen or very rare for NPRs)

It is recommended that LAC work with PNM to set up an instance of the ADS user interface in the System Operations area. The real-time operator should loosely monitor NPR DOTs to ensure that the base schedule and the instructions align to reduce imbalance charges.

The adherence to Dispatch Operating Targets and ADS system monitoring can be built into the existing Real-Time Operations business process. No additional headcount will be required to perform these tasks.

5.3 Merchant Operations and Resource Planning

LAC System Operations handles all real-time merchant functions (will include T-75 base schedule submission) therefore the majority of pre-hour EIM responsibility lies with this team. Merchant Operations will handle Day-Ahead and short-term EIM responsibilities such as management of physical and economic parameters of generation resources and collection of market awards.

5.3.1 Current State

The merchant function as part of the Pre-Schedule Office currently performs the following EIM-relevant high-level functions:

- Monthly load forecasting
- Generation forecasting to PNM on a Day-Ahead basis

- Bilateral trading (mostly purchases) to meet long-term and short-term energy needs
- After-the-fact energy accounting
- Managing the use of existing transmission rights and purchasing of additional transmission rights as needed.

The PSO uses spreadsheets to determine optimal scheduling and load servicing in the short- and long-term. Bilateral trades are performed with counterparties and via third-party providers. The PSO creates hourly energy schedules in the OATI webTrader system.

Please refer to the Merchant Operations As-Is Business Process for more of the as-is state.

5.3.2 Merchant Operations EIM Participation Gaps

In EIM, the market optimizes the short-term commitment and dispatch of all EIM Generation to serve all EIM Load. This includes dispatch of LAC NPR generation as well as that of all Participating Resources in PNM and other EIM BAAs, subject to the Dynamic ETSR Transfer capability and physical constraints.

4.3.2.1. Model Data Management

The economic information provided to EIM for optimization is supplied by Merchant Operations. The first step is to define the Generation Resource Data Template (GRDT) which establishes the base physical properties of all LAC Resources. This effort must be coordinated with Network Modeling, System Operations, Outage Management and Metering to ensure consistency of information. This will include details on the ramping, min, max, fuel type, and many other characteristics and may include heat rate information. Once defined, a process should be created to periodically (e.g. annual) review and refresh the information, file updates with CAISO to reflect updated modeling parameters. Additionally, this process will apply to each new generation resource added to the system.

4.3.2.2. Day-Ahead Workflow

The general Day-Ahead process can be much the same in EIM. While there will be some changes to Resource definition, the main process of creating energy and generation schedules appears sufficient. LAC 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. The utilization of third parties to procure economic day-ahead energy purchases will not change in EIM as the energy procured is tagged and visible to the market as intertie base schedules accounted for by PNM.

4.3.2.3. After-The-Fact Market Analysis

EIM introduces the new activity of after-the-fact analysis. 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 actuals, shadow prices on specific constraints, and dozens of others). LAC may opt to develop processes to review market results.

4.3.2.4. Gaps for EIM Participation

With LAC electing not to integrate Participating Resources there are few gaps for merchant EIM participation, the main being:

- Base schedule creation and submission in the Day-Ahead horizon
- After-the-Fact Analysis
- Generation Data Template definition

For Day-Ahead Generation Base Schedule Creation, it appears that only the LANL CT is in scope. The LANL CT generation schedule is known well in advance and the resource plan is generally followed. PNM will provide a PCI-based user interface to 3rd party entities such as LAC for generation base schedule submission. They will also provide a programmatic means to submit base schedules. Since there is only one resource currently in scope, LAC can use the PCI user interface to submit their hourly base schedule. The base schedule can be submitted days in advance for multiple hours. This activity can be completed in less than an hour per day. It is expected that Merchant Operations can add base schedule submission for the LANL CT to their scope of work without increasing headcount.

The other main process is After-The-Fact Market Analysis. This is a light weekday-only process due to it being limited to NPRs, and likely to consume less than an hour per day. This responsibility is likely a team effort with the Supervisor also being involved.

5.4 EIM Settlements and Invoicing

5.4.1 Current State

Currently LAC performs invoicing and billing functions for bilateral trades that are captured in WebTrader and E-Tagging. LAC is not currently a participant in organized markets (such as CAISO MRTU intertie bidding), therefore EIM settlement is a new activity.

Meter Data Management for intra-ties are known and handled by PNM and Tri-State. Intra-tie data management is handled via SCADA data. Revenue quality meter data collection for generation meters does not exist today.

5.4.2 EIM Settlements Participation Gaps

With LAC electing not to integrate Participating Resources there are few gaps for EIM Settlements and Invoicing, the main being:

- Consumption and payment of PNM EESC charge code sub-allocations to LAC
    - Optionally shadow settle PNM charge codes if desired. **Note**: Most counterparties, especially those of LAC's size do not shadow settle.
    - **Note**: Since LAC has not elected to integrate Participating Resources, there will be no CAISO-sourced PRSC settlement statement
- The collection and submission of meter data for intra-ties between LAC and PNM (this process is done today) for charge code sub-allocation

    - Here we assume that the quality, granularity, and accuracy of intra-tie meter data management for EIM sub-allocation is handled by PNM
- The collection, validation, and submission of meter data for generation resources

4.4.2.1. PNM EESC Charge Code Sub-Allocations

In the EIM, PNM will act as the EIM Entity Scheduling Coordinator (EESC) who settles with CAISO on behalf of the entire Balancing Area Authority (BAA), including the LAC sub-BA. PNM will receive its own EIM settlement statements, invoices, and make invoice payments to the ISO independently. PNM will perform the following settlements activities on behalf of the entire BAA:

- Retrieve EIM market results data from CAISO systems (CMRI, OASIS, SIBR, ADS)
- Download EIM Statements from CAISO for all Settlement runs (T+3B, T+12B, T+55B, etc.)
- Confirm accuracy and completeness of CAISO EIM Statement Settlement Charge Codes
- Download EIM Invoice from CAISO
- Confirm accuracy of EIM Invoice based on previously confirmed ISO EIM Statements
- **Perform EIM Settlement Allocation to PNM Transmission Customers**
    - PNM has made updates to its OATT to allow EIM charges associated with transmission customer activities to be sub-allocated.
    - 30+ EESC charge codes are in scope for sub-allocation to each OATT customer
    - An allocation software module has been implemented to create statements for transmission customers
    - Prior period adjustments

LAC will need to be capable of consuming PNM's transmission customer settlement allocation and debiting or crediting accounts as prescribed. LAC does this already for PNM OATT-based charges; this process will need to account for EIM EESC charge code sub-allocations.

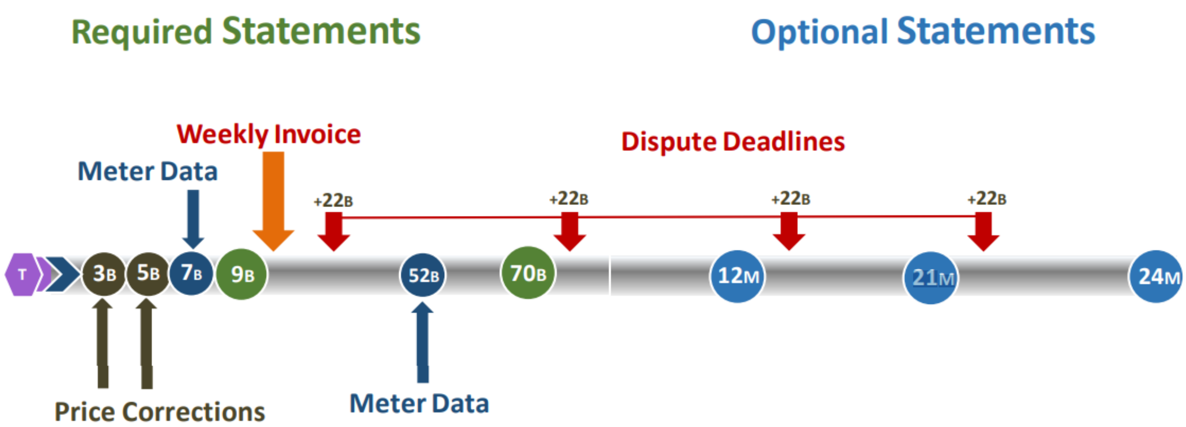
LAC may elect one of the following methods:

1. **Take PNM Sub-Allocations As-Is (most counterparties choose this option)**
    a. Trust that PNM allocated EIM charges correctly and accurately
    b. Pay invoices as billed
2. **Commission Vendor software to shadow settle PNM EESC sub-allocations**
    a. Collect relevant bill determinant data into a software system
        i. Bill determinant data includes but is not limited to meter data, CAISO bill determinant data (sourced from MRI-S, OASIS), PNM-specific data
    b. Implement calculations that mimic the calculations that PNM uses to sub-allocate
    c. Report deltas between PNM sub-allocation and parallel LAC calculations
    d. Dispute the differences for charges on up to a 5-minute level
3. **Commission a consultant or local software firm to build out a spreadsheet-based solution**
    a. Address major imbalance charge codes that PNM sub-allocates
    b. Collect relevant bill determinant data into a software system
        i. Bill determinant data includes but is not limited to meter data, CAISO bill determinant data (sourced from MRI-S, OASIS), PNM-specific data

c. Implement calculations that mimic the calculations that PNM uses to sub-allocate

If LAC chooses to implement a shadow sub-allocation settlements system, Utilicast recommends looking at either expanding the current OATI tools / modules or exploring other vendors such as PCI, MCG, or PowerSettlements to meet LAC needs. Note that PCI will implement PNM's settlements sub-allocation module so PCI could implement a sub-allocation shadow settlements module for LAC relatively quickly.

Figure 15: Excerpt from CAISO Payments Calendar



4.4.2.2. Generation Meter Data Collection and Submission

Following the Operating Day, LAC must submit meter data for NPR generation resources. This will be a new responsibility for LAC. There are still some decisions to be made on addressing this aspect. For the purposes of this report it is assumed that the PSO along with PNM will ultimately be responsible for the collection, validation, and submission of generation meter data.

Generation resources such as San Juan and LANL CT have revenue quality meters. LAC has a process to collect revenue quality meter data directly from generation meters. LAC can also collect ACCUM and ANALOG meter data via their EMS. Either a new process would need to be developed and new technology integrated to collect at least 15-minute granularity meter data from generation meters, or a CAISO exemption would be required to substitute ACCUM or ANALOG meter data for revenue quality meter data.

4.4.2.3. Settlements Training

The EIM responsibilities will require some training for the Settlements resources. Content will include:

- Understanding CAISO Charge Codes.
- Meter Data Management. Understanding the Verification, Editing, and Estimation process (VEE) and meter data submission process.
- Navigating CAISO Timelines. For Settlements Validation, Disputes, Resettlements, Invoices, etc.
- LAC Business Processes. Addressing the changes from pre-EIM processes.
- Tools (Systems and Applications).

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- Front Office. To better aid in the investigation of Settlement discrepancies, the settlements team(s) should understand the front office concepts and mechanisms.

5.5 Outage Management

5.5.1 Current State

Currently LAC does not maintain an outage management system to identify, schedule, and manage generation and transmission outages. Their power system is small and the generation resource count is low enough that formal rigor of a management system is not required.

5.5.2 EIM Outage Management Gaps

4.5.2.1. Generation Outage Management

On an on-going basis in EIM, PNM will be managing generation outages and submitting generation availability limits to the CAISO OMS. Managing outages requires considerable effort and precision. The main generation resources in scope for outage management are LANL CT, San Juan share, El Vado, Abiquiu.

It is anticipated that PNM will enter generation outages into CAISO OMS (for EIM).

There are several rules and complications in the way 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. These complexities make learning to actively manage outages and availability within EIM significantly challenging. LAC will need to precisely and quickly provide PNM with relevant generation outage and derate information.

Utilicast recommends a workload equivalent of 0.05 additional resources for generation outage management.

4.5.2.2. Transmission Outage Management

On an ongoing basis, LAC (LANL) will be managing transmission outages and submitting availability limits to the CAISO OMS. Managing outages requires considerable effort and precision. There is minimal to no impact to the existing transmission management workflow.

5.6 Load Forecasting

5.6.1 Current State

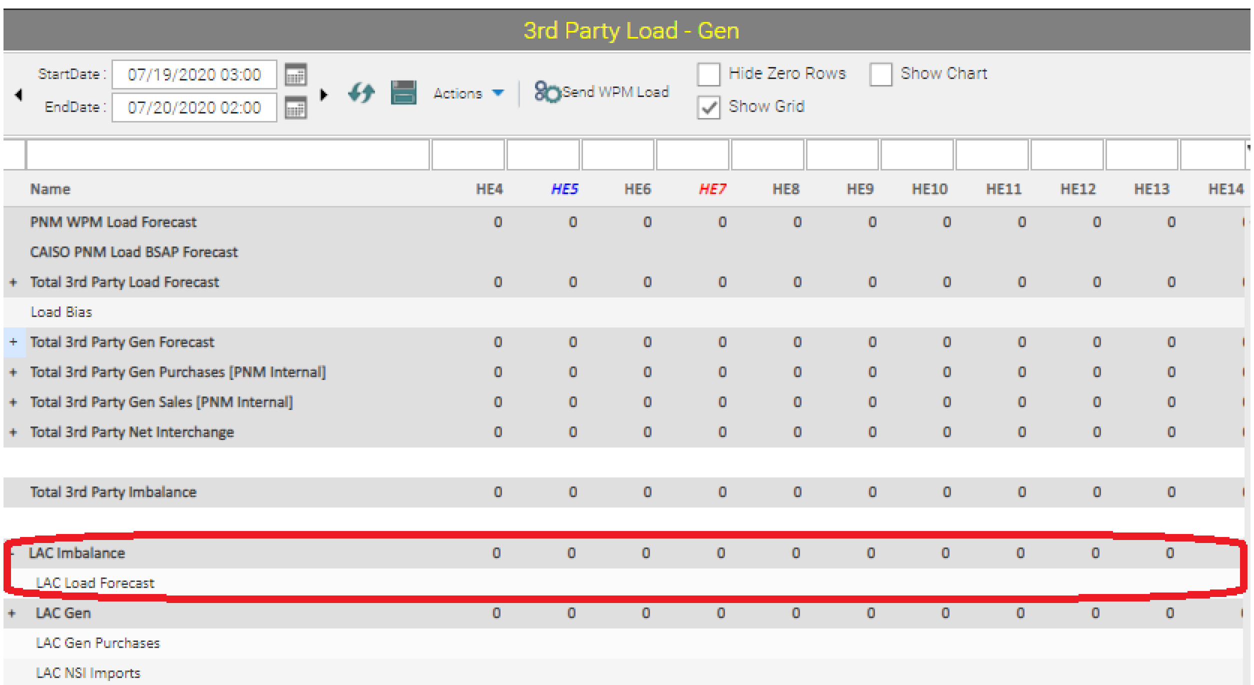
LAC provides PNM with their load forecast at the beginning of each month for use in PNM's overall *Balancing Area* (BA) load forecast. Additionally, LAC sends updated load forecasts at T-3 (Three days prior to each trade date) via an Excel spreadsheet delivered by email. There is an effort underway to automate load forecast communication by utilizing a database to send PNM a 7-day load forecast, updated weekly.

See the Merchant Operations As-Is State – Load Forecasting for additional load forecasting detail.

5.6.2 Load Forecasting EIM Participation Gaps

As PNM is balancing supply and demand for the entire PNM BAA, they must include 3rd party load in their workflow. CAISO will provide PNM with a PNM BAA Load Forecast. PNM requires the load forecast from all third-party entities (including LAC) to determine what portion of the BA load they are required to serve. For power balance, PNM will utilize the CAISO PNM Load Forecast, netting out third-party load.

Figure 16: PNM 3rd Pary Load and Gen Management Screen



Name	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14
PNM WPM Load Forecast	0	0	0	0	0	0	0	0	0	0	
CAISO PNM Load BSAP Forecast											
+ Total 3rd Party Load Forecast	0	0	0	0	0	0	0	0	0	0	
Load Bias											
+ Total 3rd Party Gen Forecast	0	0	0	0	0	0	0	0	0	0	
+ Total 3rd Party Gen Purchases [PNM Internal]	0	0	0	0	0	0	0	0	0	0	
+ Total 3rd Party Gen Sales [PNM Internal]	0	0	0	0	0	0	0	0	0	0	
+ Total 3rd Party Net Interchange	0	0	0	0	0	0	0	0	0	0	
Total 3rd Party Imbalance	0	0	0	0	0	0	0	0	0	0	
LAC Imbalance	0	0	0	0	0	0	0	0	0	0	
LAC Load Forecast											
+ LAC Gen	0	0	0	0	0	0	0	0	0	0	
LAC Gen Purchases											
LAC NSI Imports											

LAC will have three options to submit the load forecast:

1. Manual entry into a PCI screen or programmatically via an API. (Not Recommended / Not Feasible)
2. LAC has chosen to implement the data transfer via an API integration, and thus will not require additional headcount for load forecast submission. (Recommended)

3. Work with PNM and PCI to determine if an Excel file can be manually imported into the PCI system (Recommended approach if Option 2 is not feasible)

5.6.3 LANL Load Management for Market Integration

LAC provides load service to LANL and is a part of LAC's load forecast calculations. The LANL energy requirements and schedules are made available to the Pre-Schedule Office and Real-Time Operations more than a month into the future. There exists some significant seasonal load based on LANL's linear super computing requirements, but these are well scheduled at the hourly level. Between supercomputer batch jobs, there is some downtime, which could make large energy consumption deltas in the 5- and 15-minute markets. As a result, LAC as an EIM Sub-BA could face imbalance energy impacts. The EIM would alleviate real-time energy shortfalls or excesses, possibly resulting in financial risk. LAC would be required to purchase or sell energy at the 5-minute market price, which can be very volatile.

Utilicast recommends LANL and LAC's Power Operations and Scheduling groups coordinate to "smooth out" the load to reduce financial imbalance risk.

5.6.4 Variable Energy Resource Forecasting

At the time of this writing no Variable Energy Resources (VERs) exist in the LAC fleet; thus VER integration is outside the scope of this effort.

There is a possibility that 10MWs of LANL solar (behind-the-meter) may be integrated into the fleet in the next few years. Note that VERs require a real-time load forecast to be submitted to CAISO (via PNM), with the following characteristics:

- Submission Timing: Up to every 5 minutes
- Submission granularity: Up to 5-minute intervals
- Forecast Horizon: Up to 5 hours ahead

Any scheduled or forced curtailment in output requires CAISO outage submission.

If VER resources are integrated in the future, the following actions are required:

- Development of a VER forecast, typically with a vendor
    - Consumption of locational weather data such as temperature, humidity, etc.
- Develop ability to send VER forecast to CAISO as prescribed above
- Resource modeling with CAISO and PNM
- Modeling and submission of VER outages, derates or other curtailments
- Development of an hourly generation base schedule based on the forecast, and the ability to submit the base schedule to CAISO (via PNM). Ability to adjust base schedule while accounting for actual generator output.
- Monitoring of VER forecasting technology for availability

5.7 Information Technology Management

Today most information technology support comes from within the core team including the supervisor, Real-Time Operations, and the PSO. Desktop support and some EMS-related support are provided by additional teams at LAC and LANL.

EIM requires several new technical data integrations and systems that must maintain high availability. New integrations and systems may include:

- Base Schedule Submission API (EIDE)
- Load Forecast API (EIDE)
- ADS Terminal setup

Each of these systems and integrations must be managed and supported. See the support matrix below for LAC activities:

Figure 17: System Responsibility Matrix

System / Integration	Managed By	Supported By
Base Schedule Submission API	LAC	LAC
Load Forecast Submission API	LAC	LAC
ADS User Interface Terminal	CAISO	LAC

Utilicast recommends adding 0.25 FTEs to support additional information technology needs. The higher value is based on inclusion of the EESC Sub-Allocation Shadow Settlements System.

5.8 LAC 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 LAC will define workstreams, which will have both resource and milestone interdependencies. For projects of this magnitude, it is useful to pair 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. 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
- LAC Customers
- LAC Internal Stakeholders
- PNM Support
- Vendors of EIM Application and Services
- Integrator

An effective EIM project will require input and direction from LAC's executives and key managers who do 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.

5.9 Gap Assessment Highlights

The following table highlights the areas where gaps were found in people, processes, and technology, along with a recommendation for how to remediate the gaps:

Figure 18: Gap Assessment Highlights

Functional Area	People	Process	Technology
Base Schedule Submission	Automated hourly workflow requiring analyst validation and possible data entry	Creation & Submission of hourly base schedules	Integration of energy systems, new user interface
Generation Outage Submission	Continuous workflow requiring minimal data entry and validation	Submission of availability limits in real-time with precision while observing rules	New system and user interface
Load Forecast Submission	Automated workflow requiring light analyst validation	Submit rolling 7-day load forecast to PNM	Integration of energy systems, new user interface
LANL Load Management	LANL/LAC coordination to manage seasonal load	"Smooth out" LANL load to avoid financial risk	Super computing requirements planning tools (where applicable)
Automated Dispatch Control Monitoring	Continuous workflow requiring light monitoring	Ensure dispatch signals align with market inputs to avoid financial risks	New system and user interface
Technology Support	Support technical data integrations for high availability	Required; Must adhere to 5-min dispatches within bid range. Must adhere to startup/shutdown instructions	N/A
After-The-Fact Analysis	Merchant review of market results	"Sanity Check" of market results	Not recommended, options provided
Recommendation	**Hire one (1) new analyst to perform market-related activities**	**Implement capital project to integrate with PNM and CAISO**	**Integrate technology as prescribed above**

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6. EIM Integration Cost Assessment

The EIM Gap Analysis concludes with the EIM Integration Cost Assessment. The cost assessment utilizes information gathered in the *As-Is State of Operations Assessment*, applies the decisions made in the *EIM Participation Approach* (Non-Participating Resource decision), and integrates the comparisons made between the current state and EIM requirements in the *EIM Participation Gap Assessment* section. Utilicast employs a cost assessment methodology that follows the CAISO timeline and "track" structure that identifies the amount of internal and external labor is required.

6.1 Cost Assessment Assumptions and Inputs

Utilicast employed the following major assumptions and inputs to build the cost assessment:

1. While building the assessment, Utilicast employed a "least cost" approach to reduce cost where possible. LAC has a relatively small footprint when compared to other PNM Sub-BAs such as Tri-State. Without large volume and ability to spread costs, the "least cost" approach is prudent.
2. LAC, as a Sub-BA, is a "small fish in a large pond". The activities required for EIM participation are proportionately greater than the relative load served. There are fixed market actions that must take place regardless of size. Although technical automation has been designed where possible, the associated costs with these market requirements are reflected in this cost assessment.
3. LAC has chosen to adopt the Non-Participating Resource methodology to enter the CAISO EIM. This is the least requirement approach to join the market in terms of human resources, software, business processes, legal requirements, and market settlements.
4. The Capital Cost assessment covers the EIM Implementation time horizon, with a start date of September 7th 2020 and completion date of May 31st 2021. This schedule aligns with LAC and PNM's EIM entry on April 1st 2021.
5. The Operations and Maintenance (O&M) assessment for the remainder of 2021 assumes a start date of June 1st 2021, ending on December 31st 2021. The 2022 O&M Cost Assessment covers the full year and uses 3% inflation on labor costs.
6. LAC/LANL employee loaded rates have been used to develop the cost assessment. LAC/LANL analysts and managers already have a very high utilization rate of over 90%.
7. The 2020 Utilicast rate schedule has been used to support external labor costs where deemed necessary.
8. LAC Annual Net Load has been estimated at 600,000 MWh to calculate CAISO Grid Management Charges. The 2020 CAISO Budget and Grid Management Charge Rates document provides relevant market and system operations charge definitions.
9. Utilicast and LAC have engaged software vendors to provide active offers for use in this cost assessment.
10. No CAISO Participation and Implementation Fees will be charged to LAC. PNM has already paid load-based fees (~$455,000) for the entire PNM BA, including the LAC Sub-BA.

11. Like other EIM counterparties and small sub-BAs, LAC has chosen not to pursue a shadow settlements system at this time. Not employing a shadow settlements system eliminates large amounts of software cost, internal labor, consulting services, and business process changes.
12. A contingency amount was added to the Capital Cost Assessment and O&M Cost assessment at 15% and 10% of the subtotal cost respectively. Contingencies provide

6.2 Track-Based Project Schedule (Capital)

The Capital Cost Assessment employs the following track-based schedule between September 2020 through May 2021. CAISO uses these tracks to align relevant people, processes, and technology for efficient execution. It provides a useful model to assess cost and level of effort.

Figure 19: CAISO Track-Based High-Level Project Schedule for Capital Project

Track-Based Activities	Sep 2020	Oct 2020	Nov 2020	Dec 2020
Utilicast	Site Acceptance Testing	Site Acceptance Testing	Day-In-The-Life	Market Simulation
Track 1 - Project Management	Set Up teams, kickoff. Prepare for Market Readiness. Vendor RFP Support	Testing, Vendor Management	Testing, Vendor Management	Market Simulation Support
Track 2 - Legal and DEB	Review of OATT Impacts. CAISO Agreements. 3rd Party Bilateral Provider Agreements	PNM OATT Conversations	OATT Updates & Stakeholder Review	OATT Updates & Stakeholder Review
Track 3 - Full Network Model	Review progress made with PNM	Make any adjustments required for Generation, Meters	Make any adjustments required for Generation, Meters	Submit changes to CAISO for inclusion in FNM
Track 4 - System Integration	Qualify quotes from vendors, hardware review	Integration efforts with OATI, PCI	Integration efforts with OATI, PCI	Integration efforts with OATI, PCI
Track 5 - Metering & Settlements	SQMD status review, meter upgrade evalulation (if needed). MDMA process review	SQMD Adjustments	SQMD Adjustments	Settlements Market Readiness Support
Track 6 - Training	CAISO BPM Review	CAISO CBTs	Business Process Training	Business Process Training
Track 7 - Market Readiness	Business Process & Procedure Review	Update Business Processes	Update Business Processes	Enforce Business Process

Track-Based Activities	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021
Utilicast	Market Simulation	Parallel Operations	Parallel Operations	Go-Live & Stabilization	Settlements Support & Stabilization
Track 1 - Project Management	Market Simulation Support	Parallel Ops Support	Parallel Ops Support	Go-Live Support	Stabilization Support
Track 2 - Legal and DEB	OATT Updates & Stakeholder Review				
Track 3 - Full Network Model	Adjust model as required	Adjust model as required	Adjust model as required	Go-Live Model Connectivity Support	Stabilization Support
Track 4 - System Integration	Check Transmission Outage Management with EIM Resources	Integration Support	Integration Support	Integration Support, Go-Live Connectivity Support	Stabilization Support
Track 5 - Metering & Settlements	Settlements Market Readiness Support	Settlements Market Readiness Support	Settlements Market Readiness Support	Billing & Invoicing Support	Billing & Invoicing Support
Track 6 - Training	Training Support	Training Support			
Track 7 - Market Readiness	Enforce Business Process	Adjust Business Process	Adjust Business Process		Stabilization Support

6.3 Capital Cost Summary

The following section highlights the Capital Costs necessary to implement the EIM project. Areas of consideration include:

- Technical Integration between WebTrader and PCI systems
- Base schedule workflow
- Load Forecast submission to PCI (PNM)
- ADS integration
- Requirements and Design
- Implementation & Testing
- External Consulting Services & related labor
- CAISO Integration and Market Readiness Activities
- Training
- Tariff / OATT review
- Business Process change management
- Post Go-Live Support

Figure 20: Capital Cost Summary

Capital Cost Summary			
Cost Component	**Total Dollars**	**Sub-Component**	**Sub-Component Cost**
Internal Labor	**$ 75,462.50**		
		LAC/LANL Labor	$ 75,462.50
External Labor	**$ 123,078.75**		
		Utilicast Labor	$ 97,025.00
		Utilicast Travel	$ 14,553.75
		Legal Labor	$ 11,500.00
Software	**$ 16,000.00**		
		WebTrader -> PCI Integration (Capital)	$ 16,000.00
Subtotal	**$ 214,541.25**		
Contingency	**$ 32,181.19**		
Total Capital Cost	**$ 246,722.44**		

6.4 Operations & Maintenance (Ongoing) Cost Summary

The following section highlights the Operations & Maintenance Cost Summary. This section represents the incremental ongoing costs for market participation. Areas of consideration include:

- **Ongoing incremental LAC/LANL Labor**
  - One (1) additional resource is deemed required to perform EIM market related activities. The incremental work may be spread across multiple analysts in the organization. The resource cost is based on a blended cost where the analyst and manager perform the work in ratios of 90% and 10% respectively.
  - The incremental market-related work activities include:
    - Base schedule submission validation (hourly)
    - Generation outage submission (event-driven)
    - Load forecast submission validation
    - Automated Dispatch Control monitoring
    - Technology Support for APIs
    - Sanity check of market results
- **Software licensing**
  - OATI software to integrate WebTrader with PCI for base schedule and load forecast submission is required. The monthly licensing cost amounts to $500.00
- **CAISO Grid Management Charges** (estimated), including:
  - 4564 EIM System Ops GMC Charge (per MWh, 2020 rates)
  - 4564 EIM Market Services GMC Charge (per MWh, 2020 rates)

The Operations & Maintenance (O&M) costs are provided for:

- The remainder of 2021 (June 2021 through December 2021) to represent the partial year after the completion of the capital implementation project (September 2020 through May 2021)
- The entire 2022 calendar year. The 2022 Full Calendar year is a useful representation for future years' ongoing costs.

Figure 21: Operations and Maintenance Cost Summary

Operations and Maintenance (O&M) Cost Summary		
O&M Cost Component	**Remainder of 2021**	**2022 Full Calendar Year**
Additional LAC/LANL Labor	**$ 40,072.50**	**$ 99,059.22**
Software	**$ 3,500.00**	**$ 6,000.00**
CAISO GMC Charges	**$ 84,240.00**	**$ 112,320.00**
Subtotal	$ 127,812.50	$ 217,379.22
Contingency	**$ 12,781.25**	**$ 21,737.92**
Total O&M Costs	**$ 140,593.75**	**$ 239,117.14**

7. Glossary of Terms and Acronyms

Term	Literal Meaning	Function
ABC	Available Balancing Capacity	The Regulation Up and Regulation Down capability on a generating unit offered to EIM for use in reducing market infeasibilities. NPR capability is defined via Default Energy Bids.
ADS	Automated Dispatch System	CAISO system communicating market dispatch, start-up, shutdown, and MSG transition instructions.
ATC	Available Transfer 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.
BAA	Balancing Area Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority

		area, and supports interconnection frequency in real time.
BSAP	Base Schedule Aggregation Portal	Receive and process Base Schedules and perform sufficiency tests.
CAISO	California Independent System Operator	Regional Market and Transmission Operator that manages the EIM.
DEB	Default Energy Bid	In EIM, the 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.
EIM	(Western) Energy Imbalance Market	Electricity market that trades energy in 5 and 15-minute blocks to maintain near-term power balance driven by market economics.
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.
FTE	Full-Time Employee	A measure of level-of-effort used in cost assessment.
GRDT	Generator Resource Data Template	Registered PR or NPR operating characteristics utilized by market model to dispatch resources.
IRDT	Intertie Resource Data Template	Registered ETSR Transfer and bilateral market trade point characteristics used by market model to dispatch resources.
LMP	Locational Marginal Price	Location-specific, incremental market price of energy.
MDMA	Meter Data Management and Acquisition	System for gathering, performing VEE, and submitting meter data.
MMA	Major Maintenance Adder	Registered costs for major maintenance by generating resource.
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	A registered generator in an EIM BAA that does not bid or follow market dispatch except under limited circumstances
NSI	Net Scheduled Interchange	The sum of transactions between a BAA and its neighbors
OASIS	Open Access Same-Time Information System	System used to manage transmission reservations, manage transmission availability, purchase transmission capability, and report curtailments
OMS	Outage Management System	CAISO system that manages coordination and scheduling of transmission and/or generation outages, mapped to the network model for incorporation in market engine.
PR	Participating Resource	Registered generator in an EIM BAA that may bid and must follow market dispatch including generator starts, stops, transitions.
PRSC	Participating Resource Scheduling Coordinator	CAISO registered representative scheduling and bidding EIM participating resources.
RC	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System (BES), has the wide area view of the BES, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations
RTSI	Real-Time Schedule Interchange	Aggregation of interchange schedules into various CAISO-defined categories and scheduling paths, and submission to CAISO every 5-minutes for incorporation in market engine, affecting optimal solution for BAA balancing.
SCADA	Supervisory Control and Acquisition Data	Technology which enable monitoring and the issuing of process commands, like generator set point changes.
VEE	Validation, Estimation & Editing	Meter data process to review raw meter data prior to submission for use in settlements.
VER	Variable Energy Resource	An energy generating resource that has intermittent availability, typically wind and solar.