Transactive Incentive-signals to Manage Energy-consumption (TIME)

The System- and Market-Based Transactive Load Management (TLM)

2018 TECHNICAL REPORT

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ABSTRACT

The electric grid of the future must be inextricably linked with technological and regulatory advancements to realize business and consumer benefits. In the United States, one key driver for the future of the electric grid is the transformation from centralized to distributed energy generation. This transition contributes to extreme spatial and temporal variability in electricity generation—on the order of gigawatts. System-wide integration of variable generation can further increase costs in the absence of expanded balancing such as might be provided by demand response (DR) resources responding to actual system needs. Access to the system- and market-based economics to leverage load flexibility from consumers provides a unique value proposition in support of efficient grid operations—i.e., it enables transactive load management (TLM). Early-stage advanced DR markets and automation systems have shown an average of 8% site-specific demand reduction in response to price signals.

Through quantitative and qualitative analyses and feedback from experts, this report proposes the design of a grid-integrated TLM signaling framework and system deployment techniques. The report further proposes a reference design using open standards that considers existing electricity market practices to accelerate stakeholder acceptance and adoption. The interim findings show the critical need to integrate California's electricity markets to unlock the full value from customers' DR resources and enable cost-efficient integration of variable renewable generation. The findings can be used by the industry and research organizations to develop new practices for widespread adoption of economics-driven transactive technologies and systems for an integrated electric grid of the future.

Keywords

Transactive Load Management
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PRIMARY AUDIENCE: Electric Utilities, System Operators, Regulatory Agencies, and Energy Consumers

SECONDARY AUDIENCE: Demand Response Technology and Service Providers

KEY RESEARCH QUESTION

The system-wide integration of variable generation can further increase costs in the absence of expanded balancing such as might be provided by demand response (DR) resources responding to actual (also referred to, as real-time) system needs. Access to the system- and market-based economics to leverage load flexibility from consumers provides a unique value proposition in support of efficient grid operations—i.e., it enables Transactive Load Management (TLM).

The critical questions addressed by the research relative to the TLM signal include the following:

- What should the signal design be?
- What elements should the signal be made up of, and in what proportion?
- How do variations in the signal's composition affect consumer behavior?
- How can the design and operation of TLM signals and systems integrate supply- and demand-side markets in California?

RESEARCH OVERVIEW

This research reviews California's pathways for a clean energy system with emphasis on the scope of the solicitation and TLM signals for electricity markets and demand response (DR) programs. The report focuses on the framework for the TLM system, and the TLM pricing and signal design structure to lead California toward the planned clean energy system. The research methodology includes: (1) review of the existing California electricity market, regulatory structures, and electric grid; (2) review of the Group 1 and Group 2 project proposals that use the TLM signals; and (3) literature review on existing supply-side and demand-side DR programs and advanced pilots that leverage DR as a grid resource. In close coordination with the advisory committee members, the study proposes a TLM framework and design that incorporates early-stage research and a TLM reference model that is leveraged through a collaborative approach and in field tests of technology applications.

KEY FINDINGS

The interim findings show the critical need to integrate California's electricity markets to unlock the full value from customers' DR resources and enable cost-efficient integration of variable renewable generation.

The detailed project findings are as follows:

1. The 24-hourly day-ahead California wholesale electricity market prices constitute the consensus temporal base case for TLM Prices. There are outliers with intra-hour price notification and price duration signals.

2. The Pnode locational marginal prices (LMPs) published by the CAISO can be the lowest desired spatial disaggregation for wholesale electricity market prices. Likewise, the APnode prices for the IOU LAPs are the lowest spatial disaggregation for wholesale electricity market demand prices.

3. The distribution system variability (demand/supply) adjustment and electricity service providers and operations may be considered for customer-level TLM System and Prices that reflect integrated system and market conditions.

4. An integrated and inclusive approach to the CAISO (transmission and generation) domains and the electric utilities (distribution) domain is critical to determine “fair market” and integrated TLM Prices.

5. The determination of TLM Price must include data inputs for pre-market planning and real-time analytics for both wholesale (supply-side), generation sources (for GHG) and retail (demand-side) markets. This ensures that advanced analytics are used to calculate Prices that consider real-time system and market conditions.

HOW TO APPLY RESULTS

The findings can be used by the industry and research organizations to develop new practices for widespread adoption of economics-driven transactive technologies and systems for an integrated electric grid of the future. The solicitation project participants conducting field tests shall leverage the system and signals developed in this research to deploy advanced DR automation technologies to identify customer response strategies, end-use loads, system architecture, and value.

LEARNING AND ENGAGEMENT OPPORTUNITIES

For the purposes of applied research and development, the next one-year activity will focus on operationalizing and maintaining the TIME systems and TLM signals. Electric grid operators, service providers, regulators, and technology innovators can use these interim research findings to identify value in their regions and the grid- and customer-side benefits of using TLM system and signaling design constructs.

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1 INTRODUCTION

The electric grid of the future must be inextricably linked with technological and regulatory advancements to realize business and consumer benefits. In the United States, one key driver for the future of the electric grid is the transformation from centralized to distributed energy generation. This transition contributes to extreme spatial and temporal variability in electricity generation—on the order of gigawatts (GW). The analysis by the California Independent System Operator (ISO) shows early morning and late evening variability in the range of 7 GW—14 GW, respectively [1]. The system-wide integration of variable generation can further increase costs in the absence of expanded balancing such as might be provided by demand response (DR) resources responding to actual (also referred to, as real-time) system needs. Access to the system- and market-based economics to leverage load flexibility from consumers provides a unique value proposition in support of efficient grid operations—i.e., it enables Transactive Load Management (TLM).

This report defines the term, *Transactive Load Management* (TLM), as a method to leverage flexibility through demand response (DR) strategies using economic incentives, such as real-time electricity prices and advanced energy technologies to motivate customer response. The design and architecture of the TLM-based system are based on an integrated grid and markets and includes many electric grid stakeholders. Through quantitative analyses and feedback from experts, this report proposes the design of a grid-integrated TLM signaling framework and system deployment techniques. The report further proposes a reference design using open standards that considers existing electricity market practices to accelerate stakeholder acceptance and adoption.

In addition to the qualitative analysis, a key quantitative analysis used for the design of the TLM is a summary of responses and field implementation of the proposed TLM design from the eight California Energy Commission (CEC) Grant Funding Opportunity (GFO) 15-311 Group 1 and 2 projects that are developing a framework to test efficacy of such an approach. Considering that these projects are in early-stages of deployments, the results of field-tests are outside the scope of this interim report.

Per the CEC GFO-15-311, a TLM system combines actual system information with forecasts of loads (demand) and distributed generation (DG) production to develop an (economic) incentive or price (TLM) “signal” that reflects system needs [2]. The design of the TLM System and resulting prices considers existing electricity markets and stakeholders within the regulated structure and identifies enhancements needed to transition California to a TLM future. As expressed in the CEC’s solicitation, GFO 15-311, Advancing Solutions That Allow Customers to Manage Their Energy Demand [2]:

> *"The purpose of the research…will be to develop, test and operationalize one or more transactive signals that can be used by utility customers – and the other Recipients under this solicitation – as a basis for automating their load management strategies. It is expected that the signal development process will involve collaboration with Group 1 and 2 Recipients."*

The critical questions raised by the solicitation relative to the TLM signal include the following:

- What should the signal design be?
- What elements should the signal be made up of, and in what proportion?
- How do variations in the signal's composition affect consumer behavior?
- How can the design and operation of TLM signals and systems integrate supply- and demand-side markets in California?

This report reviews California's pathways for a clean energy system with emphasis on the scope of the solicitation and TLM signals for electricity markets and demand response (DR) programs. The State's Assembly Bill (AB) 32 – Global Warming Solutions Act of 2006 – and Senate Bill (SB) X1-2 – Renewables Portfolio Standard – are primary drivers for these goals. AB 32 mandates the greenhouse gas (GHG) emissions reduction goal of returning to 1990 levels by 2020 and a cap-and-trade program. SB X1-2 requires retail sellers of electricity and local publicly owned electric utilities (POUs) to increase their procurement of eligible renewable energy resources to 20% by the end of 2013, to 25% by the end of 2016, and to 33% by the end of 2020.

While there are other laws and regulations that mandate the approaches (for example, energy storage systems and integrated energy policy), this report focuses on the framework for the TLM system, and the TLM pricing and signal design structure to lead California toward the planned clean energy system. It contains initial findings and next steps developed through a collaborative and pragmatic approach as required by the solicitation. This report proposes a TLM framework and design that incorporates early-stage research and a TLM reference model that is leveraged through a collaborative approach and in field tests of technology applications.

The collaborative approach, which was requested by the solicitation, was initiated via a survey sent to all Group 1 and 2 recipients. This survey, included as Appendix D of this report, solicited input from the associated projects with respect to many of the potentially salient characteristics that a TLM Signal to communicate TLM Prices might possess. The project then reviewed and grouped the responses to identify common elements and characteristics that were of interest to most of the recipients. A note was also taken of unique or infrequently requested features (referred to as "outliers"). This report describes the "design" activity for "implementation" and "operation" of the TLM signals, as shown in Figure 1-1.

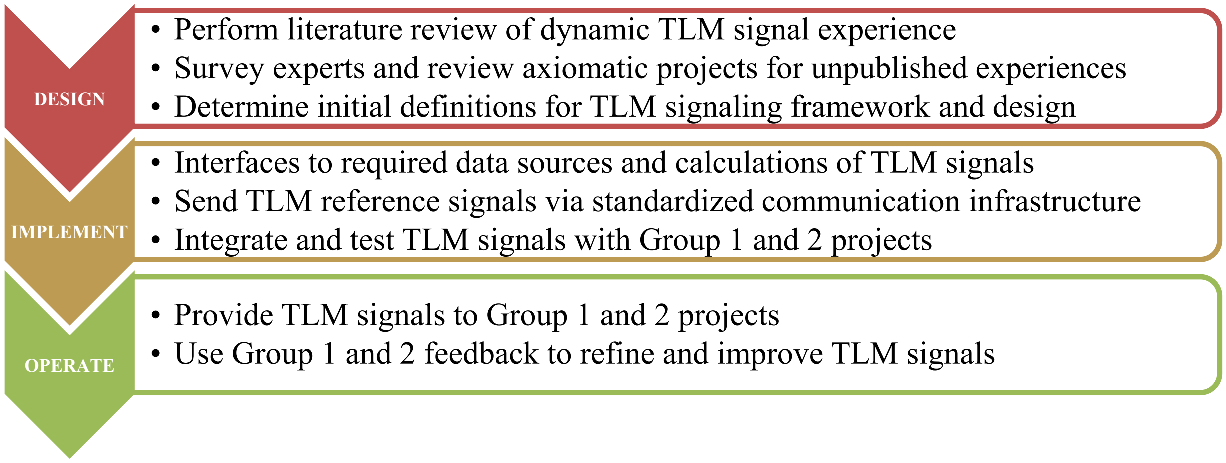


Figure 1-1
Research, Development, and Demonstration Strategy for Transactive Load Management

Methodology

California's regulated market structure limits most customers' DR participation in retail programs within the distribution system (referred to as demand-side DR or load-modifying DR) to those that are offered by California's investor-owned utilities (IOUs). Early-stage advanced DR markets and automation systems for retail markets have shown an average of 8% site-specific demand reduction in response to price signals. To maximize these benefits from DR in the bulk generation and transmission system, which is managed by the California Independent Systems Operator (CAISO), this regulated market structure must also consider customers' options for load integration and participation in the wholesale DR markets (referred to as supply-side DR).

To design TLM signals that are representative of and that can be readily leveraged by, electric grid stakeholders and consumers, the study reviewed the existing California electricity market, regulatory structures, and electric grid. This included the consideration of operations of existing electricity markets, demand response (DR) programs and related electricity rate tariffs, and plans for a future electricity system with high penetration of renewables and advanced real-time price-based demand response that leverages "price-elastic" demand.

The project team reviewed the Group 1 and Group 2 project proposals and literature on existing supply-side and demand-side DR programs and advanced pilots that leverage DR as a grid resource. The findings were used to propose the TLM signaling and pricing framework and the TLM signal design. This methodology is shown in Figure 1-2 below.

Figure 1-2
Methodology for the Design of TLM Signals and Prices

These results were discussed with the members of the technical advisory committee (TAC) that was set up for this project. The TAC comprises leading practitioners and subject-matter experts in price-responsive signals and standardization. It is planned to have the TAC remain engaged throughout the duration of the project. The TAC members and their affiliated organizations are listed in Appendix A.

The methodology was used to propose an integrated and inclusive TLM framework that will be used for the design and development of a prototypical TLM signaling system, called Transactive Incentive-signals to Manage Energy consumption (TIME).

Key Terms and Definitions

Transactive Load Management (TLM): Method used to leverage flexibility through demand response (DR) strategies using economic incentives, such as real-time electricity prices and advanced energy technologies, to motivate customer response.

Transactive (or TLM) System: A system that combines real-time system information with forecasts of loads (demand) and distributed generation (DG) production to develop an (economic) incentive or price (TLM) “signal” that reflects system needs [2].

Transactive (or TLM) Prices: Spatially and temporally distinguished energy and/or power prices within the Transactive System and markets that are determined based on the actual system and market conditions and used, specifically, for TLM.

Transactive (or TLM) Data Models: Representations of Transactive Signal components in a machine-readable, and potentially in a standardized, format.

Transactive (or TLM) Signals: Taxonomy, data constructs, and transport mechanisms to communicate the Transactive Prices to customers using methods such as the Internet.

Transactive (Or TLM) Price Services Interface (PSI): The demarcation point between the grid Transactive System and consumers that are the final recipient of the standardized TLM Signals [6].[1]

[1] Adapted from the National Institute of Standards and Technology term, Energy Services Interface, for “device or application that functions, as the gateway between the energy providers and consumers.

2
CALIFORNIA'S FUTURE ENERGY SYSTEM

A large share of variable renewable electricity will be needed to support California's future energy system. To reach this goal, a similarly large share of "grid balancing" and "flexible demand" resources will be necessary to address grid reliability, stability, and cost-effectiveness. While TLM and the supporting TLM system may address some or all of these requirements, the design and architecture should be based on assessing the existing electric grid infrastructure and markets. This section of the report reviews California's existing regulated market structure, electricity market supply planning and operations, the wholesale electricity market pricing system, and DR programs that enable customer load participation through TLM in alignment with the project goals and objectives.

Regulated Electricity Market Structure

The California Independent System Operator (CAISO) operates California's day-ahead and real-time (intraday) wholesale energy markets. The locational value of supply-side resources is calculated at thousands of *pricing nodes* ("Pnodes") around the state and these prices are used in the settlement of generation and supply-side demand response resources. On the other hand, loads (including demand-participating DR loads) are settled at much less granular *load aggregation points* ("LAPs") that usually are the average of the locational prices within the service territories of the California investor-owned utilities (IOUs).

A consequence of this design is that projects under this solicitation that are participating as supply-side resources (Group 1) are directly exposed to wholesale transmission locational prices. On the other hand, compensation of demand-side resources (Group 2) might depend on a variety of additional considerations, including local distribution system constraints, retail tariffs, and third-party aggregation agreements.

More information on the California markets is available on the CAISO website [7].

Electricity Market Supply Planning and Operations

The CAISO comprehensively operates the wholesale electricity markets and manages the reliability of its transmission grid, including both energy and capacity markets.

- The energy markets are managed for day-ahead supply and real-time reliability of the grid through wholesale DR markets and generation dispatches.
- The capacity markets are operated to provide resources that the CAISO can use for ancillary services from participants to meet CAISO's reliability requirements.

The daily CAISO markets operate on a timeline that starts well in advance of the operating day and ultimately extends down to 4-second regulation signals. Following the operating period, a settlements timeline continues for several more weeks. The energy prices calculated for the "day-ahead" market (DAM) are determined the morning before the operating day, which runs from midnight to midnight. The market-clearing price for energy in each hour of the day is derived from the bids and offers received from market participants (supply-side and/or demand-side) prior to the market close. The resulting schedule of feasible power flows in the transmission network is then used to calculate the costs of congestion and losses in the grid. These are then combined with the cleared energy costs, resulting in the final list of thousands of Pnode prices across the state that is posted at 1:00 PM on the afternoon preceding the operating day (which runs from midnight to midnight).

Because of the timing of this process, the DAM prices are at least 11 hours old at the start of the operating day and will be at least 35 hours old by the end of the operating day. To help bring the system into balance during the operating day, the CAISO also runs a load-following "real-time" market (RTM) that posts updated hourly prices 45 minutes before the beginning of each operating hour.

Wholesale Electricity Market Pricing System

As described above, the participants in the CAISO markets are exposed to two price regimes. One, based on the detailed LMPs across the grid, forms the basis of supply-side resource compensation. The other, based on aggregations of Pnodes into large aggregations or LAPs, forms the basis of settlements with load-side resources. Depending on the nature of the projects receiving the TLM Prices, one or the other of these prices may provide a more appropriate motivational TLM Signal.

The specific mappings of Pnodes into aggregations for LAPs (and Sub-LAPs) are defined by the CAISO and are available on the CAISO website [8].

Customer Load Participation: Demand Response Resources

A challenge in developing the TLM System is determining how the economic incentives can be made relevant for both demand-side and supply-side resources. Supply-side resources such as large loads or aggregations of small loads that participate in the CAISO energy markets can use signals that incorporate demand forecasts, including weather effects, the costs of supply, delivery and network constraints, etc.[2] These LMPs based on the market-clearing rules are used to determine settlement payments to these direct market participants. Besides providing the foundation for deriving the TLM Prices for supply-side participants, these prices could also motivate those demand-side consumers that choose to respond to calls for conservation even in the absence of other incentives (for the "greater good" of the grid or of the environment, for example).

It is a core concept of this and the supporting projects that the energy resources respond to a single source of transactive signals and that these signals must reflect actual electricity market and power system conditions that test and evaluate the response capabilities of DR resources with different characteristics. This strategy reduces the bias and connects the Group 1 and 2 project findings to a common baseline pricing and signal design. While certain customers' elasticity is driven by pure economics, some customers can be sensitive to the source of generation (e.g., renewable generation mix). With the project focus on economic motivation of

[2] The CAISO Market Clearing Prices (MCPs) are expressed at the Pnodes, as Locational Marginal Prices (LMPs)

TLM, the source of generation can be a key factor in determining the TLM Prices. On the demand side, the situation is more complex. The variety of electricity consumers suggests that there is likely to be a similar range of motivations to which they would respond. Additionally, a variable spatial distribution congestion conditions can exist within a diverse set of service providers and customer-side technologies. An example is where a certain sub-station or transformer-level congestion can exist, as opposed to system-wide congestion. Hence, no single TLM Price may be optimal for all demand-side responders and diversity in the electricity network, and a possibly extensive set of TLM Prices, each tailored to a different class of responder within a targeted location, might be required to maximize the response. Creating a large set of tailored TLM Prices and their corresponding Transactive Signals and TLM Data Models is not feasible for this project, and it will be important to understand the Group 2 demand-side DR projects to identify the higher priority TLM Prices, which they wish to receive.

Thus, a single system-wide integrated TLM Price that would work effectively for both supply-side and demand-side resources, while appealing in its simplicity, is impractical. Not only are supply and demand prices for electricity is settled differently, but the magnitude of the dynamic CAISO prices may not be reflected in the relatively static TOU rates to which demand-side customers may be subjected to, and these rates will certainly not reflect administratively set peak tariffs whenever they are invoked. This is further complicated by the capacity payments that are made to resources. These payments may include DR resources, which are earned merely by making themselves available (even if they are never dispatched and would therefore never receive an energy payment).

In California's wholesale electricity markets, due to long-term and day-ahead capacity and energy market settlements, the costs of energy procured in the CAISO may not reflect the short-term energy costs of serving demand-side consumers. A viable solution may, therefore, require that different TLM Signals be created, one that closely tracks the CAISO LMPs (for supply-side resources that participate – and would settle – in the CAISO markets) and at least one other signal that aligns more closely with the costs incurred by the users that operate demand-side resources. Such pricing system requires to track generation and demand conditions to make real-time and spatial price adjustments to ensure grid reliability (e.g., large magnitude of battery energy storage charging during low price periods) for the transmission and the distribution system.

Since a DR customer can participate in either supply-side and demand-side DR programs with different rules and the same available load(s), the TLM Signal must address various types of customers and loads and electricity market constructs that exist now and can be envisioned to work in the future, as shown in Figure 2-1.

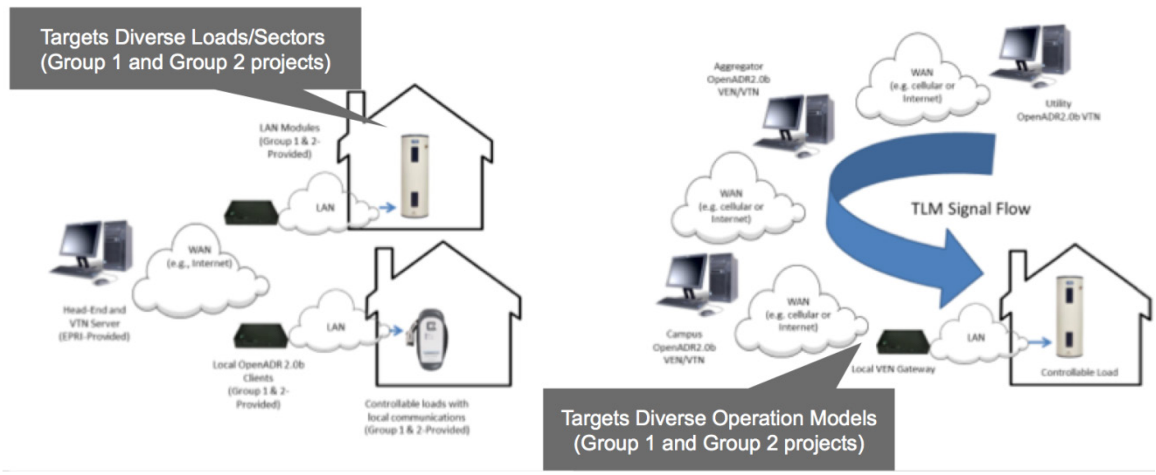


Figure 2-1
TLM Signals to Target Customer and Operational Diversity

State of Markets: Dynamic and Real-time Rate Tariffs

Most DR customers in California receive service under electricity rate tariffs from the three investor-owned utilities (IOUs): Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). The California Public Utilities Commission regulates these IOUs and approves the electricity rate tariffs (tariffs) for all customer categories (Commercial, Industrial, and Residential).

The table in Appendix C contains a snapshot of a large variety of the ninety-nine tariffs that are deployed by PG&E to service a diversity of customer categories, classes, power levels, and territories. While some of the tariffs are flat energy rates (for example, residential), other customers are subjected to demand charges, time-of-use (TOU) rates, and dynamic prices. The energy kilowatt-hour (kWh) rates for the tariffs can be classified, as (a) fixed energy price; (b) time-of-use prices (TOU); or (c) dynamic prices. In addition, certain customers are subjected to fixed demand or power (kW) rates. These tariffs and their links to DR are explained below.

Fixed Energy Prices: In a tariff with fixed energy rates ($/kWh), the price of energy is constant throughout a contractual period and is based on the total energy used, billed monthly. While such fixed energy rates can encourage energy efficiency when billed in increasing block tier prices by the amount of energy consumed, they do not provide any other incentive for participation in DR programs.

Time-of-Use (TOU) Prices: In a tariff with time-of-use (TOU) rates ($/kWh), the price of energy varies temporally for fixed intervals during the contractual period. This temporal variation can vary seasonally (in summer or winter) or across the day (day vs. night). While the TOU-based tariffs encourage daily peak load management, because they are fixed for each interval, they too do not provide the incentive for participation in dynamic DR programs.

Dynamic Prices: In a dynamic pricing tariff, the kWh price of electricity is subject to shorter temporal variations, as per agreed terms between the customer and the utility. The dynamic price changes can either be provided day-ahead or during the operating day. The DR programs can use dynamic prices to encourage customer participation, reflecting variations in supply and demand.

Presently, the information and grid-based analytics framework constraints limit the calculation and frequency of dynamic prices that account for real-time system and market conditions.

Demand Charges: In addition to the energy pricing, some customers' total electricity costs are also determined based on the peak demand ($/kW) during a billing period (usually monthly). These "demand charges" are based on the peak demand and added to the energy ($/kWh) bill. While demand charges can increase a peakier customer's energy bill, such customers have incentives to manage their peaks on a day-to-day basis. Such demand charges are typically intended to provide revenue recovery for the existing distribution network infrastructure.

Among the California IOUs, the dynamic pricing tariffs offer the smallest spatial and temporal variations in prices to customers to encourage DR. While most of the DR programs require participation as a demand-side resource, some of the recent dynamic pricing tariffs, such as base interruptible program (BIP), allow enrolled customers to participate in the CAISO wholesale DR markets as a supply-side resource [9]. The existing market structures, rate tariffs, and DR programs provide no mechanisms that enable customer DR participation based on TLM Prices that reflect real-time system and market conditions. The present market structures also do not integrate CAISO wholesale market electricity LMPs with the distribution system electricity rate tariffs in real-time. The TLM approach will require close coordination among the CPUC, CAISO, and the IOUs to enable pricing structures that can consider the design and estimation of TLM Prices.

As evidence that this approach can be a feasible strategy, the recent IOU proceedings before the CPUC consider a separate tariff for electric vehicles (EVs). A dynamic price proposal for a pilot tariff from SDG&E is the closest to a TLM-based pricing structure. This pilot tariff encourages flexibility in charging among EV and infrastructure owners through vehicle-grid integration (VGI).[3] This VGI pilot tariff is described below.

San Diego Gas and Electric's Electric Vehicle Grid Integration Pilot Tariff

This pilot tariff provides price signals with the goal of minimizing EV charging impacts on SDG&E's distribution system and local distribution capacity by influencing customer decisions regarding EV charging. It employs an hourly variable rate that is communicated to customers by publishing it on a website and through mobile applications. The present SDG&E tariffs comprise of the following nine components:

1. *Transmission (T):* "charges for costs to deliver high-voltage electricity from power plants to distribution system."
2. *Distribution (D):* "charges for costs to distribute electricity to customer premises."
3. *Public Purpose Programs (PPP):* "charges to pay for state-mandated programs such as low-income and energy efficiency programs."
4. *Nuclear Decommissioning (ND):* "charges to pay for the retirement of nuclear power plants."
5. *Competition Transition Charges (CTC):* "charges to pay the above market costs for long-term power contracts."

[3] Application of SDG&E for approval of EV grid integration pilot program; Filed before the CPUC, April 11, 2014

6. *Reliability Services (RS):* "charges for services provided by generating facilities to maintain system reliability."
7. *Total Rate Adjustment (TRA):* "charges/credits applied to handle the capping of residential tiered rate pursuant to Assembly Bill (AB) 1X and Senate Bill (SB) 695."
8. *Department of Water Resources Bond (DWRB):* "charges to pay bonds issued by DWR to cover of cost of purchasing power during the 2000/2001 electricity crisis."
9. *Commodity (C):* "charges for electricity, which includes charges for energy provided."

The pilot VGI tariff incorporates a subset of these nine components to form an integrated transmission and distribution network-based variable price.

The pilot VGI tariff includes an hourly "base" rate component to recover costs through the components and is illustrated graphically in Figure 2-2:

Base Rate = T + PPP + ND + CTC + RS + DWRB

The hourly C component includes the following components:

C = CAISO day-head hourly price + Critical peak price (CPP) hourly adder[4] *+ day-of pricing benefits*[5]

The hourly D component includes the following components:

D = D - CPP hourly adder (Circuit-level CPP)[6]

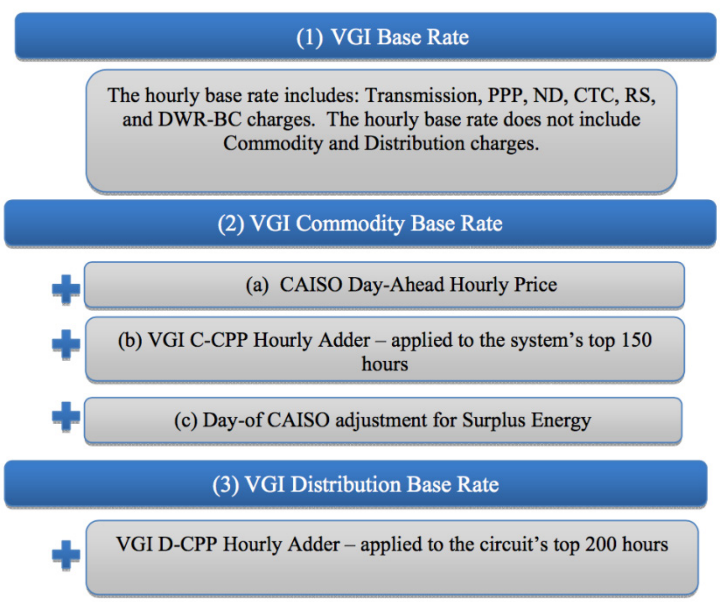


Figure 2-2
SDG&E Pilot VGI Rate Structure and Components

[4] The CPP adder is applied to the "top 150 system hours" and published to customers on a day-ahead basis.

[5] This price is added in an "event that CAISO day-of prices drop below a threshold level relative to CAISO day-ahead prices."

[6] This price is applied to the "top 200 circuit hours" and provided to customers on a day-ahead basis.

Essentially, this pilot VGI rate integrates the wholesale day-ahead electricity market rates with the distribution system network pricing, while mitigating the negative price risks from real-time electricity market volatility. Although this tariff does not contain strong GHG-related components, it nonetheless is a good precedent for California’s transition to a TLM Price paradigm and electricity market structures.

3
FRAMEWORK FOR TRANSACTIVE LOAD MANAGEMENT DESIGN

The framework for the design of the TLM System and Prices was primarily based on analysis of the Group 1 and Group 2 project requirements. The California market structure and electricity pricing system that consider clean energy system mandates were used to provide the context for proposing an analytical framework to calculate the TLM Prices and disseminate the TLM Signals using a standardized platform that supports the TLM Data Model reference design.

The evolution of the electricity system from centralized to distributed generation and the variability of renewable generation resources are leading to a customer-centric strategies for flexible energy-use. A pricing system that encourages such flexibility within the regulated electric grid must fully account for the following:

1. Demand response, as both a supply-side and demand-side resource
2. Fixed and variable generation from resources within the transmission grid, the distribution system, and behind-the-meter customer sites (electricity consumers who produce electricity, termed *prosumers*)
3. Linkages between real-time wholesale and retail electricity market prices
4. Account for greenhouse gas or carbon component of the generation resources (as a proxy for the social cost)

The proxy prices and system to communicate the TLM Data Models in the project will use a reference demand response (DR) communication standard used by the California utilities to publish prices to the Group 1 and 2 participants. The summary of requirement responses is included in Appendix B, Tables B-1 and B-2.

The objectives of the Group 1 and 2 projects are summarized in Table 3-1:

Table 3-1
Summary of Objectives of Group 1 and 2 Projects Using TLM Signals

BMW	EV smart charge management and optimization based on cost and carbon savings.
Center for Sustainable Energy (CSE)	Demonstrate the resource model for CAISO Proxy DR (PDR).
OhmConnect	Generate load changes from large numbers of residential customers at specific times and in specific geographic areas.
Alternative Energy Systems Consulting (AESC)	Demonstrate optimization of residential energy consumption based on day-ahead hourly pricing posted to the HEMS or aggregation.
California Institute of Energy and Environment (CIEE)	Use real or projected prices to initiate control sequences in small to large commercial building HVAC, lighting, and plug loads.
Electric Power Research Institute (EPRI)	Demonstrate aggregation of a wide variety of load types and products for residential and small- and medium-business (SMB) customers.
University of California Los Angeles (UCLA) Luskin Center	Study how consumer response to incentives varies with weather, the day of the week, and time of day.
Universal Devices	Demonstrate residential and commercial automated and self-managed energy use and storage.

It should be emphasized that the design of the TLM System and Prices is independent of any data communication standard. This means that the TLM Signals can be transported by an existing standard, by extending an existing one, or by developing a new standard. Such an analysis is outside the scope of the project. The TLM Signal design and proposed framework are generic. At a minimum, the determination of prices would include data inputs for pre-market planning and real-time analytics for both wholesale (supply-side), generation sources (for GHG), and retail (demand-side) markets, as shown in Table 3-2. The day-ahead analysis is similar to the current wholesale electricity market planning and operations. These data inputs are further described in Section 4, Proposed TLM Pricing and Signal Design.

Table 3-2
Day-Ahead and Real-time Parameters for Point of Price Proxy Analytics

Day-Ahead Parameters	Real-Time Parameters
Planned system operations	Electricity system changes
Planned market operations	Electricity market deviations
Generation source purchases	Generation source deviations
Demand forecasts	Supply and demand variability

Figure 3-1 shows both these analytical needs and integration with Group 1 and 2 project participants. The analysis of forecasting models and real-time TLM Prices based on the actual system and market conditions should consider both supply and demand sides, including the environmental considerations of the generation sources, as inputs at the "point" (dotted rectangle on the left). This point can be a generic construct within the grid based on potential future advanced TLM System designs that may account for spatial granularity. Examples of this may be Pnodes, LAPs, substations, etc. It is imperative that the TLM Prices can influence the transmission and distribution system deferral costs by the efficient use of the network. Hence, such factors are not discussed. The information determination for the TLM Price output forms the basis to communicate the TLM Signal to a Price Service Interface (PSI). The Group 1 and 2 projects' PSI would receive the published TLM Signal (dotted rectangle on the right). This activity of determining analytical needs for price determination is outside the scope of this project. However, as mentioned earlier, for this project, the study considers a generic TLM Signal for loads that participate in supply-side or demand-side resources through an OpenADR 2.0 based communication signal, as a standards-based reference model. Thus, for this first release, the projects can use the reference communications and prices to make an adjustment to the signal to more closely reflect the value of energy at a specific customer location.

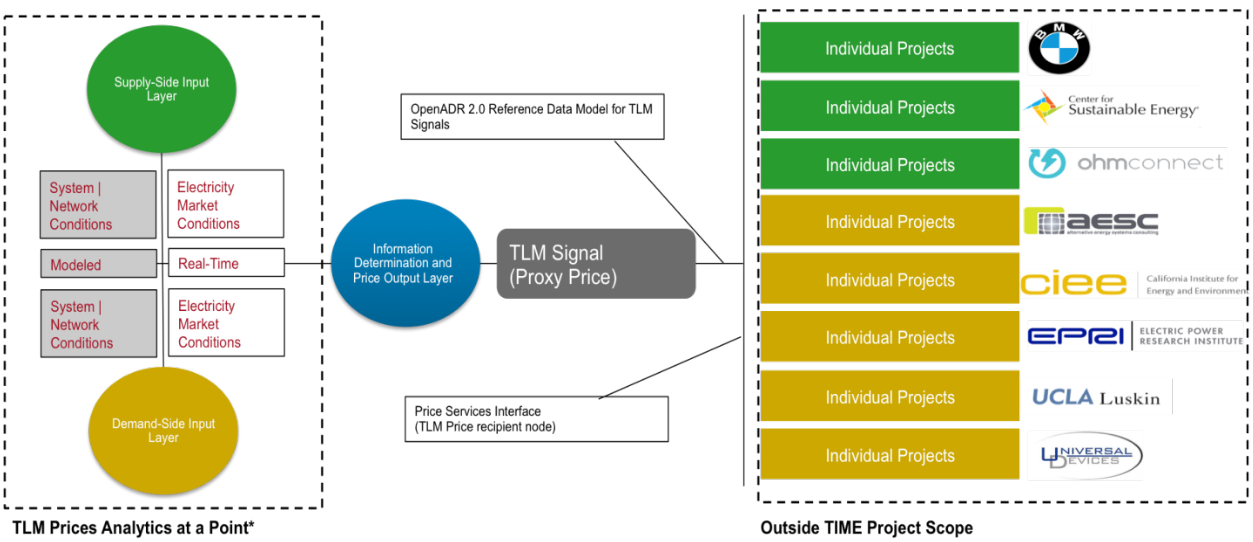


Figure 3-1
Framework for TLM System and Prices and Integration with Projects*

The analysis of the requirements from the Group 1 and 2 projects and the TAC survey resulted in the identification of the following quantitative determinants, which are further explained below. These determinants were used to propose a generic design framework for the TLM Price(s) and TLM signal(s) that is described in the following sections.

1. Price and generation source
2. Locational targeting

* The TLM Price Analytics "Point" can be a generic construct within the electric grid based on the future advanced TLM System design that may account for spatial granularity.

3. Source of generation or social costs
4. Notification period and intervals.

Price and Generation Sources

Consideration of the social costs, such as environmental or GHG contributions of California's electricity generation sources, is one of the objectives for the projects. Such a need was highlighted in the recent evaluation of impacts from California's energy storage mandate, Assembly Bill (AB) 2514, through the Self Generation Incentive Program (SGIP) that is required to meet the State's RPS goals [10]. The evaluation report findings conclude that while SGIP benefits customers by reducing the electricity costs, it is not meeting the program goal of reduction in GHG emissions [11]. To reflect the GHG component in the TLM Prices, the economic incentives and variability in electricity prices are used for cost optimization, and the electricity generation source is used for carbon optimization. In support of economic principles, as a key motivation for TLM Prices, the study focuses on communicating the TLM Prices and basic TLM estimation methods, as opposed to advanced methods that determine the TLM prices based on the real-time system and market conditions.

The CAISO LMPs at the pricing nodes (Pnodes) are used to determine the wholesale market electricity prices [12].[7] The day-ahead market, the 15-minute market, and real-time dispatch are used to compute the three variations of LMPs. The Pnodes are updated when the CAISO physical network model changes. For example, a creation of a new injection or withdrawal point would trigger the need for a new Pnode and vice versa.

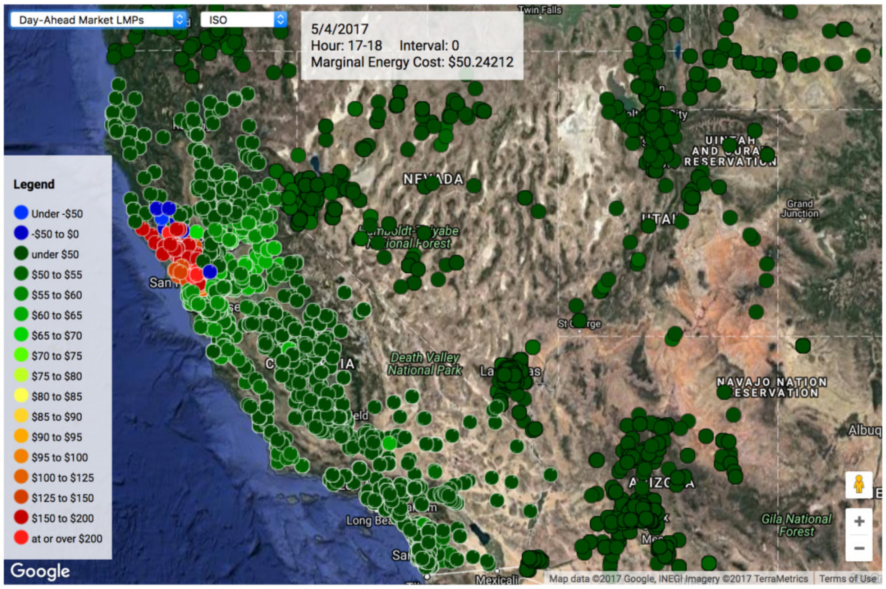
The components used by the CAISO to determine the LMP are:

$$LMP = Energy + Congestion + Losses$$

An Aggregated Pnode (APnode) is used to define a group of Pnodes.[8] The CAISO publishes the APnode prices for each of the three California IOUs and other APnode prices are published for the custom Sub-LAPs used by certain DR aggregations.

These Pnode LMPs, as shown in Figure 3-2, reflect prices at points within the electric grid where the supply resource connects to the grid and where the CAISO high-voltage transmission system connects to the medium- and low-voltage substations to supply power to customers using the distribution grid network.

[7] **Pnode:** "A single network Node or subset of network Nodes where a physical injection or withdrawal is modeled and for which a Locational Marginal Price is calculated and used for financial settlements." (Source: CAISO). Pnodes are created (if needed) in response to new interconnection requests. **LMP:** "The marginal cost ($/MWh) of serving the next increment of demand at that Pnode consistent with existing transmission constraints and the performance characteristics of resources." (Source: CAISO)
[8] **APnode:** "A Load Aggregation Point, Trading Hub or any group of Pricing Nodes as defined by the California ISO." (Source: CAISO)



(*Source:* http://www.caiso.com/pages/pricemaps.aspx)

Figure 3-2
CAISO's Locational Marginal Price Nodes

Locational Targeting

Locational targeting enables technologies and platforms to identify grid congestion areas and take actions to alleviate it. In this instance, variable prices can be a proxy for grid health and a customer incentive to exercise demand flexibility. One of the CAISO's challenges related to multi-location aggregated load bidding into the wholesale DR markets is determining the Pnode location of a responding resource. Another axiomatic CAISO challenge is congestion management via targeting resources within the multi-location and single-location aggregated loads and individual loads within a distribution network.

The Pnodes can be within any of the CAISO's single sub-load aggregation points (sub-LAPs), which some of the projects reference.[9] A sub-LAP is a subset of Pnodes within a default LAP. Figure 3-3 shows the CAISO-determined twenty-four sub-LAP regions that have aggregate patterns of supply congestion and price volatility within each utility territory.

[9] **LAP:** "A set of Pricing Nodes that are used for the submission of Bids and Settlement of Demand." (Source: CAISO)

Sub-LAP: "A California ISO defined subset of Pnodes within a Default LAP. (Source: CAISO)

(Source: CAISO Reliability Demand Response Product)

Figure 3-3
CAISO-Determined Sub-LAPs

Source of Generation or Social Costs

California has set aggressive renewable generation policy objectives of having 33% and 50% of all generation coming from renewable sources by 2020 and 2030, respectively. Customers' elasticity to loads that account for the source of electricity and are responsive to the generation mix is being considered in the optimization strategy under select Group 1 and 2 projects. For example, in addition to economic optimization, the vendor BMW plans to optimize demand, as a supply-side resource, based on renewable generation source. The UCLA project considers social cost of carbon, wherein the cost of generating electricity from coal is weighted more heavily than the cost of generating from solar. The study recognizes that the social costs are broader than the fuel sources and can account for other factors such as air quality, health, etc. This study uses greenhouse gases (GHG) as a proxy for social costs and focuses on the economic motivation.

The CAISO runs an energy imbalance market (EIM) at the bulk generation and transmission system level to make generation within the western U.S. a dispatchable resource. This larger pool extends beyond the state's boundaries and is intended to address the variability of renewable generation on a least-cost basis. While the details of the EIM are outside the scope of this study, the important part of this activity is the consideration of GHG as another price adjustment component within the LMPs (since the California GHG regulations apply to imported electricity). The GHG component allows the cost recovery of the dispatched generation resource resulting from meeting the compliance obligations inside the CAISO territory [13].

Presently the CAISO LMPs consider energy, congestion, and losses, and these are the only components that determine California's wholesale electricity market prices. Since the congestion and loss components are defined by the physics of the grid itself, the only price component that could possibly account for GHG (or other social costs) is the energy price, which is determined by the clearing price resulting from (non-transparent) electricity supplier offers. Thus, unless a supplier factors in social costs (such as the cost of carbon, for example), there is no mechanism for including such costs.

Notification Period and Intervals

Any signal that notifies customers to exercise demand flexibility must account for the notification period and intervals. The notification period begins with the publication of the TLM Signal and ends when the proxy price becomes valid. The TLM Signal intervals include one or more durations for which the particular proxy TLM Price is valid. Most of the projects can use day-ahead (DA) notification of hourly price intervals for a 24-hour duration since it provides an ability for forward planning of demand-side operations. To ensure efficient integration with disparate technologies and architecture of Group 1 and 2 projects, the DA hourly price signal shall be standardized and published, as a proxy TLM Price. Additional granularity in the notification period (for example, intra-hour) and shorter intervals (such as 15- and 5-minutes) will be considered, as needed.

4
TRANSACTIVE LOAD MANAGEMENT PRICING AND SIGNAL DESIGN

The Pnodes and LMPs are critical factors in enabling granular price communications and allowing new flexible loads, such as electric vehicles, to leverage the benefits of smart charging and load shifting – both temporally and spatially. The Pnodes represent the lowest spatial disaggregation of TLM Prices for the wholesale electricity markets.

California's day-ahead and real-time electricity price indicators represent the state of the transmission system at the wholesale level (*Wholesale Market Pnode LMP*). For distribution electricity customers, the study proposes distribution service provider or operator-level distribution system and supply-demand variation adjustments (*Distribution System Price Adjustment*) for the retail electricity prices that reflect actual system and market conditions.[10] These adjustments should consider utility-specific needs and existing market and tariff requirements. The resulting integrated and the inclusive market-based price is termed, as the "*Integrated TLM Price.*"

To produce the integrated TLM Price and corresponding TLM Signal, the design and price determination considers both the existing Pnode LMPs from the wholesale electricity markets and adjustment within the distribution system. This is similar in concept to the VGI pilot tariff that was proposed by SDG&E. The design framework to determine the TLM Price is shown in Figure 4-1.

While the reference components of TLM Price on the wholesale markets exist, the distribution system adder can be a multiplier that is indicative of the state of the distribution system and markets and expressed in $/kWh. This ensures a common representation of both wholesale proxy costs from electricity markets and the existing system of cost recovery of energy services provided to the generation resources and customer's energy use. However, as requested by select Group 1 and 2 project participants, these proposed determinants could also consider that the GHG or social cost may be another component of the TLM Signal. Additionally, supply and demand variability that will result from renewable generation at different domains within the electric grid can be considered for advanced TLM Price determination. The resulting integrated TLM Price would be a wholesale and retail market integrated price that is indicative of the T&D systems and market conditions.

[10] Note that these are still proxy prices used to motivate responses: they do not necessarily represent the prices users pay as determined by their retail tariffs.

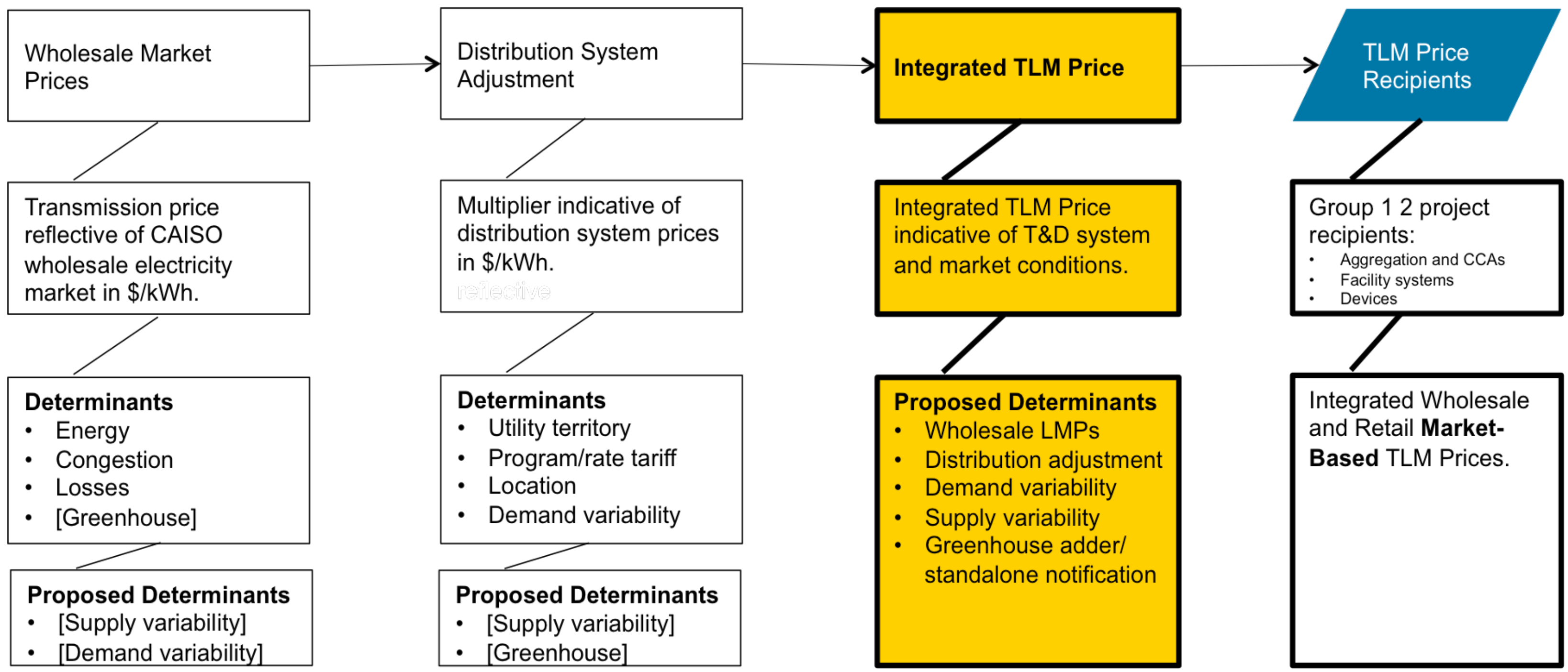


Figure 4-1
Design Framework for TLM Price Analysis at each Point within the Grid

The current and proposed determinants for the TLM electric price analysis framework are defined as shown in tables 4-1 and 4-2 for wholesale market prices and distribution system adjustment, respectively. The proposition behind this framework reflects the goals and objectives of the project, as well as the consideration of current California's bifurcated wholesale and retail electricity prices and stakeholders under the regulated environment and utility business models. The end goal is to ensure that the electric customers and stakeholders benefit by leveraging the real-time prices and advanced technologies to better manage the grid, energy-use, and save costs.

Table 4-1
Determinants of Wholesale Market Price or Cost

Wholesale Market Price: Reflects the current state of pricing determinants for wholesale electricity markets, including the proposed new determinants that consider intra-hour supply-side variability and any changes in the distribution system conditions.[11]	
Energy	The CAISO analysis of DAM and hour-ahead energy prices calculated, as $/MWh
Congestion	The CAISO analysis of congestion costs based on the feasible power flows in the transmission network calculated, as $/MWh
Losses	The CAISO analysis of loss costs based on the feasible power flows in the transmission network calculated, as $/MWh
Demand Variability	The CAISO analysis of DA and hour-ahead demand forecasts calculated, as MW
Supply/Generation Variability (Proposed)	Includes intra-hour variability analysis for high penetration of renewable generation to meet the policy mandates of 33% and 50% renewable portfolio standards for 2020 and 2030, respectively; and any resulting transmission system changes, calculated, as MW.
Greenhouse Gas or Carbon (Proposed)	Proxy for social costs that aligns with the Group 1 and Group 2 projects and GHG consideration in the CAISO-run EIM for the bulk generation and transmission system, calculated as $/MWh

[11] The consideration for distribution system conditions is due to the distributed generation model and the paradigm shift from the traditional centralized bulk generation. This change can be the proxy through demand-side variability analysis.

Table 4-2
Determinants of Distribution System Adjustment

Distribution System Adjustment: An adjustment that is reflective of a localized distribution system and market conditions that accounts for generation and demand.	
Utility Territory	From the DR programs that are tailored to specific utility territories
Programs and Rate Tariffs	DR market design that is tailored specifically to a utility territory's electricity rate tariffs (such as peak-day pricing or demand bidding).
Location	From the DR programs that are tailored to a utility territory's location-specific needs (such as zones or substations).
Supply/Generation Variability (Proposed)	Includes inter-hour and intra-hour variability analysis for behind-the-meter and DG to meet the policy mandates of 33% and 50% renewable portfolio standards by 2020 and 2030, respectively, and any resulting distribution system conditions, calculated as kW.
Demand Variability (Proposed)	Includes intra-hour demand variability based on components, such as the weather and behind-the-meter and distributed generation (DG), and CAISO analysis of DA and hour-ahead demand forecasts, calculated as kW
Greenhouse or Carbon (Proposed)	Proxy for social costs that aligns with the Group 1 and Group 2 projects for the distribution system generation system, calculated as $/kWh

The "Integrated TLM Price" output from these existing and proposed determinants for generation, transmission, and distribution systems reflects the integrated grid conditions and utility objectives (distribution adjustment) that proactively considers the following: variability in demand and supply/generation, the greenhouse/carbon considerations, and distribution system conditions based on both forecast and real-time conditions.

Generic TLM Pricing Signal Design

Based on consideration of the customer load participation in either demand-side and/or supply-side markets and the needs of the Group 1 and Group 2 project participants, the study proposes a generic signal design without the inclusion of distribution determinants or GHG components. As mentioned earlier, the individual projects can potentially make a price adjustment to the signal to more closely reflect the value of energy at a specific location and such adjustments can also consider these additional components. The final integrated TLM Price, however, must consider the distribution and GHG components to meet California's clean electricity system goals and current utility electricity pricing structure and business models. This generic signal design is associated with one or many price proxy nodes within California's transmission and distribution system. The project scope extends to supporting TLM Prices based on the Pnode LMPs (with optional Group 2-supplied distribution adder), as a "proxy" TLM Price. This TLM Price would be communicated via a TLM signal. This generic TLM Signal design that maps to existing CAISO wholesale DR market price notification framework and IOU DR programs is shown in Figure 4-2.

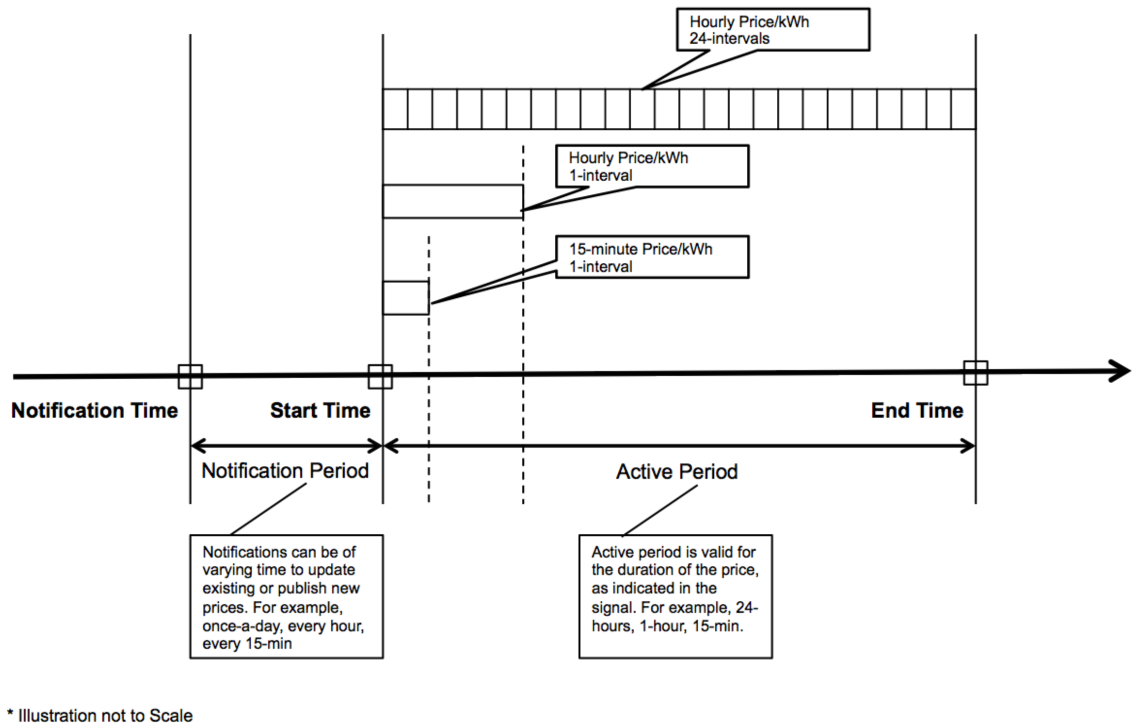


Figure 4-2
Construct for the Design of Generic TLM Signal(s).

This generic signal design includes the elements of the wholesale electricity market prices and the constructs used for the retail DR program design that communicates the prices (as for a peak-day pricing program). While the signal design is agnostic to any specific communication standard or data model representation, this project created a reference design using an existing standard that the project team had expertise in and had deployed infrastructure.

Standards-Based Reference Signal Communication Data Model

For this study, OpenADR 2.0 standard was used, as a reference communication and data model to publish the TLM Signals [14]. This includes the following OpenADR components in support of economic motivation to influence customer's demand flexibility.

1. Market-based economics (DA notification with hourly LMP price schedule for a 24-hour period) in the following format: [*ProgramTariff* | *Market Context*]
2. Targeted location: The Pnode or APnode locations (for all or select Pnodes across California) will represent the location of the price: [*Pnode* | *APnode*]
3. Integrated distribution utility service territory (PG&E, SCE, and SDG&E) adjustment: [*DistributionUtilityTerritory*]

Each project's OpenADR clients shall receive one or many of the TLM Signals, including different electric service provider variations of Group 1 and 2 projects. These LMP signals are distinguished in the market context in the following format:

[*ProgramTariff* | *MarketContext*] . [*Pnode* | *APnode, DistributionUtilityTerritory*]

Although this wholesale electricity market context covers the supply-side prices, a demand-side program may want the LAP (or Sub-LAP) prices. If these were not sent, the project participants would have to subscribe to relevant APnode prices. The project will consider a simple distribution system adjustment to either the Pnode or APnode to provide TLM Price that reflects the demand-side program.

Other mechanisms supported by OpenADR might be useful for some projects. For example, group addressing of VENs or other mechanisms for targeting specific locations might prove to be more efficient. Determination of the exact mechanisms to be used will require further understanding of the architecture of the recipient projects.

5
PRELIMINARY FINDINGS AND NEXT STEPS

The fundamental basis of this study was to determine the high-level architecture of TLM System analysis in support of California's future energy systems and propose a generic TLM Price and TLM Signal design that can be deployed using any standards-based data model platforms. California's existing regulated electricity market structure, literature reviews, Group 1 and Group 2 project reviews, and feedback from the technical advisory committee were used to recommend key metrics that should constitute the TLM System, Price(s), and Signal(s). The TLM Price signals will enable DR participation in both supply-side and demand-side markets in support of grid reliability under California's aggressive renewable generation goals.

The interim findings show the critical need to integrate California's electricity markets to unlock the full value from customers' DR resources and enable cost-efficient integration of variable renewable generation. The findings can be used by the industry and research organizations to develop new practices for widespread adoption of economics-driven transactive technologies and systems for an integrated electric grid of the future.

The detailed project findings are as follows:

1. The 24-hourly day-ahead California wholesale electricity market prices constitute the consensus temporal base case for TLM Prices. There are outliers with intra-hour price notification and price duration signals.
2. The Pnode locational marginal prices (LMPs) published by the CAISO can be the lowest desired spatial disaggregation for wholesale electricity market prices. Likewise, the APnode prices for the IOU LAPs are the lowest spatial disaggregation for wholesale electricity market demand prices.
3. The distribution system variability (demand/supply) adjustment and electricity service providers and operations may be considered for customer-level TLM System and Prices that reflect integrated system and market conditions.
4. An integrated and inclusive approach to the CAISO (transmission and generation) domains and the electric utilities (distribution) domain is critical to determine "fair market" and integrated TLM Prices.
5. The determination of TLM Price must include data inputs for pre-market planning and real-time analytics for both wholesale (supply-side), generation sources (for GHG) and retail (demand-side) markets. This ensures that advanced analytics are used to calculate Prices that consider real-time system and market conditions.

Next Steps

The scope of the project is to design, develop, implement, and operationally deploy the TLM System, Prices, and Signals (representing proxy TLM Prices) to facilitate DR by California's utility customers and others. In this analysis, the study proposes a design and development methodology for the TLM System, TLM Prices and TLM Signal and the use of a reference communications data model distribution mechanism based on an existing DR standard to publish proxy TLM prices to Group 1 and 2 project participants. Considering the shortcomings of the electricity system readiness for a future with a large renewable mix, the TLM must address them by including the supply- and demand-side system and markets, and stakeholders. The future activities must focus on the following:

1. Analyze the impacts of distribution system cost adjustment on electric utility operations and planning, and on existing electricity rate tariffs and business models.
2. Leverage the state and federal efforts to design and develop methodologies to estimate transmission and distribution system TLM cost adjustments at different points within the grid.
3. Develop a roadmap and evaluate the impacts on utility business models and technology of adjusting the CAISO LMPs to produce a distribution system price based on real system and market conditions.
4. Develop a TIME prototype software system and signaling tool using LMPs (wholesale) and substation (distribution) models.
5. Evaluate the technology and cost-effectiveness of the TIME System for various scenarios for moving California toward a more renewable-enabled transactive grid.

For the purposes of applied research and development, the next one-year activity will focus on operationalizing and maintaining the TIME systems and TLM signals. The Group 1 and Group 2 project participants shall leverage the system and signals to deploy advanced DR automation technologies to identify customer response strategies, end-use loads, system architecture, and value. The final report at the end of the project shall report on the results of the implementation of this system and prices and future research necessary to advance the concepts and the reference design identified in this report.

6
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A

LIST OF TECHNICAL ADVISORY COMMITTEE (TAC) AND TECHNICAL ADVISORY BOARD (TAB) MEMBERS

The **Technical Advisory Committee (TAC)** comprises leading practitioners and subject-matter experts in price-responsive signals and standardization. The TAC remains engaged throughout the duration of the project through bi-monthly or quarterly meetings.

The **Technical Advisory Board (TAB)** comprises visionaries and experts that review and guide high-level project goals and objectives and provide feedback for tangible applications. The TAB remains engaged at strategic milestones of the project through semi-annual meetings.

Tables A-1 and A-2 list the organizations that member names that participate in the TAC and TAB, respectively.

Table A-1
Organizations and Member Names for the Technical Advisory Committee

Organization*	TAC Member Name
Alternative Energy Systems Consulting (AESC)	Mike Ferry
BMW of North America, LLC (BMW)	Adam Langton
California Energy Commission (CEC)	David Hungerford (Project Manager)
California Institute of Energy and Environment (CIEE)	Carl Blumstein
Center for Sustainable Energy (CSE)	Shawn Jones
Electric Power Research Institute (EPRI)	Sunil Chhaya
Institute of Electrical and Electronics Engineers (IEEE)	Bob Heile (IEEE 2030.5 WG)
IEEE 2030.5 Standard (Smart Energy Profile 2.0)	Robby Simpson (Test and Certify)
OhmConnect	John Anderson
OpenADR Alliance (OpenADR 2.0 Standard)	Barry Haaser
Organization for Advancement of Structured Information Standards (OASIS)	Laurent Liscia
Smart Grid Interoperability Panel (SGIP)/ Smart Electricity Power Alliance (SEPA)	Dave Hardin
Universal Devices/ TeMIX	Ed Cazalet
University of California Los Angeles (UCLA) Luskin Center	Julien Gattaciecca

Table A-2
Organizations and Member Names for the Technical Advisory Board

Organization*	Member
California Energy Commission (CEC)	David Hungerford (CAM)
California Independent System Operator (CAISO)	Jill Powers
California Public Utilities Commission (CPUC)	Cathleen Fogel
Lawrence Berkeley National Laboratory (LBNL)	Mary Ann Piette
National Institute of Standards and Technology (NIST)	David Holmberg
Pacific Gas & Electric Company (PG&E)	Abigail Tinker
Pacific Northwest National Laboratory, GridWise Architecture Council (GWAC)	Steve Widergren
Sacramento Municipal Utility District (SMUD)	Denver Hinds
San Diego Gas and Electric (SDG&E)	Tony Rafati
Southern California Edison (SCE)	Mark Martinez
US Department of Energy (DOE)	Chris Irwin

B
SUMMARY ANALYSIS OF GROUP 1 AND 2 PROJECTS

The tables below shows the results of the analysis from the Group 1 and Group 2 projects that are participating in the California's supply- and demand-side (load modifying) electricity markets. The tables also show the key framework used for analysis that includes the key TLM signal characteristics – *notification period, temporal and spatial requirements, and the end-point system architecture* used by advanced technology to enable demand response (DR).

Table B-1
Summary of EPIC GFO 15-311 Group 2 Project Respondents (Supply-Side).

Project/Signals	Objectives	Notification	Temporal	Spatial	End-point
BMW	EV smart charge management and optimization based on cost and carbon savings.	Day-ahead (DA) Optionally, real-time (RT)	Hourly price intervals. Optionally, DA and RT 15-min and 5-min price intervals.	Across 10 counties of PG&E and CCA	Aggregation cloud, as the single-point managing entity.
Center for Sustainable Energy	Demonstrate the resource model for CAISO Proxy DR (PDR).	DA (stage 1) May consider RT energy or spinning/ non-spinning reserve.	Hourly price intervals. Optionally, minutes.	System-wide and/or LMP.	Aggregation cloud, as the single-point managing entity.
OhmConnect	Generate load changes from large numbers of residential customers at specific times and in specific geographic areas.	Two hours for many aggregated loads. Seconds for a small number of loads.	Five minutes	Can utilize precise spatial targeting to dispatch loads in targeted areas	Aggregation cloud, as the single-point managing entity.

Legend: DA: Day Ahead, RT: Real-Time (broadly defined, as a signal with intra-hour notification period); SMB: Small and Medium Business, LSE: Load Serving Entity, BtM: Behind-the-Meter

Table B-2
Summary of EPIC GFO 15-311 Group 1 Project Respondents (Demand-Side).

Project/Signals	Objectives	Notification	Temporal	Spatial	End-point
Alternative Energy Systems Consulting	Demonstrate optimization of residential energy consumption based on day-ahead hourly pricing posted to the HEMS or aggregation.	DA Intra-hour	Hourly price intervals for DA 15-min intervals for intra-hour	Within distribution circuit, CAISO Pnode.	HEMS behind the SDG&E meter. Aggregation cloud manager.
California Institute of Energy and Environment	Use real or projected prices to initiate control sequences in small to large commercial building HVAC, lighting and plug loads.	DA Can handle hour ahead as well.	Hourly intervals for 24-hour Can handle 15-minute intervals.	Sites in southern and northern CA	Signal received at each of 20 buildings. Can set up an aggregation point.
Electric Power Research Institute	Demonstrate aggregation of a wide variety of load types and products for residential and SMB customers.	DA minimum. 5-15 minutes are workable and possibly ideal.	N/A - Hourly?	N/A	End devices, aggregators or Facility EMS depending on the test scenarios.
UCLA Luskin Center	Study how consumer response to incentives varies to weather, day of week, and time-of-day.	Optimally, DA price signals.	Events take place over 3 hour intervals	Disaggregation within PG&E and SCE territory.	Aggregation cloud, as the single-point managing entity.
Universal Devices	Demonstrate residential and commercial automated and self-managed energy use and storage.	3-minutes	Next 24 hourly intervals Next 5 minutes or 15-minutes.	Single location at Moorpark SCE Substation Pnode	Cloud-based TEMIX platform for Distribution Operators and LSEs

Legend: DA: Day Ahead, RT: Real-Time (broadly defined, as a signal with intra-hour notification period); SMB: Small and Medium Business, LSE: Load Serving Entity, BtM: Behind-the-Meter

C
UTILITY ELECTRICTY RATE TARIFFS FOR PACIFIC GAS & ELECTRIC COMPANY

Tariff Name	Title
A-1	Small General Service
A-10	Medium General Demand-Metered Service
A-15	Direct-Current General Service
A-6	Small General Time-of-Use Service
AG-1	Agricultural Power
AG-4	Time-of-Use Agricultural Power
AG-5	Large Time-of-Use Agricultural Power
AG-ICE	Agricultural Internal Combustion Engine Conversion Incentive Rate - Expiration Transition Rate
AG-R	Split-Week Time-of-Use Agricultural Power
AG-V	Short-Peak Time-of-Use Agricultural Power
CCA-CRS	Community Choice Aggregation Cost Responsibility Surcharge (Interim)
DA-CRS	Direct Access Cost Responsibility Surcharge
E-1	Residential Services
E-19	Medium General Demand-Metered TOU Service
E-20	Service to Customers with Maximum Demands of 1000 Kilowatts or More
E-31	Distribution Bypass Deferral Rate
E-37	Medium General Demand-Metered Time-of-Use Service to Oil & Gas Extraction Customers
E-6	Residential Time-of-Use Service
E-9	Experimental Residential Time-of-Use Service for Low Emission Vehicle Customers
E-AMDS	Experimental Access to Meter Data Services
E-BioMAT	Bioenergy Market Adjusting Tariff
E-BIP	Base Interruptible Program
E-CARE	Care Prog Serv For Qualif Nonprof Grp-Liv & Qualif Agri Empl Housing Facils

Tariff Name	Title
E-CBP	Capacity Bidding Program
E-CCA	Services to Community Choice Aggregators
E-CCAINFO	Information Release To Community Choice Aggregators
E-CHP	Combined Heat and Power PPA
E-CHPS	Combined Heat and Power Simplified PPA
E-CHPSA	Combined Heat and Power Simplified Under 500 kW PPA
E-CREDIT	Revenue Cycle Services Credits
E-CSAC	Commercial Smart A/C Program
E-DASR	Direct Access Services Request Fees
E-DCG	Departing Customer Generation CG
E-DEPART	Departing Customers
EDR	Economic Development Rate
E-DRP	Demand Response Provider Services
EE	Service to Company Employees
E-ECR	Enhanced Community Renewables (ECR) Program
E-ECR-PDT	E-Enhanced Community Renewables Project Development Tariff
E-EFLIC	Energy Financing Line Item Charge (EFLIC) Pilot
E-ERA	Energy Rate Adjustments
E-ESP	Services to Electric Service Providers
E-ESPNDSF	Electric Service Provider Non-Discretionary Service Fees
E-EUS	End User Service
E-FERA	Family Electric Rate Assistance
E-FFS	Franchise Fee Surcharge
E-GT	Green Tariff (GT) Program
EITE	Emissions-Intensive and Trade-Exposed Customer Greenhouse Gas Allowance Revenue Provisions
EL-1	Residential CARE Program Service
EL-6	Residential CARE Program Time-of-Use Service
E-LORMS	Limited Optional Remote Metering Service
EL-TOU	Residential CARE Program Time-of-Use Service
EL-TOUPP	Residential CARE Program Time-of-Use Pilot Project Service

Tariff Name	Title
EM	Master-Metered Multifamily Service
EML	Master-Metered Multifamily CARE Program Service
EML-TOU	Residential CARE Program Time of Use Service
EM-TOU	Residential Time of Use Service
E-NMDL	New Municipal Departing Load
E-NWDL	New WAPA Departing Load
E-OBF	On Bill Financing Loan Program
E-OBMC	Optional Binding Mandatory Curtailment Plan
E-OBR	On-Bill Repayment (OBR) Pilots
E-PWF	Section 399.20 PPA
E-REMAT	Renewable Market Adjusting Tariff (REMAT)
E-RSAC	Residential Smart A/C Program
E-RSMART	Residential Smartrate Program
ES	Multifamily Service
E-SDL	Split-Wheeling Departing Load
ESL	Multifamily CARE Program Service
E-SLRP	Scheduled Load Reduction Program
E-SOP	Residential Electric SmartMeter(TM) Opt-Out Program
ESR	Residential RV Park and Residential Marina Service
E-SRG	Small Renewable Generator PPA
ESRL	Residential RV Park and Residential Marina CARE Program Service
ET	Mobilehome Park Service
ETL	Mobilehome Park CARE Program Service
E-TMDL	Transferred Municipal Departing Load
E-TOU	Residential Time-of-Use Service
E-TOUPP	Residential Time-of-Use Pilot Project Service
EV	Residential Time-Of-Use Service for Plug-In Electric Vehicle Customers
LS-1	PG&E-Owned Street and Highway Lighting
LS-2	Customer-Owned Street and Highway Lighting
LS-3	Customer-Owned Street and Highway Lighting Electrolier Meter Rate
NEM	Net Energy Metering Service

Tariff Name	Title
NEM2	Net Energy Metering Service
NEM2V	Virtual Net Energy Metering Service
NEM2VMSH	Virtual Net Energy Metering For Multifamily Affordable Housing (Mash/Nshp) With Solar Generator(S)
NEMBIO	Net Energy Metering Service for Biogas Customer-Generator
NEMCCSF	Schedule NEMCCSF- Net Energy Metering Service For City and County of San Francisco Municipal Load Served By Hetch Hetchy At-Site Photovoltaic Generating Facilities
NEMFC	Net Energy Metering Service for Fuel Cell Customer-Generators
NEMV	Virtual Net Energy Metering for a Multi-Tenant or Multi-Meter Property Served at the Same Service Delivery Point
NEMVMASH	Virtual Net Energy Metering For Multifamily Affordable Housing (MASH/NSHP) With Solar Generator(s)
OL-1	Outdoor Area Lighting Service
PEVSP	Plug-In Electric Vehicle Submetering Pilot - Phase 1
PEVSP 2	Plug-In Electric Vehicle Submetering Pilot - Phase 2
RES-BCT	Schedule for Local Government Renewable Energy Self-Generation Bill Credit Transfer
S	Standby Service
TBCC	Transitional Bundled Commodity Cost
TC-1	Traffic Control Service

D
SURVEY INSTRUMENT FOR GROUP 1 AND 2 PROJECT PARTICIPANTS

Questions to the EPIC GFO 15-311 Group 1 and Group 2 Projects

Electric Power Research Institute (EPRI) is gathering information for the EPIC GFO 15-311 Group 3 project, Transactive Incentive-signals to Manage Electricity-consumption (TIME)—a system for transactive load management. Please keep the responses succinct.

Please return the completed responses to: [EPRI contact]

Project Title and Lead Institution: [Insert data here]

Project PI and Contact Information: [Insert e-mail and phone data here]

1. What are the key objectives your project will address using transactive signals that accurately represent system conditions or costs?

2. What is the required minimum price notification period for the transactive signals? (Notification period is the period between the publishing of the transactive signal and initiation of the demand-side load change. For example, day-ahead notification)

3. What are the minimum time interval resolution (temporal) and interval period for the transactive signal? (For example, hourly intervals for a 24-hour period)

4. Do you have any spatial (geographic) requirements for transactive signals? (For example, a day-ahead 24-hourly interval signal that represents multiple locations across a utility territory)

5. What is the lowest level of end-point that would receive transactive signals to initiate the demand-side load change? (For example, centralized facility management system or aggregation point for all facilities)

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