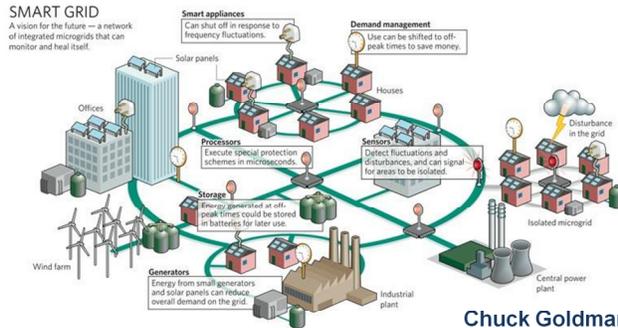


# An Introduction - Smart Grid 101

## Chapter 6: Demand Response



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The Smart Grid is a compilation of concepts, technologies, and operating practices intended to bring the electric grid into the 21<sup>st</sup> century. Smart Grid concepts and issues are difficult to address because they include every aspect of electric generation, distribution, and use.

While the scope of smart grid covers the entire utility system from generation to how customers use energy, this chapter addresses the topic of demand response.

Our objective throughout this chapter is to more clearly define demand response, and to point out how policy, technology, and customer behavior combine to define the capabilities and potential benefits of Smart Grid.

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The contents of this chapter are divided into six sections.

- As with our prior webinars and chapters, we start with a narrow set of objectives and try to focus on attention on demand response (DR) issues principally related to regulatory policy.
- Section 4 provides updated information on the two principal NIST standards efforts related to DR.

## Chapter Objectives



1. Provide an overview of evolving smart grid demand response requirements.
2. Identify demand response regulatory and policy issues.
3. Examine the status and implications of demand response standards development.

Note:

*This presentation addresses demand response principles and concepts, not specific retail or wholesale programs.*

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- This chapter has three objectives.

1. Provide an overview of evolving smart grid demand response requirements.
2. Identify demand response regulatory and policy issues.
3. Examine the status and implications of demand response standards development

## Smart Grid Objectives



### Smart Grid is System Integration

The Smart Grid is a system of information and communication applications integrated with electric generation, transmission, distribution, and end use technologies which will :

- Promote Customer Choice [1] enable consumers to manage their usage and chose the most **economically** efficient offerings
- Improve Reliability [2] use **automation** and alternative resources to maintain delivery system **reliability** and **stability**, and
- Integrate Renewables [3] utilize the most environmentally gentle **renewable**, **storage**, and **generation alternatives**.

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- Our perspective on DR emphasizes the concepts and objectives of the smart grid. As a result, while existing utility DR programs are real, productive, and interesting much of our focus will emphasize how DR needs to evolve to provide capabilities consistent with smart grid needs.
- Under smart grid DR takes on an expanded role that goes beyond conventional peak shaving and system reliability. Under smart grid , proponents envision that DR would have an expanded role to address and provide ancillary services and integrate of large amounts of renewable energy.
- DR under smart grid must also must look beyond utility load shaping objectives and more seriously consider the domain of customer choice: who controls the customer loads and who provides customer automation choices like smart appliances, also becomes a consideration.
- This slide identifies three smart grid objectives that influence and guide future DR options, which include:

## Defining Demand Response



**“Demand Response:** Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. “<sup>1</sup>

**Issue :**

**The historic focus of DR on reducing usage during periods of high wholesale market prices or maintaining system reliability does not fully address potential new applications of DR in areas of distribution congestion management, renewable integration, balancing, and volt/VAR applications.**

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This definition of DR comes from the most recent February 2011 FERC staff report on demand response and advanced metering. (see Slide #40, References for a link to this report).

While this definition expands the focus of DR consistent with the expected vision of a smart grid, it needs to be expanded even further to address a future perspective that sees DR as a tool for transmission and distribution (T&D) congestion management and expanded ancillary services.

## Demand Response Options



2010 FERC Survey Program Classifications <sup>1</sup>		Description
1	Direct Load Control	Sponsor remotely shuts down or cycles equipment
2	Interruptible Load	Load subject to curtailment under tariff or contract
3	Emergency Demand Response	Load reductions during an emergency event Combines direct load control with specified high price
4	Load as Capacity Resource	Pre-specified load reductions during system contingency
5	Spinning Reserves	Load reductions synchronized and responsive within the first few minutes of an emergency event
6	Critical Peak Pricing w/Control	Combines direct load control with specified high price
7	Non-Spinning Reserves	Demand side resources available within 10 minutes
8	Regulation Service	Increase or decrease load in response to real-time signal
9	Demand Bidding and Buyback	Customer offers load reductions at a price
10	Time-of-Use Pricing	Average unit prices that vary by time period.
11	Critical Peak Pricing	Rate/price to encourage reduced usage during high wholesale prices or system contingencies
12	Real-Time Pricing	Retail price fluctuates hourly or more often to reflect changes in wholesale prices on day or hour ahead
13	Peak Time Rebate	Rebates paid on critical peak hours for reductions against a baseline
14	System Peak Response Transmission Tariff	Rates / prices to reduce peaks and transmission charges

79%

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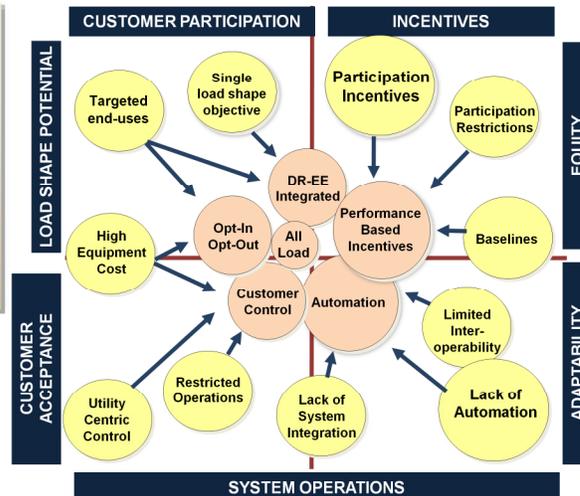
- There is also a need to rethink basic DR concepts at a very fundamental level. For example, what is DR?
- Is DR a program, a rate, or incentives that motivate independent customer actions and behavior?
- This list of DR options taken from the FERC report referenced earlier, illustrates part of the dilemma in how to think about DR. This list includes rate designs (#6,10-12), provision of ancillary services to support generation and the grid (#5,7-8), and typical utility programs (#1-4, 9) which combine a rate or incentive with technology and contractual elements.
- What we also see from this list/survey is that conventional utility DR programs focused on system reliability (#1-3) account for about 80% of existing DR resources under current utility and ISO programs and tariffs.
- What this tells us is that much of the expanded potential for DR is still waiting to be harvested.

## Transitioning DR to Smart Grid



### Demand Response

- Bundled structure emulates a “pilot”
- separate incentives
- targeted end-uses
- participation restrictions
- utility control
- high equipment costs
- restricted operations



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One of the major objectives of this chapter is to explain how DR is evolving to address expected Smart Grid requirements. To do that it is useful to break existing DR programs and options into elemental features and then explain how and why each of these features will need to evolve.

This slide provides a more feature map perspective of demand response issues that relate directly to existing utility program features. Each feature, like Utility Centric Control (lower left corner) embodies implicit concepts that may or may not be compatible with smart grid. For example, Utility Centric Control, where the utility directly controls the customer load or where the utility specifies exactly how much load the customer must supply or how the customer needs to control their load, may be practical for pilot or limited scale programs, however utility controls become exceedingly complex and less practical when expanded to millions of end-uses, electric vehicles, and general alternatives. Utility control also carries with it customer acceptance and potential liability problems. Many existing DR options limit customer flexibility to either participating under the utility terms or leaving the program, which constrains how customer adapt to changing conditions at their own site.

What this exhibit attempts to show, is that many features of existing DR options will need to evolve and take on new capabilities to fulfill smart grid objectives. The labels around the outside of this matrix categorize DR into seven (7) categories: The circles inside the matrix identify existing features (yellow circles) and how they will be expected to evolve (pink circles) as part of implementing a Smart Grid vision.

Starting in the lower left quadrant, the key DR features include:

1. Customer Acceptance
2. Load Shape objectives
3. Customer participation
4. Incentives
5. Equity
6. Adaptability and
7. System Operations

Within each quadrant we've highlighted very specific features and issues.

Review key features.

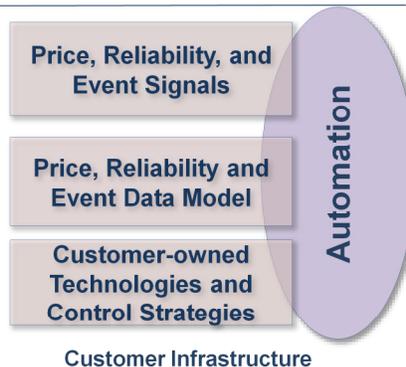
## Transitioning DR to Smart Grid



### Conventional DR



### Approach to Smart Grid DR



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An integrated perspective that contrasts the most dominant DR options today with a smart grid DR perspective might look like this.

- On the left conventional DR might be characterized as the “utility-centric” option that bundles rates/incentives, technology, and utility control strategies into a specific customer offering.
- On the right, we’ve characterized a potential way that DR could evolve with a Smart Grid. Under this structure automation at the customer site becomes a foundational element of smart grid. Customer owned energy management systems, programmable controllable thermostats, and embedded controls in smart appliances become key elements that facilitate and automate customer behavior changes and allow customers to establish their energy use parameters and then “set it and forget it”. The automation provides the capability to respond to a variety of day-ahead and real-time signals, using customer preferences in each case to determine what is and what is not both feasible and acceptable.
- Because of widespread customer automation that allows control of their loads, there is a need for digital price, reliability and event signals. Digital signals that can be read directly by customer automation systems and become the activation variables for customer response.
- Standardized data models, or more universal ways to communicate price and reliability are also required. Standard data models that allow multiple vendors to provide equipment and systems that know what to look for is already underway in the NIST PAP 3,4, and 9 working groups. You’ll also see as we get to the standards part of this webinar that these concepts and standards are already being integrated into many commercialized DR options
- Finally – the diversity of potential loads and generation alternatives necessitates customer ownership of the control technologies (automation) and customer, not utility determination of control strategies. Customer ownership is necessary to create a market for smart appliances and to expand DR participation. Customer-oriented control strategies have both a practical and logical basis which will be explained later.

## Why Should Regulators be Concerned ?



- ❑ **Conventional DR signaling is not necessarily compatible with system operating or customer needs, automation, or smart appliances.**
- ❑ **DR control strategies may not be compatible with smart appliances, evolving customer automation technologies, or carbon mitigation.**
- ❑ **DR rate and incentive options do not provide capability to support integration of intermittent resources or electric vehicles.**
- ❑ **Conventional retail DR cost effectiveness will be influenced over time due to appliance and building efficiency gains and renewable penetration.**

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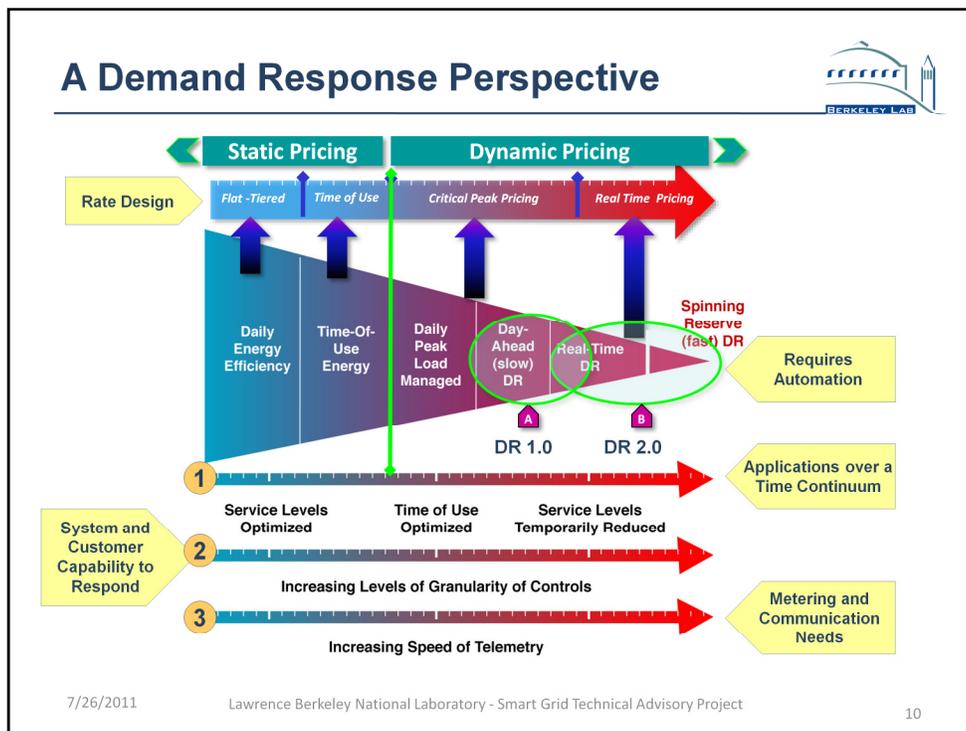
Conventional DR does not provide the full range of capability to address smart grid requirements or expectations.

Existing DR control strategies may not be compatible with smart appliances, evolving customer automation technologies, support policies intended to mitigate carbon emissions.

Moreover, some time-based rates or designs of existing DR programs may not support integration of intermittent resources or electric vehicles.

More significantly, existing conventional DR substantially under-performs what is technically feasible.

The cost effectiveness of conventional DR options that focus on single customer loads, like air conditioning and water heating, should be expected to decline over time as older less efficient units are replaced with more efficient units. State and federal appliance efficiency standards have had significant impacts on appliance efficiency over the last ten years. This trend is expected to continue. To adapt, utility DR options need to expand pricing and operational features to include a broader based of customer loads and system load shaping objectives.



One of the underlying assumptions of the preceding material is that Smart Grid will require a fundamental set of changes to existing demand response options. This exhibit provides a roadmap that describes the continuum of demand response options under Smart Grid and how the options within this continuum relate to three areas; rate design/pricing, customer service levels, and meter and communication functional capability.

The focal point of this slide is the multi-segment triangle located in the middle of the graphic. This triangle depicts a hierarchy of customer and utility energy management options, that tend to increase in priority and system value as you read from left to right. Across the top of the triangle are a series of labels that map the segments of the triangle to various rate forms or pricing options.

There are three arrow scales below the triangle successively addressing (1) customer service levels, (2) granularity of controls, and finally (3) increasing speed of telemetry. Again, for each of these scales, complexity, system value, and cost increase as you move from left-to-right.

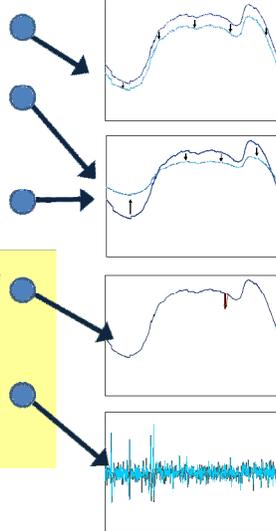
The green circle on the left labeled "A" encompasses "Day-Ahead" and part of the "Real-time" category of DR options. The "A" group encompasses what are considered traditional demand response options, also referred to as DR 1.0. These options are generally supported by fixed incentives (participation or capacity payments) or rate forms (CPP, PTR). DR 1.0 options are typically limited to a maximum number of events, targeted to a specific season and fixed block of hours. Controlling actions are relegated to peak load shedding or load shifting from peak to off-peak periods.

The green circle on the right labeled "B" highlights real-time DR applications to support balancing, spinning reserve, and other ancillary service applications. These options can be facilitated by rate design and fixed incentive payments, however they are more likely to be associated with contractual agreements that require special terms and conditions that can also include fixed load reduction obligations, automated controls, and supplemental advanced metering, telemetry, or other special communication equipment. Based on the specifics of the rate design real-time pricing can be classified as both a DR 1.0 and DR 2.0 option. For real-time pricing, DR 2.0 opportunities require short-duration pricing intervals and short advance notice (5-15 minutes). DR 2.0 options are generally available year-round and have few if any limitations on either the frequency of occurrence or time-of-day. DR 2.0 options may only be required for 10-20 minutes at a time however, controlling actions can not only include load shedding and shifting, but load building.

## Smart Grid Load Shaping Objectives



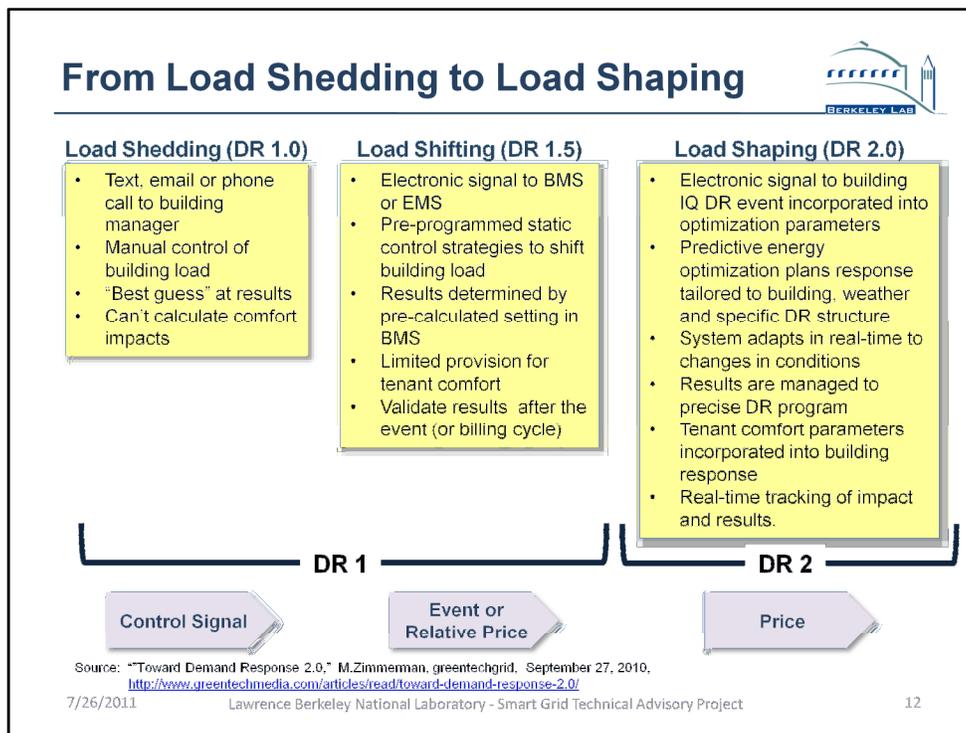
1. **Energy Efficiency** programs reduce overall electricity consumption, generally also at times of peak demand.
2. **Price Response** programs move consumption from times of high prices to times of lower prices (real time pricing or time of use) – expanded to address transmission distribution congestion management.
3. **Peak Shaving** programs require more response during peak hours and focus on reducing peaks on high-system load days – expanded to address transmission distribution congestion management.
4. **Reliability Response** (contingency response) requires the fastest, shortest duration response. Response is only required during power system “events.” – This is new and slowly developing.
5. **Regulation Response** continuously follows minute-to-minute commands from the grid in order to balance the aggregate system load and generation – This is also very new and appears to be very promising for certain loads.



1. Adapted from: Demand Response Spinning Reserve Demonstration Project, Consortium for Electric Reliability Technology, LEHL, Joseph Eto presentation October 19, 2009.  
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These four load shaping objectives generally correspond to one of the segments of the triangle on the preceding slide. For example, the first segment of the triangle on the far left ‘daily energy efficiency’ matches the first load shaping example that illustrates a general lowering of usage in most hours. Energy efficiency focuses only on usage, not time, consequently, a reduction in any one hour or all reductions grouped into a single hour would be consistent with the efficiency objective, even if these changes aggravated the peak or reduced the load factor.

What is most significant are the Reliability and Regulation response impacts which illustrate very different load shaping objectives than what is usually representative of most existing utility demand response programs. Where conventional DR is generally thought of as an option targeted at the top 100 hours a year (which may translate into 1-15 days with 4-6 hour control periods) Option #4 (Reliability) and Option #5 (Regulation) may translate into one or more operations each day, every day of the year, for brief 10-20 minute control intervals.



What we are trying to depict is a transition from what is often referred to as DR 1.0 or conventional load shedding, to DR 2.0 which has been characterized as load shaping.

Load shedding and load shifting, which we've labeled DR 1.0 and 1.5 respectively, are similar in several respects. Both prescribe reasonably static control strategies, usually targeted to a single customer load with a fixed start/stop limitation on the normal operating cycle and limitations on the number of events each year. DR 1.5 provides a substantial improvement over DR 1.0 in how events are activated, by providing electronic, digital signals that can be used to directly activate automated controls – avoiding the need for a person to be in the DR communication loop.

Load shaping, which we've labeled DR 2.0, extends the use of automated digital signals from DR 1.5 to introduce expert systems on the customer side of the meter that can dynamically adjust how loads are managed to better reflect comfort and other critical site service factors based on pre-set customer preferences.

Incorporating expert systems on the customer side would provide capability to support multiple day-ahead economic as well as day-of real-time reliability options.

There is even a DR 3.0 which integrates expert systems with automation and sensors on the customer side of the meter to produce interactive, dynamic control strategies that optimize (1) integration with the supply side of the grid while also (2) optimizing customer comfort and service.

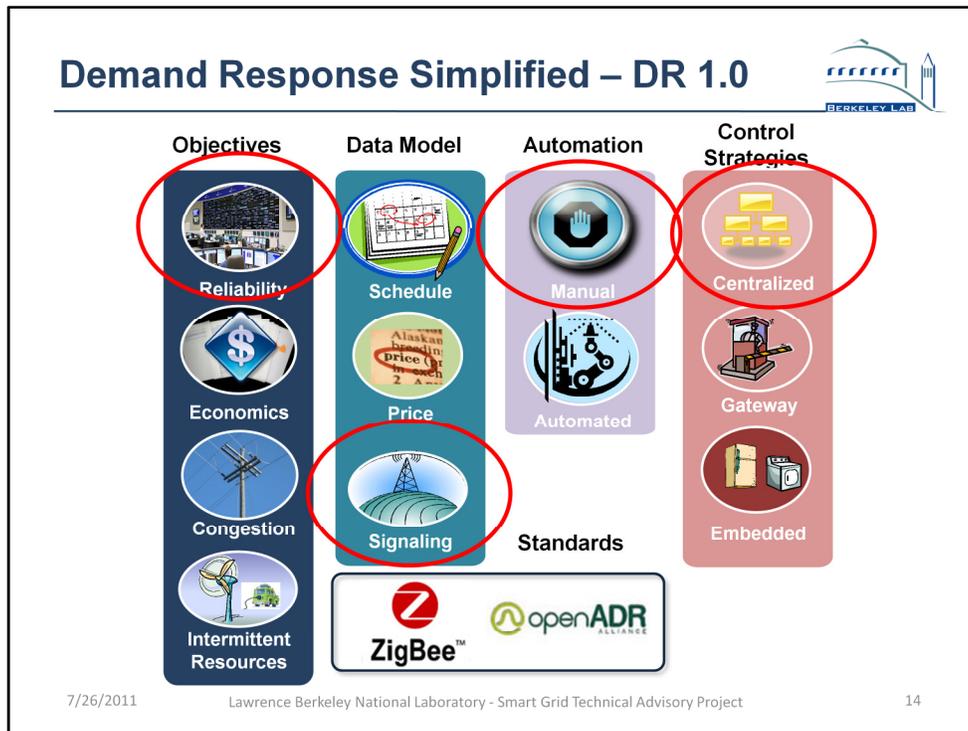
## DR Smart Grid Requirements



	Requirements	Description
Incentives	1. Performance-Based Incentives	<ul style="list-style-type: none"> <li>Customers rewarded based on their actual performance.</li> <li>Customers not paid only to participate.</li> </ul>
Operations	3. Dispatchability	DR automated and dispatchable.
	4. Ubiquitous Availability – Participation Implications	<ul style="list-style-type: none"> <li>DR available on all circuits throughout the utility system.</li> <li>Capacity and energy are inseparable from a customer perspective</li> <li>EE a condition of service for all customers, why not DR?</li> </ul>
	5. Control Strategies – Customer Choice	The customer determines what, when, and how to control their loads.
Costs	6. Simultaneous Economic and Reliability Options	Customers allowed to simultaneously participate in day-ahead economic and real-time reliability options.
	7. Market-based Technology	Customers acquire automated systems and DR equipment and services through open market providers.
	8. Integrated Demand Response and Efficiency	Incentives and operations integrate DR and EE.

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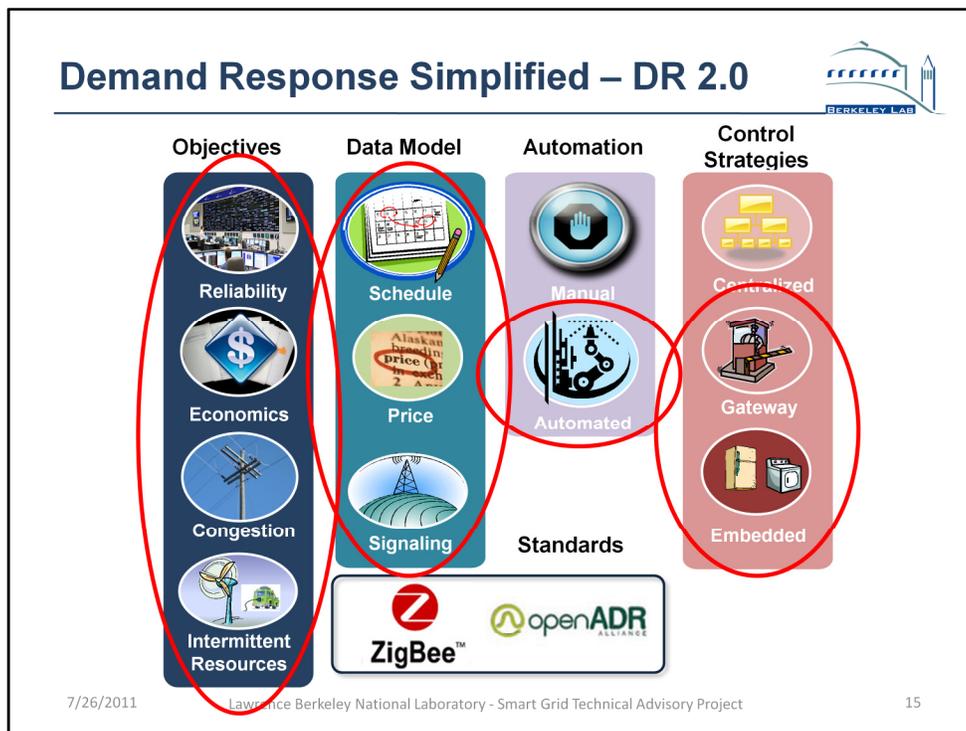
This slide highlights the key attributes and features of what might be expected with a transition to a Load Shaping DR 2.0 environment.



These next two slides attempt to graphically portray the fundamental differences between where we are today with DR and what we have to address to support the transition to smart grid.

For conventional DR (DR 1.0) we have utility programs generally established to address a single objective, with utility signaling, some form of utility provided automation, and a centralized utility defined control strategy.

Signals might be reflective or even proxies for price, however because these signals are separate from the underlying customer rate – they are not necessarily perceived nor do they necessarily reflect the cost impact on the customer or their incentives.



Under a smart grid envisioned environment (DR 2.0 or DR 3.0) demand response will have to be structured to be flexible and adaptable – to simultaneously address a range of reliability, economic, congestion management, and renewable/DER integration options. Several different data models will have to be accommodated, some simultaneously. A key difference is that control strategies delivered through gateways and embedded controls will generally be managed by the customer, (not the utility).

There will always be a need for single purpose, conventional DR programs, however it is very likely that the customer automation equipment will have capability to support multiple options.

## Demand Response Issues



1. **Market Model: Utility versus Customer Centric?**
2. **Participation: Opt-in versus Opt-out**
3. **Rates and Incentives – is dynamic pricing necessary ?**
4. **Control Strategies: utility vs. customer control ?**
5. **Automation – necessary or not ?**
6. **Standards – ZigBee SEP and OpenADR**

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What are the key issues that regulators need to be aware of ?  
We've identified six priority issues .

1. **Market Model: Utility versus Customer Centric?**
2. **Participation: Opt-in versus Opt-out**
3. **Rates and Incentives – is dynamic pricing necessary ?**
4. **Control Strategies: utility vs. customer control ?**
5. **Automation – necessary or not ?**
6. **Standards – ZigBee SEP and OpenADR**

# 1. Market Model: Bundled versus Open ?



	Utility Centric DR	Customer Centric DR
Participation	<ul style="list-style-type: none"> <li>Targeted loads</li> <li>Limited to Large C/I &amp; Residential</li> </ul>	All Customers
Who Controls	Utility	Customer
What is Controlled	<ul style="list-style-type: none"> <li>Interruptible Rates</li> <li>Res. HVAC, Water Heating</li> </ul>	All Loads Available
Control Equipment	<ul style="list-style-type: none"> <li>Utility Provided</li> <li>Few Suppliers</li> </ul>	<ul style="list-style-type: none"> <li>Customer Provided</li> <li>Many Market Suppliers</li> </ul>
Incentives	<ul style="list-style-type: none"> <li>Fixed / Participation Payments</li> <li>Baseline metrics</li> </ul>	<ul style="list-style-type: none"> <li>Retail Dynamic Prices</li> <li>Reservation payments</li> <li>Pay-for performance</li> </ul>
DR Products	Generally limited to Reliability and Economics	Capacity, Energy, Ancillary Services Markets; Congestion Management
DR, EE, Renewable Integration	No	Yes

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The prior slides have highlighted several structural and logical differences necessary to make demand response compatible with the vision for Smart Grid.

This slide highlights seven key differences between conventional demand response and what is necessary to support Smart Grid. Two key differences are highlighted by the red circles, specifically: (1) smart grid will require a move to distributed, price responsive control and away from direct load control by the utility, and (2) demand response control strategies will have to consider options that integrate efficiency, reliability and renewables.

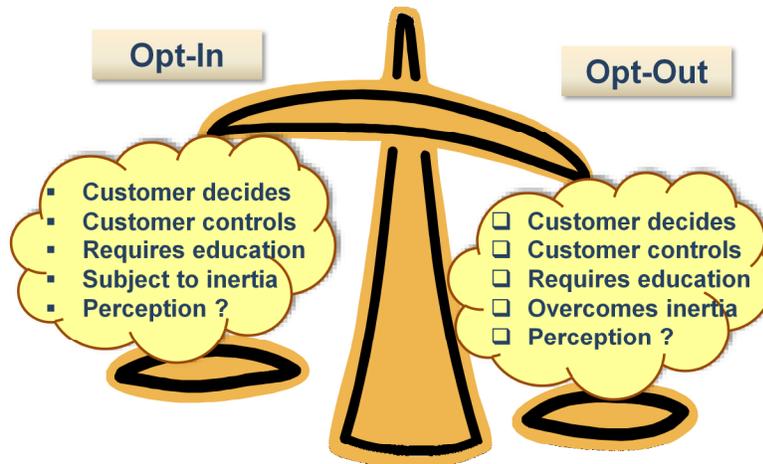
Structurally, demand response needs to move toward a modular structure based on a technology platform that can provide an electronic automated utility-customer link. On the utility side, this interface will provide capability to provide price, reliability and event signals. On the customer side this interface will provide a stable platform for connecting customer energy management and control options and smart appliances. This linkage can be provided by an energy management system, home automation system, or by capability using a gateway device or through technology embedded in individual appliances (smart appliances). A move away from bundled, stand alone DR programs to a technology platform approach should reduce the cost of demand response and improve flexibility to adapt to changing needs.

Operationally, DR based on distributed control by customers provides greater potential load impacts, more flexibility and options for customers, and eliminates many of scale and control issues associated with implementation of very large scale direct control.

## 2. Participation: Opt-in versus Opt-out



*"..how a choice is presented can affect the actions of decision makers, who have a tendency to stick with the default option." \**



\* Choi, J.J, Laibson D, Madrian B, Metrick A. Optimal defaults. American Economic Review 2003; 93(2): 180-185.

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Opt-in versus Opt-out continues to be a key issue in all pricing options. Conceptually, both approaches support customer choice, the key difference being that opt-out overcomes the inertia of customer inaction, potentially resulting in higher customer participation levels than occurs with opt-in. Both approaches also differ substantially in the types and cost of customer marketing and education needed. Both approaches will require substantial customer education, however opt-out education will tend to emphasize how customers can benefit and or change to another option, while opt-in will emphasize “selling” and customer enrollment.

Fundamentally, the major difference between the two options may actually be dependent upon many other implementation decisions. Many of the customer concerns may be averted if “Transition Plans”:

- stage rate implementation over a number of years (rates differentials eased in over a 2-5 year period) and
- incorporate an extended period of shadow billing to more clearly show customers actual billing impacts, and
- active efforts to identify, support, and even move customers who can’t adapt to more manageable non-dynamic rates .

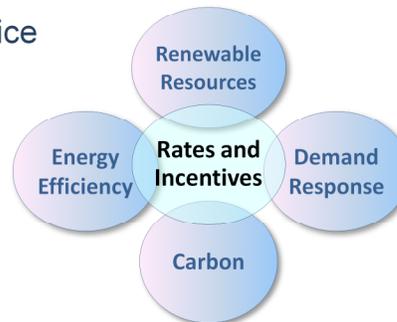
### 3. Rates and Incentives



#### Is dynamic pricing necessary ?

Yes, especially to achieve consumer benefits:

- ❑ Rate structures provide price signals that link the utility system and the customer.
- ❑ Price establishes the customer value function.
- ❑ Price enables benefits of smart grid to be achieved.



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While some of the smart grid objectives can be achieved with variations of non-dynamic rates (time-of-use and peak-time rebate), none of these options is capable of achieving the most significant smart grid benefits, especially those expected to accrue to customers.

For example, smart appliances which can automate demand response and provide customers with flexibility to address both day-ahead and day-of real time benefits are not considered feasible by appliance manufacturers without dynamic rates. Dynamic rates are expected to provide small day-to-day economic benefits that cumulatively create a consumer value function that justifies purchase decisions.

Another example is electric vehicles. Dynamic rates provide opportunities to target vehicle recharging during period of low prices, which may not be confined to fixed night-time off-peak schedules. Why restrict charging when it may not be necessary?

### 3. Rates and Incentives



#### Is dynamic pricing necessary ?

Smart Grid Objectives	Non-Dynamic Rates		Dynamic Rates		
	Tiered*	Time of Use (TOU)	Peak Time Rebate No TOU	Critical Peak Price + TOU	Real Time Price
Energy Efficiency	Need longer-term studies and coordination with demand response and distributed resource programs.				
Demand Response – Reliability (Day-ahead)	No	No	Yes	Yes	Yes
DR – Congestion Mgt, Ancillary Services (Day-of)	No	No	No	Yes	Yes
Solar Photovoltaic's	No	Yes	No	Yes	Yes
Energy Storage	No	Yes	No	Yes	Yes
Electric Vehicles	No	Partial	No	Yes	Yes

\*Flat rates do nothing toward these goals. Tiered (inclining block) rates theoretically incent conservation. Peak time rebates and dynamic pricing require advanced metering systems.

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This table provides a simplified example that matches smart grid objectives (left column) to five common rate forms.

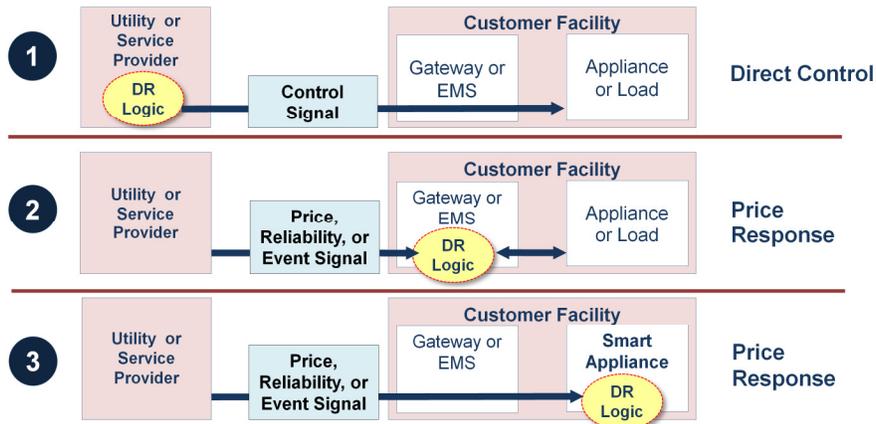
Critical Peak Pricing (CPP) and Real-Time Pricing (RTP) are shown to support all of the smart grid objectives. Peak Time Rebates (PTR), while classified as a dynamic rate is only considered compatible with the day-ahead DR reliability objective. PTR requires a baseline calculation which is dependent upon a supply of “normal” uncontrolled days during each billing period. This baseline restriction automatically eliminates PTR from supporting ancillary services, T&D congestion management, or any other option that might occur on a frequent basis.

The other non-dynamic rate forms (e.g., Tiered) do not provide capability to address most objectives associated with a long-term vision for a smart grid.

## 4. Control Strategies:



### Utility vs. Customer Control



Source: "Direct versus Facility Centric Load Control for Automated Demand Response, Grid Interop 2008, Koch, E., Piette, M"

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There are three conceptual approaches for developing and providing demand response control strategies, one characterized as direct control (option #1) and two characterized as price response or distributed control (options #2 and #3).

Direct control (graphic #1) has been the dominant approach to demand response since PURPA legislation was introduced in the mid 1970's. With direct control, the utility creates and manages the control strategy, represented by a control signal that is usually sent directly to a switch or control logic in the targeted end-device. With Direct control signals, the utility tells the end-device either how much time it can run or how much time it is off, during each time interval.

Price response or distributed control strategies have been historically associated with time-based rates. However, critical peak and real-time rates that can be dispatched, convert price signals into proxy demand response signals. The primary difference with price response is that the customer is responsible for translating and acting upon the price, reliability, or event signal.

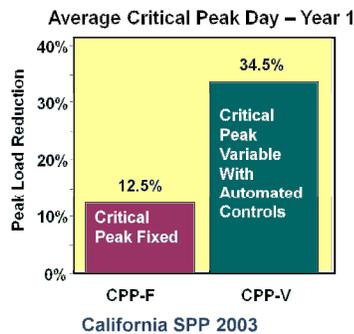
In graphic #2, the price, reliability or event signal is processed in a gateway device, either an energy management system or home automation system that the customer has programmed to control their energy using end-devices using these signals as activation variables. The customer gateway device translates the price, reliability and event signals into control strategies and settings established by the customer that are passed on to the end-devices.

In graphic #3, the price, reliability or event signals are processed directly by the end-devices. Again, logic in the end-devices translates the signal into a control action or setting established by the customer.

## 5. Automation: Necessary or Not ?



- Automation increases load response.
- Provides customers with “set and forget” it capability.
- Improves persistence of response over time.
- Provides fast response necessary for real-time response.



Rate Group	No Smart Thermostat	With Smart Thermostat
Residential-CPP	29%	49%
Residential-Peak Time Rebate	11%	17%
All Electric-CPP	22%	51%
All Electric-Peak Time Rebate	6%	24%

PowerCents DC 2010

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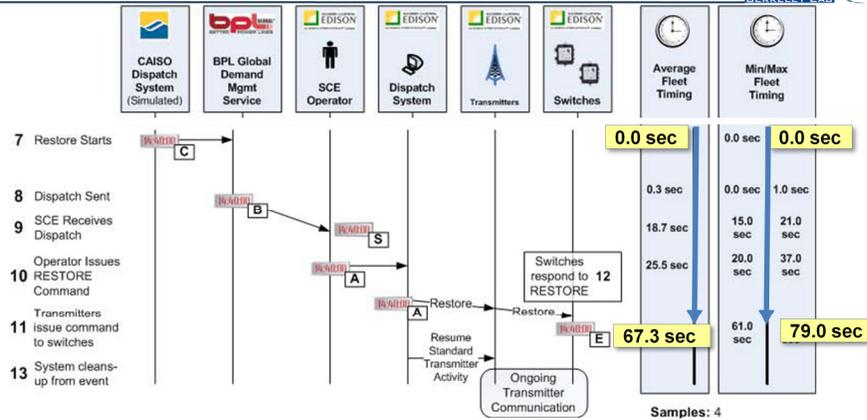
22

Is automation really necessary to support smart grid?

Smart grid encompasses a wide range of load shaping and resource integration objectives (see slide #20). Many of the day-ahead reliability and most of the day-of (ancillary services, congestion management, etc.) objectives require a speed of response that is not feasible under manual control by customers. Automation is required, not just to assure that control actions occur within the critical time window but also to provide persistence of response. Automating customer control actions provide a more consistent, persistent set of load impacts that make forecasting of load impacts more reliable. Automating customer response also improves the potential reliability value of the demand response / price response resource.

Finally, prior pilots have consistently shown that automating customer response increases customer load impacts, regardless of the rate form or price signal.

## 5. Automation: Necessary or Not ?



**“NERC and WECC rules for contingency reserve response (both spinning and non-spinning) require full response in 10 minutes. The SCE load management dispatch system consistently demonstrated full response from all four distribution feeder groups in less than 80 seconds.”**

1. Demand Response Spinning Reserve Demonstration Project, Phase 2 Findings from the Summer of 2008, April 2009, LBNL, Joseph Eto, <http://cerfs.lbl.gov/pdf/lbnl-2490e.pdf>

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This example further illustrates the need and value of automation. This graphic charts the timing for radio signals that adapted a conventional air condition load control switch for use in day-of load balancing. The highlighted times in the boxes on the right track the cumulative time from operator activation (0.0 seconds) to actual control (67.3 to 79.0 seconds) monitored during system operation. As this graphic shows, the actual times experienced during system tests came in well under the NERC and WECC rules for spinning and non-spin applications. None of this would have been possible under a customer dependent manual system.

## 6. Standards: ZigBee-HomePlug SEP Status



### DEFINITION:

- ZigBee is the brand name for a low-power wireless radio communication standard built on the IEEE 802.15.4 standard.
- HomePlug is the brand name for a power line communication standard built on IEEE P1901.
- Both ZigBee (wireless) and HomePlug (power line) require hardware and software components certified by each groups alliance-designated testing facilities.

### PURPOSE:

- ZigBee-HomePlug Smart Energy Profile (SEP 2.0) is expected to provide software applications and code to support pricing, demand response, and related energy applications.
- Expected to operate within the customer premise, supporting device registration, device monitoring, and utility control.

### STATUS AND POTENTIAL ISSUES:

- (a) lack of backward compatibility between SEP 1.0 and SEP 2.0
- (b) SEP 1.0 built into existing meters, not activated due to security concerns
- (c) SEP 2.0 still in development, originally due out May 2010.
- (d) March 2011, SGIP forms 90-day emergency PAP 18 to resolve SEP 1.0-2.0 compatibility issues.

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NIST identified two standards in its list of 16 targeted explicitly targeted to support demand response: ZigBee SEP and OpenADR.

ZigBee SEP is still in the development stage. ZigBee SEP is managed under the direction of the ZigBee Alliance, a private membership-based industry group. Unfortunately, as of May 2011 ZigBee SEP standard development activities were undergoing technical, political, and organizational issues which have resulted in substantial development delays. While originally scheduled to be completed and released in May 2010, SEP 2.0 is now expected sometime in the first or second quarter of 2012.

## 6. Standards: OpenADR Status



**DEFINITION:** OpenADR is an open standards-based communications data model designed to promote common information exchange for demand response price and reliability signals between the utility, aggregator, or Independent System Operator and electric customers.

**PURPOSE:**

- Provides Internet-based interoperable price, reliability, or event signals to customer programmed automated facility energy management or control systems.
- Customer systems listen for OpenADR signals, which preserves the customer firewall and internal system security.
- Applications support all customer types and DR options allowing demand response to be a dispatched, fully automated event, with no manual intervention.

**STATUS AND POTENTIAL ISSUES:**

- (a) Developed and commercialized by the Demand Response Research Center at the Lawrence Berkeley National Laboratory.
- (b) Pilots began in 2003, commercialized in 2006
- (c) Broad implementation support by over 60 control vendors, with implementations planned and in process in multiple states and countries.
- (d) National standard work due for completion 2011.

Resource Links: <http://newscenter.lbl.gov/press-releases/2009/04/27/openadr-specification/>

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OpenADR was developed in response to the California blackouts during the 2000 /2001 energy crisis. The objective was to identify and develop a low-cost, automated way to support demand response. The Demand Response Research Center (DRRC) at the Lawrence Berkeley National Laboratory developed and began testing OpenADR in 2003.

OpenADR uses Internet Protocol. Utilities use OpenADR to “post” price, reliability, and event signals on a server. Customer automation equipment, either an energy management system, gateway, or smart appliance, queries the utility server to read the price, reliability or event signals. If Internet is not available, OpenADR signals can be mapped to other formats and use a bridge client (software) to broadcast signals over any communication option. OpenADR is communication independent.

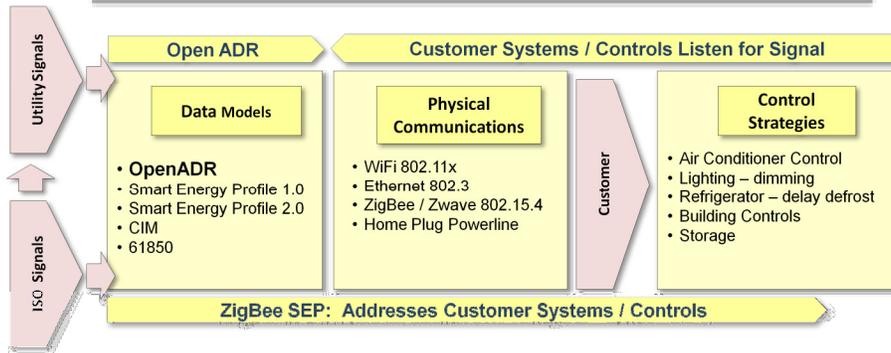
NIST identified OpenADR as a one of its first 16 standards. (standard #13).

OpenADR is an open protocol (not proprietary) that was donated by the DRRC to the Organization for the Advancement of Structured Information Standards (OASIS) and independent Standards Development Organization (SDO). OpenADR is on target to complete the national standards process by the end of 2011. It is also completing 8 years of commercialization with wide vendor support, and world wide application development.

## Standards: System Architectures



Many Methods for Integrating Pricing, Communications and Control to Automate Demand Response



OpenADR and ZigBee included among the original NIST 16 Smart Grid Standards.

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This graphic depicts the basic differences between OpenADR and the ZigBee SEP approach.

OpenADR provides ISO/RTO or utility price, reliability and event signals that can be accessed by customer systems via any communication option. OpenADR is not linked or restricted to any physical communication media. As a result, OpenADR does not go into the customer premise. This preserves the customer firewall and enhances cyber security management.

ZigBee SEP, particularly versions of SEP 1.x, provide signals over a fixed communication media into the customer premise.

## Standards: OpenADR



### What is the Demand Response Research Center ?

- ❑ **Established:** in 2004 at the Lawrence Berkeley National Laboratory by the California Public Interest Energy Research Program (PIER) as an initiative of the California Energy Commission
- ❑ **Objective:** to develop, prioritize, conduct and disseminate multi-institutional research to facilitate demand response.
- ❑ **Scope:** technologies, policies, programs, strategies, and practices, emphasizing market connections and implementation
- ❑ **OpenADR** – initially established as a research project in 2003 to automate and expand demand response in large commercial and industrial facilities.

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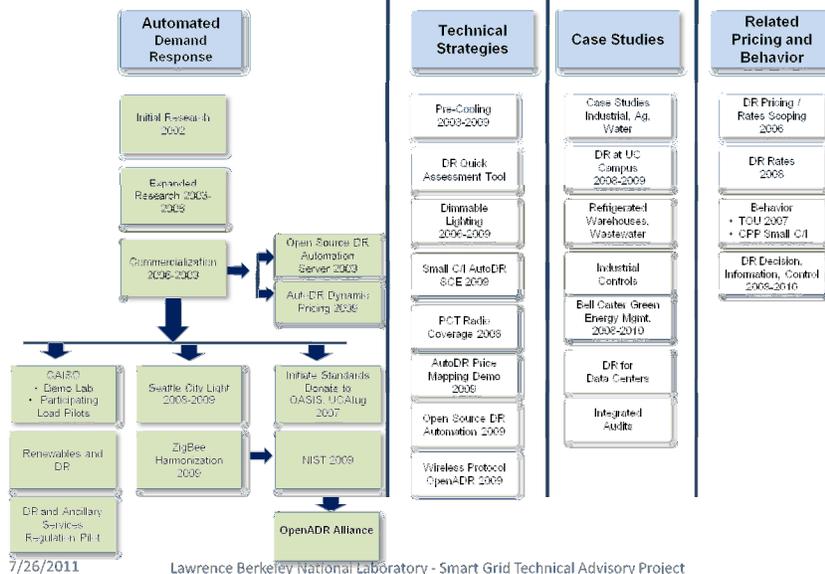
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The Demand Response Research Center (DRRC) is an organizational group within the Lawrence Berkeley National Laboratory. The DRRC was established in 2003 to conduct research in demand response and facilitate and accelerate the development and implementation of cost effective demand response options.

The DRRC conducts research projects in rates, technology, system operations, and customer behavior related to and necessary to support demand response implementation. The DRRC works directly with investor owned and municipal utilities, regulatory agencies, other research organizations, equipment manufacturers, and other service providers.

The next slide identifies a series of DRRC research projects from 2003 to 2009.

## Standards: DRRC OpenADR Research



This graphic illustrates the first six years of research projects, field trials, and commercialization activity conducted by the DRRC to support development of OpenADR.

- 2003-2006 Field tested the infrastructure with different building systems and different information being exchanged (prices, DR events, etc)
- 2006 – CPUC mandated investor-owned utilities in California to offer Automated DR programs using LBNL’s definition.
- 2007-2009 - First three years of its commercialization. Programs expanded with the participation of industrial facilities.
- 2009 – present - DRRC continued to push the limits trying to apply the infrastructure to enable faster DR and to take it outside of California to consider its application in different climates and different markets.
- 2010 – OpenADR Alliance, led by industry, is established to provide a conformance path for commercially available systems and devices through the development of a certification program.

## Standards: OpenADR Design



### OpenADR Data Models for Price and Reliability

- Automation**
  - ❑ Allows DR to be a dispatchable resource
  - ❑ Improves DR reliability, predictability, and value
  - ❑ Increases customer participation and reduces response cost
- Open Data Models**
  - ❑ Simplify and reduce cost of DR
  - ❑ Creates interoperability among customer systems
  - ❑ Creates interoperability between wholesale and retail systems
- Price and Reliability Signals**
  - ❑ Allows customers to choose level of response and how to enable DR strategies
  - ❑ Provides ability to embed automation in customer control systems.

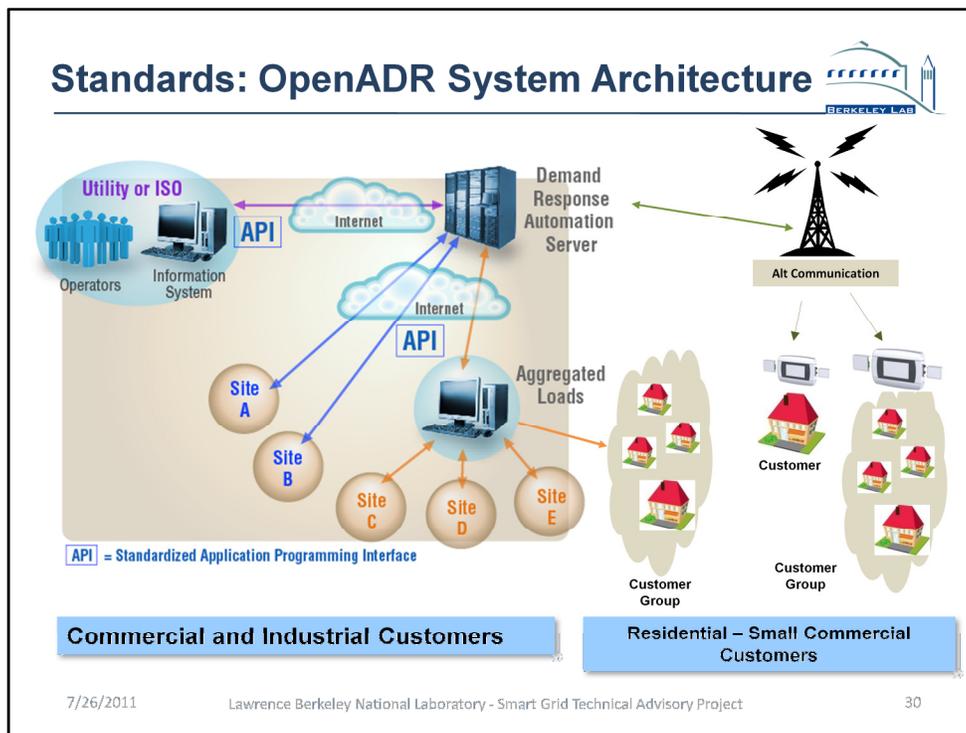
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OpenADR embodies three key principles that evolved out of the lessons learned and best practices derived from examination of past DR pilot programs across the US, specifically:

1. Automation is key to participation
  2. Open Data models are key to adoption.
  3. Customers should have access to price and reliability information.
- ❑ OpenADR uses existing Internet infrastructure to support standardized, high speed communication while at the same time leveraging existing security and privacy capability.
  - ❑ Price, reliability and event signals are posted to a server – which customer systems and equipment listen to and reacts to. OpenADR does not go into the customer premise – this preserves the customer firewall and existing customer security.
  - ❑ Automation equipment is integrated into the customer site – EMS, EMCS or control units for individual lighting or other specific loads. This approach clearly cements customer buy-in and provides the foundation for building in energy efficiency (EE) and permanent load shifting opportunities.
  - ❑ The customer determines what to control, how to control, and when to control. Even with that level of choice, 8 years of implementation continually demonstrate reasonably consistent peak reduction response.



This slide shows the architecture of the OpenADR infrastructure. At its core, this is a server-client architecture where the server publishes the price and reliability signals over the Internet in the OpenADR information exchange model and the clients that are located at each of the facilities, either embedded in or connected to the energy management and control systems, listen to the signals and trigger customer pre-programmed DR strategies. This all takes place without a human in the loop. In the case of the aggregators, the clients can be located at the aggregator's Network operations center (NOC) and passed down to individual sites as OpenADR signals or as an aggregator proprietary signal.

Communication between the server and the clients is secure, continuous, and two-way with the server publishing the price and reliability signals and the clients acknowledging their receipt. The open Application Programming interface fosters interoperability.

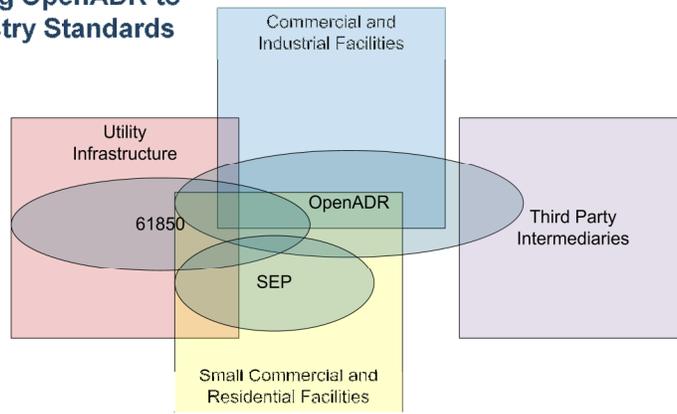
The same infrastructure was tested in Sacramento Municipal Utility District using a bridge client that converted OpenADR signals from Internet to radio broadcast signals using RDS. PCTs at each residence were able to listen to these broadcasts and respond to price signals.

Bridge clients could also be developed to support existing utility FM broadcast signals used in many air condition load control programs. Use in this manner, bridge clients can provide a form of interoperability that would allow existing control switches to operate while utilities and customer switch over to Internet or other more advanced controls.

## Standards: OpenADR Conformance



### Rationalizing OpenADR to Other Industry Standards



- ❑ OpenADR - only existing open data model to bridge communications between utility and control systems in commercial, industrial and residential facilities.
- ❑ “Price Mapping Demonstration Project” extended OpenADR capability into small commercial and residential.

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This graphic is meant to illustrate that the development of OpenADR recognized and addressed the need to integrate it with other standards development activities. OpenADR has been harmonized with SEP and IEEE 61850.

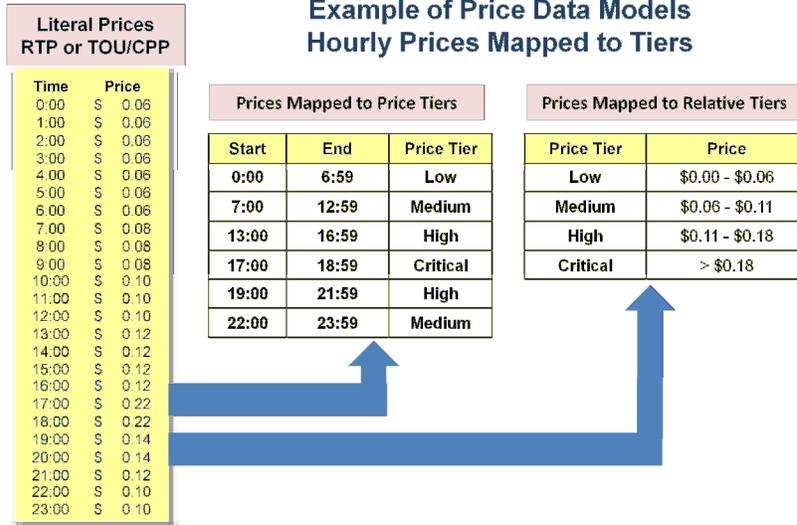
To date, OpenADR has been used to communicate price and reliability signals with:

- Large and Small Commercial Buildings,
- Industrial Facilities
- Residences.
- By Aggregators

# Standards: OpenADR Data Model



## Example of Price Data Models Hourly Prices Mapped to Tiers



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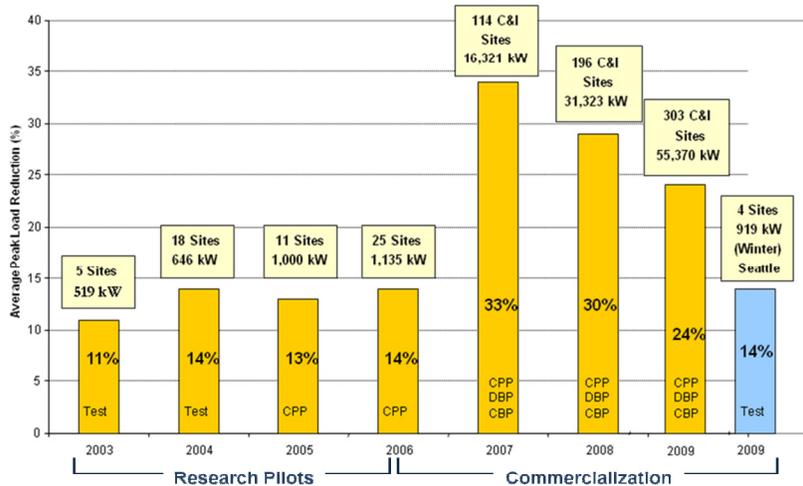
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The purpose of this slide is to show how OpenADR can represent prices.

The data model is flexible and can deliver prices at various intervals. For example, OpenADR can provide hourly or more frequent real-time prices, as illustrated by the “Literal Prices” depicted in the yellow columns on the left. These hourly or literal prices can be mapped to reflect tiered rates (middle table) or relative tiers (Table on the right).

Customers can use the literal real-time, tiered, or relative tiers prices to establish and activate thresholds supported in their OpenADR clients.

## Standards: OpenADR Price Response



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This slide summarizes participation and load impact results from field tests and the initial commercialization phase from 2003 through 2009. From 2007 to 2009 OpenADR was implemented in several different DR program options, which is noted by the initials in the lower segment of each bar (see key below).

Across all test years, commercial buildings, on average reduce 11-14% of their whole building peak power. Starting in 2007, a number of industrial sites were recruited by the utilities and added to the test mix. Industrial participation, due to the size of the loads and size of block power reductions, increased the average demand reduction for the entire portfolio. Over time the variety and number of automated DR programs also increased, which impacted the reported average load reduction but not necessarily in a consistent manner. Several of the added programs (DBP and CBP) were structured such that they were not dispatched very often or very effectively, which had a tendency to reduce the reported portfolio load reduction.

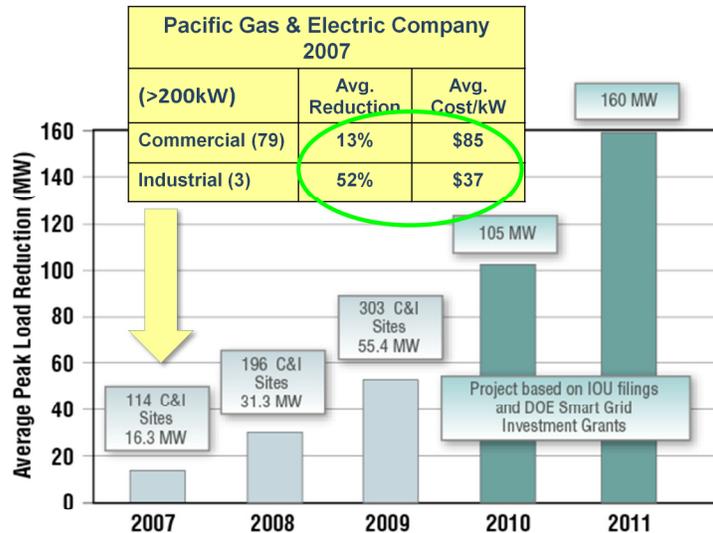
In addition to the commercially available DR programs in California, cold winter morning tests in Seattle yielded 14% demand reduction on average from 4 commercial buildings. Testing is or has been conducted by EPRI, Tendril, and is planned for SMUD, Duke, Martha's Vineyard, and for projects in Ireland, Canada, and several other countries.

CPP – Critical Peak Pricing

DBP – Demand Bidding Program

CBP – Capacity Bidding Program

## Standards: OpenADR Price Response



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Automated DR programs using OpenADR continue to grow. By the end of 2011, OpenADR supported programs at the three California investor-owned utilities accounted for 160 MW of peak capacity.

After the first year of its deployment by PG&E, the DRRC collected the cost data for all customer installations. Costs include the time necessary to identify what to control and how to configure and program control strategies into their energy management systems. Costs can also include hardware to provide additional control switches and/or to provide digital control signal capability to older analog systems.

There were 79 commercial facilities and 3 industrial sites enabled and included in the early OpenADR test phase. The average demand reduction at commercial buildings was 13% and the average cost of technology installations was \$85/kW. At industrial facilities, the average demand reduction was ~52% with an average implementation cost for setup and technology of \$37/kW.

Keep in mind, these setup and technology related implementation costs are “one-time” costs. Once implemented, customer automation with OpenADR capability can continue to operate for many years, generally only requiring periodic maintenance. Changes to control strategies due to changing equipment within the facility and changes in utility incentive and load shaping conditions can also require a revisit and updating of system controls.

## Standards: OpenADR DR-EE Integration



### SMUD Small Commercial EE-DR Integration

Business Type	Program Option	Energy Efficiency	Demand Response	Monthly Bill
		% 2007 baseline	% 2008 baseline	% Standard GSN Bill
Office	Direct Control (11)	-27%	-38%	-27%
	CPP (23)	-32%	-24%	-32%
Retail	Direct Control (8)	-15%	-22%	-26%
	CPP (20)	-19%	-14%	-31%
Restaurant	Direct Control (1)	-8%	-1%	-7%
	CPP (8)	-10%	-3%	-12%
<b>All Customers (71)</b>		<b>-20%</b>	<b>-14%</b>	<b>-23%</b>

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This slide illustrates an application of OpenADR with small commercial customers during a SMUD pilot program in 2008. A key feature of this program was to illustrate how demand response can be successfully integrated with energy efficiency.

The SMUD program provided customers with Programmable Communicating Thermostats and a choice of two control options: (1) a fixed participation incentive in combination with a conventional direct control option where SMUD would raise the PCT setpoint by 4 degrees on control days, and (2) a Critical Peak Pricing rate where the customer would determine all PCT and other settings. Both options also offered the customer two pre-programmed PCT control strategies: (1) a conventional shedding strategy, and (2) a pre-cooling control strategy.

While the samples were relatively small the results were statistically significant.

The table of results includes a mix of utility direct control and customer-control that actually mirrors what might occur in an offering that provides customer choice. The combined "All Customer" results are significant.

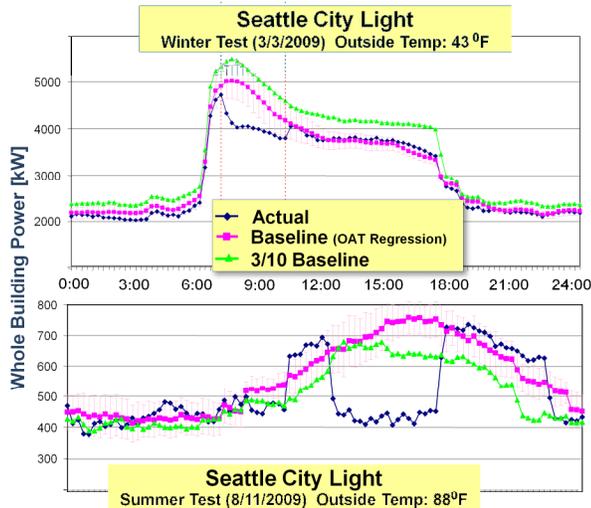
Because the Programmable Communicating Thermostats at that time did not have OpenADR software clients (they do now) the OpenADR price signals were mapped to a bridge client and rebroadcast over an FM side band to the PCT.

SMUD integrated EE with DR by offering customers full energy audits if they would agree to participate in the DR pilot.

Energy usage was tracked prior to the pilot to create a baseline that was used to track energy usage during and for a year following the pilot.

The DR impacts were measured from the reduced usage baselines.

## Standards: OpenADR Winter/Summer Impacts



- Same buildings in summer and winter DR events.
- Same infrastructure used to respond to signals during summer / winter events.

BPA Seattle City Light		
	Avg. Reduction	Avg. Cost/kW
Winter (4)	14%	\$76
Summer (5)	16%	\$108

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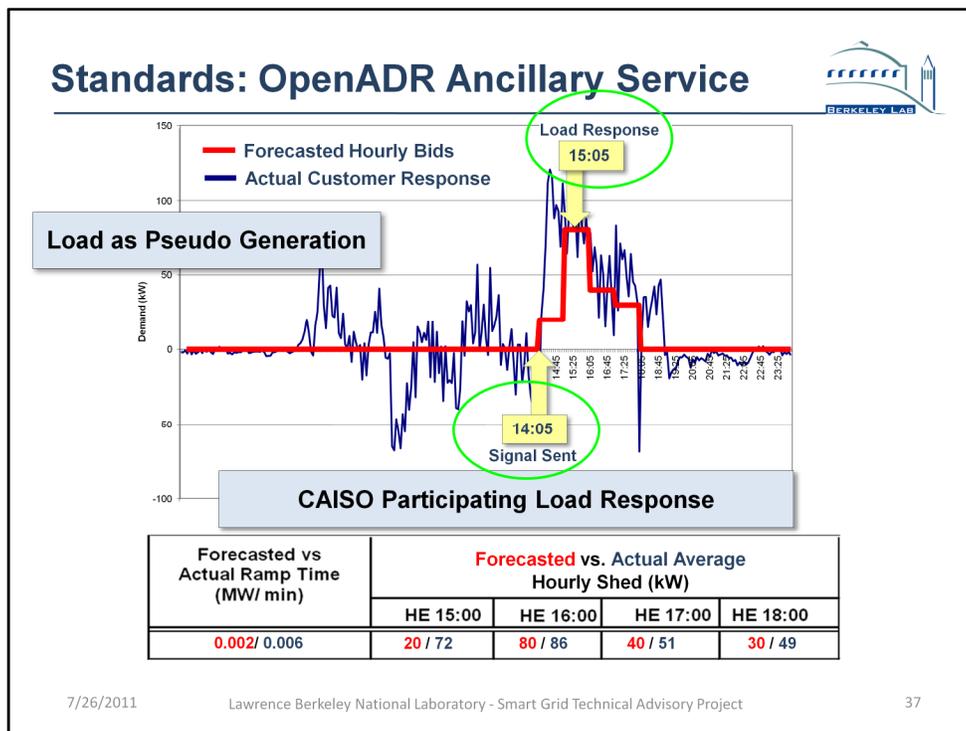
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These two plots illustrate results from a summer / winter test conducted by Seattle City Light. The top graph is from Seattle Municipal Tower during a winter DR event. The bottom graph is from a Target store during a summer DR event.

The same OpenADR infrastructure was used to test the automated DR capability for both summer and winter events. Electric heating is the major contributor to winter peaks.

On average, the percent demand reduction was similar to other field tests conducted in California.



Applications of OpenADR continue to expand each year. The graph and table in this slide provide results from a Participating Load Pilot conducted with the CAISO, PG&E and the DRRC. The purpose of this pilot was to see if DR could be used to support spinning reserve and other ancillary service applications.

**Objectives and Results:**

Objective #1: Can commercial buildings with HVAC DR Strategies meet CAISO non-spinning product requirements (10 minutes ramp, 2 hrs availability)?

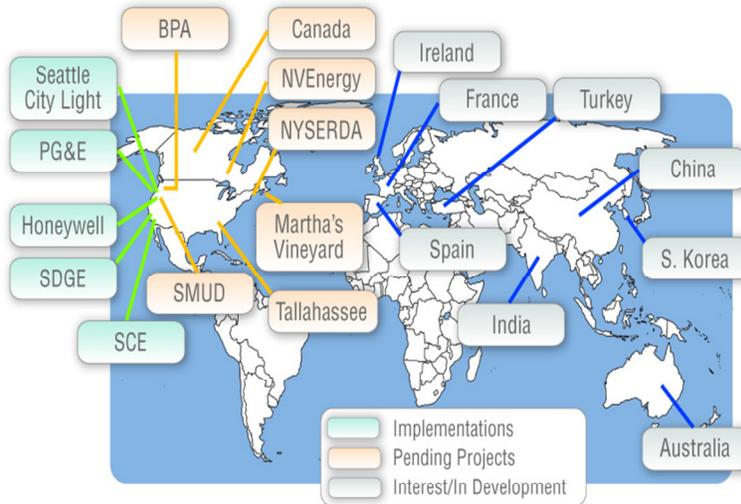
Result #1: Yes. OpenADR dispatch consistently activated load control strategies within about a 60 second time window.

Objective #2: What infrastructure changes are required to the facility to facilitate OpenADR from a slow response retail to fast-response wholesale application?

Result #2: Additional telemetry was required to monitor response speed. No other changes to the facility equipment or OpenADR strategies was required.

Three buildings that participated in PG&E’s Critical Peak Pricing Program successfully switched over and participated in this CAISO’s Ancillary Services market as Non-Spinning reserves.

## Standards: OpenADR Development



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While initially developed at LBNL by the DRRC, OpenADR pilots are being conducted in many locations in North America, Europe, and Asia. There are active pilots in Australia and China.

# Standards: OpenADR Industry Support



## Utilities, Aggregators, and ISOs



## Research Organizations



## Testing, Certification, & Alliances



## Technology Integrators



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## Control and Technology

### Industrial



### Commercial & Industrial



### Commercial



### Small Commercial and Residential



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There has been a tremendous support from the industry for OpenADR. There are over 70 companies supporting OpenADR development either by providing services, or OpenADR compliant software clients within their devices or equipment.

## Standards: OpenADR Lessons Learned



### Automation

- ✓ Allows DR to be a dispatchable resource (**wholesale and retail DR**).
- ✓ Improves DR reliability, predictability, and value (**summer / winter**).
- ✓ Increases customer participation and reduces response cost (**transparent retail to wholesale DR conversion**).

### Open Data Models

- ✓ Simplify and reduce cost of DR (**embedded clients**).
- ✓ Creates interoperability among customer systems.
- ✓ Creates interoperability between wholesale and retail systems.

### Price and Reliability Signals

- ✓ Allows customers to choose level of response and how to enable DR strategies (**increases DR response**).
- ✓ Provides ability to embed automation in customer control systems (**increases DR reliability, customer participation**).

### Cost

- ✓ Expanding support for OpenADR and use of embedded software clients reduces implementation costs.

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Research studies and pilot programs over since 2003 have provided the DRRC with a wealth of experience and results. Those results were used to develop a compendium of lessons learned and best practices, which are noted in this slide.

### A Qualifying Note to Cost:

As OpenADR becomes more widely adopted vendors and service providers will expand the use of embedded software clients. Embedded software clients will make OpenADR just another option within energy management systems, eliminating the need for any retrofits or supplemental hardware. As efficiency is integrated with DR, like the SMUD example earlier, the savings will increase and the marginal cost of implementation will drop and eventually become insignificant.

## 6.30 Demand Response



### References

	<b>Title</b>	<b>Link</b>
1	Assessment of Demand Response & Advanced Metering, Staff Report, FERC, February 2011	<a href="http://www.ferc.gov/legal/staff-reports/2010-dr-report.pdf">http://www.ferc.gov/legal/staff-reports/2010-dr-report.pdf</a>
2	Coordination of Energy Efficiency and Demand Response, LBNL, Goldman, Reid, Levy, Silverstein, January 2010.	<a href="http://sites.energetics.com/madri/pdfs/lbnl-3044e.pdf">http://sites.energetics.com/madri/pdfs/lbnl-3044e.pdf</a>
3	Demand Response Spinning Reserve Demonstration Project, Consortium for Electric Reliability Technology, LBNL, Joseph Eto presentation October 19, 2009	<a href="http://certs.lbl.gov/pdf/lbnl-2490e.pdf">http://certs.lbl.gov/pdf/lbnl-2490e.pdf</a>

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