CALIFORNIA ENERGY COMMISSION

PROPOSED LOAD MANAGEMENT STANDARDS

DRAFT COMMITTEE REPORT

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Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

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This report was prepared by the California Energy Commission's Efficiency Committee as part of the Load Management Standards proceeding - docket # 08-DR-01. The views and recommendations contained in this document are not official policy of the Energy Commission until the report is adopted.

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Acronyms Used in this Report

AMI ....Advanced Metering Infrastructure
AMR............................Automated Meter Reading
BOMA..........................Building Owners and Managers Association
California ISO ....California Independent System Operator
CFM.............................Common Forecasting Methodology
CMUA..........................California Municipal Utility Association
CPP..............................Critical Peak Price
CPUC ....California Public Utilities Commission
DR................................Demand Response
DRA.............................Division of Ratepayer Advocates
DRRC ....Demand Response Research Center
GRC.............................General Rate Case
IOU..............................Investor-Owned Utility
IP..................................Internet Protocol
kW ....Kilowatt (a measure of power equal to 1000 watts)
kWh.............................Kilowatt-hour (a measure of energy)
LADWP ....Los Angeles Department of Water and Power
MRTU ....Market Redesign and Technology Upgrade
MW..............................Megawatt (a measure of power equal to 1000 kilowatts)
MWh ....Megawatt-hour (a measure of energy equal to 1000 kilowatt-hours)
OII................................Order Instituting Informational proceeding
OIR ....Order Instuting Rulemaking proceeding
PCT..............................Programmable Communicating Thermostat
PCD ....Programmable Communicating Device
PG&E ....Pacific Gas & Electric company
PIER.............................Public Interest Energy Research (a Division of the Energy Commission)
POU.............................Publicly Owned Utility
RF.................................Radio Frequency
RPS ....Renewable Portfolio Standard
RUC.............................Residual Unit Commitment
SCE ....Southern California Edison company
SDG&E........................San Diego Gas and Electric company
SMUD ....Sacramento Municipal Utility District
SPP...............................Statewide Pricing Pilot
TDV ....Time-Dependent Valuation
TOU.............................Time-of-Use

Unit Conversions

1 MW = 1000 kW
1 MWh = 1000 kWh
1 kWh = 1 kW of power used for 1 hour

ABSTRACT

Load management slows the rising cost of electricity and improves the reliability of the electricity grid by improving the efficiency of the generation, distribution, and consumption of electricity. Load management standards support these goals by establishing cost effective utility programs that result in improved electric system efficiency, reduced or delayed need for new electric generation capacity, and reduced fuel consumption at existing electricity generating stations. On January 2, 2008, the Energy Commission approved an Order Instituting Informational and Rulemaking Proceeding (OII/OIR) on Load Management Standards, the Efficiency Committee hosted six workshops on various aspects of Load Management over the past ten months, and numerous interested parties have submitted comments to the record. This document is the Efficiency Committee's first draft of proposed standards under this proceeding.

Keywords: Load Management, LMS, Demand Response, Energy Efficiency, Electricity Rates

Executive Summary

On January 2, 2008, the Energy Commission approved an Order Instituting Informational and Rulemaking Proceeding (OII/OIR) on demand response equipment, rates, and protocols. The Energy Commission's Efficiency Committee hosted six workshops in Sacramento between March and July 2008 under this OII/OIR. All major utilities and numerous other stakeholders participated in the workshops, and many participants submitted written comments for the record.

The Purpose of Load Management

Load management slows the rising cost of electricity and improves the reliability of the electricity grid by improving the efficiency of the generation, distribution, and consumption of electricity. Load management standards support these goals by establishing cost effective utility programs that result in improved electric system efficiency, reduced or delayed need for new electric generation capacity, and reduced fuel consumption at existing electricity generating stations. The purpose of this proceeding is to:[1]

(1) Assess which rates, tariffs, equipment, software, protocols, consumer information, and other measures would be most effective in achieving demand response.

(2) Adopt regulations and take other appropriate actions to achieve a voluntary, price-responsive, electricity market.

In the April 25, 2008 scoping order, the Energy Commission Efficiency Committee pursued new load management standards in the following areas:[2]

- Adoption of advanced technologies for operation and management of the electric grid that will benefit electricity customers in California,
- Statewide deployment of advanced metering,
- Implementation of time-of-use and dynamic rate design,
- Adoption of design criteria and deployment of enabling technologies, and
- Development and implementation of customer assistance and education strategies.

To achieve effective load management and demand response, consumers must have three things: information, incentives, and tools. The first step to providing consumers with information is to install advanced meters capable of recording electricity consumption on an hourly or shorter time scale, and make that information available to customers. Rates that reflect the time-varying cost of electricity provide a fair and equitable incentive for consumers to either conserve during high-cost peak periods or shift that consumption to off-peak times and to

[1] *Informational and Rulemaking Proceeding on Demand Response, Rates, Equipment, and Protocols*. Docket Number 08-DR-01. California Energy Commission Order Number 08-0102-10. January 2, 2008.

[2] *2008 Order Instituting Informational Proceeding and Rulemaking on Load Management Standards*. Docket Number 08-DR-01. California Energy Commission Efficiency Committee Scoping Order. April 25, 2008.

respond with additional load reductions during critical periods. Finally, consumers require tools that facilitate their response to emergencies and varying prices. All three components are important to building sustained, cost effective, and successful load management programs.

Over time, upgrades to the electric infrastructure and prices that better reflect the cost of service are expected to contribute to lower system costs and reduced carbon emissions:

- Reliable and dispatchable system-wide load reductions during peak periods will reduce the need to construct new peak generation and the financial cost to procure peak capacity in the market.
- Peak conservation and load shifting will improve the system load factor, resulting in more efficient use of existing infrastructure.
- The shift to dynamic pricing will fostering greater consumer awareness and understanding that will help accelerate adoption of higher levels of efficiency and conservation.
- As experience with automation technologies grows, innovation and cost reduction will expand demand response options, and increase the opportunities for developing programs and tariffs that use demand response resources as a substitute for reserves and for balancing intermittent renewable generation.

Electric System Characteristics

Electricity is a unique commodity that cannot be stored in quantity without large losses. Large scale electricity generation and consumption must be kept in balance at all times because if that balance is disrupted, the system will cease to effectively deliver energy. In essence, whenever someone turns on a light, a power plant must be throttled up somewhere to supply that energy.

The demand for electricity varies with the time of day and the season. Most Californian consumers demand more electricity during the day than at night, and more in summer than winter. With the rapid increase in demand due to air conditioning and other consumer electronics over the last few decades, the maximum peak load has grown in most regions, and is projected to continue growing. That peak load creates inefficiencies within the system. As electricity demand goes up at peak times, power companies generally dispatch power plants in decreasing order of efficiency; therefore as the load goes up, the overall efficiency of producing electricity goes down. When demand falls, the opposite occurs. System operators must manage generation output in real time to match demand as it rises and falls to prevent excessive voltage and frequency changes which could interrupt or damage electrical devices. To protect consumers, federal and state power quality regulations strictly limit the degree that voltage and frequency are allowed to vary.

Because peaking units generally operate only a few hundred hours per year, operators must pay for the unit's ownership and operating costs over a much shorter period. This results in much higher rates when compared with facilities that can spread their fixed costs over more hours of operation. Peaking units are necessary, however, to ensure that adequate amounts of power are available during peak times or to meet unexpectedly high load requirements.

California Load Characteristics

In California, the state-wide peak annual demand for electricity is currently approximately 60,000 megawatts (MW), and the total electricity consumption each year is approximately 300 million megawatt-hours[3] (MWh). Of that 60,000 MW peak demand, approximately 6,000 MW is required for less than 60 hours each year.[4] That means approximately 10 percent of our generation capacity is used for less than one percent of the time to generate approximately 0.1 percent of our energy[5]. Californians currently pay for the equivalent of 120 large peak combustion turbine engines[6] to sit idle for approximately 8,700 hours per year, more than 99 percent of the time. Although this is necessary to keep the lights on when demand is highest, with cost effective improvements in the way electricity is used, Californian consumers could minimize this cost. These efforts would help slow the rising cost of electricity, and reduce the likelihood of wide spread power outages on the most critical demand days by making the job of maintaining the stability of the electric grid easier.

Air conditioning is a critical component of California's growing peak demand. Thirty years ago, fewer than ten percent of buildings were air conditioned. Now, more than 40 percent of buildings in most regions, and over 70 percent in some areas, are equipped with air conditioning.[7] As a direct result of this change, peak electricity demand now follows temperature (Figure 1).

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[3] http://www.energyalmanac.ca.gov/electricity/total_system_power.html

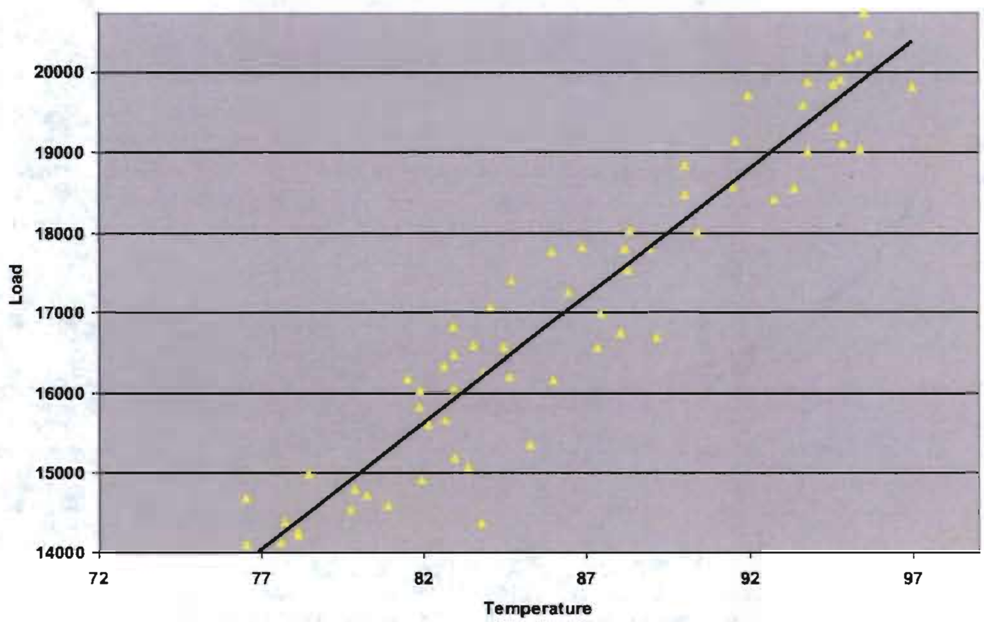
[4] California Energy Commission. *Summer 2008 Electricity Supply and Demand Outlook*. CEC-200-2008-003. May 2008.

[5] California Energy Commission. *2007 Net System Power Report*. CEC-200-2008-002-CMF. April 2008.

[6] Based on 50 MW simple cycle combustion turbine engines.

[7] California Energy Commission. *Memorandum to Commissioner John L. Geesman and Commissioner Jim D. Boyd, Supplementary Information on Historic Load Factors (Docket 04-IEP-1D)*. October 4, 2005.

Figure 1: Load (MW) vs. Temperature (F°)



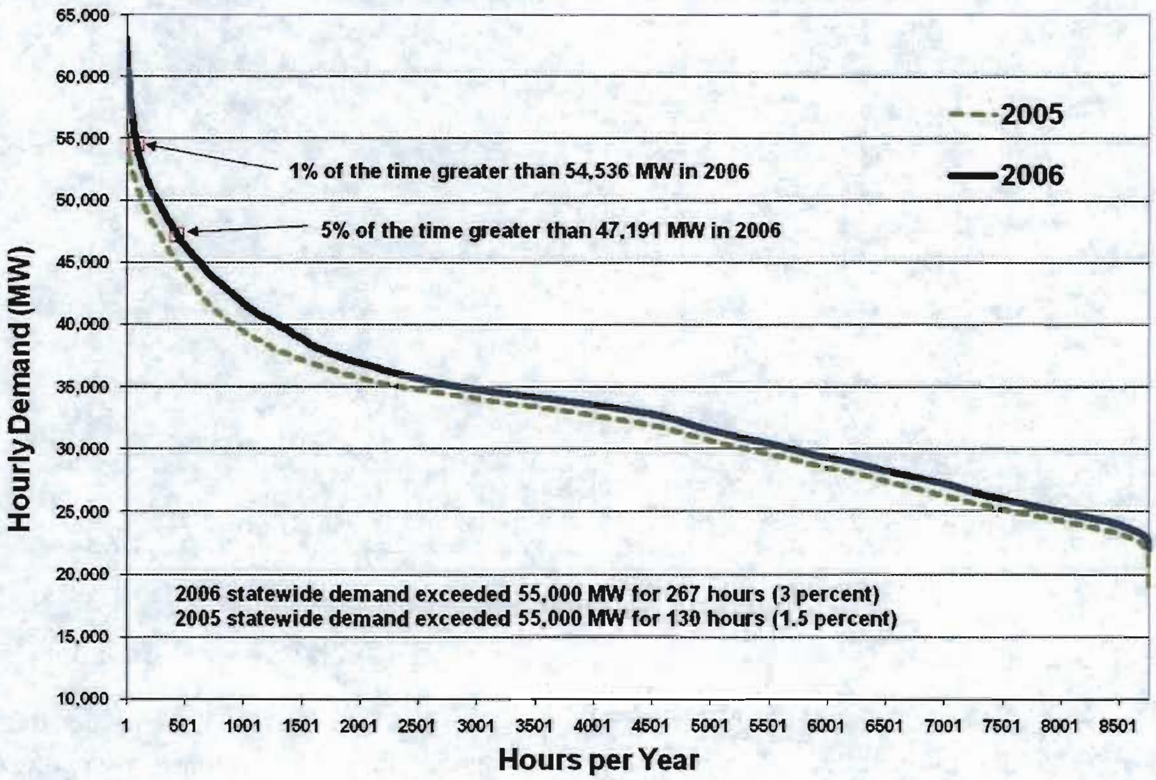
Source: California Energy Commission, *2008 Electricity Supply and Demand Outlook*. CEC-200-2008-003. May 2008.

This example shows the relationship between temperature and demand (load) using 2004 data from Southern California Edison's service territory. The trend line indicates that, on average, a one degree increase in temperature resulted in a 317 MW increase in peak demand for the utility, a 1.5 to 2.5 percent total load increase per degree.

Demand Response, Energy Efficiency, & Load Management

Load management standards support the goal of reducing costs and improving reliability by focusing on strategies that promote energy efficiency and demand response. This reduces or delays the need for new electric generation capacity and reduces fuel consumption for electricity generation. Public Resources Code section 25132 defines Load Management as "…any utility program or activity that is intended to reshape deliberately a utility's load duration curve." A load duration curve is a graph of electricity demand over time. For example, Figure 2 shows the California state wide load duration curves for 2005 and 2006.

Figure 2: California Load Duration Curve (2005-2006)



Source: Federal Energy Regulatory Commission Form 714 data compiled by Energy Commission staff

A large peak load for a small number of hours each year is expensive because enough generation must be available to meet the maximum load each year, no matter how infrequently it is needed. This means that peaking power plants sit idle for all but a few hours each year, thus the costs of building, operating, and maintaining that capacity must be recovered in those few hours. Energy efficiency and demand response are the two primary forms of load management, and are defined as:

- *Energy Efficiency*: Reduction in overall energy use by using less energy intensive applications, ideally with similar or better quality of service.
- *Demand Response*: is the means that end-use electric customers can reduce their electricity use over a given time period, shift that use to another time period, or contribute to grid reliability in response to a price signal, a financial incentive, an environmental condition, or a reliability signal.[8]

Efficiency efforts frequently measure their cost against the cost of the energy potentially saved over time. For example, improved air conditioner efficiency programs can reduce total energy

[8] This definition is derived from the California ISO MRTU Vision for Demand Resources Working Group draft document: California Demand Response: A Vision for the Future. June 12, 2008. http://www.caiso.com/1fe3/1fe3ebb5d860.pdf

consumption and the peak energy demand during the cooling season. Such efficiency improvements also lower total energy consumption and customer bills, but provide the same or improved quality of service. In California, efficiency impacts are valued using Time-Dependent Valuation (TDV), which weights peak savings higher than off-peak savings. The efficiency impacts of technology improvements which have their greatest impact during peak periods such as efficient air conditioners and office lighting, are properly assessed according to their load characteristics. Since efficiency efforts produce overall energy savings, load managing efficiency approaches will also produce savings during peak periods.

Demand response strategies generally reduce energy use during those few hours of near maximum load each year, but can result in "load shifting" to an off peak and lower price time period. This can significantly reduce the peak electricity use, but generally has minimal impact on the overall total energy consumption. For example, a customer who understands that electricity is expensive on a hot summer day may adjust their thermostat by a few degrees to reduce their end of the month bill. The same customer, when made aware of the high price, may turn off unused lights, or delay use of a dishwasher for a few hours instead, with similar net bill savings. The key to successful demand response programs and strategies is educating and facilitating customer response to price and electricity grid conditions.

Voluntary Demand Response

Over the long term, customer choices and behaviors define electricity demand. Current electricity system design does not provide most end use customers with detailed or immediate feedback regarding the cost of their energy or the stability of the electricity grid. Without this information, customers will not voluntarily reduce their use when energy is most expensive, or when their actions may help avert a black-out. "Demand response" is actions taken by electricity customers to reduce or adjust their electricity use in a given time period, or shift that use to another time period, in response to a price signal, a financial incentive, or an emergency signal. This includes programs that encourage consumers to reduce peak consumption through improved efficiency as well as programs that support shifting peak demand to off-peak periods. Well designed and widely adopted demand response should help control the peak cost of electricity by reducing the pressure of peak demand on available resources, and help improve electricity distribution system reliability by giving grid operators an additional tool besides generation to use in situations where the grid is stressed or damaged.

Effective demand response strategies should be sustainable, since over time, customers should want to continue to participate in such programs, and should be satisfied with the return (either monetary or otherwise) they receive on their investments of time and money. Ideal demand response opportunities must result in real cost savings and should be understandable to the consumer (both in cost structure, and trigger reasons). Such programs should result in sustainable improvements in the cost and energy efficiency of our generation and distribution system. To move these ideal and sustainable demand response programs forward, it is important that that they are voluntary on the customers' part. When customers have the freedom to participate in a variety of demand response programs, or not to participate at all if they choose, customers will be motivated to learn about the programs available to them. That will lead to improved programs, more knowledgeable customers, and sustainable improvements in the way electricity is generated and consumed.

Cost Effectiveness

Load Management Standards should not cost customers more to implement than they save over time. A cost effective improvement will have a "payback period" over which the total cost of implementing the improvement is recovered, and after which the investment yields positive returns. For residential and small commercial customers, payback periods less than ten years are generally considered favorable, and periods less than five years are considered very favorable. Large commercial and industrial customers generally demand a substantially shorter payback period.

Public Resources Code section 25403.5 gives the Energy Commission the authority to enact load management standards and requires that, "...the standards shall be cost effective when compared with the costs for new electrical capacity...." The explicit goal of these standards is to help control the cost of energy and to support a stable supply of energy, which in itself has economic benefits.

Many, but not all, load management strategies can also reduce greenhouse gas emissions from the electricity sector. This is, in part, because peak power generation is generally the least efficient (that is, the highest carbon emitter per unit of electricity), so reduced peak demand reduces emissions, but also simple efficiency and conservation efforts reduce electricity use outright. Under the California Global Warming Solutions Act of 2006 (AB 32), these emissions reductions will have an economic value which should be included in the cost effectiveness calculations.

Each of these proposed load management standards are required to pass a cost effectiveness review, and only those that prove to be beneficial will be considered for adoption.

Chapter 1: History of Load Management in California

Since the mid 1970s California has had a policy of energy efficiency, including load management. In fact, as a result of the policies, California has the lowest electricity use per person in the nation. While the United States per capita electricity consumption increased by nearly 50 percent over the last 30 years, California per capita electricity use remained almost flat, demonstrating the success of a variety of cutting-edge energy efficiency programs and cost-effective building and appliance efficiency standards.

Legal Authority to Adopt Load Management Standards

The Energy Commission has had authority to adopt load management standards since 1976. Public Resources Code section 25403.5 directs the Energy Commission to: "… adopt standards by regulation for a program of electrical load management for each utility service area." These standards apply to all utilities in the state, including both Investor-Owned Utilities (IOUs) and Publicly Owned Utilities (POUs). Under the broad scope to adopt load management standards the Energy Commission "shall consider, but need not be limited to", the following load management techniques:

(1) "Adjustments in rate structure to encourage the use of electrical energy at off-peak hours or to encourage control of daily electrical load."

(2) "End use storage systems which store energy during off-peak periods for use during peak periods."

(3) "Mechanical and automatic devices and systems for the control of daily and seasonal peak loads."

This section of the Public Resources Code additionally states that substantive criteria for adopting load management standards are that:

(1) "The standards shall be cost effective when compared with the costs for new electrical capacity and the [Energy] commission shall find them technologically feasible."

(2) "Any expense or any capital investment required of a utility by the standards shall be an allowable expense or an allowable item in the utility rate base and shall be treated by the Public Utilities Commission as such in a rate proceeding."

In addition, the adopted load management standards may add flexibility via exemption and delays:

> "The [Energy Commission] may… grant, upon application by a utility, an exemption from the standards or a delay in implementation… Exemption or delay shall be granted only upon a showing of extreme hardship, technological infeasibility, lack of cost effectiveness, or reduced system reliability and efficiency."

Past Proceedings on Demand Response and Load Management

In 1982, the Energy Commission implemented four load management standards requiring five utilities – Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Los Angeles Department of Water and Power (LADWP), and Sacramento Municipal Utility District (SMUD) – to develop and implement load management programs. Those programs were to address residential peak load cycling (cycling air conditioners and electric water heaters), swimming pool filter pump timing, electrical use surveys of large customers, and marginal cost rates.

The residential load management standard (Cal. Admin. Code tit. 20, § 1622), required utilities to develop peak load switching programs which would provide participating customers with a remote switch for their space heaters, water heaters or air conditioners. The utility could then shut down the participating customer's device for short periods during peak or emergency times, and the customers received rebates in return. Load control programs for central air conditioners, which were instituted at SMUD and SCE in the early stages of the standards' implementation, continue to this day.

The load management tariff standard (Cal. Admin. Code tit. 20, § 1623) required utilities to provide a marginal cost-based rates to customers. As a result, all customers with more than 500 kW of peak demand were placed on time-of-use rates.

The swimming pool filter pump load management standard (Cal. Admin. Code tit. 20, § 1624), required a large scale effort to educate customers about efficient operation of swimming pool filter pumps. This standard encouraged customers to install timers that would shut off the pumps during designated peak hours each day, while maintaining enough operation time to achieve sufficient filtration and circulation.

Finally, the non-residential load management standard (Cal. Admin. Code tit. 20, § 1625), was an initiative to audit both small and large commercial customers to identify ways they could shift peak consumption to off-peak periods, or reduce overall load.

After the energy crisis of 2000-01, the threshold for time-of-use rates lowered from 500 kW demand to 200 kW demand by Assembly Bill 29X (2001). The bill also provided $35 million to install approximately 25,000 real-time meters for those same customers, whose loads comprise approximately 30 percent of California's peak electricity demand. The Governor and Legislature further directed the Energy Commission to implement an emergency program that provided over 1,000 California businesses with metering and control systems allowing them to reduce their cumulative loads by over 150 megawatts within 15 minutes of receiving an emergency signal. The legislature also passed two more bills that had an impact on peak load management. AB 970 (2000) appropriated $50 million to the Energy Commission to award incentives for conservation and demand-side management programs, but expired on January 1, 2004. SB 5X (2001) appropriated $253 million in General Fund revenues to the Energy Commission for peak electricity demand and energy conservation measures, with $35 million specifically marked for investing in building demand response systems.

In 2002, the California Public Utilities Commission (CPUC) and the Energy Commission opened a joint proceeding focused on demand response "to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment." (R. 02-06-001, Order Instituting Rulemaking, June 6, 2002 (CPUC OIR); 02-DR-01. Order Number 02-0717-01. (Energy Commission OIR)

Working in collaboration with the Energy Commission in that and subsequent proceedings and pursuant to section 454.4 of the Public Utilities Code, the CPUC has:

- Approved a series of voluntary demand response programs proposed by the investor-owned utilities (IOUs)
- Directed the IOUs to conduct a statewide pricing study that established the potential impacts of dynamic electricity pricing to residential and small commercial customers
- Approved a deployment plan for an advanced metering infrastructure (AMI) that will include interval metering and dynamic pricing capability for all customers served by Pacific Gas & Electric Company
- Incorporated demand response in procurement planning

The CPUC has recently succeeded in moving forward with advanced metering infrastructure (AMI)[9]. PG&E began installing meters for both electric and natural gas customers, and making changes to their operations in July 2006. PG&E plans to complete their deployment by 2011 at a cost of $1.74 billion. As of September 2008, over one million electric and gas meters have been installed. Since their initial approval, the costs for AMI equipment, meters in particular, have fallen substantially. PG&E filed an upgrade application in December 2007 that would result in improvements in bringing their system functionality up to the level of the other IOUs, at an additional cost of $572 million. SDG&E received approval of their AMI application in April 2007 with completion projected for 2011 at a cost of $572 million. SCE filed their updated AMI application in July 2007 and received approval in 2008. SCE projects completion of their AMI by 2013 at a cost of $1.7 billion.

CPUC efforts to institute dynamic rates are ongoing. Current opt-in critical peak pricing (CPP)[10] rates, which require customers to actively sign up for the rate, have very low enrollments and two attempts to develop default opt-out CPP rates for large customers have failed to achieve their goals due to resistance from intervening parties to what they described as "mandatory" rate changes and a lack of consensus among parties on how such rates should be structured in cases where a fixed utility revenue requirement has already been approved. The CPUC has attempted to address these concerns and move forward with dynamic pricing by including a proceeding on dynamic rate design in concert with the most recent PG&E General Rate Case (GRC). The other utilities were invited to join the proceeding with the expectation that they will use the same rate design principles developed for PG&E in their respective GRCs. The Energy Commission Public Interest Energy Research (PIER) funded Demand Response Research Center

[9] AMI is described in more detail in Chapter 2 and 3 below.

[10] CPP is described in more detail in Chapter 2 and 4 below.

(DRRC) is conducting research on dynamic rate design and will provide their research products to the utilities and the CPUC as they become available.

The Energy Commission is now receiving demand response resource information from the publicly owned utilities (POUs) as a result of SB 1037 (2005). Currently, demand response programs are treated as a supply resource and therefore not accounted for in the demand forecast, forcing utilities to potentially purchase more reserve energy than necessary.

The Integrated Energy Policy Report

The *2005 Integrated Energy Policy Report (2005 IEPR)* made four specific recommendations for developing load management and demand response:

- The CPUC was urged to develop and implement dynamic rates for customers with advanced meters.
- The CPUC was urged to require all utilities under their jurisdiction to develop an advanced metering infrastructure (AMI) for all customers.
- The Energy Commission was urged to work closely with the publicly owned utilities to better understand their demand response efforts.
- The Energy Commission was urged to deovelop goals similar to those required of the IOUs and to include demand response information in the Common Forecasting Methodology (CFM).

The *2007 Integrated Energy Policy Report (2007 IEPR)* recommended that the Energy Commission initiate a rulemaking involving the California Public Utilities Commission (CPUC) and the California Independent System Operator (California ISO) in 2008 to pursue the adoption of load management standards under the Energy Commission's existing authority. The *2007 IEPR* notes that demand response can play a critical role in California's electricity mix, cost-effectively avoiding incremental generation needs and resulting environmental costs while helping to ensure the reliability of California's electrical grid.[11]

In the Energy Action Plan II, the Energy Commission and the CPUC jointly endorsed a goal that price-induced demand response should meet five percent of California's peak demand. California has not yet achieved that goal and the *2007 IEPR* notes that the Energy Commission's load management authority is a valuable policy tool for the state to bridge the gap between the current level of demand response and its full cost-effective potential.[12]

Current Proceeding

On March 3, 2008, the Efficiency Committee held a scoping workshop to obtain public input on developing and possible adoption of new load management standards. The workshop included presentations from the Energy Commission, CPUC, California ISO, utilities, researchers, and

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[11] *2007 Integrated Energy Policy Report*. California Energy Commission. CEC-100-2007-008-CMF. Page 94.

[12] *2007 Integrated Energy Policy Report*. California Energy Commission. CEC-100-2007-008-CMF. Page 97.

invited technical experts. Discussions included review of the Energy Commission's load management standards authority and demand response accomplishments. Participants discussed current plans and research on demand response technology advancements in California, other states, and other countries. The public and other interested parties also had an opportunity to address the Efficiency Committee.

After considering the information presented and discussed at the workshop, as well as the comments received, the Efficiency Committee published a Load Management Standards Efficiency Committee Scoping Order on April 25, 2008, and held the following workshops:

On **April 29, 2008**, the Efficiency Committee held a workshop on Smart Grid Activities and Technologies. The workshop included presentations from the Energy Commission Public Interest Energy Research program, U.S. Department of Energy, California ISO, investor and publicly owned utilities, and invited technical experts. Discussions covered current utility smart grid development plans, and how state regulations could support and encourage responsible development of a smart grid in California and beyond.

On **May 27, 2008**, the Efficiency Committee held a workshop on Advanced Metering Infrastructure (AMI). The workshop included presentations from investor-owned and publicly owned utilities on their AMI business cases and rollout plans in addition to lessons learned in designing, developing, and deploying AMI. The discussion explored the relationship between AMI functionality and the capability of supporting different policy goals, and differences in functionality among current systems.

On **June 10, 2008**, the Efficiency Committee held a workshop on rate design, incentives, and market integration. The workshop included an overview of cost-based ratemaking and general rate design. Presentations from the CPUC, investor-owned utilities, and publicly owned utilities will covered current rate design policy supporting time-of-use (TOU) and dynamic rates. Discussions covered rate design in support of load shifting and energy storage technologies, and how retail rates and programs can be integrated with wholesale markets and control area operations.

On **June 19, 2008**, the Efficiency Committee held a workshop on demand response and load management enabling technologies. The workshop included presentations from government, investor and publicly owned utility, industry, and academic experts on demand response and load management data communication protocols and enabling technology under development. Participants discussed enabling technology cost and availability, opportunities for technology standards, and potential barriers to technology penetration into the market. Many industry representatives attended and provided comments.

On **July 10, 2008**, the Efficiency Committee held a workshop on customer education and needs. This workshop included presentations from technical experts, numerous industry representatives, and investor- and publicly owned utilities on current and future customer education efforts. Discussions were focused on the types of technology available to support load management. The Committee also asked participants to discuss how the Energy Commission could support customer education about voluntary demand response and load management programs, and the information customers need to respond to time-of-use (TOU) and dynamic prices.

Information about each workshop, and the Energy Commission's Load Management Standards proceeding in general, can be found on the Load Management Standards web page at: [http://www.energy.ca.gov/load_management/index.html].

Chapter 2: Components of Load Management

This chapter provides an overview of the set of component strategies that will form the basis for proposed load management standards. Each concept is discussed in greater detail in following chapters.

Advanced Metering Infrastructure

Over the past decade, utilities and electricity distribution equipment manufacturers have developed and begun installing the next generation of electric and gas meters – "advanced meters." This advanced meter has benefited significantly from advances in solid state microelectronics, and recently has benefited from economies of scale resulting in a significant drop in equipment costs. The advanced meters, the communication networks that electronically transmit the collected data back to the utility, and the information technology infrastructure that processes the data, are collectively referred to as the "advanced metering infrastructure" (AMI). AMI is essential to many load management strategies.

On May 27, 2008, the Efficiency Committee held a workshop to discuss AMI with the major utilities in California, equipment manufacturers, and other interested parties. Although the experts had some differences of definitions, there were also many concepts in common. The general consensus of opinions from this workshop was that the basic purpose of AMI is twofold:

1) To make the collection of use data more efficient, and thus less costly; and
2) To enable advanced load management, efficiency, and energy management strategies.

Traditional meter reading requires a meter reader to visit each meter periodically (usually monthly) and record the data collected. Even with electronic advances in local meter reading, such as "drive by" data collection, this is expensive and time consuming. AMI eliminates the need for and cost of visiting each meter regularly.

Customers currently have very little information regarding how their day to day energy use impacts the cost of their electric service. Although electric bills contain monthly consumption information, there is no way for customers to connect that information with individual behaviors or devices. The availability of hourly or shorter period use data should help educate customers over time about how their individual devices and activities impact their electric bill at the end of the month. Customer education is a critical benefit of AMI.

Small scale local distribution outage detection currently relies on customers to phone the utility when their power is out. Utility workers must then physically trace the distribution lines back from the outage to find the fault. AMI will allow the utility to detect the loss of power in near real time, allowing more rapid fault discovery and faster restoration of power. This infrastructure should also reduce the cost of fixing such outages since it would reduce the number of work-hours necessary to locate faults.

Periodic consumption data will allow customers, their designated third parties, and utilities to implement numerous efficiency and load management strategies that were previously infeasible or not cost effective. Dynamic rates require knowledge of dynamic consumption, but the data also allows utilities to conduct research on consumption patterns in their service territory that could lead to more efficient resource planning and lower overall costs. This type of data research will become even more critical to utility planning in the future as using technology such as distributed electricity generation (solar panels), plug-in hybrid or pure electric vehicles, and energy storage becomes widespread. Improved efficiency increases grid stability, which reduces the likelihood of unplanned outages, and reduces operational costs, which lowers customer bills.

Other AMI benefits include:

- No need to have utility workers come on to customer property to collect data
- More accurate bills with faster resolution of disputes
- Customer access to their use data
- Increase distribution system efficiency and reliability
- Reduced energy theft

Rate Design & Dynamic Electricity Pricing

Few Californian residential or small commercial customers have been exposed to electricity prices that reflect the true cost of peak versus off-peak energy. Under current utility rates, residential and small commercial consumers generally pay the same for base load electricity whether it is in the middle of the night when costs are low or for peak load electricity late in the afternoon during a heat storm when the most expensive power generation facilities are required. The costs of those few high peak load hours each year are averaged with the cost of electricity for the remaining hours of the year. This results in blunting the impacts of the temporary high costs for electricity resulting from consumption during peak hours.

Most commercial, industrial and agricultural rates have, for some time, been subject to time-of-use (TOU) rates, seasonally adjusted rates and in some cases demand charges and critical peak pricing (CPP[13]). These alternative rate designs are constructed to more closely reflect the cost of electricity than flat rates. While an hourly real-time pricing (RTP) structure would most closely achieve true cost-based pricing and provide benefits, most customers want the relative ease of responding to known, stable, and predictable price patterns. The inverted-tier rate structures used for the majority of IOU residential customers, in contrast, provide only the crudest incentive for conservation and no incentive for peak load reduction. Further, because the actual per-kilowatt hour rate is determined after the billing period ends, customers have no way of knowing the price of electricity at the time-of-use.

Electricity prices that reflect the time-differentiated cost of producing and delivering energy provide customers with the information necessary to make more informed energy use decisions. Rates that do not provide clear price signals shield consumers from the direct impact

[13] Critical Peak Pricing rates are assumed in this document to include an underlying TOU rate structure.

of the high rates and, customers, as a consequence, are then unable to make a decision based on the true cost of the electricity consumed. The consequence is unnecessarily high electricity bills and interference with customers' ability to achieve efficiency, demand response, and carbon reduction goals.

Ideally, rate designs should meet four criteria:[14]

(1) Promote economic efficiency – customers should pay prices that generally reflect long-term marginal costs.

(2) Promote equity – prices should be allocated to reflect the cost of service.

(3) Clear and simple communication of prices and costs – rates should be designed so they are understandable to the average customer and so that they create a cause-and-effect relationship between the energy a customer uses and what they pay.

(4) Time-differentiated and dynamic capability – rates should reflect the time-varying cost of production and delivery and include a dispatchable component that reflects critical system prices and reliability events.

Dynamic prices are intended to more accurately reflect costs and system operating conditions. Dynamic rates are generally lower during off-peak and higher during on-peak periods; the difference based on power production costs and system stability.

With pricing that reflects actual costs, customers will have the incentive to respond in the short-run by voluntarily reducing their lowest value loads during high price periods, or by shifting those loads from high price to low price periods. In the long-run, customers will respond to more accurate price signals by investing in more efficient end use devices and making permanent adjustments to their consumption patterns. The advantage of well designed dynamic pricing is that the end use customer makes the ultimate value judgment with regard to their use of electricity based on prices that more accurately reflect the cost of the commodity.

On July 31, 2008, the California Public Utilities Commission (CPUC) issued its "Decision Adopting Dynamic Pricing Timetable and Rate Design Guidance for Pacific Gas and Electric Company"[15] detailing the CPUC direction to PG&E as well as SCE and SDG&E regarding rate design guidance over the next four years. In particular, the Decision clearly states that the overall objectives of rate design are:

- To reflect the marginal cost of providing electric service so that consumers make economically efficient decisions,
- To flatten the load curve to reduce capital costs over time, and
- To reduce load during short-term electricity supply shortfalls.

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[14] Lawrence Berkeley National Laboratory, Demand Response Research Center. *Rate Transition Project, Draft Final Report.* September 2008.

[15] California Public Utilities Commission, Decision #08-07-045. July 31, 2008.

These objectives reflect the current state policy on electricity rate design[16].

Time-of-Use Pricing

Time-of-use (TOU) pricing divides every day into two or more predictable price periods (for example, peak and off-peak). Since the price changes generally occur at the same times each day, it is much easier for consumers to plan for the price changes and to consistently respond. Consumers are already familiar with this concept as peak and off-peak phone charges, or "weekend and night" minutes for cell phones.

Critical Peak Pricing

Under Critical Peak Pricing (CPP) customers are exposed to a very high price for a very limited number of hours per year (for example, up to ten days per year for three hours each day). A "CPP event" is only called when the grid operator or utility expects extreme conditions that would require the most expensive peaking power plants to operate and could stress the grid to the point where there could be outages. Customers are usually notified of CPP events the day before, giving them the opportunity to pre-cool their building and take any steps they choose to reduce consumption during the critical peak. CPP directly addresses the concern about the peak energy demand for less than one percent of the hours each year.

CPP pricing events are usually implemented with an underlying TOU pricing plan where the times of CPP events correspond to the times of peak TOU prices. This provides additional predictability, and helps consumers who regularly conserve during peak energy periods to be prepared for critical peak periods with minimal or no change in their response.

Enabling Technologies

It is unrealistic to expect most consumers to monitor the daily demand on the grid or the hourly price of electricity and then manually take actions in response. A critical piece of the load management puzzle can be met by providing consumers with access to information and tools that they can "set and forget" to take the actions they determine to be appropriate.

Enabling technologies include a variety of technical applications, many of which are available today and many that have yet to be invented. A real example is a programmable communicating thermostat that allows a consumer to program their thermostat to increase its set point in response to a high price or emergency signal. Properly implemented, the slight temperature change could be nearly imperceptible to the consumer, but with CPP in effect, the bill savings could be significant. Another example is a thermal storage unit that allows a building manager to store cooling energy over night when electricity is inexpensive, and then use the stored energy to cool during the afternoon when prices are high. Again, properly implemented, this enabling technology could be invisible to the building occupants, and under a favorable pricing plan could yield significant bill savings.

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[16] CPUC, Decision #08-07-045; Page 42. July 31, 2008.

Customer Electricity Consumption Information

Customers should have access to their near real time consumption data. Until recently, providing customers with real time feedback on their electricity use was technologically infeasible. In the past, meters capable of collecting and communicating hourly or more frequent electricity consumption information were so expensive that only the largest consumers could justify the expense. That is no longer the case. Cost effective advanced meters for all customers are now possible. As the CPUC authorizes the investor-owned utilities to install such meters for all customers, and many of the larger publicly owned utilities roll out advanced meters of their own, the price of these devices continues to drop. In the near future, it is expected that such advanced meters could become the norm in California as the remaining smaller utilities take advantage of the falling costs of advanced meters and cooperate with each other to achieve mass discounts similar to those realized by their larger counterparts.

Smart Grids

Californian regulators and utilities are pursuing demand response as one of many innovative strategies to create a more reliable and flexible electrical system. The combination of demand response with other strategies such as distributed generation and renewables creates a new set of challenges for California's existing electricity transmission and distribution network, known as the "grid." The existing grid was designed to put stability and reliability above flexibility. This design has served California well, but the recent push to include resources that have intermittent or variable outputs (like wind energy) or are not remotely controllable (like demand response), has revealed the need to upgrade and rethink the grid design. This upgraded and more flexible system is called the "smart grid" and widely encompasses many hardware and software technologies, energy management strategies, utility programs, and other ideas still at the research and development phase.

During the April 29, 2008, Load Management Standards Smart Grid workshop, speakers from a diverse array of organizations including utilities, federal government, state government, and the European Union presented their perspectives on the current state and direction of the smart grid. Although there was no single agreed definition of the term, the participants used many common characteristics of a smart grid:

- *Self-Healing* damage and disruptions with minimal operator input.
- *Adaptive* to both changing demand and generating conditions.
- *Interactive* with consumers, generators, and markets.
- *Optimized* to make best use of available resources and equipment.
- *Predictive* rather than reactive, preventing rather than responding to failures.
- *Distributed* control systems across geographical and organizational boundaries.
- *Integrated* monitoring, control, protection, maintenance, EMS, DMS, marketing, and IT.
- *More Secure* from attack and vandalism.

Using the smart grid concept to support California's efforts to improve energy efficiency and reduce peak load was supported by all participants at the workshop. Smart grid technology should provide faster control of the grid, allowing for quicker responses to changes in the renewable resource generation capability. Smart grid technology should integrate resources such as storage, demand response, and other generation resources (DG, CHP, etc) fast enough to allow the system to continue operating safely as rapid changes occur. Smart grid technologies should provide more reliable estimates of generation capabilities (including renewable) and actual grid load needs, further supporting grid stability and efficiency.

Smart grids are a work in progress. New laws at the federal level have directed the U.S. Department of Energy to begin the process of defining what smart grids are and build a framework for nationwide interoperability of grid networks. California regulatory agencies like the California Public Utilities Commission, California Independent System Operator (California ISO), and the Energy Commission are just beginning to seriously grapple with the issues surrounding this vitally important piece of the system.

Chapter 3: Advanced Meters

Workshop

The May 27, 2008, Advanced Metering Infrastructure (AMI) workshop facilitated discussion among the Efficiency Committee and stakeholders on the relationship between AMI functionality and the capability of supporting different policy goals. The investor-owned utilities (IOUs) described their planning processes, their business case considerations, their technology choices, and their implementation plans and timelines under the California Public Utilities Commission (CPUC) approval process. The publicly owned utilities (POUs), updated the Committee on their current perspectives on AMI and the different stages of that process.

The Committee described some possible areas for development of load management standards involving AMI, including:

- Adopting statewide information standards for AMI functionality.
- Requiring all utilities to develop business cases for AMI deployment consistent with statewide standard protocols for AMI functionality.
- Requiring all utilities to prepare a business case for deploying AMI.
- Requiring all utilities to deploy AMI.

The Committee heard presentations from IOUs, POUs and their representative organizations, staff from the CPUC's Energy Division and the Division of Ratepayer Advocates (DRA), and other stakeholder groups, including The Utility Reform Network, who have been actively engaged in CPUC proceedings on AMI. The workshop was organized in two panels, one for the IOUs and one for the POUs.

Prior to the IOU presentations, the CPUC Energy Division staff provided a preliminary comparative overview of the IOU AMI cases, and then each IOU followed with a detailed description of their AMI systems, deployment activities, and their intended use to achieve state goals for peak load reduction and efficiency. POU presentations reflected varied perspectives on the applicability of AMI to their individual service territories. Also, DRA reviewed their participation in the IOU AMI proceedings and identified some of their issues and concerns.

Investor-Owned Utility Advanced Metering

CPUC/Energy Commission Background

The IOU applications for AMI resulted from the joint CPUC/Energy Commission rulemaking (R.02-06-001[17]) on policies and practices for advanced metering, demand response, and dynamic pricing. As part of that proceeding, CPUC and Energy Commission staff, working with the stakeholders, proposed an analysis framework for AMI implementation to guide utility business case development. In a July 21, 2004 Ruling,[18] the utilities were directed to use that

[17] http://docs.cpuc.ca.gov/published/proceedings/R0206001.htm

[18] http://docs.cpuc.ca.gov/PUBLISHED/RULINGS/38293.htm

framework to compare the cost-effectiveness of a range of business case scenarios that varied across full and partial deployment, default tariff designs, financing mechanisms including costs and benefits, level of demand response, discount rates, avoided costs, and other relevant parameters.

From that initial direction, the utilities pursued AMI development through a phased series of individual applications where each business case was developed independently.[19] Over the four years that the utilities have been developing business cases and planning their AMI deployment, the technology has improved, equipment prices have fallen, the concept of a "smart grid" has grown, and the place of meters and communications in that larger system has evolved. As a result, the utilities and the regulators have attempted to ensure that the investments made over the next few years not only achieve the initial goals of reducing costs and increasing reliability but anticipate and realize emerging opportunities for increasing efficiency and conservation levels to help meet AB 32 greenhouse gas reduction goals, such as helping accommodate greater amounts of renewable generation to meet California's aggressive Renewable Portfolio Standard.

Investor-Owned Utility AMI System Business Cases

CPUC Energy Division staff provided an overview of the three IOU's AMI business cases and deployment plans, and the CPUC's role in evaluating and approving those investments.

The CPUC's definition of AMI system includes three main components:

1) Meters capable of measuring and storing interval data in one hour (or less) increments
2) Communications networks capable of moving the data from the meter to the data management system
3) Data management systems that interface with other utility functions (billing, outage management, website hosting, etc.)

This definition covers a number of capabilities, including two-way communication between the meter and the Meter Data Management System, customer feedback through web presentment of interval data, and support for dynamic electric rates.

For approval, the AMI business cases must be cost-effective and, at a minimum, provide the following functions:

- Enable dynamic pricing and feedback to the customers by:
  - Allowing prescribed price responsive tariffs (CPP, TOU, hourly RTP) by measuring, storing, and transmitting interval (e.g., hourly) consumption data to the IOU.

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[19] SDG&E http://docs.cpuc.ca.gov/published/proceedings/A0503015.htm
PG&E: http://docs.cpuc.ca.gov/published/proceedings/A0506028.htm
PG&E Upgrade: http://docs.cpuc.ca.gov/published/proceedings/A0712009.htm
SCE Phase I: http://docs.cpuc.ca.gov/published/proceedings/A0503026.htm
SCE Phase II: http://docs.cpuc.ca.gov/published/proceedings/A0612026.htm
SCE Phase III: http://docs.cpuc.ca.gov/published/proceedings/A0707026.htm

    - Providing customer access to their interval consumption data.
    - Supporting customer understanding of their hourly consumption patterns and how they relate to energy costs.
- Increase system efficiency by:
    - Enhancing system operating efficiency (remote meter reading, outage management, improved forecasting, theft reduction).
    - Interfacing with Direct Load control (DLC) communication technology.
    - Supporting IOU billing, customer support, and outage management applications.

When the utilities first estimated the costs and benefits of meeting these minimum requirements, the business cases came out negative. Because the original purpose of promoting AMI was to enable price-responsive demand response, those benefits were intended to bridge the gap between the operational savings and the system cost. PG&E's meter reading costs were high compared to the other two utilities, due in part to the size and geography of their service territory, therefore the meter reading benefits contributed substantially to the business case, leaving less of a gap to fill with demand response benefits. Even the least sanguine of assumptions about the potential of demand response benefits was sufficient to make the business case. For the other IOUs however, the larger gaps required finding ways to achieve additional operational and demand response savings to make their cases, and partially explains why SCE and SDG&E were unable to begin their deployment as soon as PG&E.

Table 1: Basic Elements of the IOU business cases

	PG&E	SDG&E	SCE
Scale	**5.1 million** electric meters **4.2 million** gas meters modules	**1.4 million** electric meters **900,000** gas meters modules	**5.3 million** electric meters SoCalGas *may* connect to this system
Total Costs	**$1.74 billon** approved **$523 million** requested for upgrade	**$581 million** approved	**$1.72 billion** requested
Deployment Timeline	2007-**2012**	2008-**2011**	2009-**2012**

Source: Tom Roberts, CPUC

PG&E originally began deploying a meter reading system using low-bandwidth power line carrier (PLC) communication technology, which was the least expensive option that met the minimum criteria. However, since the July 2004 Ruling, rapid improvements in AMI technology and reductions in cost have made additional functionality feasible and expanded the opportunities for facilitating customer participation in managing their electricity costs and achieving higher levels of efficiency. The three major additions to the system described in this workshop were the addition of remote connect/disconnect switching, which allows the utility to avoid the cost of "rolling a truck" whenever a customer moves, the ability to include two-way communications into the customer premise due to substantially lower cost for high bandwidth communications and computers with metering capability, and the rapid development of Home Area Network (HAN) technology. While the originally approved PG&E business case did not include these features, both the SDG&E and the SCE business cases (which took two to three years longer to develop) did. PG&E filed a business case upgrade application December 2007, to add this functionality and retrofit the portions of the system that have already been installed. A decision on this application is due December 2008.

Table 2: AMI Implementation Benchmarks for California IOU's

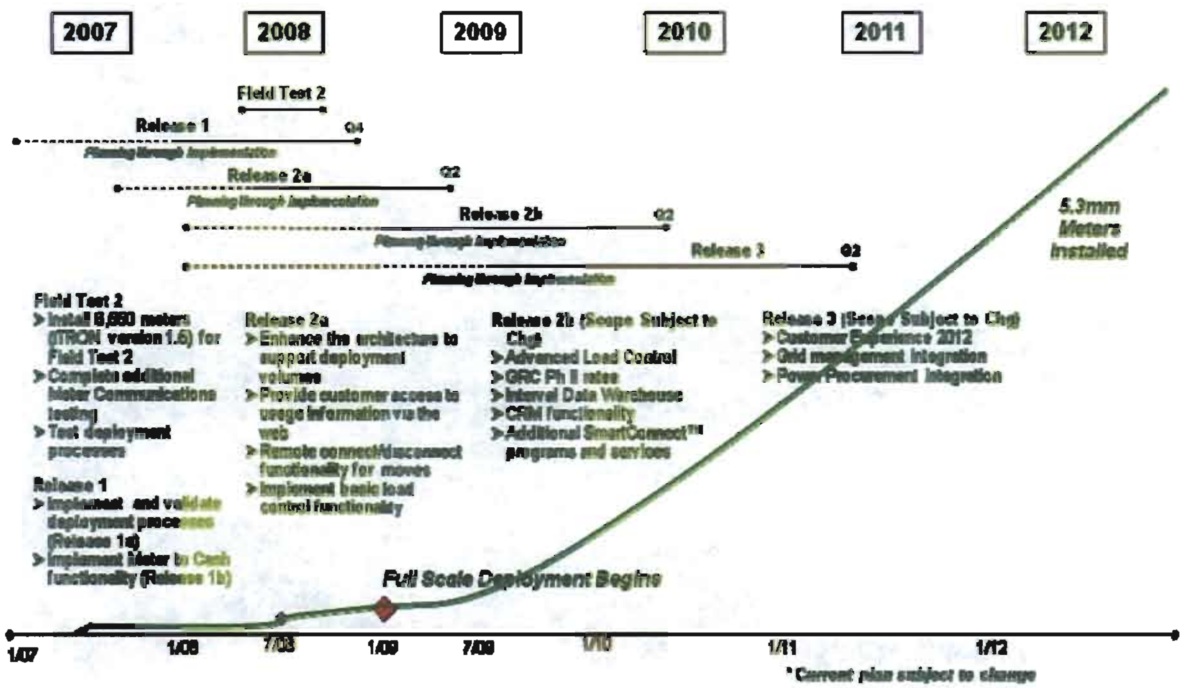
AMI Features	PG&E Approved	PG&E Upgrade	SDG&E Approved	SCE Pending
Meter Type	Module retrofits and new solid-state	New solid-state meter	New solid-state meter	New solid-state meter
Communications network	PLC for its electric: RF for gas	Radio frequency (RF) expected	RF (mesh technology) expected	RF (mesh technology)
Customer information feedback	Next-day internet access	Next-day internet access + HAN	Next-day internet access + HAN	Next-day internet access + HAN
Hourly data for residential	Yes	Yes	Yes	Yes
15-minute data for Small C&I	Yes	Yes	Yes	Yes
Net-metering capable	Yes	Yes	Yes	Yes
Voltage measurement	Yes	Yes	Yes	Yes
Two-way communication	Yes	Yes	Yes	Yes
Outage detection	Yes	Yes	Yes	Yes
Theft/tamper detection	Yes	Yes	Yes	Yes
Remote connect/discon't	Limited	Yes	Yes	Yes
Remote upgradability	No	Yes	Yes	Yes
Home Area Network (HAN) Gateway	No	Yes	Yes	Yes

CPUC staff also pointed to a major customer and system benefit that this additional functionality could provide: greater customer awareness through feedback on their energy consumption and the ability to automate their response to dynamic rates.

Deployment

All three utilities presented deployment schedules to describe the multiple parallel activities they must manage to meet their goals. SCE's graphical representation of the process is included here as illustrative of the process for all three utilities.

Figure 3: AMI Deployment Plan for Southern California Edison



IOU System Overview

PG&E's initial deployment of AMI techology began in 2006. The first technology chosen was an add-on module for the existing electric and gas meters. The gas meter module communicates by radio frequency signal (RF) to the electric meter module, which sends data from both meters back to the utilily using a powerline carrier technology. Recent advancements in meter technology and reductions in price led PG&E to file a business case upgrade to take advantage of those advancements and make PG&E's system more comparable to the systems the other utilities have proposed. Table 2 provides some detail on the differences between PG&E's original and upgrade filings, and the other utility business cases.

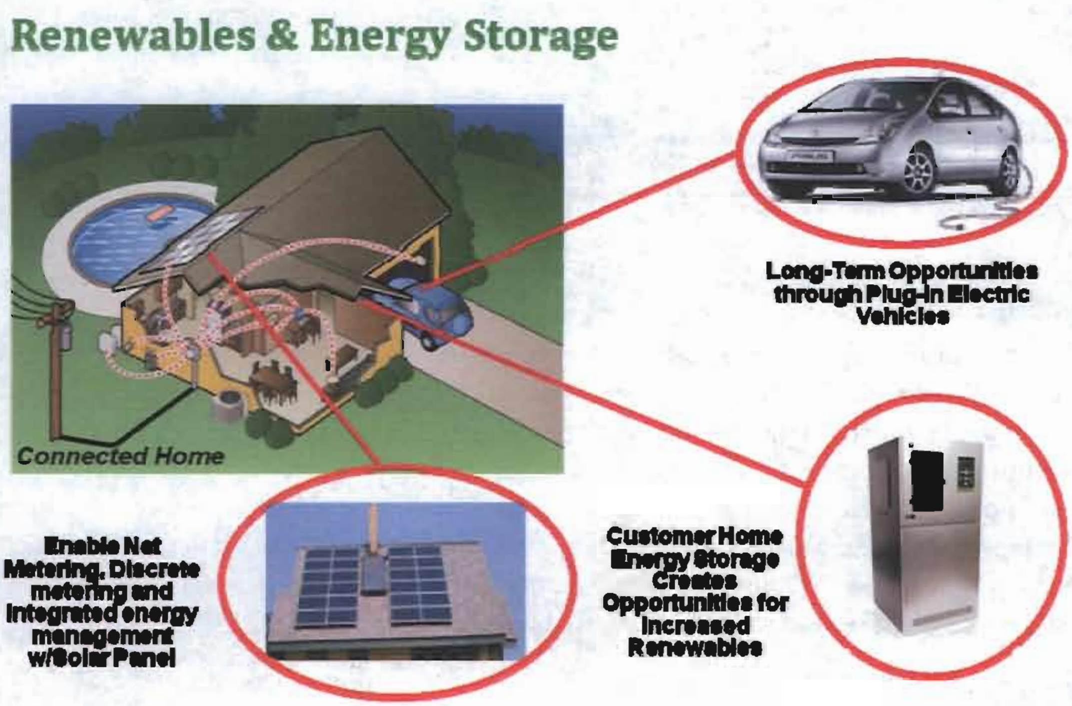
PG&E's original AMI effort was intended to deliver demand response benefits, and PG&E noted that this policy grew out of the 2000-01 Electricity Crisis. Although DR was one of the main drivers, the original business case was built on utility cost savings by eliminating manual meter reading and the savings provided by the detailed data as well as other ancillary benefits and cost reductions. PG&E anticipates additional savings from their proposed system upgrades, as do SCE and SDG&E.

Greater bandwidth and improved computer capabilities will provide additional functionality that have strong potential to improve service and lower costs. The meters – actually computers that also document electricity consumption – will have the ability to receive remote software upgrades, be connected and disconnected remotely, limit loads under certain circumstances, and accept changes in upstream operations technologies without being made obsolete. PG&E sees the smart meters as the foundation of the smart grid. The meter would serve as a "sensor" in the smart grid that is the basis for more efficient system operation and management.

SCE agreed that AMI is an essential component of the Smart Grid and pointed out that AMI is a part of the overall solution to meet state policy objectives, including expanding renewable generation to meet the RPS and reducing GHG emissions to satisfy AB 32 requirements. This can be accomplished through automated load control to balance intermittent renewable generation, the ability to facilitate more efficient use of storage, and general efficiency improvements resulting from improved customer understanding of their energy consumption and opportunities to reduce their own costs.

Ultimately, the system would provide a greater ability to integrate energy management solutions across a system where distributed generation and load management are keys to maintaining reliability while minimizing GHG emissions.

Figure 4: Relationship of AMI to Other Enabling Technologies



Source: Southern California Edison

With the technology upgrades PG&E proposes, the AMI systems installed by the three IOUs will be capable of providing similar levels of functionality.

The meters will measure consumption in five second increments and transmit the data back to the utility daily or on demand. The data will reside in "data warehouses" so they are accessible to multiple parts of the company (billing; forecasting; customer service; operations; etc.). Communication with the meter will be two-way, with the capability not only to query the meters for electric consumption but to provide a platform for processing and transmitting data from other meters (water; gas) and supporting communications on the customer side of the meter. Software in the meters will be remotely upgradeable so that changes in data preprocessing needs and meter operation will not require a visit by utility personnel.

SDG&E's vision of the AMI system was described as a "sweet spot" since the utility's investments can be leveraged for managing electric, gas, and water consumption information for utility needs and as a mechanism to provide good information to customers.

Between the three IOUs, four pathways for customer information and feedback were described. The first is through the traditional monthly bill – either a paper bill or the current online versions. The second is detailed "next day" and historical consumption data and analytical tools on a utility web site. The third is "Real Time" consumption data through an in-home display device, and the fourth is telephone contact with the customer service center.

The next day data would allow customers to use online tools to analyze their consumption, compare their bills with various rate options, and estimate savings from conservation actions or efficiency improvements, etc. Customers would also be able to request paper "bills" through the customer service center that provide additional detail.

SCE plans to develop a standard paper bill format that will use some of the information provided by the more detailed consumption data, however, they too see most of the benefit from the more detailed information coming from customer access to historical consumption data and analysis tools available over the internet. SCE customers would be able to request "on-demand reads" through their customer service center. Customers would be able to call and request a read and the customer service representative could have the system poll the customers' meter and pull up the most recent data.

Real time feedback would come from in-home display devices that would read a signal directly from the meter so the customer could monitor their own use to find and reduce unnecessary or wasteful consumption. All IOU meters will produce a signal using open-source communications protocols that would allow any manufacturer to produce and market devices to use the signal. SCE assumes three scenarios for getting these devices into people's homes. The first would be through new construction, the second through retrofits where customers self-install or hire third party services to install them, the third would be to develop a receiver that could plug into a USB port on the customer's computer. The receiver "stick" would have its own software application installed so that a customer could simply plug it in and pull up a screen that showed their real-time consumption. PG&E has included providing these sticks to some customers as part of its business case.

Another potential problem for communications between the meter and the home exists when meters are some distance from the actual premise or are located in groups, such as in multifamily dwellings, where the signals would each have to be distinguished. The utilities, through the OpenHAN group, have been working with the ZigBee Alliance and HomePlug Powerline Alliance to develop a common application layer for use in home networks.

Advanced Metering for Publicly Owned Utilities

Of the more than 40 POUs in California, seven of the larger utilities provided information on AMI during the workshop and one provided information in comments. Three quarters of California's POUs have fewer than 50,000 customers and only two, LADWP and SMUD have more than 500,000 customers. The California Municipal Utilities Association (CMUA) filed comments asking for flexibility in considering standards affecting the smaller utilities and recommended that any standards that would apply to POUs that have already started to develop AMI systems should not be "counterproductive" to those efforts.

SMUD (610,000 accounts; 10.5 million MWh/yr)

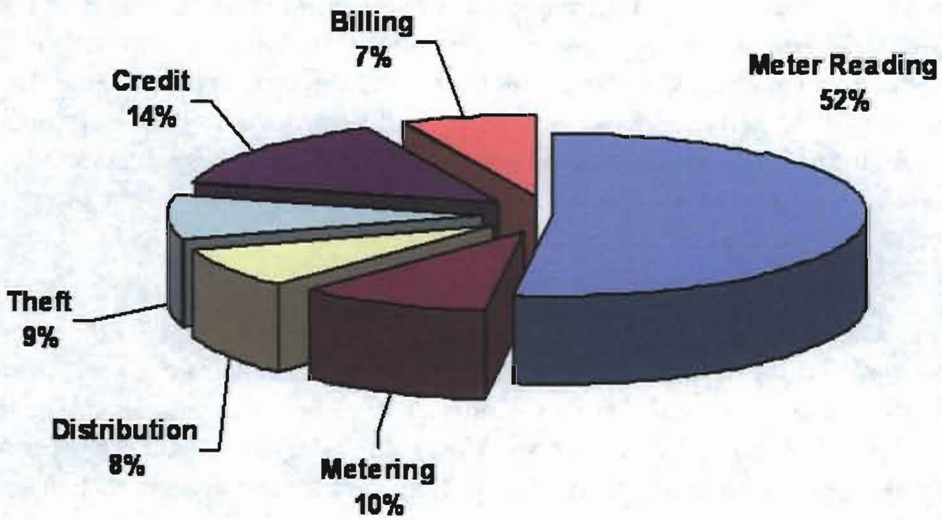
Sacramento Municipal Utility District (SMUD) serves over 610,000 accounts and has sales of over 10.5 million MWh/yr . SMUD reported on their current efforts to develop a business case for an AMI system with similar goals and functionality as the systems being developed by the IOUs.

Their project objectives include:

- Reducing ongoing operating costs,
- Improving customer service,
- Creating a platform for building efficiency, load management, demand response and time-based pricing programs, and
- Empowering SMUD customers to control their electricity use and reduce their environmental impact.

The system SMUD is planning has similar functionality to the IOU systems, with a "robust and scalable" network that anticipates future smart grid applications, two-way interval meters for 100 percent of their customers, HAN capabilities, remote connect/disconnect switching, an integrated meter data management system, and customer access to data and online tools.

Figure 5: Prospective AMI Financial Benefits



Source: SMUD

SMUD's business case had positive benefits without including any benefits from expected demand response or efficiency improvements (Figure 5), leading them to conclude that there may be substantial savings for their customers – especially when considering the risk of high future natural gas costs. SMUD's AMI deployment is expected to begin in Summer 2009 and complete by 2011.

LADWP (1.4 million accounts; 23.4 million MWh/yr)

The Los Angeles Department of Water and Power (LADWP) is the largest POU in California, serving over 1.4 million accounts with sales above 23.4 million MWh/yr.

Currently, LADWP considers a partial deployment scenario more likely to be cost-effective and is evaluating different scenarios for accomplishing that goal. The majority of their residential customers use less than 500 kWh/month, which limits the long-term benefits compared to the cost of the meters.

LADWP is considering an AMI solution for 25,000 of their largest customers that received advanced meters as part of the Energy Commission's AB 29X meter installation program in 2002, about 6,400 high-use residential customers, and about 2,500 "Critical Care" customers.

Their main criteria in considering an AMI system are:

- Open, non-proprietary communications with easily interchangeable components throughout AMI system.
- "Plug and play" – a new device would be able to register itself upon installation and immediately begin to communicate with neighboring systems.
- Minimize impact of communication technology change by installing a scalable radio frequency (RF) mesh and internet protocol (IP) backbone using a public communication network.
- Provide access to home premises for high energy residential consumers to monitor and control electric load with "off-the-shelf" network devices.
- Design a flexible AMI / Smart Grid foundation for future technology standards, system interfaces, and regulatory requirements.

LADWP has been looking at multiple communications systems, including two-way for the high-use customers and using public communications networks. Currently, they have over 1.2 million one-way RF meters that provide drive-by meter reading capability and 674,000 RF water meters.

LADWP has made a number of investments in competing communications technologies pilots to inform their business case development (Table 3).

Table 3: LADWP Investments in Communication Technology Pilots

Technology	2006 Endpoints	2010 Endpoints	2007 Investments	Cumulative 2007-2010 Investments
BPL	30,000	400,000	$50 million	$200 million
Mesh	40,000	5 million	$100 million	$400 million
Proprietary RF	12 million	12 million	$100 million	$400 million
Public Wireless	2.8 billion	3.5 billion	$30 billion	$120 billion

Source: LADWP

Their ongoing research program is considering a number of possible technologies, including remote connect/disconnect, calendar billing month for large customers, improving safety (for meter readers) by installing automated meter reading (AMR) in difficult/dangerous to read areas, enhancements to their ability to offer special rates such as CPP and net metering, improving customer service, and supporting energy efficiency programs.

LADWP recommends that the Energy Commission consider a statewide Load Management Standard with the following elements:

For Residential Customers with Monthly Consumption Over 1,200 kWh:

- Public wireless network.
- Two way communication.
- "Plug and play" – a new device would be able to register itself upon installation and immediately begin to communicate.
- Home Load Management.
- Time-Of-Use.
- Net metering.

For Critical Care Customers:

- Public wireless network.
- Two way communication.
- Power Outage Notifications.

For High Turn Over Area:

- Public wireless network.
- Two way communication.
- Remote Turn on/off.

Southern California Public Power Association (SCPPA)

Glendale Water & Power, representing SCPPA, presented the current AMI-related activities of a number of SCPPA members.

Anaheim Public Utilities (110,000 accounts; 2.5 million MWh/yr)

- Initiating residential AMI pilot in June 2008 (220 meters); add 3,000-5,000/yr and evaluate whether or not to accelerate deployments.
- RF mesh technology.

Burbank Water & Power (50,000 accounts; 1.0 million MWh/yr)

- Developing Wi-Fi communications technology; use existing effort to create citywide wi-fi network.
- Installing AMI on all customers using more than 250kW (~50 percent of sales).
- Thermal storage HVAC for targeted customers.

Glendale W&P (83,000 accounts; 1.1 million MWh/yr)

- Deployed 6,400 AMR meters deployed on select accounts; water department replacing all meters; working on business plan; assuming a positive business case; begin install early 2009.
- Concerned about lack of standard communication protocols; requires system that supports electricity and water.

Pasadena (60,000 accounts; 1.2 million MWh/yr)

- In final stages of installing AMR meters – remote meter reading (drive-by).
- Much of the potential AMI benefit is not available.
- Currently developing AMI business case.

Imperial Irrigation District (128,000 accounts; 3.1 million MWh/yr)

The Imperial Irrigation District (IID) described their goal of improving operational efficiency and customer service through technological improvement and increased customer rate choices. They are evaluating a variety of different rate choices before moving to full-scale implementation. These pilots include Internet Protocol meters at 334 commercial and industrial sites, 12 percent of their customer base with ERT (solid state with AMR) meters, and TWAX DCSI Powerline carrier systems on about 750 meters.

The plan is to upgrade the meters on their normal replacement schedule or when the budget allows. IID explained that currently IID has not done a business case because they believe prematurely replacing the meters would require them to raise rates, which they do not consider an option. Replacing them on the current schedule allows them to fully depreciate the existing equipment.

Conclusions: Advanced Meters

In the relatively short time since the CPUC first required the IOUs to file preliminary business cases for AMI systems, the industry and the regulatory environment have changed substantially. AMI has evolved from a way to reduce meter reading costs and support dynamic rates to a key component in a future "smart grid" that holds substantial promise for helping reduce GHG emissions by lowering energy consumption through efficiency, and integrating expanded renewable and distributed generation portfolios. As the IOUs have engaged with the industry and regulators to develop functionality requirements, estimate costs, and plan adjustments to their operations, technology costs have fallen, functionality has increased, communications protocols and standards have been developed; essentially, the definition of an AMI system has evolved. While this shift in the industry is by no means limited to California or even the United States, it is clear that the prospect of California's IOUs investing over $4.5 Billion in their AMI systems and the policy direction provided by state regulators have been key drivers for increasing competition and spurring innovation.

The Energy Commission's goals of improving utility system efficiency, lessening or delaying the need for new electrical capacity, reducing fuel consumption, and lowering the long-term economic and environmental costs of meeting the State's electricity needs are unlikely to be met by anything less than AMI systems that meet the current minimum functionality requirements required of the IOUs by the CPUC. Further, the additional functionality incorporated in the IOU proposals provide a clear model for POUs to follow when developing AMI business cases. Most of the work has been done and at IOU ratepayer expense.

The Energy Commission proposes a new Load Management Standard (LMS-1) requiring all California utilities that have not already done so to develop new business cases for AMI that meet the following minimum criteria:

- Meters capable of measuring and storing interval data in one hour (or less) increments
- Communications networks capable of moving the data from the meter to the data management system
- Data management systems that interface with other utility functions (billing, outage management, website hosting, etc.)

This definition covers a number of capabilities, including two-way communication between the meter and the Meter Data Management System, customer feedback through web presentment of interval data, and support for dynamic electric rates.

For approval of the AMI business cases, the systems must be cost-effective and, at a minimum, provide the following functions:

- Enable dynamic pricing and feedback to the customers by:
    - Allowing prescribed price responsive tariffs (CPP, TOU, hourly RTP) by measuring, storing, and transmitting interval (e.g., hourly) consumption data to the utility.
    - Providing customer access to their interval consumption data.
    - Supporting customer understanding of their hourly consumption patterns and how they relate to energy costs.
- Increase system efficiency by:
    - Enhancing system operating efficiency (remote meter reading, outage management, improved forecasting, theft reduction).
    - Interfacing with Direct Load control (DLC) communication technology.
    - Supporting utility billing, customer support, and outage management applications.

In addition, the systems must be operated in such a way as to achieve the following goals:

- Realize operational savings and reduce utility costs.
- Minimize GHG emissions.
- Integrate distributed renewable generation and storage.
- Support default dynamic rates.
- Provide customers with useable information about their electricity consumption.

It is not the intent of the Energy Commission to create undue burdens on any utility or to increase costs for utility customers. Exceptions may be granted at the discretion of the Executive Director on the basis of feasibility or undue financial cost to ratepayers for utilities with fewer than 50,000 service accounts or less than 500,000 MWh of sales per year.

Chapter 4: Rate Design

Rates, Incentives and Market Integration

For California to achieve its efficiency, demand response (DR) and greenhouse gas reduction goals, rates and tariffs must reflect accurate system costs and present clear price signals that allow customers to make rational investment and tradeoff decisions regarding how they use their electric service. Competing objectives and legislative mandates have contributed to rate designs with subsidies and a level of complexity that hinders this customer decision process. Confusing rates with price signals that are often at odds with policy objectives unnecessarily complicate customer education and produce less than effective efficiency and demand response results.

On June 10, 2008, the Energy Commission Efficiency Committee held a collaborative workshop with the California Public Utilities Commission (CPUC) to address rate design issues. Industry experts, including representatives from the CPUC and California Independent System Operator (California ISO), investor-owned and municipal utilities, customer advocates, and interested members of the public presented information that addressed four key rate design topics: (1) rate design and the demand response opportunity; (2) the rate design process and future directions; (3) utility perspectives, and; (4) customer perspectives.

Rate Design and the Demand Response Opportunity

Over the last 30 years, most demand response programs have been structured as voluntary reliability programs, supported by cash incentives and rate discounts to compensate customers for service interruptions triggered to prevent imminent outages. These programs were limited to very large customers. Cash incentives are typically administered separately from the customer's underlying rate, which creates participation restrictions, baseline evaluation problems, and other equity related issues. For some utilities, the rate discounts reflected in non-residential curtailable and interruptible rates were designed or have evolved into economic development incentives to offset rising electric costs, with little expectation of interruptions.

Integrating new advanced metering infrastructure (AMI), digital control technologies, and innovative rates provides an improved platform for demand response.

1. AMI can now support dynamic rates that reflect current system conditions, expanding demand response to address not only conventional reliability but also economic and ancillary service opportunities;
2. AMI provides customers with significantly expanded access to their own detailed use information, which they can use to make informed consumption decisions;
3. Expanded communication options and digital control technologies can support customer specific control strategies that automatically monitor and respond to day-ahead or real-time utility price and event signals; and
4. The integration of AMI, digital control technologies, and the Smart Grid facilitates the introduction of default dynamic rates to support price-driven demand response.

Dynamic rates provide customers with better price information. Communication and digital control technologies, like the programmable communicating device (PCD), provide the customer with an automated way to respond to price and a capability to balance their service level with service costs. Consequently, under a fixed revenue requirement, dynamic rates almost always reduce collective customer costs.

Dynamic rates make demand response a more visible, explicit condition of service for all customers. Traditional flat and tiered rates average all costs of service, including the necessary demand response to keep the system stable. Customers are already paying for this necessary system stability, but providing rates that dispatch and make visible the most critical top five percent of peak prices would allow customers the opportunity to respond and reduce their costs. The opt-in approach to demand response, which is the general practice within the utility industry today, was a practical necessity of the pilot testing process. While suitable for pilots, the opt-in approach does not eliminate the responsibility for peak demand costs from those who don't actively participate. Consequently, moving all customers to a voluntary, but default, dynamic rate simply shifts peak electricity procurement costs from being hidden to being visible, thus giving customers control over their portion of those costs.

Default but voluntary (opt-out) dynamic rates are expected to include more customers and result in greater response levels. Figure 6, summarizes modeling results from the Brattle Demand Response Research Center project, which contrasts estimated peak demand and avoided cost estimates for California under opt-in and default opt-out scenarios projected out to 2030. Based on Brattle's modeling assumptions, opt-in dynamic rates are expected to provide approximate peak load impacts of 1,600 MW and $1 billion in system avoided costs. Default opt-out dynamic rates are expected to substantially increase peak load reductions to 4,100 MW and system avoided costs to $4 billion. Expanding dynamic pricing options to include economic, reliability, and ancillary service options, which go beyond the Brattle modeling, would be expected to further increase the peak load and system avoided cost benefits under a default rate option.

Finally, a default opt-out dynamic rate provides two other potential benefits not possible with an opt-in approach. A default opt-out rate provides a system-wide demand response capability, which is necessary to support California ISO system operating objectives and utility distribution management applications. A default opt-out rate also integrates incentives for efficiency and demand response within the customer rate, providing customers with more clear cut incentives to improve efficiency and permanently reduce demand.

Phil Pettingill, Manager of Infrastructure Policy with the California ISO, expanded on the retail issues raised in the Brattle presentation. The California ISO has identified a need to expand and better integrate demand response retail options into the wholesale market. According to the California ISO, existing utility reliability-based demand response options do not have the visibility, geographic presence, or dispatchability to fully realize California ISO benefits.

Figure 6: Opt-In vs. Default Opt-Out Peak Load Impacts[20]

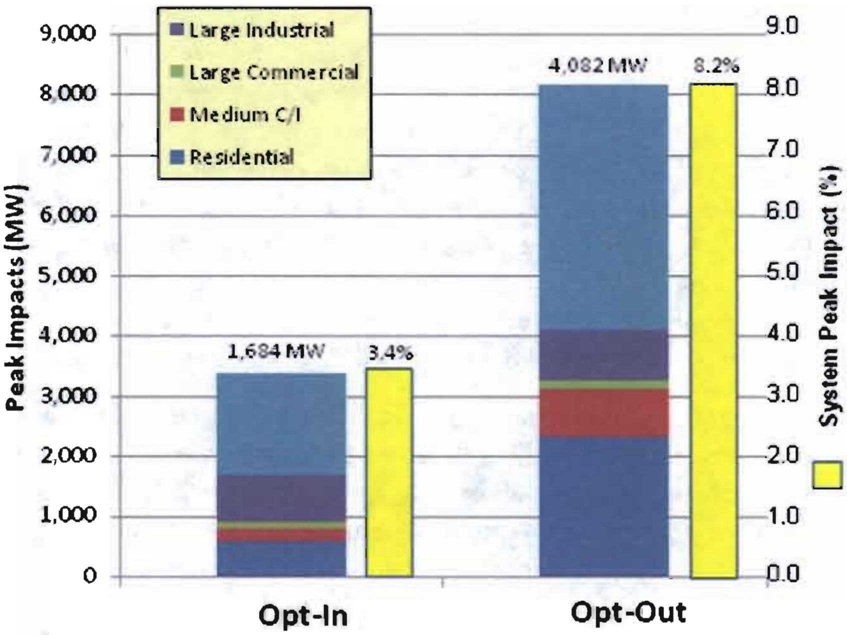
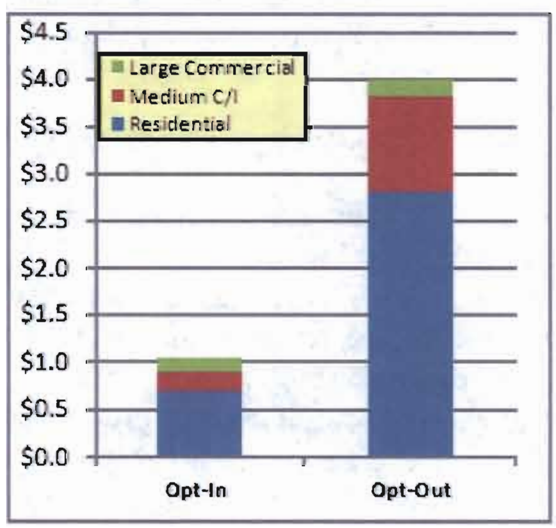


Figure 7: Opt-In vs. Default Opt-Out Avoided Cost (billions)[21]



[20] California Energy Commission Workshop on Rates, derived from Incentives, and Market Integration, Brattle Presentation, Ahmad Faruqui, June 10, 2008, slides #9-#12.

[21] California Energy Commission Workshop on Rates, derived from Incentives, and Market Integration, Brattle Presentation, Ahmad Faruqui, June 10, 2008, slides #9-#12.

Establishing a dynamic rate as a default opt-out versus an opt-in rate option has substantial impacts on the potential system wide peak demand and avoided cost benefits. Figure 6 and Figure 7 summarize modeling results from a Brattle Demand Response Research Center project[22], which contrasts estimated first-year peak demand and avoided costs for the state of California under opt-in and default opt-out scenarios. Based on Brattle's modeling assumptions, opt-in dynamic rates could be expected to provide approximately 1,600 MW, or a 3.4 percent reduction in the California ISO all-time 2006-2007 system peak, with a value of $1 billion in system avoided costs. Default opt-out dynamic rates could be expected to substantially increase peak load reductions to 4,100 MW or 8.2 percent, with system avoided costs of $4 billion. Expanding dynamic pricing options to include economic, reliability, and ancillary service options, which go beyond the Brattle modeling, would be expected to further increase both the peak load and system avoided cost benefits under a default opt-out rate option.

It is important to understand how demand response is included in utility forecasts and schedules to the California ISO and when utilities will and will not use demand response. Utility system wide forecasts often do not provide visibility to the California ISO regarding when, where within their system, or how much demand response will be called. For example, as part of their residual unit commitment (RUC) process, the California ISO described how they attempt to rationalize the demand response bid in with the expected load to be served the next day. If the California ISO finds an imbalance, they are obligated to procure additional capacity. However, if utility demand response capability is or was available but is not clearly visible to the California ISO, then the RUC process results in unnecessary capacity purchases.

While the RUC process looks at the day-ahead needs, similar opportunities exist for the day-of, hour-ahead operations, and in ancillary services. According to the California ISO, demand response resources provide operational and market benefits in three major areas:

1. Reduces the load forecast and frees up resources that must be committed to meet the peak demand,
2. Provides reliability service to the grid by adding resources capable of providing balancing energy and operating reserves,
3. Enables emergency services by providing resources to resolve transmission emergencies and capability for more precise, controlled load shedding in specific areas of geographic need, in lieu of bulk dispatching of utility programs.

The ability to target the dispatch of demand response to specific groups of customers, in specific geographic areas was emphasized as a particular benefit for addressing transmission contingencies and to provide fast ramping, fast start-type resources to better manage wind and other renewable resources.

One element of the California ISO Market Redesign and Technology Upgrade (MRTU) process is intended to address a Federal Energy Regulatory Commission (FERC) order with regard to scarcity pricing. "The concern here is that prices do not necessarily rise when the system

[22] Demand Response Research Center, Rate Transition Project, Webcast, January 25, 2008, slides #27-#28.

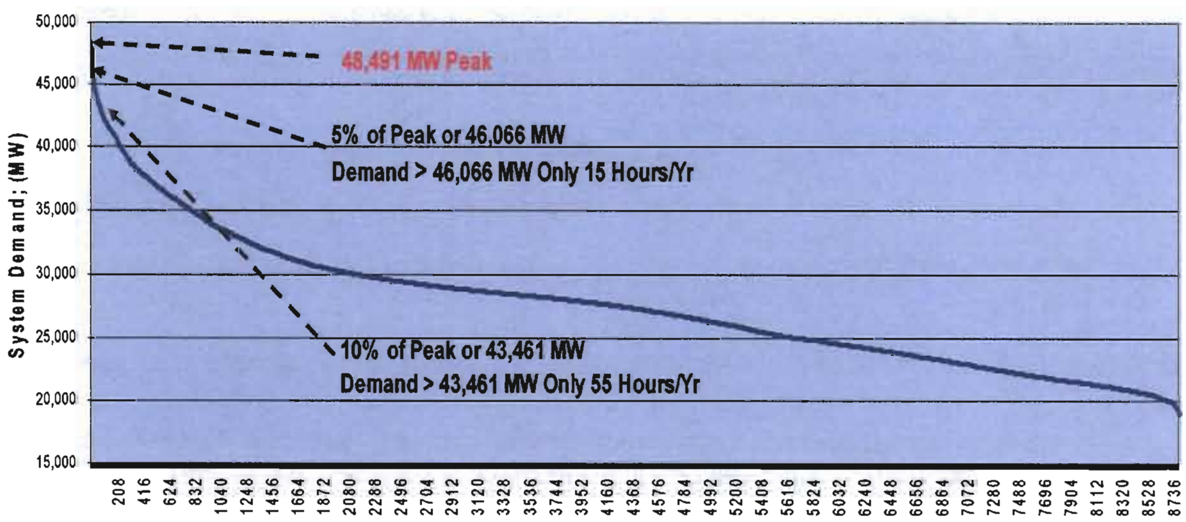
operator is experiencing a shortage in operating or other capacity reserves."[23] With scarcity pricing, as reserves drop to specified levels, "hard triggers" will automatically increase prices to help facilitate demand response. From a rate perspective, this will require rate forms like dynamic pricing that accommodate dispatchable prices and some form of automated customer response.

To quantify the potential benefits from demand response, the California ISO provided peak load examples using system load duration curves from the summers of 2006-2007 and 2007-2008. Table 4 summarizes the hours associated with the top five percent and ten percent of the state wide system peak load for each year. Figure 8, provides a representation of the 2006-2007 load duration curve.

Table 4: California ISO System Peak Demand Response Opportunities

Year	System Peak (MW)	Top 5% of System Peak		Top 10% of System Peak	
		Load (MW)	Hours	Load (MW)	Hours
2007-2008 – Normal Summer	48,491	2,425	15	5,030	56
2006-2007 Hot Summer	50,085	2,505	20	5,009	57

Figure 8: California ISO Load Duration Curve – Normal Summer[24]



For 2007-2008 represented in Figure 8, the top five percent of capacity (2,425 WM) was only needed for 15 out of the 8,760 represented hours. The top five percent of capacity (2,505 MW)

[23] Transcript of the June 10, 2008 LMS Workshop, page 15.

[24] P. Pettingill, California ISO, "Why Market Integration of Demand Resources?", California Energy Commission Load Management Rates Workshop Presentation, June 10, 2008.

listed in Table 4 for 2006-2007 represents the California ISO all-time system peak, which only represents a duration of 20 hours. Dispatchable demand response capable of addressing just a few hours each year could technically reduce system resource needs and the associated costs rather significantly.

According to the California ISO, integrating demand response into the wholesale market can produce both economic and reliability benefits. To address the diverse geographic issues inherent in the state, demand response will be most effective if the California ISO and utility systems have access to all customers and all loads. "But most importantly, I think what is essential is to provide the price transparency so that the demand products can be properly valued."[25] Dynamic rates provide a framework that would allow a utility to submit a price-responsive schedule to the California ISO that clearly links wholesale price points to capacity and energy needs.

The Rate Design Process and Future Directions

The CPUC provided an overview of rate policy and a brief summary of investor-owned utility rate practice. Rate policy has been directed in part by elements in the Energy Action Plan and more specifically by a history of CPUC decisions that have encouraged development of dynamic rates. Numerous CPUC decisions dating back to April 2005 outline utility requirements to develop real-time, critical peak pricing, and hedging products for each of the various customer classes.

An overview of the key features in the just released CPUC decision in the PG&E Dynamic Pricing proceeding was presented.[26] This forward looking decision set a framework for SCE and SDG&E, in which the CPUC provides a dynamic pricing timetable and rate guidance to support three questions fundamental to the original proceeding.

1. What types of dynamic pricing rates should PG&E offer its customers?
2. When should PG&E offer each type of dynamic pricing rate to each customer class?
3. How should the dynamic pricing tariffs be designed and integrated into PG&E's overall rate design?

Table 5 summarizes the rate options and timetable included in the CPUC decision. Rate options will be implemented in conjunction with the PG&E AMI implementation schedule, with built in delays to allow adequate time for customer education. The decision timetable does not adopt specific rates but instead provides the schedule for when rate design applications will be considered.

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[25] Transcript of the June 10, 2008 LMS Workshop, page 20

[26] Which originated out of PG&E's 2007 General Rate Case Phase 2 Application (A.) 06 03-005, originally filed on March 2, 2006.

Table 5: CPUC Dynamic Pricing Decision[27] – Rate Options and Time Table*

Customer Class	2008	2009	2010	2011	2012
Large C&I (>= 200 kW)	TOU (CPP)	TOU (CPP)	TOU/CPP (TOU)	TOU/CPP (TOU,RTP)	TOU/CPP (TOU,RTP)
Medium C&I (>=20 kW, <200kW)	Flat	Flat	Flat	TOU/CPP (TOU,RTP)	TOU/CPP (TOU,RTP)
Small Commercial (<20kW)	Flat	Flat	Flat (TOU, CPP)	TOU/CPP (TOU,RTP)	TOU/CPP (TOU,RTP)
Large Agriculture (>200kW)	TOU (CPP)	TOU (CPP)	TOU (CPP)	TOU/CPP (TOU,RTP)	TOU/CPP (TOU,RTP)
Small and Medium Agriculture	Flat (TOU,CPP)	Flat (TOU,CPP)	Flat (TOU,CPP)	TOU (CPP,RTP)	TOU (CPP,RTP)
Residential **	Tiered, Flat (TOU,CPP)	Tiered, Flat (TOU,CPP)	Tiered, Flat/PTR (TOU,CPP)	Tiered, Flat/PTR (TOU,CPP,RTP)	Tiered, Flat/PTR (TOU,CPP,RTP)

Definitions of Rates: Flat = a seasonal, non-time-variant rate; TOU = Time-of-use ; CPP = Critical Peak Pricing; TOU/CPP = Critical Peak Pricing with time-of-use during non critical peak periods; RTP = Real Time Pricing; PTR = Peak Time Rebate

* Rate options in ( ) represent alternatives that customers can select in lieu of the prescribed default.

** PG&E must file a proposal for default TOU/CPP after AB1X protections end.

Guidance regarding how dynamic pricing tariffs should be designed identified three specific sets of principles, a general set of principles to guide all rate features and distinct guidance specific to both CPP and RTP rates. Significant to all of these principles is the focus on promoting simplicity in rate design, customer choice, structuring rates to promote economically efficient customer decisions, and strong linkages to the forthcoming California ISO day-ahead market.

Design principles for CPP and RTP rates are very specific regarding critical rate design attributes. For RTP rates, the CPUC guidance directs that energy charges be indexed to the California ISO day-ahead hourly market price, further enhancing and strengthening the retail-wholesale linkage. The indexing approach specifically addresses one of the limitations inherent in California ISO wholesale prices identified in earlier presentations.[28]

The most significant elements in the CPUC guidance are a set of recommendations that identify very specific CPP rate design criteria. According to the CPUC guidance, CPP rates should:

- Represent the marginal cost of capacity plus the marginal cost of energy.
- Not include generation demand charges, and
- Be designed to allow a variable number of critical peak events throughout the year for any day of the week, based on actual system conditions.

The CPUC emphasized that while critical peak pricing is considered a dynamic rate, the CPUC recognizes that the practical limitations inherent to the rate design process, many that were highlighted in prior presentations, result in administratively set prices that at best act as a

[27] D.08-07-045 July 31, 2008, Attachment B. August 1, 2008.

[28] By Mr. Pettingill and Dr. Barkovich.

market proxy. The advantage of this approach is the ability to move away from the complexity in current rates and provide customers with more meaningful price signals.

Utility Perspectives

A panel representing investor-owned and municipal utilities made a series of presentations describing their current rate activities and general positions regarding rate design and dynamic pricing in particular.

While the IOUs all reported a variety of time-of-use and dynamic rate offerings, almost all of these rates evolved out of CPUC mandates. PG&E and SCE expressed concerns regarding the transition to dynamic pricing citing potential rate and bill volatility, the elimination of inter-class subsidies, and customer education needs. Both utilities were consistent in their preference for opt-in rather than default opt-out dynamic rate options.

SDG&E reported the most aggressive approach to dynamic pricing with the introduction of default CPP rates on May 1, 2008, for their largest commercial and industrial customers with peak loads greater than 200 kW. The SDG&E CPP rate, which was approved in their recently concluded general rate case, includes a three-part time-of-use foundation, generation demand charge, and capacity reservation option that allows customers to hedge or specify how much of their load should be exposed to the CPP pricing. While customers were also provided with a 45 day opt-out provision, SDG&E indicated few customers had exercised that option.

SMUD was the only POU reporting plans to pursue service area implementation of AMI. SMUD was also the only POU to highlight a dynamic pricing pilot and plans that included consideration for future dynamic rate options. The LADWP reported that they currently offer time-of-use (TOU) rates only to their largest commercial and industrial customers. They have no plans for the introduction of AMI and are just now introducing tiered and TOU rates to their residential customers.

Representatives from the Northern California Power Authority (NCPA) and Southern California Power Authority (SCAPA) described the metering and rate design differences within their various member utilities. While load characteristics and supply needs vary substantially across their member utilities, NCPA and SCAPA reported that they are interconnected with the ISO and also have their own power purchase pool that provides a process for transferring and trading among pool members. Consequently the opportunity exists for member utilities to accrue and create economic and reliability benefits through coordinated load shifting and transfers between utilities. Discussion and questioning on the supply-demand relationships between utilities emphasized the integrated nature of the California electric system, how those interconnections impact price and reliability, and the need to focus on collective rather than independent utility operations.

Customer Perspectives

A panel of five customer representatives presented a diversity of opinions regarding the acceptability and viability of dynamic rates. Representatives from The Utility Rate Network (TURN) and the Division of Rate Payer Advocates (DRA), which is an independent branch of the CPUC, both expressed skepticism and little support for dynamic rates. TURN expressed strong support for continuing with residential inverted tier rates to provide price signals and conventional direct control of customer air conditions to obtain demand response. DRA stated that anything other than voluntary opt-in rates would lead to mass customer confusion.

The Association of California Water Agencies (ACWA), brought an entirely different perspective to the rate discussion. ACWA stated that implementing additional water storage facilities would allow water agencies to provide as much as 500 MW to 1,000 MW of additional permanent peak load reduction; however, ACWA also stated that as public sector entities, water agencies were not subject to retail rates. Consequently, water agencies do not or cannot participate in traditional demand response options. ACWA also emphasized that storage development was a capital intensive investment that would require financial incentives and consistency not typically found in electric rates.

The Building Owners and Managers Association (BOMA), stated that their membership was very interested in, and was promoting, a move to real-time pricing (RTP). BOMA members own and operate many of the high-rise, large commercial office buildings in major cities. Because of their size they are subject to TOU rates. BOMA reported that the rate structures for these largest customers often include demand charges that account for as much as 30 to 50 percent of their summer electric bills. They see RTP as a "more granular version of time-of-use pricing" where prices will be derived more from market forces than administrative fiat. They also believe that RTP will provide more efficient price signals. BOMA encouraged the commissioners to consider long-term incentive structures that enable commercial buildings to become demand responsive and to favor investments that permanently reduce demand. BOMA also pointed out that demand responsive measures were often difficult to implement in many tenant-occupied commercial buildings, due to lease terms that contractually mandate temperature, lighting and other conditions of service. While BOMA recently was successful in changing CPUC rules to allow building owners to sub-meter their tenants, he emphasized that changes to lease terms may take time.

The California Large Energy Consumers Association (CLECA) encouraged the commissioners to consider retaining the interruptible rate options that their constituents strongly support. CLECA stated that dynamic rates, like CPP, introduce more price uncertainty over longer rating periods than current interruptible options that could adversely impact manufacturing and business operations. CLECA expressed support for technology enabled demand response, like the AutoDR approach supported by the DRRC. Spreading options like AutoDR over a larger population would reduce the load reduction pressures now administered through interruptible options on CLECA members. Finally, while there is some support for CPP and RTP based rates, she also raised concerns about the inability of wholesale market prices to properly reflect system stress conditions. She clearly stated that the lack of higher California ISO wholesale prices during system stress conditions is indicative of a more significant problem that administratively based scarcity pricing won't resolve.

Conclusions: Rate Design

Dynamic pricing and improved rate design practices provide California with an opportunity to substantially reduce system costs and improve reliability, and the Committee proposes LMS-2 to address this. Estimates provided in the Brattle and California ISO presentations indicate that dynamic pricing alone may be able to reduce system peak demand to sufficiently offset the top five percent of system load and a significant portion of California ISO residential unit commitment purchases, even during the most extreme conditions.

It is also apparent that dynamic pricing rates have the potential to incent expanded demand response applications and benefits beyond those identified in the Brattle presentation, specifically:

Municipal Utility Opportunities: With the exception of SMUD, most municipal utilities appear to be lagging far behind the IOUs in applications of AMI, consideration of dynamic pricing rates, and implementation of demand response. While individual municipal utilities may have different peak load conditions, most municipal utilities purchase power through power pools that are interconnected with the California ISO. As a result of these interconnections, municipal and investor-owned utility operations and demand response practices can impact each other's resource costs, reliability, and retail rates. Interconnection and power pool agreements provide opportunities for every utility to reduce costs and improve reliability benefits from demand response. AMI and dynamic pricing policies guiding the IOUs should be extended to the municipal utilities.

Public Agency Opportunities: Public entities, like the ACWA water agencies, have the potential to permanently reduce their peak demand without sacrificing or even changing existing customer services. However, these changes will require dynamic rates and other incentives to encourage the development of financially sound long-term investments in storage. Other public entities not now subject to retail rates should also be explored for similar opportunities.

Commercial Tenant-Occupied Buildings Opportunities: Lease conditions for tenant-occupied commercial buildings that mandate space conditioning, lighting and other conditions create a barrier to EAP demand response objectives and the push for dynamic pricing rates. Introducing dynamic pricing rates without also addressing relief for these lease conditions exposes building owners with the incentive to change their operations and reduce demand, but without the means to do so. The Energy Commission and CPUC should work with BOMA to explore options for resolving this situation.

Commercial and Industrial Opportunities for Automated Demand Response: While targeting a few large commercial and industrial customers with curtailable and interruptible rates has provided IOUs with valuable emergency demand response capability, the option of interrupting high-value industrial load requires appropriately high levels of remuneration while providing only a "last-ditch" emergency resource to the system operator. The CLECA and BOMA representatives both acknowledge the success of the DRRC AutoDR applications in automating and providing reliable demand response. Expanding AutoDR capability beyond the largest customer segment would spread the burden for demand response to a greater population of customers, reduce the magnitude of response needed from any individual customer, and improve the reliability of the aggregate response. Furthermore, expanding AutoDR capability to all customer populations would provide the ubiquitous "all customers and all loads" described by the California ISO to support additional statewide demand response applications in ancillary services and transmission and distribution congestion management.

The recent CPUC decision in the PG&E Dynamic Pricing proceeding provides an excellent framework to guide rate design for investor-owned and municipal utilities alike. The CPUC timeline is linked closely with AMI implementation. Their guidance for CPP and RTP rates takes significant and aggressive steps toward resolving the historical complexities in rate design and the inconsistencies between rate-based price signals and state efficiency and demand response policy objectives. However, while this framework provides a timeline and rate guidance, it also has to be recognized that this decision does not provide actual rates. Consequently, the CPUC and Energy Commission should continue to work diligently to make certain investor-owned utility rate designs actually embody the improvements enabled by this decision.

Because the investor-owned and municipal utilities are ultimately interconnected through their power pools and the California ISO, there is also an interconnection with price and reliability. Consequently, it makes sense to extend the rate design framework in the CPUC dynamic pricing decision to municipal utilities. However, extending the rate design framework presupposes that the municipal utilities develop business cases that support the implementation of AMI.

Finally, there is a need to pursue repeal of AB1X to allow default, opt-out, dynamic rates for IOU residential customers. The CPUC decision in the PG&E Dynamic Pricing proceeding recognizes this limitation and conditions the implementation of residential dynamic pricing on changes to or the expiration of these limiting conditions. As an interim solution, the CPUC has approved the introduction of Peak Time Rebates (PTR) as a transition option.

There is no evidence to suggest that PTR provides a transition to dynamic pricing. To the contrary, the attributes of PTR and the education and marketing campaigns to introduce it will just further confuse residential customers and jeopardize rational long-term investments in demand response.

Investor-owned utility demand response projections for PTR may be more optimistic than is warranted. Contrary to investor-owned utility representation and comments made by the DRA representative during her presentation, PTR does not introduce the concept of time-varying costs of electricity.[29] PTR is an overlay to the existing residential tiered rate that has no time-dependent variation. Because PTR includes a problematic baseline calculation it adds to, rather than reduces, rate complexity and injects even more confusion in the customer billing process. Even the DRA representative clearly identified rate and bill simplification as a first step in the education process by stating "But if educations are to be done they ought to start with how bills are calculated now, rather than forcing a customer onto a default rate structure that is different from the current rate structure…"[30] Unfortunately, PTR forces a customer onto a default rate that works at odds to the very guidance provided in the CPUC dynamic pricing rate decision.

[29] Transcript of the June 10, 2008 LMS Workshop, page 208.

[30] Transcript of the June 10, 2008 LMS Workshop, page 207

PTR does not introduce time varying price signals. Applications of baseline calculations will add confusion to existing billing process. By its very nature, PTR discourage load shifting. Implementation of PTR should be reconsidered.

Since AB1X is in place today and may be for some years into the future, the preferred implementation strategy for demand responsive rate, default, opt-out, dynamic pricing, is not available to the IOUs. Consequently, for them, rate designs to take advantage of AMI must be opt-in. While not optimal, proceeding this way is not ruinous either. In order to achieve significant levels of demand response from the wide scale installation of advanced meters, the IOUs need to offer *and promote* rate designs that incent customer response.

Chapter 5: Enabling Technologies

The success of load management and demand response is enhanced by technologies that allow customers to choose to modify their energy use responding to dynamic rates and time-of-use rates at minimum cost. These enabling technologies provide benefits in one or more of the following ways:

- Information technologies can provide customers with significantly more and better information about their energy use, so that they can consider efficiency investments and or behavioral changes to reduce their overall and on-peak energy use. Examples of these technologies are in-home displays, energy management systems, and integrated energy use sensors.
- Adjustment technologies can allow customers automatic responses to price and reliability signals that reduce or manage their costs, based on settings chosen by the customer. Examples of these technologies include programmable communicating thermostats (PCTs) and other programmable communicating devices, demand-response automated servers and energy management systems, and integrated sensor and control technologies.
- Load-shifting technologies allow customers to permanently modify their energy use pattern, generally shifting their energy use to times when costs are lower and reliability higher. Examples of these technologies include thermal energy storage systems, other customer-based storage options, small solar generation, and fuel-shifting or energy reducing technology investments aimed at peak end-uses of electricity.
- Distributed system technologies allow utilities to manage and balance load and supply at a distribution level to moderate calling on larger peaking resources and to enhance distribution circuit reliability. Examples of these technologies include distribution scale utility storage systems, such as thermal and battery storage, and additional intelligence in distribution technology.

The June 19, 2008 workshop on demand response and load management enabling technologies included discussion and presentations about all of these types of technologies, in addition to drawing the connections between enabling technologies and dynamic rates and advanced metering infrastructure. The workshop, subsequent comments from parties, and additional staff analyses of enabling technologies provided information for developing the recommended load management standards and other actions in this report.

Enabling Technologies for Demand Response

When demand for electricity rises to the highest levels, usually on the hottest summer afternoons, the system calls on the highest cost supply sources and on consumers to reduce their demand to avoid these high costs. At times, supply may be scarce enough to threaten the reliability of the electricity grid, and the call for consumers to reduce demand becomes more important. This can also happen suddenly at other times, if some supply resources shut down unexpectedly, or if transmission becomes unavailable, and can also happen if supply, transmission, or distribution problems prevent power from getting in sufficient quantities to where it is being demanded.

The call for consumers to reduce demand in these cases comes through either price or reliability signals, letting consumers know that they can save money by reducing their demand when the price is high, or telling them that they can help prevent an electricity emergency by choosing to reduce demand, or both. While some consumers may monitor the daily demand on the grid or the hourly price of electricity and then manually take actions in response, most consumers are not interested in devoting much of their time for this purpose. Enabling technologies can provide consumers with the benefits of responding to price or reliability signals, without the costs of personally monitoring for signals and manually taking responsive actions. These technologies provide consumers with access to information and inexpensive tools that they can "set and forget" to take the actions they have pre-determined to be appropriate.

California's statewide pricing pilot (SPP)[31,32] was designed to test the impact of several time-varying rate structures on the electricity use patterns of residential and small commercial customers. A critical peak pricing (CPP) rate was offered to a sample of residential, commercial, and industrial customers in Southern California Edison's service territory with demands below 200 kW. The sample was segmented into two size strata, customers with demands below 20 kW and customers with demands between 20 and 200 kW. The SPP analysis showed that customers on a CPP rate:

- Reduced peak period energy use on critical days by an average of between 5 and 7 percent without enabling technology, and
- Reduced peak period energy use on critical days by up to 13 percent when provided with enabling technology to voluntarily automate their response.

Presenters at the June 19 workshop documented the increased demand response resulting from programs using automated enabling technologies. In the statewide pricing pilot, automation approximately doubled the energy savings achieved in both residential and commercial applications (Figure 9 and Figure 10). Automated response achieves the desired energy reduction from more program participants because customers have already chosen and pre-programmed their level of response to a demand response signal, eliminating the need to take action at the time a signal is sent. This reduces the time and effort required for consumers to participate in demand response programs, and saves them the energy costs they would otherwise incur if they did not actively respond. At the same time, this preserves the consumers' choice to actively reduce their load – or not – in individual situations.

During the June 19 workshop, a variety of demand response enabling technologies were presented and discussed, including the programmable communicating thermostat (PCT) for the

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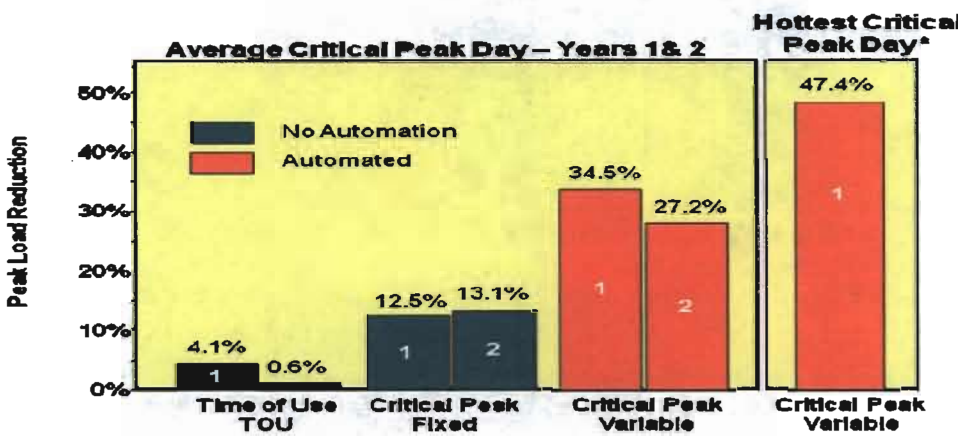
[31] S. George, A. Faruqui, and J. Winfield. *California's Statewide Pricing Pilot: Commercial and Industrial Analysis Update*. CRA International. June 28, 2006.

[32] S. George, A. Faruqui, and J. Winfield. *Impact Evaluation of the California Statewide Pricing Pilot*. CRA International. March 16, 2005.

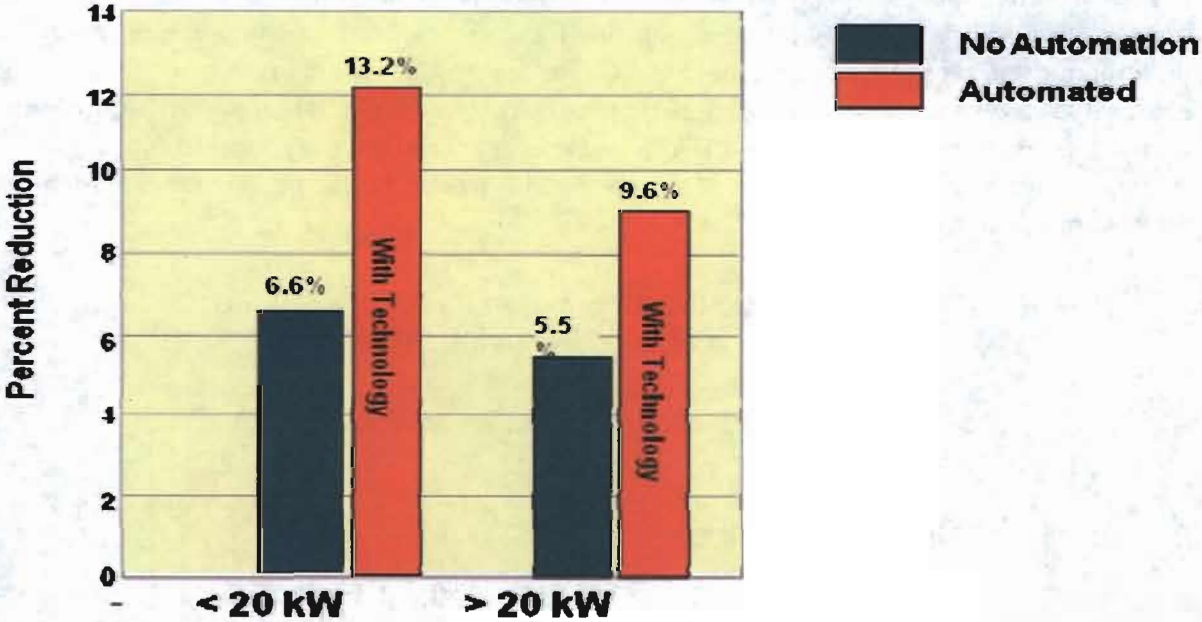
residential and small commercial sector and AutoDR-related technologies such as Demand Response Automation Servers (DRAS) or demand response enabled energy management systems (EMS). A programmable communicating thermostat allows a consumer to program their thermostat to respond to a signal to change the temperature set point a few degrees when electricity is most expensive or when the grid may be in danger of failure. The AutoDR concept is an information protocol that allows DRAS and energy management systems to automatically reduce specific loads when prices are high or a signal is received calling for demand reductions for system reliability.

Figure 9: Residential Automation Response Results from the Statewide Pricing Pilot[33]



[33] Critical Peak Fixed rates applied the critical peak charge for the duration of the pre-defined peak period. Critical Peak Variable rates dispatched the critical peak charge for 2-4 hours, as needed, during the pre-defined peak period. Both the Fixed and Variable rates applied the same critical peak charge.

Figure 10: Commercial Automation Response Results



The IOUs have included PCT information as part of their AMI business cases and PG&E has included a PCT option in the utility's Smart AC Cycling program. AutoDR programs developed by the Demand Response Research Center have achieved success in reducing load when called upon, and have been expanded as a result. While there is significant activity and concept development in the IOU service areas for these technologies and concepts, POUs have not explored this area.

In addition, cost and effectiveness information is readily available, from the last few years of development of these technologies and concepts, to support load management standards for these technologies.

While PCTs and AutoDR efforts can provide consumers with significant benefits, there are a number of other technologies, in the market or under development, that will also provide comparable benefits. All technologies will require standardized information models and inexpensive and widely available products, or the results will be less cost-effective and not provide the degree of demand response desired. There is an opportunity for the state to jump start the market for these technologies, by providing clear regulatory direction facilitating market development. There are manufacturers already producing these technologies and ready to provide devices to consumers, in response to utility programs or other efforts facilitating market demand.

Although PCTs are currently the most commercially available example of enabling technology, the basic concept of an appliance or device having the capability to receive a price or reliability signal and automatically adjust its energy use in an appropriate, customer-chosen, manner goes well beyond thermostats. A variety of home appliances and commercial equipment can be configured to automatically adjust energy use at prices or events chosen by the consumer. The concept of programmable devices shows significant promise for allowing consumers to identify low-value loads that they are willing to have reduced during conditions where high prices or system needs require a demand response contribution. Appliance and equipment manufacturers are exploring adding digital components of their products that will allow consumers to choose an automated level of participation in a Smart Grid future electricity system. The Committee recommends an Executive Level Smart Grid Advisory Committee continue oversight of developing technologies and these technologies should be considered in a future load management standards proceeding.

Enabling Technologies for Customer Information

Some enabling technologies have the primary aim of simply providing consumers with more information about their energy use, allowing consumers to adjust their use through behavioral changes or investments in energy efficiency measures. These technologies can also be configured to connect to advanced metering infrastructure and to automated demand response technologies throughout the home or business. At the June 19 workshop, the SMUD described a pilot program they were conducting: the Power Choice (TOU) Home Energy Display Pilot. This program uses a combination of advanced meters and in-home displays to provide feedback on energy use to residential Time-Of-Use rate customers. Other programs and vendors are using or have developed in-home displays that work with a customer's television set or computer to provide feedback. The simplest of these type of technologies involves a glowing orb or other feedback device that indicates to customers when electricity prices are high or when there is an imminent system reliability event.

In-home displays and similar devices can facilitate easier programming of automated response for a variety of communicating devices, making automated response easier and more effective. Additional information and market development for these kinds of customer information technologies is necessary prior to development of a load management standard. Hence, the Committee recommends continued monitoring of developments in this technology space for future consideration of a possible load management standard.

Enabling Technologies for Load-Shifting

There are a variety of load management technologies that can help alter the system daily load shape, not in response to a relatively immediate price or reliability signal, but rather as a long-term load-shifting investment. Strategies here can involve technologies to pre-cool buildings, create and store needed cooling off-peak for release to a building on-peak, and shifting on-peak uses to alternative fuels, such as solar and natural-gas fired chillers for cooling.

For example, a thermal storage unit allows a building manager or homeowner to store cooling energy over night when electricity is inexpensive, and then use the stored energy to cool during the afternoon when prices are high. At the June 19 workshop, presenters described some of these technologies, and Commissioners expressed support for the concept, but indicated that there may be no need for a standard to address their market penetration at this time. With all customers moving toward at least TOU rates under AMI, the value of such technologies to customers would appear to be increasingly attractive. Properly implemented, this enabling technology could be invisible to the building occupants and provide significant bill savings under a favorable pricing plan, while assisting the system overall by shifting load off-peak.

The Committee recommends that utilities provide information about the potential for load-shifting technologies to customers as they are moved onto dynamic rates.

Enabling Technologies for Distribution Modulation

Similar storage technologies can also be employed by the utility, as part of the distribution system or in combination with large customers, to provide better grid stability and reliability. SMUD and other presenters at the June 19 workshop described a variety of different storage technologies that are being tested and demonstrated for such purposes. SMUD described working with the communities light rail system to demonstrate temporary storage using ultra-capacitors, discharging the energy stored here to pare down the surge in power needed as light rail trains accelerate away from stations. SMUD and others discussed demonstrations of longer term battery banks for distribution reliability.

The Committee recommends that utilities continue exploring and demonstrating these load management technologies, and that the Energy Commission monitor these projects and market developments for a possible future load management standard development.

An additional benefit for the state of developing a Smart Grid that fully incorporates these types of enabling technologies is that the distributed storage and demand response resources can provide support for integration of intermittent renewable resources such as wind. Wind generation can vary unexpectedly as the wind blows harder or softer, and as the percentage of wind power on the system increases at any particular time, this can require an increased ability within the system to adjust to this variation in wind generation. To a lesser degree, similar system integration is needed with solar resources. Automated enabling technologies and storage technologies in a Smart Grid can be structured to increase the ability of the electricity system to respond in such situations in a more cost-effective and environmentally responsible manner.

Conclusions: Enabling Technologies

Given the background information, the Committee proposes the following load management standards:

LMS-3. Statewide Time-Differentiated Rate Broadcast. A standard that requires each utility in the state to broadcast rate and reliability signal information using an open-protocol, Internet compatible, information model based on the Open AutoDR (*date & version*) standard developed by the Lawrence Berkeley Laboratory Demand Response Research Center, so that customers that have time-differentiated or dynamic rates can use the information carried by the signal to communicate with an in-home display and/or automate their load reductions using Programmable Communicating Devices.

LMS-6. Enabling Technology Adoption Program. A standard that requires each utility in the state to offer programs that provide appropriate discounts for, and information about, standardized programmable communicating devices (PCDs) to customers equipped with an advanced meter capable of recording consumption data necessary for dynamic pricing rates. Eligible PCDs would be compliant with a PCD reference design proposed in this standard. The utility programs would be structured to allow customers to voluntarily program any price response strategy they choose to take in response to a dynamic pricing rate.

Chapter 6: Customer Information and Needs

Perhaps the most difficult part of load management policy is the customer side of the equation. What information do customers require and how much information is too much? What load management actions can customers take to reduce their cost of service and improve reliability, and more importantly, what actions *will customers be willing* to take to achieve those goals? What tools do customers need to adapt their consumption patterns to new price structures and incentives, and how can regulators support the development of those tools?

Customer Education and Needs Workshop

On July 10, 2008, the Efficiency Committee held a workshop on customer education and needs. This workshop included presentations from technical experts, numerous industry representatives, and investor-owned and publicly owned utilities on current and future customer education efforts. The presentations were focused on three areas:

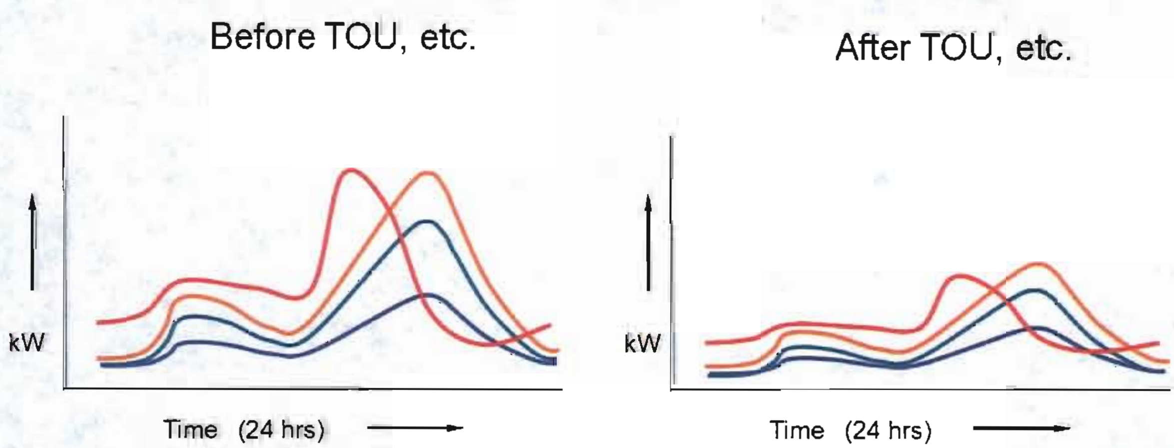
1. Research on customer education and needs.
2. Technologies available to support customer load management.
3. Current utility load management programs.

The presenters also were asked to discuss how the Energy Commission can use this proceeding to support existing efforts and investigate what new opportunities exist for improving customer participation in load management programs.

Current Research on Customer Education

Residential use tends to peak in the afternoon and early evening, and the idealized effect of time-of-use rates and other load management policies is to reduce that peak (Figure 11).

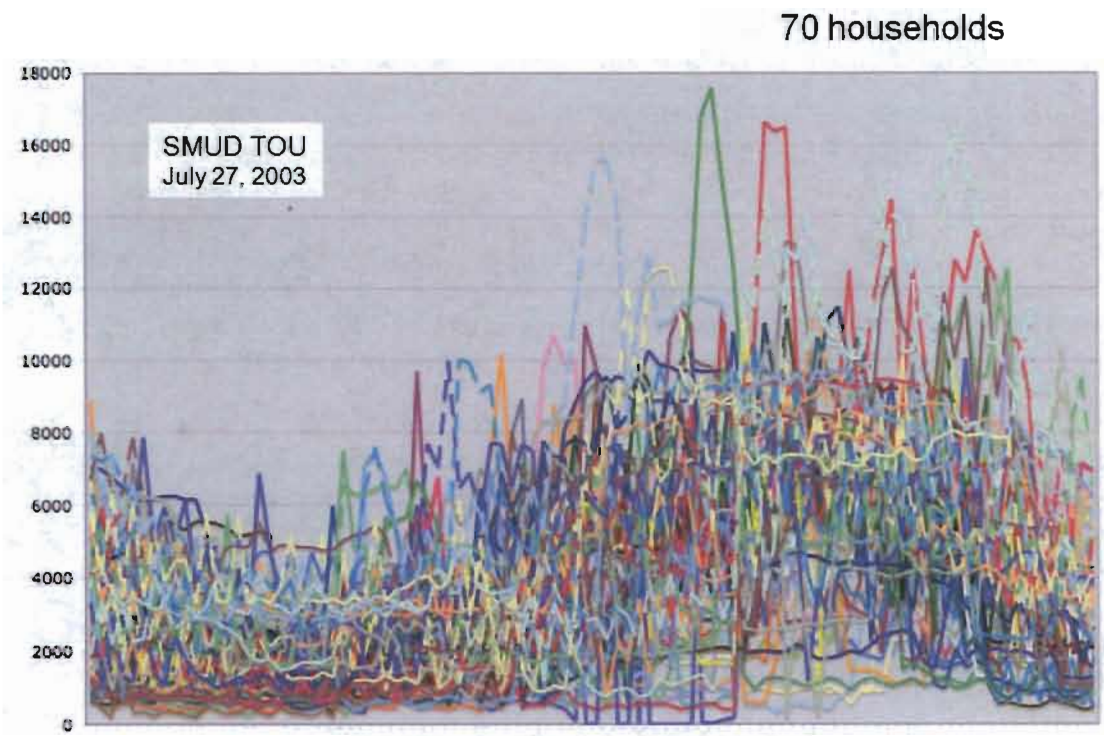
Figure 11: Idealized Load Profile Impact of Load Management



Source: Dr. L. Lutzenhiser. Load Management Standards Workshop on Customer Education and Needs. July 10, 2008. Page 9.

Dr. Loren Lutzenhiser[34] from Portland State University has collected data on energy consumer behavior over the past eight years, and stated that the challenge is daunting. Energy literacy is low, and the information necessary for customers to respond is significant. As many as 20 percent[35] of residents never see a utility bill, because it is taken care of automatically, averaged over the year, or paid by someone else in the house hold. Those customers that do see bills generally find them confusing or unintelligible. Residential energy flows are nearly invisible to consumers, possibly intentionally. Customers receive almost no feedback from either conservation efforts or excessive consumption patterns. Dr. Lutzenhiser discussed how actual residential load profiles are much less predictable, as the actual use data from 70 households below shows (Figure 12).

Figure 12: Actual Load Profiles



Source: Dr. L. Lutzenhiser. Load Management Standards Workshop on Customer Education and Needs. July 10, 2008. Page 31.

There is good news, however. Driven by economic problems, concern about the environment, and energy security, consumers are willing to take load management actions. In research on time-of-use rates, more customers found conservation and peak reduction changes they made to be "manageable" or "not painful" than those who found the changes to reduce comfort or quality of life.

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[34] Professor of Urban Studies and Planning, Portland State University

[35] Transcript of July 10, 2008, LMS Workshop. Page 12.

One problem observed by most presenters is that customers generally do not understand their rates. Customers understand that they receive a bill at the end of the month, but the connection between daily electricity consumption and the amount due on the bill is at best vague. Education efforts must be more involved than simply providing information, and success hinges on the quality of the information provided and the program. How customers receive information, when and where they are presented information, and who provides that information is all as important as the quality of the information itself. In short, there are many ways to get it wrong, and few past education efforts have been done right.

Recent experience with the 2001-02 California electricity crisis does provide some positive signs. The call for conservation resulted in widespread responses and conservation efforts. Polling showed that approximately 72 percent[36] of households reported taking at least one conservation action in response to the crises. This real system peak reduction was based on altruistic, civic, and environmental motives. Further, approximately 77 percent[37] reported that the changes either had no significant impact on their comfort or actually improved their quality of life.

Residential energy use is complex and highly variable between households. Dr. Lutzenhiser emphasized that further research is required to address this issue and achieve lasting demand response. Many current efforts are focused on technological fixes, but the real change required is behavioral.

Dr. Mithra Moezzi from U.C. Berkeley presented an overview of time-of-use rates, including specific finding from the SMUD PowerChoice program (2007-2008). The PowerChoice program is a pilot time-of-use rate offered to select residential customers in SMUD territory.

Time-of-use (TOU) rates were first promoted by engineers during the early days of electrification (1890-1910), and were applied to some residences at that time, but not widely adopted. TOU rates were revived in the 1970s and 1980s after the first energy crisis by economists as a way to encourage energy conservation. Currently, 148 utilities in the United States offer optional TOU rates, but less than 2 percent of customers subscribe to such rates.

The PowerChoice research was ongoing at the time of the workshop, but Dr. Moezzi discussed two of the ongoing program test concepts. The first provided technical use information in combination with social marketing principals in an effort to encourage a sense of community among the program participants, and improve the lasting impact of the changes. The second provided real-time consumption monitors to program participants to investigate the impact of real time information on consumption patterns. The literature suggests that real-time feedback should result in 5 to 15 percent conservation, but this depends on many assumptions such as the rate structure and the availability of response automation tools. Early results show that customers are primarily concerned about finances, but are also concerned about reliability, environment, and to a lesser extent, security. Almost all participants reported already taking

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[36] Dr. L. Lutzenhiser. *Load Management Standards Workshop on Customer Education and Needs*. July 10, 2008. Page 17.

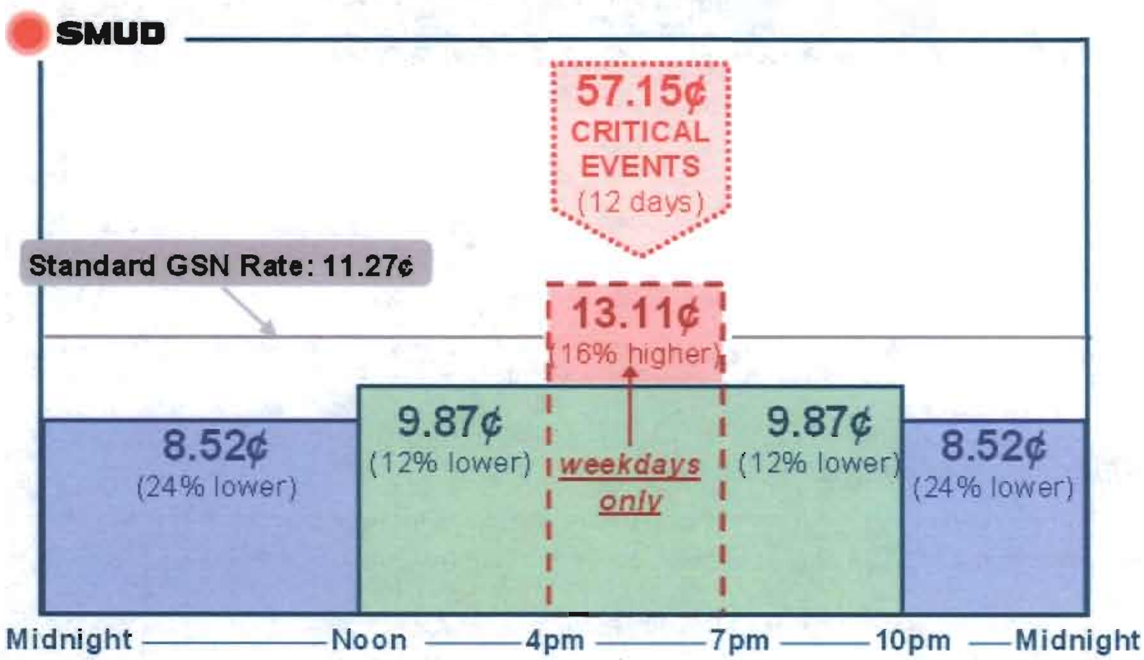
[37] Ibid. Page 19.

steps to conserve energy, but almost all took new steps to conserve once they joined the program.

Mr. Girish Ghatikar from the Lawrence Berkeley National Laboratory Demand Response Research Center reported that most commercial and industrial customers lack the necessary knowledge, experience, and expertise to minimize energy use and develop cost effective load management strategies. Complex DR programs, tariffs, and incentives structures hamper development of operational strategies. Constantly changing demand response options and restrictive participation conditions create uncertainty and risks. Separating efficiency and demand response programs can lead to conflicting investment and operating recommendations. Lack of communication and technology standards increase costs and reduce effectiveness of equipment. Finally, lack of energy information systems and performance monitoring tools create barriers to operation and investment among commercial and industrial customers. Research since the 2001 electricity crisis, however, shows that there is significant potential for load management in the commercial and industrial sectors.

Dr. Karen Herter presented results from the ongoing SMUD Small Business Summer Solutions Pilot program, started in May 2007, and scheduled to conclude in December 2008. Under the program, small businesses on a critical peak and time-of-use rate are equipped with programmable communicating thermostats (Figure 13).

Figure 13: SMUD's Small Business Summer Solutions Rate (per kWh) (Critical Peak rate with underlying Time-of-Use rate)



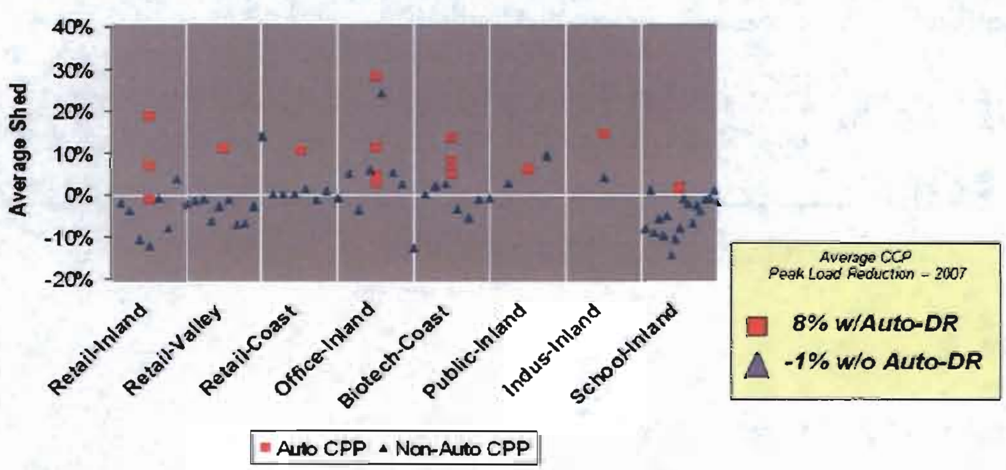
Source: Dr. K. Herter. SMUD's Small Business Summer Solutions Pilot. July 10, 2008. Page 10.

Technology to Support Customer Load Management

As Seth Kiner from SCE observed at the workshop, "customers don't want a third job… energy management is a third job."[38] Most customers do not want to worry about their energy management. However, customers want to save money, be in control of their energy use and finances, and help the environment. While customers do not want government or utilities to require them to spend large amounts of time to achieve these goals, they are open to opportunities that do not require excessive time investment as long as they are voluntary.

One key to customer participation is automated energy management tools that allow customers to program their response to events ahead of time. Field testing has shown that facilities equipped with automated demand response equipment such as an energy management system using the Open Automated Demand Response communication standard (OpenADR) or a PCT have not only more consistent response to requests for load shedding, but also larger average load reductions. Figure 14 shows how facilities equipped with demand response automation equipment in 2007 achieved a significant improvement in the quantity of load reduction during demand response events.

Figure 14: AutoDR Results – Manual vs. Automated



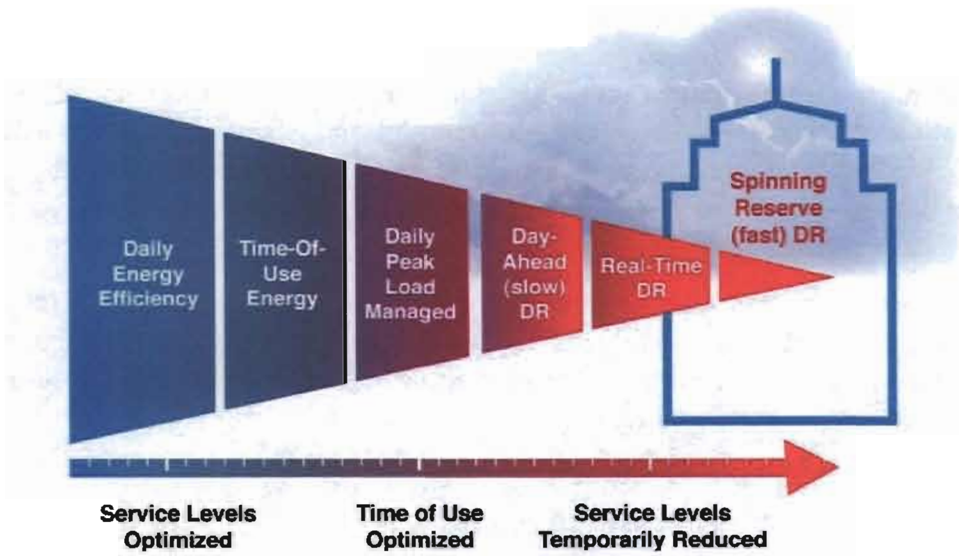
Source: Mr. G. Ghatikar. Commercial & Industrial Customer Education: Lessons from Automated DR. July 10, 2008. Page 4.

Utility Load Management Programs

It is important when considering existing utility programs to understand that not all load management is of equal value to either the utility or the customer (Figure 15).

[38] Transcript of July 10, 2008, LMS Workshop. Page 180.

Figure 15: Energy Value Chain



Source: Mr. G. Ghatikar. Commercial & Industrial Customer Education: Lessons from Automated DR. July 10, 2008. Page 6.

Generally speaking, the load management resources that respond faster are of greater value to the grid. Current utility demand response programs generally do not focus on the higher value resources due to historic technological limitations. One of the goals of this proceeding, however, is to explore the feasibility of the more valuable, faster response, demand response resources.

Jodi Stablein, Director of Marketing Strategy & Governance at PG&E, stated, "the objective here is to educate customers to adopt a more conservation-conscious energy behavior, especially as demand increases. We need to be able to provide information, tools, technology so that customers can understand the options that they have; evaluate financial and environmental impacts; as well as make appropriate decisions as to whether or not they can participate." PG&E envisions a four step process of customer education:

1. *Awareness*: Customers are educated about the need for demand response.
2. *Engagement*: Customers are voluntarily given the choice to select the DR option that meets their needs.
3. *Adaptation*: Customers adapt to demand response options by initially and repeatedly using data, tools, and technology to better manage their consumption and change their behavior.
4. *Adoption*: Customers adopt demand responsive pricing behaviors.

PG&E emphasized the need for flexible load management programs that allow customers to choose from different options and customize their load management to their individual needs.

Conclusions: Customer Information and Needs

Previous demand response and energy efficiency efforts have taught regulators and utilities alike that it is critical to have customers involved. With few exceptions, existing residential demand response options focus only on a single appliance load, central air conditioning, and employ control strategies dictated by the utility. The Statewide Pricing Pilot and other similar pilots have clearly demonstrated that "customer choice" produces significantly more load response and much greater customer satisfaction than utility control. With customer choice, the customer, not the utility, determines what loads to control, and when, if, and how much to control those loads. To support customer choice, customers must have understandable and current information on their energy use, clear price signals, and well designed, inexpensive automated energy management options.

All parties agreed that further research is necessary on how to provide customers with understandable information. It is clearly easy to overload customers with information, or to provide confusing information. Research shows that customers have many reasons for being interested in load management programs, including support for:

- Reducing the cost of their utility bills.
- Environmental benefits of conservation.
- Community benefits of improved grid stability.
- Increased choice and control over their energy consumption and bills.

Given the background information, the Committee proposes the following load management standards:

LMS-3. Statewide Time-Differentiated Rate Broadcast. Establishes a standard method and requirement for transmitting current rate and reliability information to customers.

LMS-7. Customer Access to Meter Data. Establishes the legal standing of customers to access their electricity use data.

Chapter 7: Smart Grids

The current load management proceedings are focused on how best to achieve demand response and adopt regulations and take other appropriate actions to achieve a price-responsive electricity market. Demand response is one of many strategies pursued by California to create a more reliable and flexible electrical system. The combination of demand response with other strategies such as distributed generation and renewables creates a new set of challenges for California's existing electricity transmission and distribution network, known as the "grid."

The existing grid was designed to prioritize stability and reliability over flexibility. It is often said that if Alexander Graham Bell were somehow transported to the 21st century, he would not begin to recognize the components of modern telephony – cell phones, texting, cell towers, personal digital assistants, etc. – while Thomas Edison, one of the grid's key early architects, would be totally familiar with the grid. This design has served California well, but our recent push to include resources that have variable outputs (like wind energy) or are not remotely controllable (like demand response), has revealed the need to upgrade and rethink our grid design. This upgraded and more flexible distribution system is called the "smart grid."

Smart grid technology can provide faster control of the grid and allow for quicker responses to changes in the renewable resource generation capability. Smart grid technology will integrate resources such as storage, demand response and other generation resources (DG, CHP, etc) fast enough to allow the grid system to continue operating safely even though the these rapid changes occur. Smart grid system estimating technologies will provide more reliable estimates of generation capabilities (including renewable) and actual grid load needs.

The Energy Commission Efficiency Committee was tasked to develop a set of Load Management Standards that grow demand response resources while simultaneously ensuring the continued safe and reliable operation of the grid. Smart Grids is the vehicle identified by the commission as one of the key elements in the accomplishment of that task.

Smart Grid Activities and Technology Workshop

During the April 29, 2008 Load Management Standards Smart Grid workshop, speakers from various organizations including utilities, federal government, state government, and the European Union presented their perspectives on the current state and direction of smart grid. The workshop was also attended by Commissioner Chong of the California Public Utilities Commission (CPUC), demonstrating that these proceedings have relevance to stakeholders across the state.

During the workshop presenters and panel discussants were asked to explore four key questions with regards to smart grids:

1. What is a "Smart Grid"?
2. What is the current progress toward Smart Grids in and outside California?
3. What challenges exist to implementing the smart grids?

4. What intervention or coordination on the part of the Energy Commission or CPUC is necessary to ensure success?

What is a "Smart Grid"?

The definitions of a Smart Grid were diverse, however a high level, non-technical definition of a Smart Grid emerged as one that includes, at a minimum, the following attributes:[39]

- *Self-Healing* and *Adaptive*.
- *Interactive* with consumers and markets.
- *Optimized* to make best use of resources and equipment.
- *Predictive* rather than reactive, to prevent emergencies.
- *Distributed* across geographical and organizational boundaries.
- *Integrated*, merging monitoring, control, protection, maintenance, energy management systems, demand management systems, marketing, and information technology.
- *More Secure* from attack.

This attribute-focused definition captures only a directional sense of where smart grids are going rather than an objective definition of what it is. Mike Gravely from the Energy Commission stated that, "…we just haven't come up with a comprehensive definition that everybody can agree with yet."[40] Walter Johnson from the California ISO commented that the California ISO is also struggling with defining a Smart Grid, and he said, "…the attitude seems to be, for the most part, that the smart grid is characterized by its behaviors not by what it's made out of, not by how it's constructed."[41]

The European Union (EU) has made great strides in moving toward a Smart Grid approach. Richard Schomberg of Electricite de France (EDF), made it clear that a Smart Grid isn't something you can "take a picture of."[42]

The U.S. Department of Energy (DOE) is currently undertaking a project to define and encourage development of "Smart Grids" for the nation. In collaboration with the National Engineering Technology Laboratory they held workshops in June 2008 to help define the Smart Grid concept. In their published results, *"The Smart Grid: An Introduction,"* their definition of a Smart Grid is no more clear or definitive than any presented at the workshop. Rather than define a Smart Grid in specific terms, the publication presents some of the benefits that will accrue from a smart grid without defining specifically what will constitute that grid as a whole.

Finally, even Sacramento Metropolitan Utilities District (SMUD), one of the most progressive utilities in the state with regards to adoption of new technologies, in their presentation stated that they "haven't really defined the Smart Grid."[43]

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[39] From California ISO Presentation *"eGrid: CAISO's Vision for California's Smart Grid"* presented at the Energy Commission Load Management Workshop on April 29, 2008

[40] Energy Commission Smart Grid Workshop transcript, held April 29, 2008. Pg. 16

[41] Energy Commission Smart Grid Workshop transcript, held April 29, 2008. Pg. 27

[42] Energy Commission Smart Grid Workshop transcript, held April 29, 2008. Pg. 63

[43] Energy Commission Smart Grid Workshop transcript, held April 29, 2008. Pg. 192

What is a Smart Grid?

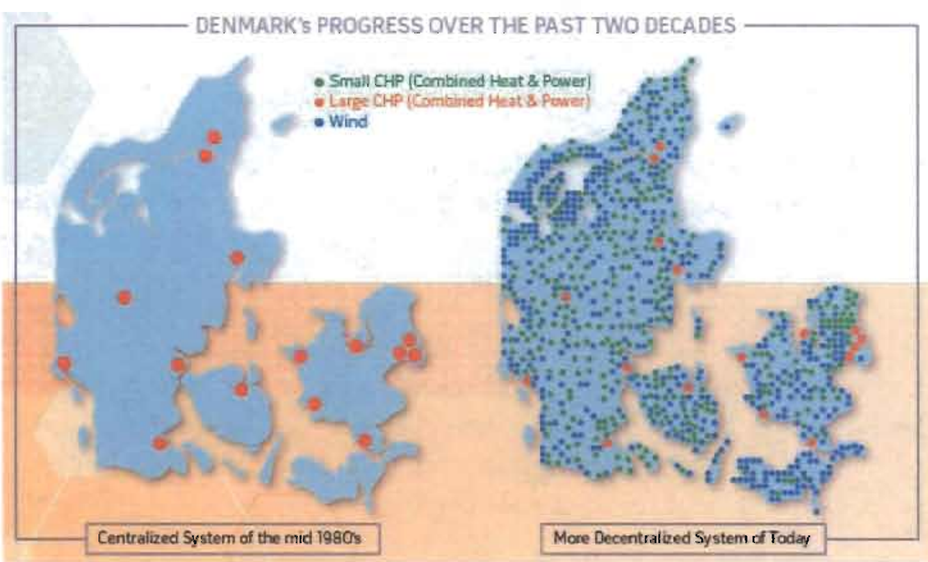
There currently is no one definition of what a "Smart Grid" is. Our current thinking only indicates in what ways the future grid will be smarter than the grid of today and some of the functionality and benefits that will accrue from these improvements.

What is the Current Progress of Smart Grids Inside and Outside California?

Smart grids are a topic of intense discussion among utilities and regulators around the world. Many European nations are improving the intelligence of their grids due to the integration of large-scale renewables. Richard Shomberg commented that the EU is investing $3.6 Billion between 2007 and 2013 pursuing Smart Grids under the *EU Framework Program 7*. Their investment is focused mainly on having a more interactive distribution network and includes control and implementation strategies for handling the distributed injections of power from many small generators.[44]

DOE used Denmark to illustrate the profusion of small generators over the last two decades that is driving the need for a Smart Grids(Figure 16).[45] Despite the investment and driving need for progress toward a Smart Grid, very little progress has been made in the U.S.

Figure 16: Decentralization of Generation in Denmark



The IOUs presented their individual perspectives on how smart grids will grow and many of them are investing in research and development toward those ends. SCE diagrammed their activities on page 7 of their presentation, placing the different technologies in visual context to the energy supply chain. PG&E presented a layered conceptualization of the components of

[44] Energy Commission Smart Grid Workshop transcript, held April 29, 2008. Pg. 46-47

[45] The Smart Grid: An Introduction, Pg. 9

Smart Grids on page 3 of their presentation, and SDG&E provided an excellent overview of the key players in the field of Smart Grids on page 9 of their presentation.

Overall, these utilities, and in fact all the presenters, conceded that Smart Grids are a work in progress. Some of the technology necessary for their implementation currently exists; however no one has brought all of these technologies, infrastructures, and strategies together under one roof and moved forward with a holistic vision of what Smart Grids are. And even if they had, according to Energy Commission staff, it would not be immediately transferrable to California's unique challenges.[46]

> *What is the current progress of Smart Grids in and outside of California?*
>
> *Some of the necessary technologies exist, but Smart Grids remain a work in progress. Europe is developing a Smart Grid and the DOE is currently investigating how to do so in the US. Currently, there does not exist an example of an operational Smart Grid anywhere in the world.*

What Challenges Exist to Implementing Smart Grids?

During the workshop, many of the presenters and participants identified challenges to implementing smart grids. Some of these were technical in nature and others were policy oriented.

Richard Schomberg stated that the challenge faced by utilities in Europe with relation to the smart grid is to model and simulate the state estimation and behavior of the grid.[47] While modeling and simulation has been all but mastered for transmission aspects, the actual distribution activities of a smart grid are an open question that has yet to be tackled.

Another key challenge discussed was the potential for fragmentation and a lack of interoperability between large portions of the grid. Eric Lightner from the DOE stated that he and his team recognized this as a critical element to be tackled,[48] while Richard Schomberg used a graphical representation of the costs associated with fragmentation to make the same point.

A grid that is capable of advanced high speed communications like the one envisioned in Smart Grids, will be susceptible to security risks not faced by today's grid. Mike Montoya from SCE confirmed the fact that prior to Smart Grids, their organization has maintained a strict separation of their energy management system from their distribution system.[49] The Smart Grid concept requires them to bridge that gap and opens up security risks that will need to be addressed.

CPUC Commissioner Chong questioned the panel of utility representatives on how they planned on making sure that the benefits of Smart Grids were available to all consumers and

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[46] Energy Commission Smart Grid Workshop transcript, held April 29, 2008. Pg. 19

[47] Energy Commission Smart Grid Workshop transcript, held April 29, 2008. Pg. 47

[48] Ibid, Pg. 85 and 104

[49] Ibid, Pg. 129-130

not just those who could afford computers or internet connections. The utilities offered the possibility of a low cost interface, but did not offer a specific plan for addressing the problem.

In their June workshop, U.S. DOE identified five fundamental technologies that will drive the Smart Grid:[50]

- Integrated communications, connecting components to open architecture for real-time information and control, allowing every part of the grid to both 'talk' and 'listen'
- Sensing and measurement technologies to support faster and more accurate response such as remote monitoring, time-of-use pricing and demand-side management
- Advanced components, to apply the latest research in superconductivity, storage, power electronics and diagnostics
- Advanced control methods, to monitor essential components, enabling rapid diagnosis and precise solutions appropriate to any event
- Improved interfaces and decision support, to amplify human decision-making, transforming grid operators and managers quite literally into visionaries when it comes to seeing their systems

Each of these technologies represents an area of needed research and development, and therefore a challenge to implementing Smart Grids on a regional or national level.

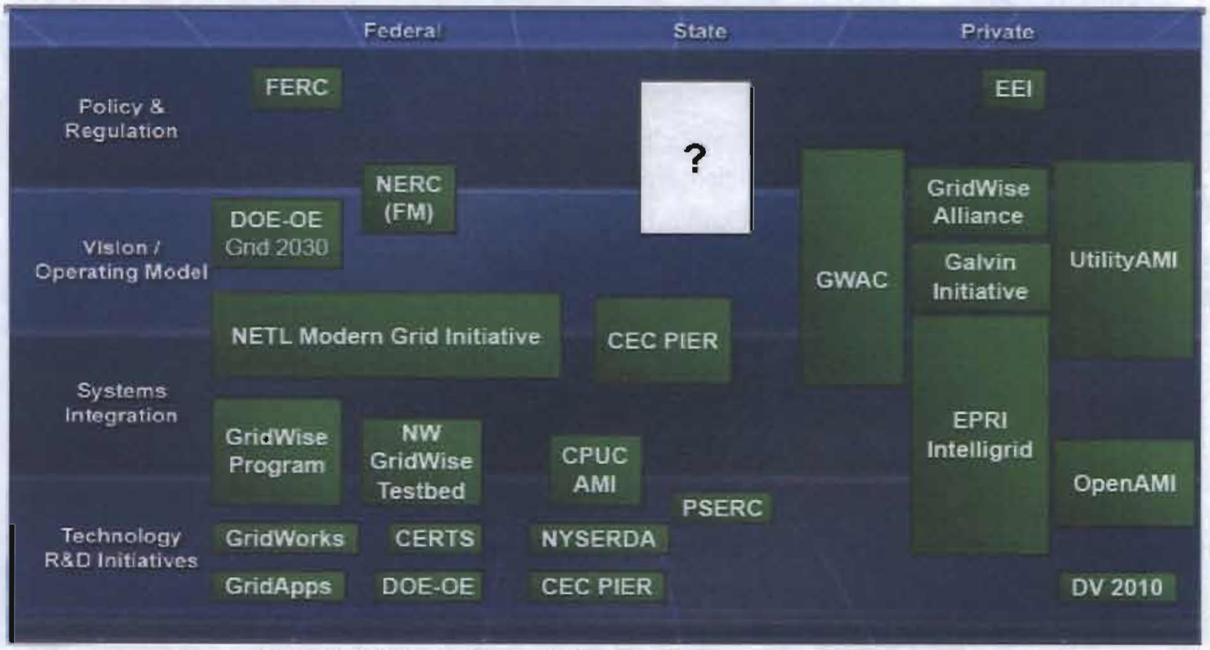
> *What challenges exist to implementing Smart Grids?*
>
> *A wide variety of technical and policy challenges still exist to implementing Smart Grids. The Smart Grid workshop touched on a few and many more exist. Questions of policy and technology must be solved for implementing Smart Grids in California.*

What Intervention or Coordination on the part of the Energy Commission or CPUC is Necessary to Ensure Success?

In their presentation at the Smart Grid workshop, Terry Mohn of SDG&E provided a figure showing the current roles of various stakeholders in Smart Grid Development (Figure 17):

[50] The Smart Grid, An Introduction: Pg. 29

Figure 17: Activities of Stakeholders and Governments Toward Smart Grid

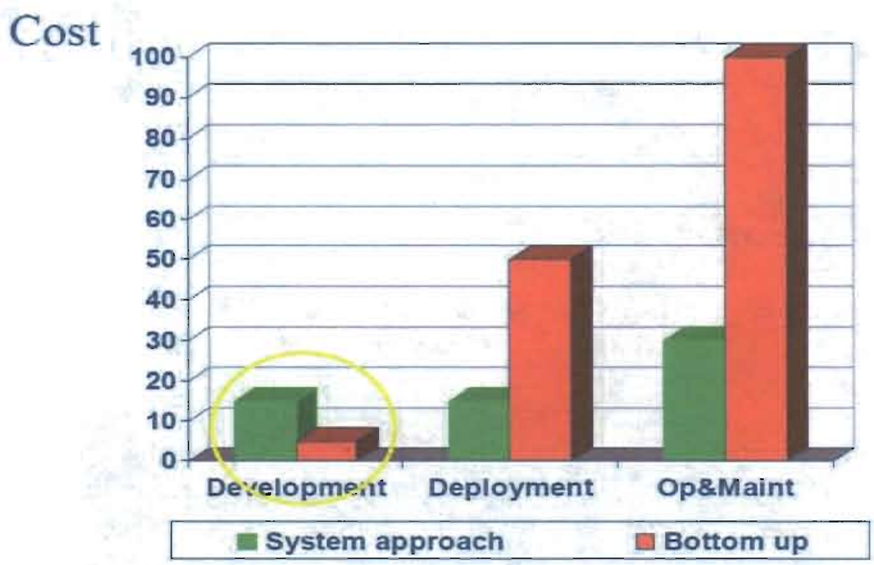


Source: SDGE Presentation, April 29, 2008 at California Energy Commission

This graphic effectively shows the lack of coordination at the state level for determining policy, regulation, vision, and an operating model. When asked directly if he believed that someone should be moving people towards a common definition or a common set of milestones and standards, Mr. Mohn of SDG&E said that he thought the current U.S. DOE efforts, combined with the Gridwise Program, were sufficient.[51]

[51] Energy Commission Smart Grid Workshop transcript, held April 29, 2008. Pg. 170

Figure 18: Normalized Costs for Systems versus Bottom-up Development



Earlier in the day, Richard Schomberg of EDF helped illustrate the argument that while a lack of coordination may have a lower initial cost to stakeholders (shown in the lower development costs of a "bottom up" approach), a systems approach would yield the lowest lifetime costs possible (Figure 18).[52] The publicly owned utilities represented by SCPPA expressed their concerns that "failure to adopt a standard or set a standard quickly will delay…our demand response programs, our energy efficiency programs."[53] And the commissioners themselves questioned the seeming total agreement on the part of utilities in their attempt to assure the commission that "all is well" with the development of Smart Grids.[54]

It is clear that while the DOE is approaching Smart Grids from a national level, the size and complexity of the California electrical grid will require more coordination and effort to ensure a smooth implementation.

On a separate policy issue, the IOU's stated that the rapid rate of change in technology associated with Smart Grids combined with the reduction of the expected life of associated equipment made investment in Smart Grids a high risk proposition. They suggested that what is needed was a change in the depreciation policies. Rather than depreciate assets relating to Smart Grids over 20, 30, or 40 years, to reduce that depreciation time to around seven years.[55]

[52] Energy Commission Smart Grid Workshop transcript, held April 29, 2008. Pg. 57
[53] Energy Commission Smart Grid Workshop transcript, held April 29, 2008. Pg. 185
[54] Energy Commission Smart Grid Workshop transcript, held April 29, 2008. Pg 219 and 221
[55] Energy Commission Smart Grid Workshop transcript, held April 29, 2008. Pg. 158

What intervention or coordination on the part of the Energy Commission or CPUC is necessary to ensure success?

The Energy Commission and CPUC, in collaboration with California ISO and stakeholders need to establish some kind of clear policy and guiding vision for Smart Grids to be successful in California. The cost associated with allowing them to grow in a "business as usual" manner, trusting in a national standard that may or may not provide the elements necessary for success in California is simply too high.

Conclusions: Smart Grids

Smart grids are a work in progress. New laws[56] at the federal level have directed the U.S. DOE to begin the process of defining what smart grids are and build a framework for nationwide interoperability of grid networks.

California regulatory agencies like the CPUC,[57] California ISO, and even the Energy Commission are just beginning to seriously grapple with the issues surrounding this vital piece of the solution. The Energy Commission, CPUC and California ISO are expected to open a Joint Rulemaking on smart grids in the near future. This will begin the much needed process of adapting California's regulatory structures to this rapidly developing area.

The outcome of the Smart Grid workshop was illuminating regarding to the complexity of the issues involved. Following is a brief summary of the questions and their respective answers:

1. What is a Smart Grid?
    a. *There currently is no one definition of a "Smart Grid." Our current thinking only indicates in what ways the future grid will be smarter than the grid of today and some of the functionality and benefits that will accrue from these improvements.*
2. What is the current progress of Smart Grids in and outside California?
    a. *Some of the necessary technologies exist, but Smart Grids remain a work in progress. Europe is developing a Smart Grid and the DOE is currently investigating how to do so in the US. Currently, there is no example of an operational Smart Grid anywhere in the world.*
3. What challenges exist to implementing Smart Grids?
    a. *A wide variety of technical and policy challenges still exist to implementing Smart Grids. The Smart Grid workshop touched on a few and many more exist. Questions of policy and technology remain to be solved for implementing Smart Grids in California.*

[56] Energy Independence and Security Act of 2007

[57] Presentation of Commissioner Grueneich at GridWeek, September 25, 2008

4. What intervention or coordination on the part of the Energy Commission or CPUC is necessary to ensure success?
    a. *The Energy Commission and CPUC, in collaboration with the California ISO and stakeholders, need to establish some kind of clear policy and guiding vision for Smart Grids to be successful in California. The cost associated with allowing them to grow in a "business as usual" manner, trusting in a national standard that may or may not provide the elements necessary for success in California is simply too high.*

There are many questions remaining to be answered regarding smart grids. The most important is defining smart grid to standardize the strategies and technologies. Following the development of a workable definition of "smart grid", a strategy must be developed to move from our current system to one that is functional at a smart grid level. Based on the inputs of experts and stakeholders, the Committee does not recommend load management standards at this time, but does recommend the following:

1. ***Form an Executive Level Smart Grid Advisory Committee for California*** – Because of the size and complexity of California's grid, the Energy Commission, CPUC, California ISO and high level stakeholders need a forum in which to discuss and resolve issues surrounding smart grids. An Executive Advisory Committee would provide just such a forum at this critical juncture in the development of smart grids.

2. ***At the conclusion of the existing Load Management Standards (LMS) Proceedings, open a new LMS proceeding focused on smart grids*** – The Load Management Standards, by virtue of applying to every utility in California, brings together stakeholders from a wide variety of perspectives and will ensure that our solutions work for both the largest and smallest electrical utility providers in our state. This should be undertaken as a collaborative effort of the Energy Commission, CPUC, and California ISO to ensure consistency across their individual areas of responsibility.

Through the two mechanisms listed above, the Energy Commission will ensure that the growth of demand response and other innovative tactics for addressing California's energy needs are not constrained by a distribution system that will not allow us to take advantage of them. Also through these mechanisms, and continuing research and development funded through the Public Interest Energy Research (PIER) program we can answer critical questions with regards to cost, barriers to implementation, and technological limitations.

Chapter 8: Proposed Load Management Standards

By providing customers with the information, motivation, and tools necessary to make intelligent and cost effective decisions about how they use energy, these standards will support the voluntary and permanent adoption of efficient energy consumption behaviors.

Advanced Metering Infrastructure

LMS-1. Advanced Metering Infrastructure (AMI) Schedule

Purpose: To require all utilities to prepare a plan for deploying advanced meters to all customers within their service territory.

Applicability: The provisions of this section will apply to all California utilities.

Effective Date: Compliance with this article shall be enforceable 30 days after the Load Management Standards are filed with the Secretary of State.

Each utility shall establish a schedule for automated metering infrastructure (AMI) deployment, if feasible and cost-effective.

1. All utilities shall report to the California Energy Commission Executive Director within six months of (DATE when this becomes effective) on the feasibility and cost-effectiveness of installing an advanced metering infrastructure for their service territory.
2. If the report determines that AMI is neither feasible nor cost-effective at the time, the utility will conduct a follow-up feasibility study within two years of the initial study.
3. All utilities, specifically small publicly owned utilities, are encouraged to work in collaboration with other utilities – including both publicly owned and IOUs – and/or through other industry organizations to meet the reporting requirements of this section and to cooperatively develop AMI infrastructures to capture economies of scale and leverage with equipment vendors, with the goal of reducing costs to ratepayers.
4. All utilities shall develop a business case for the installation of AMI with the following minimum capabilities:
   a. Support of a wide range of price responsive rates.
   b. Compatible with utility system applications that promote and enhance system operating efficiency and improve service reliability, such as advanced metering infrastructure, outage management, reduction of theft and diversion, improved forecasting, workforce management, etc.

5. Exceptions

    a. Utilities which have developed business cases and begun deployment of AMI systems are exempt from the reporting requirements of this section. They are still subject to the functionality requirements specified in the Section.

Dynamic Electricity Rates

LMS-2. Dynamic Electricity Rates

Purpose: To require utilities to develop and offer rate designs that support the state's objectives of providing cost-based price signals to reduce peak electricity consumption, improve system load factor, reduce load during short term electricity supply shortfalls, more efficiently allocate costs among consumers, encourage efficiency and conservation, and reduce capacity, energy and distribution costs.

Applicability: This standard will apply to all utilities in California.

Effective Date: Compliance with this article shall be enforceable 30 days after the Load Management Standards are filed with the Secretary of State.

All utilities shall develop a plan for implementing default, opt-out dynamic rates for all customers. In addition to the default dynamic rate, the utilities are required to develop optional rates that address different customer preferences for risk. These optional rates must fairly allocate the cost of risk. This plan shall include a "straw man" dynamic rate design for consideration as part of their plan. All utilities shall report the details of their plans to the California Energy Commission Executive Director within 270 days of the adoption of this standard. Dynamic rates considered in this evaluation shall address the rate design criteria listed below. The report to the Executive Director shall include, at a minimum, the following information:[58]

1. Explanation of how their proposed rate design reflects the cost of providing electrical services.
2. Explanation of how their rate deployment plan supports the state goals of energy efficiency, demand response, and greenhouse gas reductions.
3. Explanation of how the proposed design is superior to alternative rate designs for achievement of efficiency, demand response, and greenhouse gas reduction objectives.

[58] From CPUC Commissioner Chong's *"Assigned Commissioner's Ruling Requesting Comments on Draft Timetable and Rate Guidance and Updating Schedule."* January 23, 2008. Decision 08-07-045 in Application 06-03-005.

General Rate Design Criteria

4. Peak Time Rebate (PTR) designs or any other rate built around a rebate structure are considered the least effective and least preferred method of dynamic rate design and shall not be considered a valid design for meeting this standard.

All Dynamic Pricing Rates

5. Rate designs should promote economically efficient decision making.

6. Rate designs should reflect long-run marginal costs.

7. Rate designs should also seek to provide stability, simplicity, and customer choice.

8. Rate designs should provide customers with a clear cause-and-effect value function, where customer reductions in use that reduce utility costs produce a commensurate reduction in the customer bill.

Critical Peak Pricing (CPP)

9. Critical peak rates should include a critical peak price in combination with an underlying time-of-use rate for non-critical periods.

10. The critical peak price should reflect the marginal cost of capacity used to meet peak energy needs plus the marginal cost of energy during the critical peak period.

11. The critical peak price should reflect the cost of avoided capacity as well as avoided energy.

12. Rate designs should make provision to call or dispatch critical peak events at any time, even on weekends and holidays, year round.

13. Rate designs should make provision and include revenue adjustment measures that provide the utility with capability to call or dispatch a variable number of critical peak events each year. The rate should be designed based on the number of events that would be called during a typical year.

14. Utility Rate rollouts should be accompanied by information and education promotional programs.

Enabling Technology

LMS-3. Statewide Time-Differentiated Rate Broadcast

Purpose: To establish a standard method for transmitting current rate and reliability information to customers.

Applicability: This article will apply to all utilities in California.

Effective Date: Compliance with this article shall be enforceable upon the first day of availability of time-differentiated rates (or any other form of dynamic rate) to utility customers, and six months after the Load Management Standards are approved by the Secretary of State.

Each utility shall adopt an open-protocol, Internet compatible, information model (Information Model) for communicating all time-differentiated rate and demand response event signals. This Information Model shall be based on the Open AutoDR (*date & version*) standard developed by the Lawrence Berkeley Laboratory Demand Response Research Center, and shall be submitted to the Executive Director for approval. This Information Model shall be incorporated as a required feature in all time-differentiated tariffs and in the rules and governance for all demand response options.

The utility shall keep its published rate information current and refreshed as often as necessary to provide customers with the ability to react in a timely manner to changes in rate and reliability status.

All utilities shall provide two modes of access to this published information, without additional charges:

1. Through an RDS (a.k.a., RBDS) broadcast signal from an OpenADR client residing at utility-approved radio stations.
2. Through direct access as an OpenADR client via the Internet.

Each utility may provide additional modes of access to the published information via other means using any non-proprietary communication protocol, and may charge for such additional services. Providing additional modes of access shall not relieve the utility of the obligation to provide information via RDS and Internet as specified above.

Utility Programs

LMS-4. Home Energy Rating System Information

Purpose: To require utilities to provide their customers with information about the Home Energy Rating System, designed to promote the use of in-home energy audits and subsequent cost effective energy efficiency improvements.

Applicability: This article will apply to all utilities in California.

Effective Date: Compliance with this article shall be enforceable 30 days after both these Load Management Standard and Home Energy Rating System standards are filed with the Secretary of State.

Each utility shall provide the following information to its customers:

1. How to contact Home Energy Rating System providers.
2. The type of energy use information available through in-home audits.
3. How to calculate the benefits of energy improvements.
4. Costs and financial assistance for audits.
5. Availability of financing options for home energy improvements.

LMS-5. Existing Building Peak Energy Efficiency Improvements

Purpose: To require utilities to develop and expand programs that encourage cost effective energy efficiency improvements in existing building stock within their service territory.

Applicability: This article would apply to all utilities in California.

Effective Date: Compliance with this article shall be enforceable 30 days after the Load Management Standards are filed with the Secretary of State.

Within six months of the effective date of these standards, each utility shall submit to the Executive Director a proposal for a Building Efficiency Information Gateway program. The program shall:

1. Target buildings with the greatest potential for energy savings.
2. Compile energy use data to identify those customers meeting specific targeting criteria.
3. Provide feedback on customer energy use through utility websites.
4. Provide online building energy audit information in a multi-level format that allows customers to explore their energy use patterns, options for saving energy, and comparisons to other customers. Additional levels of energy audits (for example, over the phone, in person) should be provided to targeted and/or interested customers.
5. Coordinate energy ratings with utility incentives programs.
6. Connect customers with energy efficiency upgrade financing programs administered by the utility or other institutions.
7. Provide customers with energy efficiency program marketing materials through bill stuffers, media campaigns, or other proven means.

LMS-6. Enabling Technology Adoption Program

Purpose: To require utilities to develop programs supporting customer adoption of enabling technologies. These programs should support consumer purchase of these devices in a traditional retail environment. These technologies should be capable of facilitating customer load reductions responding to dynamic prices using the Open Automated Demand Response communication standard internet protocol through the Statewide Time Differentiated Rate Broadcast and through additional communications channels, including the utility AMI systems. This standard creates a customer-driven market for programmable communicating devices (PCD's) such as programmable communicating thermostats, pool pump controls, plug-in switches that customers can use to automate any plug-in device, and customer owned home automation systems. This standard also supports automation of commercial and industrial customers and PCDs designed specifically for application outside the residential sector. The PCD reference design is included as an appendix to this standard.

Applicability: This article will apply to all utilities in California that install advanced meters.

Effective Date: Compliance with this article shall be enforceable 30 days after the Load Management Standards are filed with the Secretary of State.

All utilities that have installed or plan to install advanced meters within their service area shall also offer a PCD Program to its customers. Within four months of the effective date of these standards, each utility shall submit to the Executive Director a proposal for a PCD Program. The program shall provide:

1. A plan for publicizing the PCD Program to building owners at the time the utility AMI can support billing from interval data.
2. A customer incentive covering a portion of the retail cost of "Appendix A: California PCD Reference Design" compliant PCDs for building owners where an advanced meter has been installed or is planned to be installed.
3. A customer incentive covering a portion of the wholesale cost of "Appendix A: California PCD Reference Design" compliant PCDs for building developers where advanced meters will be installed.

Utility Data Availability Requirements

LMS-7. Customer Access to Meter Data

Purpose: To establish the legal standing of customers regarding data collected by utilities about electrical use and billing information.

Applicability: This article will apply to all utilities in California.

Effective Date: Compliance with this article shall be enforceable 30 days after the Load Management Standards are filed with the Secretary of State.

Utilities shall conduct customer research to develop forms of information display and analytical tools that effectively communicate time-varying rates to customers and allow them to formulate load shedding strategies.

Each utility shall provide each customer (and their designated third party representatives) with access to the customer's historical consumption data over the previous 12 calendar months. This shall include data up to and including the hour 24 hours prior to the request. Data shall be provided without additional charges.

Data shall be made available via a secure internet accessible web site.

The data shall be provided in a format that supports customer education and understanding of energy consumption patterns, the variable cost of energy, efficiency opportunities, and demand response programs.

Physical (paper) copies of consumption data shall be available to the customer and their designated third party representatives for a reasonable fee. The fee shall be no larger than necessary to cover the cost of handling and shipping the physical document.

Utilities shall not deny access to real time or near real time information to customers who pay the utility fee for access.

Utilities shall provide prompt service to those customers who desire access to real time or near real time information. For services requiring the scheduling of a site visit by utility service personnel, 30 calendar days from the date of request to completion of service is considered prompt. For services that do not require the scheduling of a site visit by utility service personnel, seven calendar days from the date of request to completion of service is considered prompt.

Consumers retain ownership of the access rights to any and all data collected by utilities. Specifically, the utilities must obtain permission from the customer before releasing data relating to that customer to any party outside of the utility.

Appendix A: California PCD Reference Design

(PCD Reference Design incorporated either in full or by reference here)