Update on Demand Response and Advanced Meters in California

Bruce Kaneshiro

Energy Division

California Public Utilities Commission

Demand Response in the Energy Action Plan

- **The Energy Action Plan identifies several key Demand Response action items:**
  - Process the IOUs' proposed Advanced Metering Infrastructure (AMI) installation plans for statewide implementation of AMI for all small commercial and residential IOU customers
  - Issuing timely decisions on dynamic pricing tariffs to allow increased participation by customers with AMI technology.
  - Educate Californians about the time sensitivity of energy use and how they can participate in demand response programs.
  - Create standardized measurement and evaluation mechanisms to ensure demand response savings are verifiable.
  - Integrating demand response into retail sellers' electricity resource procurement efforts so that these programs are considered equally with supply options.

Types of Demand Response Programs in California

- **“Day-Ahead” or Price-Responsive DR Programs**
  - Critical Peak Pricing: Participants receive reduced on-peak energy rates for most summer hours in exchange for paying high on-peak rates during 12 “critical peak” periods.
    - Triggered by the IOU under the following conditions: high wholesale electricity prices, temperature, high system peak demand and/or low generation reserves.
  - Demand Bidding Program: Participants ‘bid’ load reductions they can provide the following day and are paid for the actual amount of load they reduce.
    - Triggered by the IOU upon issuance of a day-ahead Alert by the CAISO for the affected territory or a CAISO day-ahead forecast of 43,000 MW.

Types of Demand Response Programs in California (Continued)

- **Day-Ahead/Price-Responsive Programs (Continued)**

  - Capacity Bidding Program: aggregators nominate load and are compensated with capacity/energy payments.
    - The program is triggered by a heat rate (when the utility anticipates the use of a peaker plant to meet its load).

  - Peak Day 20/20 Program: customers receive a 20% discount for a 20% reduction in their average demand (SDG&E only)
    - Triggered about 12 times per year by temperature, utility system load, high spot market prices, or a special alert by the CAISO.

Types of Demand Response Programs in California (Continued)

- **Emergency or Day-Of Programs:** ***triggered by the IOUs upon notification by the CAISO of statewide or local emergencies (Stage 2 alert or transmission-related)***

    - Interruptible tariffs and programs: Participants receive rate discounts or bill credits based on the amount of load they are willing to reduce in emergency situations. Penalties are assessed for failure to reduce to their contracted firm service level.

    - Air Conditioner Cycling: Participants receive bill credits based on number and length of interruption to their air conditioner unit.

Types of Demand Response Programs in California (Continued)

- **Other**
    - Marketing/Customer education programs to either promote demand response programs or educate customers about demand response concepts: includes mass media campaigns *(Flex Your Power Now!)* as well as programs that target specific groups such as water agencies, medium-size businesses, government agencies.
    - Technical Assistance and Technology Incentives: customers receive free 'audits' to identify demand response potential, and rebates for technologies that can enable automated demand response.

Enrolled MWs[2/] in Demand Response Programs in California[3/]

	July 2003	July 2004	Dec. 2006	2007 Goal
Emergency-triggered, Day-of Programs	1,485 MWs	1,508 MWs	1,624 MWs	None
Economic, Day-Ahead Programs	0 MWs	531 MWs	1,036 MWs	2,500 MWs[4]

[2] "Upper-bound" estimates; programs are currently undergoing evaluation/verification to determine actual load impacts
[3] The territories of PG&E, SCE and SDG&E
[4] 5% of an assumed 50,000 MWs of system peak demand – **illustration purposes only**

CPUC approves PG&E's AMI Project

- **On July 20, the CPUC authorized PG&E's proposed budget of $1.68 billion for full deployment of AMI, based on a positive business case analysis.**
  - PG&E projects that operational savings cover 90% of AMI project costs (over 20 year period) and the remaining 10% would be covered through DR benefits.
- **PG&E selected power line carrier technology for its electric meter communications network and fixed radio frequency network for its gas meters.**
- **PG&E will retrofit existing mechanical meters with a module (that provides the necessary reading/communication functions), rather than purchase solid state interval meters.**
- **Full deployment of PG&E's AMI system technology and network is scheduled to take 5 years (2006-2011).**
- **Voluntary CPP tariffs for the residential and small C&I customer classes (under 200kW) with a one year bill protection provision.**

Update on SDG&E and SCE's AMI Projects

- **SDG&E claims a positive business case for full deployment of AMI.**
  - SDG&E's cost estimate for full scale AMI deployment is $635 million with $762 million in operational ($471 million) and demand response ($235 million) benefits.
  - A Commission decision is scheduled for the first quarter of 2007.
  - If approved, AMI deployment is expected to be completed in 2 ½ years (mid-2008-2010).

- **SCE proposed a 7 ½-year multi-phased approach to develop and deploy the next generation of AMI (2006-2013)**
  - SCE is defining its AMI functional requirements, determining commercial availability of the AMI technology, and developing its preliminary business case analysis.
  - SCE expects to have its AMI product selection in the first quarter of 2007;
  - AMI project application and business case filing is expected in summer 2007.

Key Observations - AMI

- **Three key factors in evaluating an AMI proposal presents trade-offs that need to be weighed by regulators:**
  - Functionality: how much functionality is enough?   AMI technology is continuously changing.
  - Reliability: off-the-shelf products have a track record, but less functionality than newer technology.
  - Cost: higher functionality requirements will cost more than older products

- **AMI Business Cases: the 'starting point' or baseline for measuring the cost-effectiveness of an AMI investment is a key factor in the determination of a positive or negative business case.**
  - PG&E's business case demonstrated that 90% of its AMI investment will be covered by operational savings alone (efficiencies gained in its billing system, meter reading, etc.)
  - SDG&E's business case shows that only 60% of its AMI investment will be covered by operational savings. Its meter reading system is more efficient than PG&E's for example. Thus SDG&E must depend on greater demand response benefits than PG&E to make its AMI case.

Key Observations – Demand Response

- **Customer participation – Voluntary or Default?**

  - Voluntary participation – customers have the choice to sign-up for DR programs – the customer must make the effort to enroll.
    - The ‘free rider’ problem: customers with favorable load shapes tend to participate.
    - Opt-in enrollment requires substantial amount of marketing and education to overcome customer inertia.
    - May require substantially higher incentives to attract sufficient participation.
    - Could require modifications to the programs (see next slide)

  - Default participation – customers are placed in a DR program or a tariff, but have the option to opt-out.
    - Large industrial customers are heavily opposed; many are not convinced that the benefits outweigh the costs of participation. Tend to favor interruptible (emergency-triggered) over price-responsive program as curtailment events for emergencies are less likely.
    - For small customers, regulators must ensure they have adequate notification about opt-out rights and education about the new rate and how they can respond to it.
    - Default approach will likely result in substantially higher participation because of customer inertia.

Key Observations – Demand Response (con't)

- **How long do you wait before you modify program design to increase participation?**
  - Modifying programs continuously can create customer confusion/frustration.
  - Customers/DR providers prefer 5-10 year program consistency so that DR investments are cost-effective.
  - Need some level of program continuity to develop data on program performance.
  - Standing 'pat' could delay significant participation; could run counter to policy objectives to push DR.
- **Automation and Technology: a key component to customer acceptance.**
  - Customers appear to be attracted to programs that make DR easy and convenient – this can be addressed via making DR technology available and affordable.

Key Observations – Demand Response (con't)

- **How to accurately measure/verify demand response savings?**
  - Load reductions from demand response programs (particularly price-responsive programs) has been highly variable thus far.
  - Determination of the customer baseline is difficult which adds complexity to measurement of load reductions.
  - Difficulties in measuring demand response savings leads to potential double-procurement of supply-side resources since grid operators or IOUs are unsure on how to forecast DR resources.
  - Lack of accurate load reduction measurement makes cost-effectiveness analysis of the programs very difficult.
  - Monitoring and evaluation protocols for the programs is a key.

- **Retail DR programs need to be aligned closely with ISO operational needs/markets**
  - Currently no direct connection between market prices and program incentives/dynamic tariff rates.
  - Coordination/communication with CAISO on program triggers, timing, and resource 'firmness' remains a work in progress.

Contact Information:

Bruce Kaneshiro
Supervisor, Demand Response Programs
California Public Utilities Commission
415.703.1187
bsk@cpuc.ca.gov