Summary Report on the Experiential Workshops

Day-1: September 9, 2002

Dynamic Pricing, Tariffs, and Price Responsive Demand Programs

The two-day workshop was introduced by Commissioner Arthur Rosenfeld (California Energy Commission) and Julie Fitch, Advisor to Commissioner Peevey (California Public Utilities Commission). Developed as a joint effort between the CEC, CPUC, and California Power Authority (CPA), the workshops were intended as an opportunity to update all participants in the Rulemaking proceeding on current nationwide pricing, demand response, and technology activities.

DYNAMIC TARIFFS – INTRODUCTION	
Topic	**Presenter**
Overview of Dynamic Pricing (Provided on 9-10-02)	Karen Herter, Lawerence Berkeley National Laboratory and California Energy Commission

Karen Herter provided a general introduction to dynamic pricing and an overview of the general policy initiative included in the Rulemaking proceeding. According to Karen, dynamic pricing as it is being used in this proceeding, is defined as follows:

Dynamic Pricing:

A retail electric rate designed to provide at least one or more 'dispatchable' prices that allow it to more accurately reflect the time differentiated cost of electric service.

According to the definition, dynamic pricing can include several different rate forms including:

- Real-time pricing (day ahead, day of, or hour ahead prices) and
- Critical peak pricing, which combines a traditional two or three-part time-of-use rate with a dispatchable critical peak price. The critical peak price effectively creates one additional time-of-use rating period.

The Energy Commission recommends that all California ratepayers be offered a portfolio or choice of rates, with a dynamic pricing option designated the default rate. Customers uncomfortable with dynamic pricing options or uncertain regarding the economic impacts, could select alternative, risk adjusted rates that may include a flat all-energy rates, conventional time-of-use rates, or some other rate form. The Energy Commission is not recommending mandatory dynamic pricing options for any class of customers.

Dynamic pricing options are being considered in this proceeding for two reasons. First, links to the supplier or wholesale market allow dynamic pricing options to better reflect the actual cost of service. Historical experience with dynamic pricing options show that customers can and will respond to high prices by reducing or shifting demand to lower-price periods. Allowing customers to respond to a price signal reduces system demand, reduces system costs, and improves overall system reliability for all customers, participants and non-participants alike.

Dynamic pricing also simplifies conventional tariffs by eliminating demand charges and the need for separate incentives to support demand response. By capturing and integrating hourly and critical peak prices into the customer rate, dynamic pricing can provide much more effective demand response incentives than conventional fixed dollar participation payments. By integrating the incentives into the rate, dynamic pricing options avoid paying customers to reduce usage, increase customer choice, and charge customers only for their actual peak responsibility.

In effect, dynamic pricing establishes a 'Value Proposition' that has substantial equity, administrative, and other advantages over conventional rate designs and traditional demand response frameworks. These benefits are discussed in Appendix A. Readers interested in this comparative discussion of different rate structures should review this attachment at the end of the meeting summary..

DYNAMIC TARIFFS – THE UTILITY EXPERIENCE Commercial and Industrial Real-time Pricing	
Topic	**Presenter**
Georgia Power Real Time - Pricing (Large customers) Duke Power Real Time - Pricing (Large customers)	Michael O'Sheasy, Christensen Associates
Niagra Mohawk Real - Time Pricing (Large customers)	Bernie Neenan, Neenan Associates

Michael O'Sheasy and Bernie Neenan reviewed the background, technical design, and customer response to three major commercial/industrial real-time pricing (RTP) options. Both presenters made several key observations, specifically:

- Historically, the electric power industry has faced several price-related crisis in the past 30 years. While there has always been much discussion about reforming pricing policies and rates, there has generally been little follow through.
- Effective RTP options have been designed to reflect the true cost of power or to mimic open market characteristics. They were not designed to function as a demand response program. Demand response is a byproduct of customer response to actual price.
- Utility service providers face two risks that RTP can mitigate: (1) Cost risk - where the set price may be exceeded by actual market cost, and (2) load shape risk – where the aggregate customer load shape may vary from the forecast.
- A two-part rate structure is critical to the success of RTP options.
  - Part 1 – Baseline Usage: The baseline limits the revenue risk to utilities while also limiting the cost risk to customers. Baselines are usually derived from historical usage, however, proxies and other options have been used.

- Part 2 – Marginal Usage: Exposing only the marginal usage above the baseline to real-time market prices limits the price risk for customers.

- Customers easily understand and adapt to RTP options. However, response to RTP is generally driven by the full cost of responding (investment plus price), not just price.
- RTP has been effective in reducing peak load and in producing net positive system benefits. Table 2 summarizes basic participation and impacts for each of the featured RTP options.

Table 2. RTP Status

Utility	Status	Customers	RTP Response mW
Georgia Power	operational	1,600	5,000
Duke	operational	53	53
Niagra Mohawk	operational	400	NA

- RTP options are usually designed to reflect five components of system cost: (1) system lambda, (2) losses, (3) the marginal cost of transmission, (4) outage costs, usually based on a proxy for the cheapest generation unit, and (5) risk adders.
- The Georgia Public Service Commission has authorized Georgia Power to offer customers several financial price protection products. Price protection products provide customers with regulated insurance to minimize price risk. Benefits from these products accrue to all Georgia Power ratepayers.

DYNAMIC TARIFFS – THE UTILITY EXPERIENCE Residential Critical Peak Pricing and Real-time Pricing	
Topic	**Presenter**
Gulf Power – Critical Peak Pricing (Residential)	Dan Merilatt, GoodCents Solutions
Allegheny Power – Real Time Pricing (Residential)	Ed Johnstonbaugh, Allegheny Power Ron Eigenbrod, Lightstat

Dan Merilatt, formerly with Gulf Power, provided an overview of Gulf Power critical peak pricing rate option, including the development and evaluation of the two-year pilot program and current program status. Dan identified four essential elements necessary to support critical peak pricing (CPP) for residential and small commercial and industrial customers.

1. Rate Design - a design employing time varying rates and a near real-time component
2. Control Equipment - control equipment to automate the customer response
3. Communications - capability to rapidly distribute pricing information, and
4. Billing - a means for recording, retrieving, and processing billing determinants.

The original pilot program conducted in the early 1990's, was a carefully controlled two-year examination of customer energy impacts and acceptance. The pilot results showed that customers reduced peak load, shifted energy use to off-peak time periods, and reduced their average energy bills all of which led to high customer acceptance. Gulf also found that a critical peak rate, because it measured actual customer response, reduced the policing requirements common to conventional load control programs.

The current Gulf Power CPP option, with more than 3,000 participants, has been operating for approximately three years and is demonstrating similar results, more specifically:

- A 20 percent reduction in energy use during the high priced period
- Increased energy use during the low-priced, off-peak time period
- Overall reduction in energy use in all other rating periods
- A 15 percent average reduction in annual participant energy bills

One concern voiced by a workshop participant was the impact that a large-scale program might have on utility finances. Merilatt responded that while the rate of long-term growth might be slowed, customer shifts in load reduce utility costs, which should not adversely impact overall finances. Regulatory lag in adjusting revenues to account for customer shifts might become a factor, although there are accepted practices for addressing that factor too.

Ron Eigenbrod (Lightstat) and Ed Johnstonbaugh (Allegheny Power) described a small residential RTP pilot program (20 participants) that Allegheny Power initiated in response to their move to a distribution-only service provider. Allegheny views RTP as a way to better allocate costs among customers, to reduce overall system costs, and to support a potential business venture in smart home technology.

According to Johnstonbaugh, Allegheny experiences a rather common utility price duration curve, where a few hours each year highly skew average customer pricing (Table 3). In the example provided, the top 100 hours (approximately 1 percent) alone raise average annual energy costs by 33 percent.

Table 3. Allegheny Power
Price Duration Impacts on Average Utility Energy Costs

Hours	Cost
Average 8,760 hours	$36 / mW
Average top 100 hours	> $100 / mW
Average less 100 top hours	$24 / mW

The Allegheny Power pilot uses a one-way paging-based Lightstat internet-enabled thermostat to automate customer response to day-ahead hourly prices downloaded directly from the PJM website. The RTP rate uses three rating periods (regular, high, and very high).

Customers can use the thermostat to program 'price thresholds' that automatically reduce air conditioner usage in response to price changes. The thermostat also provides hard-wire contacts to also control customer pool pumps, water heaters, and other discreet loads. While customers do not have a 'button capability' to override a price-induced control action, they can reprogram their preferences at any time.

Individual customer price response preferences are stored centrally by Allegheny and dispatched based on actual PJM prices. All other conventional setback thermostat functions operate locally without any intervention by Allegheny.

Allegheny chose a controllable thermostat because it offered a lower cost option to commercially available gateway systems, like the one used by Gulf Power. According to Lightstat and Allegheny, customer reductions in load provide a two-year payback/recovery of the $400 installed thermostat cost.

While the Allegheny RTP pilot currently targets high-usage customers with air conditioning, Johnstonbaugh stated that Allegheny has been investigating a specially designed RTP rate for low-income participants.

DYNAMIC TARIFFS – REGULATORY PERSPECTIVE (Panel Discussion)	
Presenter	**Organization**
James Gallagher, Chief, Retail Competition and Demand Response	New York State Public Service Commission
Jeff Nahigian, Consultant	Toward Utility Rate Normalization (TURN)
Scott Cauchois,	Office of Ratepayer Analysis, California Public Utilities Commission

Participants to the regulatory session were encouraged to raise and discuss the key issues they encounter within their own organizations regarding dynamic pricing and demand response. The perspectives of the three panelists were distinctly different on many issues. However, each panelist emphasized the complexities that political issues introduce to utility regulation.

<u>New York State Public Service Commission</u>

James Gallagher discussed the serious transmission problems that constrain energy supplies to New York City. While Niagra Mohawk has 200 participants enrolled in their RTP option, Gallagher reported that no customers in New York City would signup for a similar voluntary RTP option. Although the Niagra Mohawk customer base is heavily industrial and the New York City market is heavily commercial office building, Gallagher stated that political concerns played a key role in the disparate reception of RTP.

Projected short-term supply shortfalls have focused efforts to develop standardized statewide programs through their ISO. Programs fall into three categories: (1) emergency demand response, (2) special case resource programs for installed capacity (standby curtailment option), and (3) a voluntary day ahead demand response option (load bidding) that requires participants to have a interface like a generator. According to Gallagher, the ISO demand response programs produced approximately 1,600 mW's of load relief in 200. These programs cost approximately $4.2 million in incentive payments but produced estimated benefits of $24- $58 million.

While these programs are scheduled to expand even more in 2002, generators have expressing concern that downward price impacts will adversely their financial viability. The Public Service Commission is also concerned about numerous regulatory and relationship issues as the ISO programs expand to address end-users.

California Public Utility Commission

Scott Cauchois expressed a number of issues, most of which focused on equity concerns that might arise as demand response programs are expanded, specifically:

- How will low-income, senior citizen, and other low use customers be accommodated? Will they be required to participate?
- Will early adapters push revenue requirements to other groups? Alternatively, how can the CPUC establish revenue requirements to encourage savings but avoid creating cross-class subsidies?
- One of the overriding barriers appears to be the inability to sort through the multitude of programs, different pricing schemes, and lack of coordination among numerous participating agencies. This is basically a procurement problem.
- Customer choice is substantial issue, particularly:
  - How to handle customer education and migration from existing to new programs.
  - Designing programs to better account for costs and benefits.
  - Resolving who owns the meter and who owns the data.
  - Should existing tariffs be fine-tuned before or after new pilots are introduced?
- Finally, there is a need to address utility-level issues regarding potential costs, revenue losses, revenue neutrality, and risk.

TURN

Jeff Nahigian suggested that all pricing, metering, and demand response activities should focus exclusively on the largest >200kW commercial and industrial customers included in the AB1X29 metering initiative. He expressed TURN's belief that advanced metering and real-time or dynamic rates had potentially undesirable economic and equity implications for residential customers and that any potential benefits some customers might receive would be offset by meter replacement costs. His specific recommendations included:

- Inverted tiered rates should be retained because they encourage conservation.
- Fixed price energy rates with insurance contracts should not be considered a viable alternative.
- Avoid rate designs that include high customer charges.
- The first demand response options to be considered should be those that have already been proven cost effective, like air conditioner load control.
- Time-of-use rates should be developed for commercial and industrial customers but should only be offered to the largest residential customers on a voluntary basis
- Demand response is acceptable to address emergencies but not for price response.
- Residential RTP cannot work unless customer response is fully automated.

Wrap-up Panel – Audience Discussion

There was a general question-answer session at the conclusion of the individual presentations. The most significant key issue raised during the discussion dealt with whether RTP and demand response participation should be voluntary or mandatory. Several examples were cited, like the lack of RTP participants in New York City, where those causing the supply/distribution problems don't participate, shifting higher costs onto all customers. Although there was no consensus, redesigned rates and more appropriate regulatory policy were offered as potential solutions.

CUSTOMER INFORMATION & CONTROL TECHNOLOGIES)	
Topic	**Presenter**
Customer Information Needs	Joe Desmond, President, Infotility
Demand Response – A Customer Perspective	Glenn Barrett, Senior Manager, Demand Response Albertson's Supermarkets
Demand Bidding – National Perspective	Joel Gilbert, President, Apogee
Demand Bidding – Municipal Utility Perspective	Harlan Coomes, Sacramento Municipal Utility District
Demand Bidding – Aggregators Perspective	Dave Slifer, Vice President, Planergy
Lessons Learned from the CPA Demand Reserves and ISO Demand Response Programs	John Flory, President, eNMarket (Representing the California Power Authority)

The concluding panel for the first day focused on retail demand response programs that used some form of market-based or dynamic pricing incentives. Demand bidding options dominated the panel. Within California and nationally, various forms of demand bidding have been the most successful and most dominant option for addressing system reliability and are one of the few options that create links to market price.

Panelist covered a wide range of issues, including:

- One of the key barriers inhibiting customer demand response is a lack of access to uniform usage and pricing information. Information conveyed in conventional utility 'printed' billing documents is insufficient both in timing and content to support customer investment and day-to-day energy management decisions. There is also a general disconnect between customer responsibility for responding and the benefits realized through existing rates.
- Because of highly specialized applications and needs, some energy intensive customers would probably prefer flexible, demand bidding type programs to RTP or critical peak pricing options. Demand bidding is perceived as a lower risk option.

- The success of demand bidding programs nationally illustrates that real-time savings do not necessarily require RTP. This situation illustrates the need to clearly separate pricing policy and equity issues from demand response objectives.
- The success of demand bidding programs nationally and at SMUD also illustrates the value of simple, uncomplicated program designs, applications that make use of existing revenue metering, and flexible operating practices that allow customers to tailor their response to their own operating situations. The SMUD program in particular, illustrated the value of providing customers with timely information, simplified contracts, and few penalties.

Workshop Day-1 Wrap-up

At the conclusion of the final panel, representatives from the CEC, CPUC, and CPA provided summary observations on the days presentations and discussion. The comments provided below represent observations and statements by organizational representatives. They are presented without interpretation.

California Energy Commission – Mike Jaske

- Despite concerns over RTP options, a two-part tariff appears to be the best approach for addressing customer's price risks and utility revenue requirements.
- The range of customer needs and capabilities indicate that there is no single best option. Instead customers should be provided with several options.
- After assessing the pros and cons of RTP, CPP, and demand bidding none appear to yet have a clear-cut edge of the others.
- Utility marketing and customer education is important. There are, however, serious concerns regarding costs, cost recovery, and how utilities can be incented to perform.
- The automation of load response can greatly ease customer fears, but it does not diminish the need for customer override capability.
- Customers also need access to better energy usage and price information, more immediate feedback, and quicker settlements.
- Aggregate customer response can be highly predictable, even though placing control in the hands of the customer is key to a successful partnership.
- It is still unresolved whether the decision-making framework at the heart of this proceeding is (1) the market cost of energy and RTP, or (2) load reductions and demand response.

California Public Utilities Commission – Julie Fitch

- When considering customer options, it is imperative to not neglect the low-tech solution. There are cheaper solutions that do not require advanced metering.
- New programs and options should build on the existing population of participating customers. What more is available? Avoid double dipping.
- There is a huge credibility problem with existing customers.

California Power Authority – John Flory (consultant)

- Among all of the issues, adequate reserves are a priority. Constructive action needs to taken to enhance reliability.
- There is a need to 'think outside of the box'. Pricing is not the only issue. Information is a critical need.

Summary Report on the Experiential Workshops
Day-2: September 10, 2002

Utility Business Case and Metering System Technologies

Day-2 of the workshop was structured to focus on advanced metering, communication, and the other systems necessary to support dynamic pricing and price-driven demand response programs.

UTILITY BUSINESS CASE AND METERING SYSTEM TECHNOLOGIES	
Topic	**Presenter**
Overview of Advanced Metering – A Focus on Information	Roger Levy, President, Levy Associates (Representing the California Energy Commission)

Roger Levy provided a brief introduction to the technology-related issues that the subsequent speakers were asked to address. He grouped the issues into four specific areas, each characterized as a set of basic questions:

1. Is the technology commercially available? While the focus is on advanced metering, it was also pointed out that communications, data management, billing, and other systems must also be present to support a fully functional system.
2. Can the technology support dynamic pricing and demand response applications? Again, while the technology may be available, it must also be capable of supporting a variety of performance standards and application requirements.
3. Is the technology economically viable? To be viable, technology options must provide positive system benefits. A critical concern is what to include and how to evaluate the entire cost and benefit package. Experience with existing systems has demonstrated that advanced metering provides a substantial range of benefits not considered by Standard Practice cost effectiveness methodologies. Furthermore, many of the utility business cases provide evidence that advanced metering and their related support systems should be treated as a cost of service, not as a rate or demand response program specific cost.
4. What are the barriers to implementation? Answers to each of the preceding questions will help to identify technical and cost barriers that limit implementation. However, it is important to also identify regulatory, legal, and internal organizational issues that may act to impede more widespread implementation.

THE UTILITY BUSINESS CASE FOR ADVANCED METERING)	
Topic	**Presenter**
Pennsylvania Power and Light (PPL)	Michael Wiebe, President MW Consulting (Representing PPL)
Puget Sound Energy (PSE)	Todd Starnes, Vice President, Marketing Brian Pollum, Director, Metering Network Services

The economic justification for advanced metering is a critical factor underlying the development of dynamic pricing and demand response options.

Traditionally, metering and related system costs are included as a cost component of dynamic pricing or demand response options. Because pricing and demand response options are generally limited to target segments of a customer market, metering installations fail to achieve either the volume or density to achieve economies of scale. Under this situation, meter and related costs are high. This raises the costs and limits the cost effectiveness of pricing and demand response options, which in turn reduces the scope and productivity of all such programs.

Several utilities have pursued an alternative approach that considers system wide metering a technology necessary for streamlining internal operations, reducing operating costs, and providing customer service. Under this approach, metering and related systems achieve economies of scale resulting in a lower cost system. Metering and related system costs are assigned to pricing and demand response options only to the extent that additional capability is required. Removing the bulk of the metering related costs from the evaluation of pricing and demand response options substantially improves cost effectiveness, which in turn allows both the scope and productivity of these options to be greatly expanded. As cost effectiveness improves, target markets for pricing and demand response options can be expanded. This expands the benefit pool, which in turn improves the overall cost effectiveness of the original metering implementation decision.

Representatives from Pennsylvania Power and Light (PPL) and Puget Sound Energy (PSE) reviewed how each of their companies cost justified the system wide implementation of advanced metering. While both companies selected different metering and communication technologies and face markedly different market conditions, each company followed almost identical approaches for evaluating and justifying their investment decisions. The results for each of the business cases were also similar. Table 4, summarizes key features of each company business case.

Overall, PPL and PSE economically justified system wide implementation of advanced metering based on cost reductions and improvements to internal utility business operations. Neither utility considered or factored into their economic justification the value of demand response or the value of information to consumers. There were two additional conclusions that both utilities also supported:

1. All of the utilities with system wide implementations still stand by their decisions, and
2. All of these utilities report benefits that exceed those identified in their business case.

Table 4. Comparing the PPL and PSE Business Case for Advanced Metering

FEATURES	PPL	PSE
Market Structure	Deregulated, unbundled	Regulated, bundled
Meters Installed	❑ Electric: 1.3 million ❑ Gas: none	❑ Electric: 1.5 million ❑ Gas: number not available
Implementation Period	36 months	49 months
Economic Payback Period	6 years	Electric Only: 5-6 years Electric and Gas: 9 years
Implementation Objectives	1. Strategically enable the company to provide information necessary to service customers and complete in a deregulated market. 2. Meet service levels. 3. Reduce internal operating costs to meet regulatory rate reduction order.	1. Reduce internal operating costs 2. Provide information to support improved customer services and customer choice.
Meters Provide Interval Data	Yes	Yes
Meter reads per day	3	1
Cost Justification	Fully justified based on internal cost savings.	Fully justified based on internal cost savings.
Demand Response Benefits	Not considered.	Not considered.
Value of Information to the Customer	Not considered	Not considered.
Acquisition Method	Internal, purchase	Outsource
Principle Barrier to Implementation	Internal organizational resistance	None reported.

PSE also described the introduction and rollout of their Personal Energy Manager (PEM), a system that provides each customer with detailed usage information by rate period. This information is presented on their monthly bill and is accessible by Internet. According to PSE, the PEM was an essential part of a long-term program to education customers about the time-varying cost of energy, prior to a rollout of their time-of-use rate.

The Washington PSC recently ruled that PSE could rate base and recover the costs of this system. PSE reported that the incremental cost to provide customized energy usage information was approximately $1.26 per customer per month. Of that amount, the Washington PSC has authorized $1.00 to be recovered in the base customer charge, $0.16 is embedded in their time-of-use rate, and the remaining $0.10 is recovered through a conservation charge.

Several issues and observations were brought forward following the business case discussion, including:

- Should the economic justification for advanced metering be dealt with separately from the economic justification for dynamic pricing and demand response? Business case conclusions that justify implementation entirely based on internal costs savings tend to support separation.
- Does it follow that the decision for transitioning to advanced metering can be independent of a decision to deploy dynamic tariffs?
- The biggest challenges to implementation of advanced metering appear to be internal utility organizational issues. How or should this barrier be addressed in the context of this proceeding?
- Should the deployment of dynamic tariffs beyond the pilot stage include an adjustment period where customers receive simulated monthly energy bills that benchmark the new cost structure?

METERING AND COMMUNICATION SYSTEMS – TECHNOLOGY STATUS	
Topic	**Presenter**
ABB	Jim Andrus, Manager, Business Development
DCSI	Bob Richardson, Vice President, New Business Development
EMeter	Chris King, Chief Strategy Officer
IMServe	Greg Lizak, Vice President, Regulatory Affairs
Itron	Doug Staker
SchlumbergerSema	Ivo Steklac, Vice President, Marketing

This concluding session brought together a mix of technology and service providers. This participants in this group were deliberately selected because they included the dominant providers of advanced network metering systems, major suppliers of conventional meter reading equipment and systems, as well as innovative, relatively new companies providing outsourcing and system integration services. For example, SchlumbergerSema and DCSI together account for in excess of 11 million networked meters, which represents in excess of 90 percent of industry installations.

Each of the panelists was provided with a topic outline that asked them to review four major areas relevant to the basic questions posed at the beginning of this workshop session, specifically:

1. Provide an overview of your existing meter technology, communication, data management, billing and other system options.

2. Describe the basic functions and the value of the various functions provided by your systems and explain how they differ from the current base of utility installed meters.
3. Provide a top-level view of the expected costs and benefits of the advanced metering systems necessary to support dynamic pricing and draw comparisons to existing, less functional systems, and
4. Identify actual and perceived barriers to implementation.

What follows are some of the key comments, observations, and conclusions summarized from the panel presentations. Some of the statements represent generalizations across one or more of the participants. Some of the comments or observations, where appropriate, are attributed to a single participant.

- Electronic metering technologies are commercially available today to support dynamic pricing.
- There are many different communication technologies capable of supporting advanced metering applications. Tariff and demand response program requirements will drive the technology selection.
- Advanced metering systems provide a wide range of capabilities that can enhance customer service and utility operations.
- Outsourcing of metering services should be examined to determine if it is more cost effective as an alternative to conventional purchasing practices.
- For system wide implementations based on today's market, average metering costs of $2.50 to $3.50 per customer per month should be expected. The incremental cost to support advanced residential metering will probably fall in the $1.00 to $1.50 per month range.
- Utilities with system wide implementations have experienced benefits that generate payback periods from 4-9 years. Payback periods decrease substantially when the benefits of demand response are included.
- Alternatives to an increase in the customer charge should be considered for cost recovery. Distributing metering costs within the kWh charge was offered as an example.
- Pending Federal legislation to accelerate depreciation and to provide tax credits for advanced metering installations would substantially reduce system costs and improve cost effectiveness.
- Two primary barriers to more widespread implementation were highlighted: (1) dependence on cost benefit / cost effectiveness models that fail to capture the full impacts of system wide implementation on both the utility and customer, and (2) utility concern over cost recovery.

Workshop Day-2 Wrap-up

Mike Messenger, from the CEC, provided a brief wrap-up to the workshop. He observed that there is a need for infrastructure to support basic market needs in demand response, conservation, and information.

Appendix A

The Value Proposition

The 'Value Proposition' is a structured list of attributes and features for systematically comparing dynamic pricing with conventional rates and demand response programs. As the examples in Table 1 demonstrate, dynamic pricing compares very advantageously with two very common rate and demand response options. The Value Proposition structure provides a template for comparing any set of options.

Table 1. Establishing the Dynamic Pricing Value Proposition

Features - Attributes	Description	Option 1	Option 2	Option 3
		Air Conditioner Load Control	Critical Peak Pricing	Curtailable Interruptible Rate
PROGRAM POTENTIAL	The magnitude of load that any program or rate can address is limited by participation restrictions or links to specific control technologies.			
Limited Target Market	Is the program / rate limited to a specific segment of the customer market?	Yes	No	Yes
Minimum Usage / Load Required	Are there minimum annual usage or kW demand levels required to participate?	Sometimes	None	Yes
End-use Required	Does the customer have to possess a specific end-use to qualify for participation?	Yes	No	No
Operating Restrictions (seasons, TOD, hours)	Is the program operation limited to a specific season, time of day or number of annual hours?	Summer, Peak, 80 hours	80 hours	Summer, Peak, 80 hours
Supports conservation / efficiency improvements	Is the program designed to support and incent conservation and long-term efficiency improvements?	No	Yes	No
Supports demand response / load shifting	Is the program designed to support and incent short-term demand reduction / load shifting?	Demand Reduction	Yes	Yes
RATES AND INCENTIVES	Customer response and the operational value of a program / rate is dependent upon the underlying rate and magnitude and structure of the incentive.			
Incentive Type	Are incentives paid: (1) for participation, (2) as a rate discount, or (3) paid for actual performance?	1	3	2
Link between Rate and Incentive	Are the underlying rate and incentive integrated or are they administered separately?	Separate	Integrated	Integrated
Rate Reflects Time Varying Energy Cost	Does the base rate reflect time varying costs of energy?	No	Yes	Sometimes
Incentive Linked to Market	Are incentives linked in some way to the	No	Yes	No

Table 1. Establishing the Dynamic Pricing Value Proposition

Features - Attributes	Description	Option 1 Air Conditioner Load Control	Option 2 Critical Peak Pricing	Option 3 Curtailable Interruptible Rate
Value	wholesale cost of energy or capacity?			
Incentive Linked to Performance	Do incentives reflect the magnitude of individual customer contributions?	No	Yes	Yes
Incentive Verification	Are incentives based on (1) group or class averages or (2) measured customer response?	1	2	2
Incentives Payments	When are incentives paid?	End of Season	In Bill	In Bill
Penalties for Non-performance	Are customers subject to non-performance penalties?	Sometimes	No	Yes
Incentive Tax Liability	Do incentives create a customer tax liability?	Yes	No	No
CUSTOMER CHOICE	Individual circumstances and the value assigned to energy services vary substantially between customers. The ability to tailor programs to fit individual needs will impact participation and performance.			
Customer controls how to respond	Can the customer select the end-uses and technology used to control load response?	No	Yes	Yes
Customer controls when to respond	Can the customer control when to respond or not respond to a price / control signal?	No	Yes	No
Customer controls how much to respond	Can the customer determine how much load to provide in response to a price / control signal?	No	Yes	No
PROGRAM OPERATIONS	The value of a rate / program ultimately depends upon how well it serves and can be adapted to changing system conditions.			
Free Riders – incentives paid without performance	Can customers participate and collect incentives without providing a load response?	Yes	No	No
Gaming -	Can customers use technology or operating tactics to game program operations?	Yes	No	No
Supports Energy Management	Can the rate / program be operated to support energy management objectives?	No	Yes	No
Supports Reliability / Emergency Management	Can the rate / program be operated to support demand response / emergency management objectives?	Yes	Yes	Yes
Carrying Costs	Do the rate or incentive create ongoing, fixed carrying costs regardless of system operation?	Yes	No	Yes

Table 1. Establishing the Dynamic Pricing Value Proposition

Features - Attributes	Description	Option 1	Option 2	Option 3
		Air Conditioner Load Control	Critical Peak Pricing	Curtailable Interruptible Rate