BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 189

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC,	)
	)
Request to Add Schedule 111, Advanced Metering Infrastructure.	)
	)

RESPONSE TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

December 21, 2007

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My name is Bob Jenks, and my qualifications are listed in CUB Exhibit 101.

I. Introduction

The PUC staff and PGE are asking the Commission to approve a tariff which will raise rates $12.9 million, allow PGE to proceed with accelerated depreciation of its old manual-read meters, allow PGE to proceed with accelerated depreciation of the automated meters it purchased a few years ago, allow it to begin deployment of its new automated meter system, and find that it is prudent to proceed with the AMI project.

In their Testimony in support of the Stipulation, Staff and PGE re-characterize CUB's arguments poorly, and then present counterarguments. We suspect that some of the descriptions of CUB's concerns come from settlement discussions, and are, therefore, inappropriately placed on the record by Staff and PGE.[1] The Commission should ignore

[1] Joint Exhibit 102, for example, is entitled UE 189 Settlement Conference, Issues by Party.

how Staff and PGE characterize our arguments in their Testimony, and instead approach our arguments as laid out in this Response Testimony.

While CUB finds the potential of smart technology (smart meters, smart grids, smart appliances) exciting as we address electricity in a carbon-constrained world, we are unable to support PGE's proposal. As we have participated in many workshops and settlement discussions, the Company has failed to convince us that now is the best time to make a huge capital investment in a specific technology. The fact that the Company is seeking accelerated depreciation of its existing advanced meters, well short of their expected life span, makes us wary of going down this path. Finally, we are concerned about the applications that will be developed from this platform. The smart appliances and good load control programs that we envision are not yet being manufactured; instead, we believe PGE's vision is based on using punitive price signals to change consumer behavior.

II. This Is A Bad Time Technologically For PGE's AMI Project

A fundamental problem with PGE's timing of its current AMI project is that, despite the Company's protestations, the advanced metering market is far from settled. We discussed this at length in our UE 180 testimony,[2] and here reiterate our position. The reason PGE feels it must retire its current advanced meters is that the market and technology have changed, making PGE's current advanced meters, referred to as NMR, appear outdated.

> The NMR system is more costly and less functional than the systems available today.

UE 189 Joint/100/Schwartz-Owings-Tooman/18.

[2] CUB Exhibit 102. UE 180 CUB/200/Jenks-Brown/35-47.

> PGE believes that further significant cost reductions for AMI technology are not likely to occur in the near future.

UE 189 Joint/100/Schwartz-Owings-Tooman/19.

Forgive us for being skeptical, but advanced metering is still a technology that is very much developing, and for which it is not unreasonable to expect significant technological advances on the near horizon. PGE made a significant investment in advanced metering technology in late 2001 and 2002 (the Commission issued its UE 115 Order on August 31, 2001); that purchased technology had already become obsolete by the time the Company was developing its new advanced metering project to file with its UE 180 rate case. That rate case was filed in March 2006. So, somewhere between 2002 and 2005, as the Company developed its current proposal, the UE 115 advanced meters, that were supposed to be cost effective and save customers money, became old technology. That time frame does not indicate a mature, or even a settling, industry to us. Indeed, California, a state whose electric market is big enough to move vendors and shift technology, is seriously considering how to implement advanced metering, but has not yet done so. Staff and PGE point to California's actions as evidence that now is the time to proceed.

> California is marching toward an AMI decision that would enable most of all meters to support pricing and demand response options.

UE 189 Joint/105/Schwartz-Owings-Tooman/3.

It is important to recognize that under the PGE/Staff model, customers are the ones taking the risk of whether this is the right time or not. PGE already purchased $6.5 million in advanced meters, is seeking to abandon those, but only after customers pay off the remaining investment. If the Company again chooses the wrong technology, or chooses the technology before it is mature, it will simply ask customers to foot the bill.

The Staff and the Company may feel we are being too conservative with investing in this new technology, but they are proposing that we be the ones who write the checks.

Might it not be prudent to take a step back and see what falls out from California's advanced metering efforts? Instead of crowing that "over 36 million units have been sold … since 1998," might we consider that 94% of US customers do not have advanced meters?[3] We would also note that PGE's current advanced meters were installed in late 2001 and 2002, so PGE's meters, as well as the other portion of those 36 million units that were sold since 1998, are now obsolete. Nevertheless, PGE and Staff are gung-ho that advanced metering is now a tried and true technology.

PGE also felt this way in UE 115, when it was first seeking permission to purchase advanced meters:

> Contrary to CUB's suggestion, delaying deployment of the NMR/AMR system would not save money … In fact, []delaying deployment would increase cost[s] because certain costs of deployment would be duplicated later.

UE 115 PGE Opening Brief at 22.

CUB argued against those advanced meters at that time. Spending millions on new meters at the height of the energy crisis, when the Company's rates were going up 30% to 50%, seemed unnecessary. But somehow the Company was able to convince the Commission that those advanced meters were cost effective:

> We find that some of PGE's Customer Service expenses, such as the distributed generation, NMR/AMR system costs, and others related to SB 1149, should not be reduced or delayed at this time. PGE has showed that postponing these programs will not lead to decreased costs, and may actually increase costs over time.

UE 115 OPUC Order No. 01-777 at 11, August 31, 2001.

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[3] CUB Exhibit 103. The Brattle Group, "The Power of Five Percent: How Dynamic Pricing Can Save $35 Billion in Electricity Costs." May 16, 2007, page 3.

Today, we know that that was the wrong decision. PGE and Staff testify that it is "cost effective" today to replace those meters with the new, more-advanced, advanced meters.[4] The first batch of meters lasted approximately 25% of their expected useful life before PGE proposed tearing them out and replacing them. Maybe this time will be different. Maybe not.

PGE's arguments for approval of its current advanced metering project are eerily reminiscent of its arguments in UE 115. The Company's argument that AMI is now a mature technology is hard to swallow (especially in light of the fact that California has not yet produced a full-scale, time-tested utility AMI project); and, as we discuss below, the Company does not appear to have made any serious attempts at streamlining or prioritizing its costs and expenses in order to make room for discretionary projects such as advanced metering.

III. This Is A Bad Time Financially For PGE's AMI Project

PGE's rates are already high, the Company has plans to increase its rate base considerably over the next half decade, and it has shown no sign of attempting to control its costs. A discretionary project such as this, where there exists a strong argument to delay and see the market develop, is not a project that should be at the top of the Company's priority list.

PGE's rates are going up. The Company just got approval to add Phase I of Biglow Canyon to its rate base to the tune of $255-$265 million.[5] Port Westward added $279 million to the Company's rate base.[6] The Company projects Phase II and III of

[4] UE 189/Joint/100/Schwartz-Owings-Tooman/18.
[5] CUB Exhibit 104 at 1. Excerpts from PGE's EEI Presentation, November 2007.
[6] UE 180 OPUC Order No. 07-015 at 50.

Biglow Canyon to add another $600 to $700 million to its rate base.[7] Over the next 4 years, PGE plans several other large capital projects including Boardman emissions control, and hydro relicensing. PGE's past and future estimated capital expenditures are projected to be approximately:

PGE Capital Expenditures

2003	$167 million
2004	$194 million
2005	$255 million
2006	$371 million
2007	$471 million
2008	$541 million
2009	$541million
2010	$571 million
2011	$312 million

CUB Exhibit 104
Note: where a capital project was listed over multiple years, we divided the project evenly through those years

After adjusting for annual depreciation of approximately $210 million per year, this shows that PGE's rate base will grow 79% between 2006 and 2011.[8] With PGE's capital costs, and its associated rate base, growing so rapidly, PGE should be doing everything in its power to control costs. Customers will have difficulty absorbing the higher rates associated with these investments. Rate cases will likely become increasingly contentious. Unfortunately, PGE is not demonstrating that it recognizes the need to control its costs, and to limit the rate increases borne by its customers. In its recent energy efficiency filing, Advice No. 07-25, the Company asked to charge customers $1.4 million to develop a school curriculum about energy. It also asked for a

[7] CUB Exhibit 104 at 1.
[8] Ibid at 2

lost-revenue recovery mechanism that would raise rates by 4.4¢/kWh for every kWh of conservation reported by the Energy Trust.[9] With PGE's ambitious investment plans, and the shareholder benefit that will follow from a much larger rate base, the Company should be doing all it can to reduce its costs and prioritize new spending so that customers can afford the Company's plans.

Unfortunately, we cannot rely on PGE to restrain its own ambition or its own creative ability to find new reasons to raise rates; therefore, it is incumbent on the Commission to send a message to the Company that its costs will be managed. Its ambitions should be prioritized and its creativity should have limits. If the Company cannot do it, regulators must step in.

IV. UE 115 Advanced Meters Should Not Get Accelerated Depreciation

We oppose the Stipulation and PGE's plan to undertake another advanced metering project at this time. However, should the Commission accept the Stipulation, PGE should not be allowed to use accelerated depreciation to recover the costs of its UE 115 advanced meters. Of the $30 million in accelerated depreciation PGE is seeking, approximate $4.8 million is for the advanced meters that the Company purchased only 6 years ago and is now proposing to abandon.[10] The Commission should reject this request.

We are not asking the Commission to determine the prudence of that past decision, though we note that after the Commission approved its plan in UE 115, PGE's meter vendor went out of business, and PGE installed a different "second-choice system."[11] We are, however, asking the Commission to recognize that 15 years of the UE

[9] PGE Advice No. 07-25, October 26, 2007, at 3 & Schedule 123 at 123-2.
[10] UE 189/Joint/100/Schwartz-Owings-Tooman/17.
[11] Ibid.

115 advanced meters will not be used and useful within the next 2 years. This system is barely 6 years old and, according to Staff and PGE, is no longer cost effective.[12] Plant that is not used and useful should not be charged to customers. The Stipulating Parties' Testimony suggests that, among other reasons, it is reasonable to allow accelerated depreciation of PGE's past attempt at advanced metering, because that attempt was – and was intended to be – only practice.

> [A]ccelerated depreciation of the old meters … is appropriate because it completes the process begun in Docket No. UE 115.

UE 189 Joint/100/Schwartz-Owings-Tooman/10.

> PGE believes these assets have met an important objective that PGE would gain experience from the investment in order to prepare for full AMI deployment at a later date.

UE 189 Joint/100/Schwartz-Owings-Tooman/18-19.

> For the past decade, PGE has researched and tested a wide range of advanced metering infrastructure (AMI) technologies with the goal of implementing an automated meter reading system throughout its service territory.

UE 189 Joint/105/Schwartz-Owings-Tooman/1.

Unfortunately, neither PGE's Testimony in UE 115 nor the Commission's Order in that case support the notion that PGE's now-to-be-abandoned UE 115 advanced metering project was intended to be a dry run, that those expenses were to be chalked up to being a learning experience, or that customers were being charged for an investment that had a higher-than-normal risk of being a dud.

The remaining investment in the NMR meters is approximately $4.8 million. This amount represents approximately 1% of the new capital investment that PGE has made in 2007. It is a small fraction of the capital investment that the company expects to make in

[12] UE 189/Joint/100/Schwartz-Owings-Tooman/18.

the next few years, yet it is an important amount. It represents the non-used and non-useful portion of the NMR investment from 2001-2002, which, if PGE proceeds with the current advanced metering project, would provide customers with no benefit. Allowing the accelerated depreciation of abandoned UE 115 advanced meters is inconsistent with traditional ratemaking, which requires assets to be used and useful.

In contrast, PGE is also seeking accelerated depreciation of its manual-read meter system. This system has been used and useful for many decades and CUB does not oppose accelerated depreciation of it.

It should also be noted that asking the Company to write off a bad investment is not something new. For example, PGE was required to write off $20.4 million of its remaining investment in Trojan after that plant closed.[13]

We are also extremely concerned that PGE proposes to – indeed, asks the Commission for permission to – proceed imprudently, should the Commission not grant the Company accelerated depreciation of its UE 115 advanced meters. In the Testimony supporting the Stipulation, the Company writes:

> If the Commission approves the AMI proposal but does not approve the inclusion of the NMR assets in accelerated depreciation of the existing metering system, we request that the Commission allow PGE to update its revenue requirement and tariff for the additional costs needed to keep the NMR system functional.

UE 189 Joint/100/Schwartz-Owings-Tooman/19.

The Company claims that replacing both current manual-read meters, as well as the UE 115 advanced meters, is in the best interest of customers. The Staff and the Company agree that it is cost effective to rip out the NMR meters and replace them

[13] PUC Order 95-322, page 3, March 29,1995.

today.[14] If this is the case, then it would not be cost effective to leave these meters in place. It would be imprudent … yet PGE and the Staff are asking the Commission for permission to do exactly that.

If the Commission determines that equipment from PGE's UE 115 advanced metering project is no longer used and useful, it would be reasonable to require that the Company's shareholders take responsibility for that past, dry-hole investment. Ratemaking traditionally says that customers should not pay for plant that is not used and useful. Customers rely on PGE to choose and manage its investments. If PGE learned as much from these meters as it claims, then this knowledge should help ensure that this new $132 million investment will be well managed and remain used and useful throughout its projected life.

PGE's threat to continue with meters that it says are not cost effective is not appropriate. A Commission determination that it is the shareholders' responsibility to absorb the costs of a poor investment is an appropriate acknowledgement of PGE's responsibility to manage its costs in a manner that brings the best value to customers.

V. Mandatory Time-of-Use & Critical Peak Pricing

CUB has been clear in its concern that mandatory time-of-use or critical peak pricing may be foisted upon customers once PGE's current advanced metering has been installed.[15] We have ample reason to be concerned. Though PGE protests that the Company "did not specify mandatory participation [in time-of-use pricing] as either a

[14] UE 189/Joint/100/Schwartz-Owings-Tooman/18
[15] CUB Exhibit 102. UE 180 CUB/200/Jenks-Brown/46-47.

goal or an alternative," the Joint Testimony supporting the Stipulation is full of references to the importance of time-of-use pricing.[16]

A. Numerous Pitfalls in Time-of-Use and Critical Peak Pricing Programs

To start, we describe why mandatory time-of-use or critical peak pricing tariffs are not appropriate pricing methodologies for residential customers. First, there are numerous proponents of time-of-use pricing who see only the current market value of electricity, and fail to account for customers' past investment in their electricity system. Proponents of mandatory time-of-use pricing who fail to recognize that customers already own much of their generation system, feel that it is appropriate for customers to be subject to a price signal that considers only current market prices, and not the price signal that comes from customers' ownership of generation assets whose cost per kWh is well below that of the market. Such a position fails to consider that the market price is not indicative of the costs to PGE customers who have paid for and borne the risk of rate-based resources. A major purpose of the regulatory paradigm is to avoid the volatility of short-term markets; therefore, it is inappropriate to charge customers rates based on those markets.

Second, the ability of customers to respond to price signals has been shown to be dependent upon a number of factors, in particular the presence of central air conditioning, and whether or not one or more household members has a college education.[17] The blanket imposition of such pricing programs on residential customers stands to have very different impacts on different customers, and may impose the greatest financial hardship on those least-able to respond to price signals.

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[16] UE 189 Joint/100/Schwartz-Owings-Tooman/20, for example.

[17] CUB Exhibit 105 at 4 (article p. 56). Faruqui, Ahmad and George, Stephen. "Quantifying Customer Response to Dynamic Pricing," *The Electricity Journal*, May 2005, Vol. 18, Issue 4, pp. 53-63.

California's Statewide Pricing Pilot tested time-of-use, fixed critical peak, and variable critical peak pricing structures. Of the three pricing structures, the fixed critical peak group had the largest sample, and, therefore, most robust statistical results. For those customers on the fixed critical peak pricing structure who lived in California climate zone 2, the climate zone most similar to PGE's territory,[18] the percent changes in residential, summer peak-period energy use was -10.1% on critical weekdays and -3.3% on normal weekdays.[19] The prices needed to elicit this response were, for critical weekdays, a peak price of 59 ¢/kWh and an off-peak price of 9 ¢/kWh. For normal weekdays, the prices were 22 ¢/kWh and 9 ¢/kWh respectively.[20] These are relatively dramatic price differentials for modest reductions in peak demand, and would seem to indicate a greater burden on customers than the benefit in reduced usage would warrant. It should also be noted that, although the researchers attempted to separate out any self-selecting bias, the customers on the critical peak pricing tariffs *were* self-selected.[21] It is not unreasonable to expect that many, if not most, customers would simply absorb increased prices without being able or willing to take the voluntary actions that the price signals would be intended to elicit.

In the California experiment, 80% of the savings came from 30% of the participants, meaning that most participating customers did not respond significantly to very significant price signals.[22] More importantly, the experiment showed that customers with direct load control capability were the ones who responded the most to price signals

[18] The climate zone comparison comes from PGE's Confidential Response to CUB Data Request 8, Attachment 008-B. The information is used non-confidentially here with PGE's permission.
[19] CUB Exhibit 105 at 3 (article p. 55).
[20] *Id*. at 7 (article p. 59).
[21] Charles River Associates. "Impact Evaluation of the California Statewide Pricing Pilot." March 16, 2005. Final Report, page 5. PGE Response to CUB data request 14, Attachment 014-A. Due to the length of this document, it is not included as an exhibit, but it is available electronically upon request.
[22] CUB Exhibit 103 at 3.

– which is to say that their appliances responded easily to the price signals. Customers with smart thermostats reduced their load twice as much as those without, and customers with "always on gateway systems" that "adjust the usage of multiple appliances" reduced their load by 43%, more than 3 times the average participant.[23]

We are excited about the potential for smart thermostats and smart appliances working together with signals from the utility to manage demand. This is the real demand response revolution that needs to take place. Most customers lead busy lives, and cannot be expected to always be available to focus on and react to price signals. Smart appliances, on the other hand, are not dependent upon a particular customer having the ability to take a particular action on a particular day.[24]

However, since we don't yet have the smart appliances, we are concerned that demand will instead rely primarily on price signals that may or may not be easily heeded. In addition, we are concerned that we will end up developing a smart meter system that is lacking some of the capability we will later need for more important innovations. It is easy to imagine that we will be in a proceeding like this in a few years, with the Company telling us that we can have the integrated smart energy system that we want, but only if we agree to accelerated depreciation of the old UE 189 system.

B. The Threat To Customers From Mandatory Time-of-Use Pricing Is Real

CUB's concern about possible future imposition of time-of-using or critical peak pricing on customers stems from a number of considerations. PGE's projected net present value benefit based on operational cost savings for its current advanced metering proposal, $33 million over 20 years, is *not* an enormous margin over that amount of

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[23] *Ibid*.
[24] Personally, I look forward to the day when my smart appliances will talk to the smart grid and coordinate my energy usage, while I lie on the couch drinking beer and watching football, oblivious to it all.

time.[25] Should PGE's current advanced metering project prove to be uneconomical, the Company and regulators may feel increased pressure to impose time-of-use or critical peak pricing as a way to financially justify the project.

As mentioned previously, despite PGE's protestations that its current filing contains no proposal for mandatory time-of-use pricing, PGE's response to Staff data request 12, included as Exhibit 105 in the Joint Parties' Testimony, expresses enthusiasm for the use of price signals:

> Electric utilities operate at about 50% asset utilization. By comparison, asset utilization in refineries, chemical plants, pulp and paper mills, steel plants, etc., all ran at 95%+. Other industries meet their "obligation to serve" not by building rarely used production capability, but by charging higher prices when supply is low. Electricity is one of the few products whose prices do not vary with market demand.

UE 189 Joint/105/Schwartz-Owings-Tooman/2also labeled Attachment 012-A).

> With the ability to measure comes the ability to use price as the means to alleviate supply-demand imbalance.

UE 189 Joint/105/Schwartz-Owings-Tooman/4 (also labeled Attachment 012-A).

The Joint Testimony itself, when forecasting CUB's concern over PGE's long-term strategy for mandatory time-of-use or critical peak pricing tariffs, also expresses the benefits that might accrue under voluntary programs:

> **Q. Did PGE estimate potential benefits from demand response programs?**
>
> A. Yes. In Attachment 012-A, page 1-4, PGE identified a range of possible benefits from a critical peak pricing program as a long-term benefit. This range was approximately $4 million to $34 million.
>
> **Q. Did this estimate assume mandatory participation?**
>
> A. No. By way of comparison, in PGE's Scoping Plan (PGE Exhibit 103), PGE estimated a range of potential demand response benefits to be

[25] UE 189 Joint/100/Schwartz-Owings-Tooman/7.

> from zero to approximately $27 million. The top end of this range was based on a maximum 10% customer participation rate after five years.

UE 189 Joint/100/Schwartz-Owings-Tooman/20-21.

To distinguish between the two different ranges of estimated benefits of critical peak pricing, the following quote is again from the Joint Parties' Exhibit 105.

> A possible step toward increased utilization has been modeled by examining variations of an opt-out, critical peak pricing (CPP) scenario. PGE estimates that the NPV benefit could range between $4 million and $34 million.

UE 189 Joint/105/Schwartz-Owings-Tooman/5 (also labeled Attachment 012-A).

Thus, we presume the higher range of benefits is produced when the pricing program is modeled as an opt-out program, and the lower range is produced when the pricing program is modeled as opt-in. Though neither an opt-in nor opt-out tariff is mandatory, we find the lack of distinction between an opt-in and an opt-out program more than a bit unsettling. The latter is far more contentious, causes considerably more confusion for customers, and sweeps them into a pricing program that many customers are neither expecting nor prepared to handle.

We also point out that the very top end of the estimated benefits resulting from an opt-in program is based upon 10% customer participation after 5 years. Staff, in evaluating the benefits of PacifiCorp's time-of-use tariff, said that "[c]ost-effectiveness of programs is highly dependent on participation rates."[26] We continue to be concerned that a desire to increase participation rates will lead us down the path to mandatory time-of-use or critical peak pricing.

[26] CUB Exhibit 106. Excerpts from a Staff presentation to the Portfolio Options Committee. May 9, 2007.

VI. Proposed Recommendation

In light of the other capital investment needs of PGE, and in light of the continuing evolution of smart meters and their associated applications, CUB believes a more deliberate approach to AMI is warranted. We understand that it is exciting to be on the cutting edge of carbon-constrained energy policy, but it is not a good idea to stake that energy policy on a capital investment that is premature and ill-formed. As we've participated in the workshops and settlements in this case, and the ones that preceded this, we have not been convinced that the timing is optimal. We love the potential of a smart grid communicating with smart appliances, but we do not believe this is the right first step at the right time. We *do* think we will have better answers in a few years. Therefore, we conclude that it is better to wait 2 to 5 years before going forward with the next round of advanced meter technology.

If the Commission is inclined to go forward, we ask the Commission to deny PGE accelerated depreciation of the $4.8 million remaining investment in smart meters that are no longer used and useful. As PGE launches an ambitious plan to invest billions in new capital expenditures, it is important that customers' rates remain reasonable. Enforcing the traditional prohibition on charging customers for plant that is not used and useful sends a powerful message to the Company and provides them with an incentive to control costs. Because the accelerated depreciation is spread over three years, this will reduce the revenue requirement associated with this project by approximately $1.6 million per year.

WITNESS QUALIFICATION STATEMENT

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EDUCATION: Bachelor of Science, Economics
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EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, and UM 1209. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America

I. Advanced Metering Infrastructure

PGE is sort-of asking the Commission to increase rates by an additional $3.7 million, above the revenue requirement the Company filed for in this case, by approving the Company's Advanced Metering Infrastructure. They ask that the Commission find that the decision to proceed with advanced metering is "reasonable and prudent" at this time. If the Commission does not find it "reasonable and prudent" the Company will not proceed at this time.[1]

A. PGE Requests Additional Rate Hike To Install Advanced Metering

This is a little bizarre. PGE did not add this cost into their rate filing. When they noticed customers of the pending rate request, advanced metering costs were not included in that notice. The Company's analysis of the costs of advanced metering are disconnected from this case (for example, the analysis assumes the cost of capital from UE 115, not what the Company is seeking in this case). Utilities often ask for additional

[1] UE 180 PGE/800/Hawke-Carpenter-Tooman/3.

revenue requirement for new programs, but to do so without including the costs in revenue requirement is very unusual. The reason seems to be that PGE will not proceed with full advanced metering deployment without Commission approval.[2]

At this point, the Company projects the total cost to be $141 million, but the cost data is based on an initial projection, not actual bids. PGE cites "confidential budgetary quotes provided by vendors," as the basis of its cost information.[3]

The Company has issued a RFP for all of the "field equipment and the software" associated with AMI, but those results are not yet available.[4] In addition, the Company plans a "significant review by the Information Technology organization to estimate the cost of supporting the AMI projects."[5] This means that the cost information in the filing is a preliminary estimate, not actual bidding results.

Essentially the Company is providing some preliminary cost information to the Commission about a project that is a long way from being used and useful and asking the Commission to determine whether it is prudent and whether the program should be implemented. If the Commission says "yes," then later when this is used and useful and added to ratebase, the Company will be able to rely on the Commission's decision in this case to say "We did not even include it in our rate filing, but the Commission believed it to be prudent and ordered us to implement it."

Even with a strong business case for advanced metering, such a request would be difficult to grant. Putting that aside, an examination of PGE's business case does not support approval of advanced metering for the Company.

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[2] *id.* at 9.
[3] *id.* at 4.
[4] *id.* at 6.
[5] *id.* at 9.

In this section we will examine PGE's business case, which fails to support deployment of advanced metering. In fact, we believe the current evidence shows that advanced metering will not provide a benefit. We will look at the failure of PGE's current advanced metering program, a program that the Company is proposing to abandon while charging customers million of dollars in stranded costs. We will examine some of the experiences other utilities have had with advanced metering. Finally, we will propose a deliberative process that we think the Commission should consider for examining the benefits of advanced metering. This would allow PGE to implement such a program at a later date, should it make a business case for such a program.

B. PGE's Business Case Suggests Advanced Metering Is Not Cost Effective

PGE claims that the net present value of all AMI-related costs and savings will reflect a benefit between $4 million and $20 million over the next 20 years depending on what happens with the joint meter reading program with NW Natural. If NW Natural abandons the joint meter reading program, to continue manual meter reading PGE would have to hire an additional 21 new meter readers. Under this scenario, advanced metering would save $20 million. If, on the other hand NW Natural does not abandon the joint meter reading program, the benefit will be approximately $4 million. According to PGE, it "is attempting to determine but is currently uncertain as to NWN's decision" regarding maintaining the existing joint meter reading.[6]

To understand NW Natural's decision, all you have to do is ask NW Natural (and we have done so in person and in a data request), and the Company will tell you that it has no plans to abandon joint meter reading with PGE. To do so would cost NW Natural

[6] *id.* at 15-16.

customers more than $4.6 million in new capital costs plus an additional annual O&M increase of $1.6 million. CUB Exhibit 201.

This means that there is no basis to claim that the advanced metering will save customers $20 million because that assumes actions on the part of NW Natural that it is not considering. In addition, it means that the claims of a benefit to PGE customers of $4 million cannot be claimed, because many of these customers are also customers of NW Natural and the advanced metering will require NW Natural to incur one-time costs of $4.6 million and annual costs of $1.6 million.

In other words, the best case reading of PGE's business case is that it will lead to a rate increase for NW Natural customers that is significantly larger that the savings PGE will receive. In addition, PGE's case was filed without the Company able to make a determination as to NW Natural's intention to continue joint meter reading. Because determining NW Natural's intention was an easy thing to do, it raises the question of how diligent PGE's case is and how much weight the Commission can give to it.

C. PGE's Business Case So Thin, That Small Changes Yield Negative Benefit

Even if one were to focus solely on the PGE costs and ignore the effects on NW Natural's customers, PGE's business case is so thin, it is hard to conclude from it that advanced metering is a wise investment. The net present value benefit of $4 million over 20 years is a small benefit from an investment of more than $140 million. But PGE's case uses projections for meter costs, installment cost and O&M savings. Small changes in these projected numbers could easily turn the projection into a negative number.

CUB increased the meter costs by 5% in 2007, 2008, and 2009, the years when the bulk of the meters are purchased, while making no other changes in the program.

This small change led to the value changing from a $4.4 million net benefit to a $1.6 million net harm. CUB Exhibit 202.

D. Here We Go Again, Shades Of UE 115

This is not our first experience with advanced metering and PGE. In the Company's last general rate case, UE 115, PGE also claimed that advanced metering, then called NMR or AMR, would benefit its system and customers and proposed to begin the process of converting PGE to advanced metering. At that time customers were facing rate hikes of 30% to 50% and CUB practically begged the Company to put off discretionary expenditures. PGE was not deterred and argued for advanced metering which resulted in a Commission Order that concluded:

> PGE has showed that postponing these programs will not lead to decreased costs, and may actually increase costs over time

OPUC Order No. 01-777, page 11.

The experience, however, has not been what was claimed in that case. PGE has significantly cut back from the advanced metering program that was ordered in UE 115.

In its filing PGE claims this was because "we found that direct access did not proceed as rapidly as anticipated and the technology did not develop as expected."[7] In answer to a data request the Company added that "our primary vendor suffered business failure and we installed a second-choice system." CUB Exhibit 203. Now, in this filing the Company proposes abandoning meters that were purchased as part of that program, and instead embark on a whole new round of purchasing new advanced meters. As part of its proposal in this case, PGE proposes accelerated depreciation of "existing" meters.[8] However, more than $5 million of this depreciation is actually new meters that were

[7] *id.* at 9.
[8] *id.* at 7.

purchased as part of PGE's advanced metering program that was launched after the Company's last rate case. CUB Exhibit 204. PGE should be more careful this time; we should all be more careful.

In addition, we recommend that the Commission not grant accelerated depreciation of any current advanced metering equipment. While the Commission did approve advanced metering in UE 115, PGE has failed to demonstrate that advanced metering continued to be a prudent course, especially in light of its chosen vendor's "business failure" and having to install a "second-choice system." The Company has also not demonstrated that accelerated depreciation is now a prudent course. In fact, nowhere in its testimony does PGE even discuss the need to replace millions of dollars in advanced metering equipment that the Company has already purchased.

E. Other Utilities' Experience With Advanced Metering

PGE cites examples of other utilities that have implemented advanced metering, but provides little discussion of their experience. Some of this experience is important. PGE cites San Diego Gas & Electric and Pacific Gas & Electric as examples of utilities that are pursuing advanced metering. However, we show that both of these utilities claim that advanced metering is not cost effective without time-of-use pricing. PGE's claim that the business case for advanced metering shows that it is beneficial without load control is contradicted by the experience of these California utilities. PGE also cites the example of Puget Sound Energy.[9]

Puget implemented advanced metering to facilitate the move to time-of-use pricing. Time-of-use pricing was so unpopular that the Washington Utilities and

[9] *id.* at 2.

Transportation Commission abandoned the program, and returned to traditional rate structures. CUB Exhibit 205. These examples should encourage us to be cautious, to investigate load control programs, and to be realistic about what programs are likely to be accepted here in Oregon before we embark on this path.

i. California

California took a thoughtful approach to advanced metering. The California Public Utility Commission first led an investigation into advanced metering, including load control programs. This led the California Commission to issue an Order telling the utilities what functionality and programs needed to be supported by advanced metering so the utilities' business case analyses could be based on real, expected programs. CUB Exhibit 206.

As California did, we should consider what we want to do with advanced metering, so the utilities' business cases can be based on the programs and program design that stand the greatest likelihood of succeeding. The California Commission provided utilities with six functions that would go into the utilities' business cases. Included in these six functions were opt-out time-of-use pricing plans for all classes of customers. We know from our experience with NW Natural's WARM program that opt-out programs (as opposed to opt-in) create a backlash.

In 2005, SB 441 passed the California Senate on a vote of 23-12. SB 441 prohibits the California Commission from requiring advanced metering for residential and small business customers until the Commission first evaluates the following:

1. The effect on average annual electricity rates for residential and small commercial customer classes for every year of repayment for the advanced metering investment.

2. The bill impacts of any proposed mandatory time-differentiated rates on residential customers in hot climate zones.
3. The amount of peak load reduction contrasted with other demand reduction program alternatives.
4. The *feasibility and* cost effectiveness of partial deployment in selected zones contrasted with deployment throughout an entire service territory of an electrical corporation.

CUB Exhibit 207. California SB 441. Emphasis theirs.

This does not surprise us. When the Oregon PUC considered mandatory measured telephone service in the 1980s, it led to passage of a ballot measure prohibiting it. The marketplace tells us that customers want simplicity in pricing. Long distance telephone calls used to be based on time-of-use pricing but once long distance became a competitive service, plans have largely moved away from time-of-use pricing. Making time-of-use optional through an opt-out (as opposed to an opt-in) will likely do little to make customers more responsive. In fact, our experience with the WARM program suggests that customers will see the opt-out as an attempt to trick them into taking something that they probably would not want.

ii. Pacific Gas & Electric

The business cases provided by the utilities included the avoided cost value associated with time-of-use pricing. In PG&E's business case, savings from meter reading, O&M, and other costs only support 89% of the cost of advanced metering. The other 11% comes from time-of-use and other load control programs that are not part of the business case that PGE has presented to us. In addition, the PG&E order specifically deals with what the Commission will do if the cost is more than projected. It will require the Company to absorb a percentage of costs above the projected costs up to a cap which limits recovery. CUB Exhibit 208.

iii. Southern California Edison

Southern California Edison was not cited by PGE. It responded to California's order by investigating the business case for advanced metering and concluded:

> Southern California Edison Company (SCE) has completed an extremely rigorous business case analysis of Advanced Metering Infrastructure (AMI). SCE's finding indicate that an integrated AMI solution that leverages additional commercially-available technologies has the potential to provide an effective platform for enhancing routine customer services, providing more sophisticated alternatives for load management and demand response, and increasing operational efficiencies and benefits. However, these enabling technologies have yet to be cost-effectively packaged or integrated into a streamlined meter for application in the United States. Therefore, SCE has concluded that given its operational starting point, an investment in currently-available AMI technology is not cost effective for SCE's customers. Instead, SCE proposes to achieve significant increased operational and demand response benefits through a concerted and aggressive effort to develop and "advanced integrated meter" (AIM that integrate additional technologies into the next generation of meters…
>
> …SCE envisions completing full deployment of the new AIM system no later than one to two years after the time that full deployment of today's AMI technology could be completed. SCE's customers would nevertheless be advantaged, despite this slight delay, given the superior attributes of the proposed AIM technology, including more durability, versatility and the ability to deliver significant improvement ins system reliability, customer billing and service options, outage management and operational efficiencies. Thus, it is critical that SCE's ultimate investment in AMI focus on "getting it right" instead of rushing to "get it done"

CUB Exhibit 209. Executive Summary, SCE Testimony.

iv. San Diego Gas & Electric

SDG&E's business case concluded that without mandatory time-of-use rates, deployment of advanced metering may not be justified. According to SDG&E witness Edward Fong:

> Operational benefits from AMI alone do not justify full or partial deployment of AMI. The combination of demand response benefits (*i.e.,* capacity and energy) and operational benefits are required to justify AMI deployment.

CUB Exhibit 210. Testimony of Edward Fong, page 1-2.

SDG&E makes clear that in order to justify advanced metering, time-of-use rates must not be voluntary:

> A necessary condition for AMI to achieve sufficient and significant demand response benefits is the simultaneous deployment of dynamic rates. Without dynamic rates, customers would have little incentive to reduce demand during critical peak periods. Voluntary demand response programs alone are insufficient to achieve the 5% demand response targets established in this proceeding and restate in the Energy Action Plan."

CUB Exhibit 210 Testimony of Edward Fong, page 2-9.

In addition, SDG&E proposes several off-ramps: conditions under which advanced metering deployment will not be cost-effective and will be suspended, including the following:

1) Dynamic rates are not adopted by the Commission for all customers that will achieve the equivalent demand response impacts set forth in this application.
2) Customer opt-out rates from default dynamic rates after the first year (2007) of deployment appear to exceed 40%.
3) Deployment or installation price points for residential customers (meters, communications hardware, installation labor costs) exceed estimated price points contained in the business case by 20%.
4) Software development costs for AMI meter data management systems appear to be exceeding business case estimates by 50%
5) Recovery of existing meters.

CUB Exhibit 210 Testimony of Edward Fong, pages 14-16.

In reading the business case testimony of California utilities, it is clear that Oregon may not be ready to make this leap. PGE's testimony on advanced metering is 13 pages long, whereas California utilities filed business case testimony that runs hundreds of pages. The California utilities have all concluded that without time-of-use pricing, advanced metering is not cost effective. The California Commission has already determined that it will allow time-of-use pricing under as an opt-out program. The California utilities and Commission are concerned with the possibility that costs will be above what is projected. In the case of PG&E the California Commission has already determined how to deal with cost overruns. In the case of SDG&E, the utility has asked the Commission to allow it to discontinue the program if costs go beyond certain levels.

v. Puget Sound Energy

PGE also cites the example of Puget Sound Energy which installed AMI and implemented a Time-of-Use pilot program in response to the power crisis. The PSE program was controversial. In 2002, the UTC allowed participating customers to opt-out of the program and ordered that the remaining customers be charged an additional $1.00 per month in an attempt to make the advanced metering cost effective. Eventually, after determining that 94% of customers paid higher rates under the plan than they would under standard rates, the WUTC canceled the program and returned customers to standard non-time-of-use tariffs. CUB Exhibit 205.

F. CUB Recommendation

Three things are clear from our analysis of advanced metering:

- PGE has failed to make a business case for advanced metering. The record does not support the conclusion that advanced metering will provide a net benefit to customers.
- This is not surprising, since the business case does not include load control measures, and other utilities have found that load control programs are necessary to make advanced metering cost effective.
- As compared to California, which seriously examined what to do with advanced metering before asking utilities to provide business case analysis and directed its utilities to do significantly more rigorous analysis that PGE,

> Oregon is not yet ready to decide what role of advanced metering and load control programs should play.

SCE found that existing meters do not provide the proper functionality. Earlier this year, Jesse Berst of SmartGridNews predicted that prices for advanced meters will drop by 50% by 2009. CUB Exhibit 211. In its UE 115 Order, the Commission determined that not going ahead with advanced metering immediately would lead to higher costs. Instead it led to millions in stranded costs. The current evidence suggest that the benefit of waiting and being thoughtful about advanced metering might well be lower costs. In light of this, CUB recommends that the Commission reject the Company's proposal in this case, and instead the do the following:

1. Open an investigation into Load Control Programs; and
2. Invite the utility to file an advanced metering proposal outside of a general rate case, after Oregon decides what load control programs are likely to be adopted and the Company can produce a business case based on those programs.

i. Open An Investigation Into Load Control Programs

This should happen first, before spending more than $100 million on advanced metering, not after the money is spent. If the experience of California utilities is found to apply to Oregon, PGE's business case is wrong and time-of-use pricing is necessary to make advanced metering cost effective. If we spend the money first, then there will be tremendous pressure to implement time-of-use pricing in order to justify the expense. CUB believes that mandatory or opt-out time-of-use will create a backlash and might not be a sustainable policy. We saw how these programs played with Puget customers, and we will see how they play in California. We should first determine what we want to do with time-of-use pricing and other load control programs before embarking down this road. That will allow us to build a business case around what Oregon actually expects to do with advanced metering. In PGE's last Least Cost Plan, the Commission ordered PGE to examine these programs in its next least-cost planning process. PGE, however, plans to invest in advanced metering before conducting this analysis, rather than doing the analysis first.

ii. Invite PGE To File An AMI Proposal Outside Of A General Rate Case

While PGE has proposed advanced metering in this and in its previous general rate case, UE 115, there is no good reason why advanced metering must be tied to a general rate case. In this case the Company is not adding anything to ratebase, they are seeking accelerated depreciation of existing meters and deferral of costs associated with the new meters. These two types of filing can proceed independently of a rate case. This means that after there is a review of load control programs and a business case built around what is expected in Oregon, the Company can proceed if the business case supports it.

DISCUSSION PAPER

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The Brattle Group

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The Power of Five Percent

How Dynamic Pricing Can Save $35 Billion in Electricity Costs

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THE INDUSTRY FACES AN IMMEDIATE PROBLEM

Demand for electricity continues to soar in the United States, pushed along in the short term by events such as last year's heat storm that broke records in every region of the country and in the long term by the continuing expansion and electrification of the US economy.

At the national level, the peak demand for electricity is projected to reach 757,000 MW during the coming summer.[1] According to the North American Electric Reliability Council (NERC), this number will grow by 19 percent over the next decade. However, since currently committed capacity is projected to grow only by six percent, the demand-supply balance could be significantly stressed in the nation's power markets.[2]

Compounding the problem is that customers are likely to face rising electricity bills in just about all parts of the country. Capacity costs and fuel costs are on an upward trend, decade-old rate freezes are coming off in several states and there is a strong likelihood that Congress will mandate a cap-and-trade system for reducing greenhouse gas emissions in the near future. This has led some experts to believe that the "rate base" for electricity, which represents the dollar value of assets in the power business, is likely to double in the next decade. During the past several months, speakers at a wide range of power industry conferences have noted that there is very little time to "build" our way out of the problem by simply expanding the nation's generation capacity and the associated power grid, i.e., the transmission and distribution system that delivers power from the generation plants to the nation's 138.4 million customers.[3]

A consensus is forming that the best way to ensure reliability and competitive functioning of markets is to deploy an integrated approach that combines traditional solutions involving the supply-side of the business with demand-side solutions that give customers the ability to control their usage, especially during times when the power system encounters critical conditions. Such conditions most often occur during a heat wave but they can also occur when a large generation unit trips or when the grid is hit by an emergency.

1. This is the non-coincident peak demand in the United States, obtained by adding the peak demands of individual power planning councils.
2. NERC, 2006 Long-Term Reliability Assessment, states, "Available capacity margins, which include only committed resources, are projected to drop below regional target levels in ERCOT, MRO, New England, RFC, and the Rocky Mountain and Canada areas of WECC in the next 2–3 years, with other portions of the Northeastern U.S., Southwest, and Western U.S. falling below target levels later in the ten-year period."
3. Of this number, 120.7 million are residential customers, 16.9 million are commercial customers and 0.7 million are industrial customers, according to the US Energy Information Administration. http://www.eia.doe.gov/cneaf/electricity/esr/table1.xls.

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The demand for electricity is highly concentrated in the top one percent of hours. In most parts of the United States, these 80-100 hours account for roughly 8 to 12 percent of the maximum or peak demand. In California, they account for some 11 percent. In the 12 Midwestern and Northeastern states that form the PJM Interconnection, they account for 16 percent. In the Canadian province of Ontario, the top 32 hours account for 2,000 MW of demand out of a peak demand of 27,000 MW.

If a way can be found to shave off some of this peak demand, it would eliminate the need to install generation capacity that would be used less than a hundred hours a year. Such generating capacity is often gas fired and consists of combustion turbines, which is expensive since these turbines are idle for almost the entire year.

HOW DEMAND RESPONSE AND DYNAMIC PRICING CAN HELP DEAL WITH THE CHALLENGE

The fundamental idea behind demand response is to provide accurate price signals to customers that convey the true cost of power.[4] Since electricity cannot be stored and has to be consumed instantly, and since generation plants of varying efficiency are used to meet demand, the cost of power varies by time-of-day and day-of-year. This is true in markets that have been restructured as well as those that have not.

Once clear price signals are conveyed to customers, they can decide whether to continue buying power at higher prices or to curtail their usage during peak hours. This market-driven concept promotes economic efficiency in the consumption of electricity. It can also save substantial monies in the aggregate for society.

How much will be saved by demand response will depend on two things: first, how much peak load can be reduced by customers and second, how much generation (and related power delivery) investment and fuel can be offset by this load reduction. The first item itself depends on two things: how rapidly utilities and regulators move to install new pricing designs that provide the correct price signals to customers and how well customers respond to the price signals.

A prerequisite to the provision of dynamic pricing is the installation of advanced metering infrastructure (AMI). Depending on features and geography, AMI investment costs can range from $100 to $200 per meter but much of that cost can be recovered through operational benefits such as avoided meter reading costs, faster outage detection, improved customer service, better management of customer connects and disconnects, and improved distribution management.

In Northern and Central California, Pacific Gas and Electric Company that serves five million electric and four million gas customers estimates that 89 percent of its AMI investment of $1,700 million can be recovered through operational benefits.[5] The two investor-owned utilities in Southern California estimate that roughly half of their costs will be recovered through operational benefits.[6]

Many utilities have already installed AMI because they were able to recover their entire investment through op-

4. In addition to dynamic pricing, demand response can also be implemented by providing cash incentives to customers that encourage them to control usage. Examples include direct load control programs that target end uses such as central air conditioners and water heaters, interruptible and curtailable rates that target large customers and various forms of load curtailment that are practiced by independent system operators and regional transmission operators around the country. In this assessment, we focus exclusively on demand response as implemented through dynamic pricing programs. Such programs are triggered by economic as opposed to system reliability criteria. NERC estimates that about five percent of US peak load is currently enrolled in reliability-triggered programs. However, it is difficult to estimate the amount of capacity that would actually be available during an emergency.

5. California Public Utilities Commission, "Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure," July 20, 2006, No. Decision 05-06-028.

6. San Diego Gas and Electric estimates a cost of $572 million for its AMI system that would reach 1.4 million electric and 900,000 million gas customers. Southern California Edison has provided a preliminary estimate in excess of a billion dollars for its AMI system that would reach roughly 5.4 million customers.

erational benefits. According to a recent FERC report, AMI currently reaches six percent of electric meters in the US.[7] Certain states, such as Pennsylvania and Wisconsin, have AMI penetration rates in excess of 40 percent. AMI penetration rates are in the double digits in eight states.

However, most utilities with AMI system still do not have dynamic pricing designs in place. They, along with their state regulators, are uncertain whether customers will respond to such pricing signals. Some are also afraid of a customer backlash to potentially volatile prices. [8]

There is a good bit of skepticism that residential and small commercial and industrial customers, who constitute the vast majority of the nation's electricity users, will respond to dynamic pricing signals by lowering their demand during peak times. However, new experimental evidence from California and Illinois is beginning to make a dent in this skepticism.[9] This evidence is generally consistent with earlier results from pilots that were carried out in the late seventies and early eighties under the auspices of the US Department of Energy and the Federal Energy Administration.[10] It shows that, on average, customers will respond to higher prices by lowering usage during peak hours and by so doing, they will reduce their annual power bills.

In a $20 million pilot that involved some 2,500 residential and small commercial and industrial customers over a three-year period, California's three investor-owned utilities tested a variety of dynamic pricing designs. The experimental process involved a working group that was facilitated by the state's two regulatory commissions and involved dozens of interested parties and stakeholders, some opposed to dynamic pricing and some supporting it.

The California experiment provided time-varying prices and smart meters to all participants. In addition, some of the participants also received enabling technologies such as smart thermostats and always-on gateway systems. Smart thermostats automatically raise the temperature setting on the thermostat by two or four degrees when the price becomes critical. Always-on gateway systems adjust the usage of multiple appliances in a similar fashion and represent the state-of-the art.

The experiment showed that the average Californian customer reduced demand during the top 60 summer hours by 13 percent in response to dynamic pricing signals that were five times higher than their standard tariff.[11] Customers who had a smart thermostat reduced their load about twice as much, by 27 percent. And those who had the gateway system reduced their load by 43 percent.[12]

The experiment also showed that customers did not respond equally to the price signals. Some responded a lot and some did not respond at all. In fact, about 80 percent of the collective demand response came from just 30 percent of the customers. Of course, what matters in terms of demand response system benefits is the response of all customers in the aggregate, not the response of each individual customer. [13]

7. FERC, "Assessment of Demand Response and Advanced Metering," Staff Report, August 2006.

8. For a discussion of the myriad reasons for this hesitancy, see Ahmad Faruqui, "Breaking out of the Bubble," Public Utilities Fortnightly, March 2007.

9. Several other pilot programs are underway at this writing in the United States and Canada. These include those in the District of Columbia, Hawaii, Idaho, Missouri, New Jersey and the Canadian province of Ontario. However, results are not yet available from these pilots. New pilots are being planned, such as those in Baltimore, Maryland.

10. The results from that earlier generation of pilots are summarized in Ahmad Faruqui and J. Robert Malko, "Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing," Energy: The International Journal, 1983.

11. The 13 percent drop occurred during the six months of the summer season from May to September. Responses during the inner summer months of June-August were a percentage point higher. The 14 percent number might be more applicable during critical-peak conditions.

12. Ahmad Faruqui, "Pricing Programs: Time-of-Use and Real Time," in Encyclopedia of Energy Engineering, 2007, forthcoming.

13. The findings of the California pricing experiment are consistent with those of other pricing experiments that have been carried out over the past three decades, both in the US and abroad. For a recent survey, consult Chris King and Sanjoy Chatterjee, "Predicting California Demand Response," Public Utilities Fortnightly, July 1, 2003.

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The experiment also provided evidence on the response of small commercial and industrial customers. In addition, non-experimental evidence has been collected for large commercial and industrial customers, both in California and in other parts of the country. This allows us to make an initial projection of the likely impact of dynamic pricing on US peak demand.

HOW MUCH DEMAND RESPONSE CAN BE ACHIEVED THROUGH DYNAMIC PRICING?

The first projection is an estimate of technical potential. It measures what would happen if all customers used the best available DR technology. In the residential class, this is the gateway system, which has the potential for lowering peak demand by 43 percent. In the commercial and industrial classes, automatic DR programs that control multiple end-use loads and leverage the energy management system that is installed in most facilities are projected to reduce demand by 13 percent.[14] By taking a weighted average over all customer classes, we arrive at an estimate of 22.9 percent for the technical potential of demand response.[15]

The second projection is an estimate of economic potential. It measures what would happen if all customers used a cost-effective combination of technologies rather than the best available technologies. Our estimate of the economic potential for demand reduction through pricing-based DR programs is 11.5 percent.

To illustrate this computation for the residential class, recall that customers in the California experiment without an enabling technology lowered their peak usage by 13 percent. Those with a smart thermostat lowered it by 27 percent and those with the gateway system lowered it by 43 percent. If 70 percent of the customers chose no enabling technology, 20 percent chose the smart thermostat and 10 percent chose the gateway system, this would yield a weighted average estimate of 18.8 percent for the residential class. Corresponding values for the commercial and industrial classes are 7.3 percent and 9.4 percent.

The third projection is an estimate of market potential. It measures what would happen if a cost-effective combination of technologies is accepted by a realistic number of customers in the market place. It differs from economic potential that assumes that all customers accept dynamic pricing. Thus, the key unknown in estimating market potential is the number of participating customers. This, of course, depends on the conditions under which dynamic pricing is offered to customers.

If dynamic pricing is made the default rate, as it has been made in restructured states for large customers, a larger fraction of customers would be expected to stay on it than if it is offered on an optional basis. The limited literature on the topic suggests that about 80 percent would stay on dynamic pricing if it is offered as the default rate and that a substantially smaller number, perhaps 20 percent, would select in on a voluntary basis. In our analysis, we assume that the actual number is likely to be somewhere in the middle. This yields an estimate that DR programs based on dynamic pricing could reduce peak demand by approximately five percent. [16]

WHAT IS THE VALUE OF A FIVE PERCENT DEMAND RESPONSE?

What is the value of a five percent reduction in demand during critical periods? Several types of benefits can be identified even though it is not possible to quantify all of these in a preliminary projection. First and foremost is the reduction in the need to install peaking generation capacity. This is a long run benefit and consists of the

14. Much higher responses are possible in specific facilities that have time-flexible production processes, energy storage systems and back-up generation. Since these are highly facility-specific, we have not included them in our estimate of technical potential.

15. Details of all the computations made in this report are presented in the appendix.

16. Recognizing the uncertainty in such an estimate, we have used probabilistic simulation techniques on the key input variables that have gone into its computation. The specific technique we have used is called Monte Carlo simulation. We find that there is a 90 percent chance that the market potential will be at least 2.6 percent and 10 percent chance that it will be at least 7.7 percent. There is a 50 percent probability that it will be at least 5.0 percent

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sum of avoided capacity and energy costs. It can be readily estimated based on the capacity cost of a combustion turbine. The second benefit is the avoided energy costs that are associated with the reduced peak load. Third is the reduction in transmission and distribution capacity. This is also a long-run benefit but is harder to quantify and is very dependent on system configurations that vary regionally.

In order to quantify the avoided capacity cost, we first quantify the amount of capacity that will be avoided by a five percent reduction in peak demand and then value it. A five percent reduction in US peak demand of 757,056 MW amounts to 37,853 MW of peak demand. The amount of peaking capacity that is needed to meet this peak demand can be computed by allowing for a reserve margin of 15 percent and line losses of eight percent. This turns out to be 47,013 MW or roughly 625 combustion turbines.[17] A conservative value of the avoided cost of capacity is \$52/kW-year.[18] Thus, the total value of avoided capacity costs is \$2.4 billion per year.

Using the relationship that was observed between annual capacity and energy benefits in a recent PJM analysis of demand response, the annual value of avoided energy costs is estimated at \$300 million.[19]

In addition, there would be a reduction in transmission and distribution capacity needs. As noted earlier, they are system-dependent and much harder to estimate. However, they are unlikely to be zero. A conservative estimate puts them at 10 percent of the savings in generation capacity and energy costs.[20] Using this estimate, we derive an estimate of \$275 million per year for savings in transmission and distribution costs.

Adding up these three components yields long-run benefits of demand response of \$3 billion per year, as shown in Figure 1. [21] Over a 20-year time horizon, these represent a discounted present value of \$35 billion.[22]

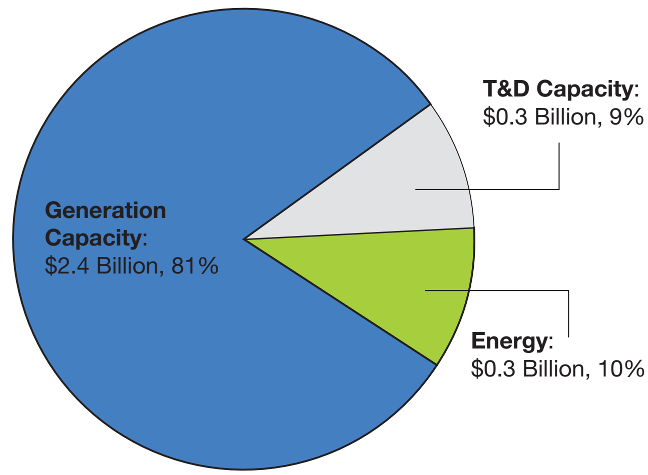

***Figure 1:** Annual Long-Run Benefis of Demand Response*

17. These turbines come in sizes generally ranging from 50 MW to 100 MW.

18. PG&E's filing with the CPUC on AMI uses two numbers, \$85/kW-year recommended by the CPUC in an ALJ ruling and \$52/kW-year, which is derived by subtracting the revenue stream associated with the sale of energy from the combustion turbine.

19. Sam Newell and Frank Felder, "Quantifying Demand Response Benefits in PJM," Study Report Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), The Brattle Group, January 29, 2007 ("PJM-MADRI Demand Response Study").

20. This estimate is based the filing of PG&E with the CPUC on AMI. From a national perspective, we cite the US Energy Information Administration's estimate that transmission and distribution costs account for some 36 percent of electricity costs. Source: Electricity Power Annual, 2007, using data from 2005.

21. We have estimated the uncertainty in this estimate by applying Monte Carlo simulations to likely ranges of the input variables. Across a wide range of assumptions, we find that there is a 90 percent probability that the estimate is at least \$1.5 billion and a 10 percent probability that it is at least \$5.3 billion. There is a 50 percent probability that it is higher than \$3.1 billion.

22. Using Monte Carlo simulations, we find that there is a 90 percent probability that the estimate is at least \$18 billion and a 10% probability that it is at least \$61 billion. There is a 50 percent probability that it is higher than \$37 billion.

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Pursuing Short-run Benefits

These long run benefits of demand response are properly viewed as an efficiency gain, since they involve real savings in total resource costs on average over time. However, there will also be an immediate reduction in the wholesale market prices for energy and capacity caused by the reduction of demand during critical times. This is a short run benefit that can be quantified through market simulations.[23] In regions that are capacity constrained, such benefits could be higher than the benefits associated with long-term avoided costs. These price mitigation benefits would persist only temporarily following the institution of dynamic pricing programs until generation capacity adjusts to the new load profile.

Nevertheless, despite their temporary nature, these short-run benefits can significantly add to the present value of demand response programs by being able to address quickly challenging wholesale market conditions that exist in regions with scarce supply. For example, our PJM-MADRI Demand Response Study showed that demand response programs that would curtail the peak load in eastern PJM by only approximately 1,100 MW (or three percent of five load zones in eastern PJM) would have produced short-term customer benefits ranging from $150 million to $300 million in 2005. Scaled up to a five percent load reduction for the entire U.S., this would translate to between $5 billion and $10 billion per year, or approximately 170 percent to 340 percent of the long-term benefit quantified above.

Clearly, the degree of supply-constrained market conditions in eastern PJM does not exist nationwide. But these results show that pursuing demand response initiatives first in markets that benefit the most from these programs creates additional benefits that increase the overall present value of the investment.

The Cost-Benefit Ratio of Investing in Dynamic Pricing?

How do the quantified long-term benefits compare to the cost of installing AMI, a pre-condition for dynamic pricing? As was mentioned earlier in this paper, a large portion of the cost of AMI can be recovered through operational benefits, such as savings in meter reader costs and faster outage detection. However, the prior experience of many utilities is that there is still a "gap" between AMI costs and the operational savings.

Assuming an approximate cost of $200 per meter, which is the upper end of expert opinion, and assuming that advanced meters are installed for the remaining 94 percent of the 138.4 million electricity customers in the U.S. that currently do not have such meters, we estimate that an investment of $26 billion will be necessary to install AMI in the entire country. If 50 percent to 80 percent of these costs are recovered through operational benefits, the remaining cost of AMI is between $5.2 billion and $13.0 billion. Thus, the net costs of AMI that would need to be recovered through demand response benefits are only 15 percent to 37 percent of the $35 billion in long-run benefits, making AMI a highly cost-effective investment from a national perspective.

OTHER ISSUES

Demand response is likely to have other benefits as well. These would include more competitive energy and capacity markets, reduced price volatility, the provision of insurance against extreme events that have not been captured in long-term resource planning scenarios, fewer environmental emissions during peak periods, improved system reliability resulting in fewer blackouts and brownouts, and AMI-based enhanced levels of customer service. In this assessment, we have not quantified any of these benefits. [24]

23. For a description of such a simulation, see our PJM-MADRI Demand Response Study.
24. For a qualitative discussion of these benefits, see our PJM-MADRI Demand Response Study.

Some additional costs would also be incurred as utilities change their billing systems and institute mechanisms for communicating the dynamic price signals to customers. All of these variables will need to be factored in and quantified in the final decision to move ahead with DR.

Finally, we recognize that there are several barriers to the institution of dynamic pricing mechanisms. These barriers involve regulatory policies and rate freezes, customers' and policy makers' apprehensions about price volatility, and perceptions about the availability of enabling technologies. Unless these barriers are addressed, the full potential of demand response will not be realized. For example, the state of California set a goal of five percent for economically triggered demand response programs for the year 2007. However, only half of this goal is likely to be realized this year. [25]

Even without counting other benefits, such as the lowering of wholesale prices in supply-constrained markets, improved reliability, or enhanced customer service, the benefits of demand response are large enough to warrant serious attention by utilities and regulatory commissions throughout the United States.

CONCLUSIONS

The potential impact of demand response is large and significant. Using best available technologies, customers could potentially lower the national peak demand by 22.9 percent. Using a cost-effective mix of technologies, peak demand could be lowered by 11.5 percent. Against this backdrop, we estimate that the market potential of demand response is five percent based on realistically achievable penetration rates.

Even a five percent drop in peak demand can yield substantial savings in generation, transmission and distribution costs. We estimate that this five percent reduction would eliminate the need for installing and running some 625 infrequently used peaking power plants and associated power delivery infrastructure. At the national level, this translates into a savings of $3 billion a year or $35 billion over the next two decades.

The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governments around the world.

We have offices in Cambridge, Massachusetts; San Francisco; Washington, DC; Brussels; and London.

25. For a detailed discussion of barriers and possible remedies, see "The State of Demand Response in California," Draft Consultant Report, California Energy Commission, April 2007.

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APPENDIX: ESTIMATING DEMAND RESPONSE BENEFITS

This appendix describes the assumptions and calculations that were used to arrive at the estimated $35 billion in potential national benefits of demand response.

The allocations of peak demand to the residential, commercial, and industrial sectors are based on a review of EIA and EPRI documents containing energy shares and load shapes by sector.

Table 1: Peak Demand Allocation by Sector

Sector	Peak Demand Allocation	% of Total
Residential	251 GW	33%
Commercial	351 GW	46%
Industrial	155 GW	20%
Total	**757 GW**	**100%**

The penetration rate of enabling technologies within the three sectors is a projection based on general industry knowledge and experience. The average customer-level peak reduction that can be achieved through each of these technologies, when paired with a CPP rate, comes primarily from the Statewide Pricing Pilot and studies conducted by the Demand Response Research Center.

Table 2: Demand Response by Sector and Technology

Technology	In-Class Allocation	Customer Response	Source
Residential			
No Technology	70%	13%	2005 CRA SPP Res. Report
Enabling Technology	20%	27%	2005 CRA SPP Res. Report
Gateway	10%	43%	2006 RMI ADRS Report
Weighted Avg		*18.8%*	
Commercial			
No Technology	60%	5%	2006 CRA SPP C&I Report
Enabling Technology	30%	10%	2006 CRA SPP C&I Report
Auto DR	10%	13%	DRRC
Weighted Avg		*7.3%*	
Industrial			
CPP	60%	7%	2006 Quantum SPP Report
Auto DR	40%	13%	DRRC
Weighted Avg		*9.4%*	

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The same sectoral allocation was used in all three projections of DR potential (as shown in Table 1). Both the technical potential and economic potential projections assume 100 percent participation by all sectors, while the market potential projection assumes roughly 43 percent participation in each sector. Customer-level demand response for technical potential is assumed to be based on the technology that allows for the largest response in each sector. In estimating the economic and market potential, a weighted average is used, based on the technology market penetration assumptions shown in Table 2. These assumptions lead to the total demand reduction estimate for each sector. Calculating a weighted average using each sector's share of the total population produces the final projections of technical, economic, and market potential for California as shown in Table 3.

Table 3: Assumptions in Calculation of DR Potential

	Technical Potential	Economic Potential	Market Potential
Sector Allocation to Total Population			
Residential	33.2%	33.2%	33.2%
Commercial	46.4%	46.4%	46.4%
Industrial	20.5%	20.5%	20.5%
Total	**100.0%**	**100.0%**	**100.0%**
Sector Participation Rate			
Residential	100.0%	100.0%	43.3%
Commercial	100.0%	100.0%	43.3%
Industrial	100.0%	100.0%	43.3%
Total	**100.0%**	**100.0%**	**43.3%**
Customer Demand Response			
Residential	43.0%	18.8%	18.8%
Commercial	13.0%	7.3%	7.3%
Industrial	13.0%	9.4%	9.4%
Total	**22.9%**	**11.5%**	**11.5%**
Total Demand Reduction Estimate			
Residential	43.0%	18.8%	8.1%
Commercial	13.0%	7.3%	3.2%
Industrial	13.0%	9.4%	4.1%
Total	**22.9%**	**11.5%**	**5.0%**

The avoided cost of generating capacity, electricity generation, and T&D capacity are all components of the financial benefits of DR. The specific calculations used to arrive at the final estimates of the present value of a five percent peak demand reduction are described in Table 4.

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Table 4: Assumptions in Calculation of Present Value of DR Financial Benefits

	Assumption/Calculation	Value	Units	Source
[A]	2007 US non-coincident peak demand forecast	757,056	MW	2006 NERC report
[B]	Market potential of DR	5%	% of peak	Calculation of Market Potential
[C]	Peak demand reduction	37,853	MW	[A] * [B]
[D]	Reserve margin	15%	% of peak	Generally accepted industry practice
[E]	Line losses	8%	% of peak	Generally accepted industry practice
[F]	System-level MW reduction	47,013	MW	[C] * (1 + [D]) * (1 + [E])
[G]	Value of capacity	52	$/kW-yr	2006 PG&E AMI Filing
[H]	Value of capacity	52,000	$/MW-yr	[G] * 1,000
[I]	Total avoided capacity cost	2,445	Million $/year	[F] * [H] / 1,000,000
[J]	Peak demand growth rate	2%	% per year	Assumption
[K]	Annual discount rate	8%	% per year	Assumption
[L]	Study time horizon	20	years	Assumption
[M]	PV of $1 annuity for 20 years	11.58	$	Assumption
[N]	Energy % of generation capacity cost	12%	% of NPV	2006 Brattle DR Study for MADRI/PJM
[O]	T&D % of energy and generation capacity cost	10%	% of NPV	2006 PG&E AMI Filing
[P]	PV avoided generation capacity cost	28,310	Million $	[I] * [M]
[Q]	PV avoided energy cost	3,490	Million $	[N] * [P]
[R]	PV avoided T&D capacity cost	3,180	Million $	[O] * [P]
[S]	PV of total avoided cost	34,980	Million $	[P] + [Q] + [R]

Sources:

- 2005 CRA Residential SPP Report: CRA International, *Impact Evaluation of the California Statewide Pricing Pilot*, March 16, 2005.
- 2006 Brattle DR Study for MADRI/PJM: Newell, Sam and Frank Felder, *Quantifying Demand Response Benefits in PJM*, Study Report Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007.
- 2006 CRA C&I SPP Report: CRA International, *California's Statewide Pricing Pilot: Commercial & Industrial Analysis Update*, June 28, 2006.
- 2006 NERC Report: NERC, "2006 Long-Term Reliability Assessment," October 2006, p. 125.
- 2006 PG&E AMI Filing: California Public Utilities Commission, "Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure," July 20, 2006, No. Decision 05-06-028.
- 2006 Quantum SPP Report: Quantum Consulting and Summit Blue Consulting, *Evaluation of 2005 Statewide Large Nonresidential Day-Ahead and Reliability Demand Response Programs*, Prepared for Southern California Edison Company and Working Group 2, April 28, 2006.
- 2006 RMI ADRS Report: Rocky Mountain Institute, *Automated Demand Response System Pilot, Final Report*, March 31, 2006.

Forward Capital Expenditures Driving Rate Base Growth

Capital Expenditures

- Attractive growth opportunities through capital investment in core utility assets
- Earnings expected to grow 6 to 8 percent per year over the long term starting with 2008
- New capital investments funded through cash from operations and issuances of debt and equity with a targeted capital structure of 50/50

<table>
<tr><th>Projects (in millions)[1]</th><th>2007</th><th>2008</th><th>2009</th><th>2010</th><th>2011</th></tr>
<tr><td>Advanced Metering Infrastructure[2]</td><td>$3</td><td colspan="3">$130 - $135</td><td></td></tr>
<tr><td>Biglow Canyon Wind Farm: Phase I</td><td>$203</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>Biglow Canyon Wind Farm: Phase II & III[3]</td><td>$19</td><td colspan="3">$530 - $630</td><td></td></tr>
<tr><td>Boardman emissions controls[2]</td><td>-</td><td colspan="4">$170 - $180</td></tr>
<tr><td>Hydro Relicensing[2]</td><td>$52</td><td colspan="4">$110 - $120</td></tr>
<tr><td>Port Westward</td><td>$16</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>Ongoing capital expenditures[4]</td><td>$178</td><td>$220 - $240</td><td>$220 - $240</td><td>$250 - $270</td><td>$230 - $250</td></tr>
</table>

- Depreciation and amortization of $180 million - $240 million (2007 – 2011)

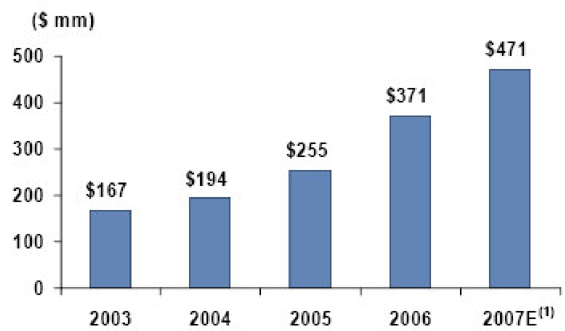
(1) Does not include AFDC.
(2) Under review; forecasted expenditures are preliminary and subject to change.
(3) Phase II & III timing subject to turbine availability and project economics.
(4) Includes upgrades on transmission, distribution and existing generation, as well as new customer connections.

Portland General Electric

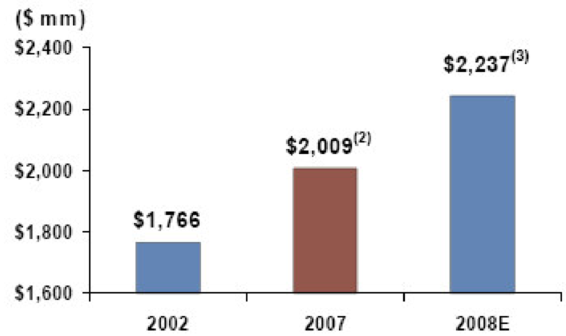
PGE EEI Presentation, November 2007
http://files.shareholder.com/downloads/POR/207703870x0x141458/b3c055ba-a445-4eff-982b-cd9438c09123/PGE_EEI_Roadshow_November2007.pdf

Rate Base Growth Opportunities

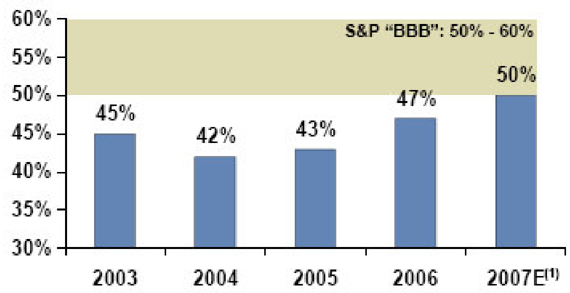
Capital Expenditures



Approved Average Rate Base



Debt/Capitalization



Current Credit Ratings

	Senior Secured	Senior Unsecured	Outlook
S&P[4]	A	BBB	Negative
Moody's	Baa1	Baa2	Stable

(1) Forecasted expenditures are preliminary and subject to change.
(2) Includes annualized rate base of Port Westward.
(3) Approved 2007 rate base plus Biglow Canyon Phase I.
(4) S&P rates the business risk of PGE at "5" on a scale of 1 to 10 with 1 being the least risky. Most integrated utility companies are rated from 4 to 6 on this scale.

Portland General Electric

PGE EEI Presentation, November 2007
http://files.shareholder.com/downloads/POR/207703870x0x141458/b3c055ba-a445-4eff-982b-cd9438c09123/PGE_EEI_Roadshow_November2007.pdf

Quantifying Customer Response to Dynamic Pricing

California's Statewide Pricing Pilot experiment showed that residential and small to medium commercial and industrial customers conclusively reduced peak-period energy use in response to time-varying prices. Responsiveness varied with rate type, climate zone, season, air conditioning ownership, and other customer characteristics.

Ahmad Faruqui and Stephen George

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The authors gratefully acknowledge the research assistance provided by their colleagues Joanna Burleson and John Winfield.

California experienced a major power crisis in its unregulated wholesale markets during 2000 and 2001. While many problems conspired to create the crisis, most people agree that it was exacerbated by the lack of dynamic price signals in retail markets. Dynamic pricing would have given customers an incentive to lower loads during peak times which, in turn, would have reduced market-clearing prices and partially mitigated market power. However, dynamic pricing requires the installation of digital interval meters and makes economic sense only if its benefits exceed the costs of the new metering infrastructure. The benefits depend on the impact of dynamic pricing on customer loads and on avoided supply-side costs, both of which are uncertain.

To help address the uncertainty regarding customer load impacts, California's three investor-owned utilities,[1] in concert with the two regulatory commissions, conducted an experiment to test the impact of time-of-use (TOU) and dynamic pricing among residential and small commercial and industrial (C&I) customers. Known as the Statewide Pricing Pilot (SPP), the experiment's primary objective was to estimate the average impact of time-varying rates on energy use by rate period and to develop models that could be used to predict impacts under alternative pricing plans. The broader policy objective underlying the SPP was to provide information that would allow each of the three utilities to determine whether the demand–response benefits from reductions in energy use and coincident peak demand from dynamic pricing were sufficiently large to offset the net metering, billing, and other infrastructure costs required to implement rate reform.[2]

This article provides a summary of the design and results associated with the SPP. In brief, the experiment showed that residential and small to medium C&I customers can and did conclusively reduce peak-period energy use in response to time-varying prices. Responsiveness varied with rate type, climate zone, season, air conditioning ownership, and other customer characteristics.

I. SPP Design and Methodology[3]

The SPP involved roughly 2,500 customers and ran from July 2003 to December 2004. Several different rate structures were tested. These included a traditional TOU rate, where price during the peak period was roughly 70 percent higher than the standard rate and about twice the value of the price during the off-peak period. The SPP also tested two varieties of critical peak pricing (CPP), where the peak period price during a small number of critical days was roughly five times higher than the standard rate and about six times higher than the off-peak price.[4] One CPP rate, CPP-F, had a fixed critical peak period and day-ahead notification. The other, CPP-V, had a variable-length peak period on critical days and day-of notification. CPP-V customers had the option of having an enabling technology, such as a smart thermostat, installed free of charge to help facilitate demand response.

The experiment showed that residential and small to medium C&I customers can and did conclusively reduce peak-period energy use in response to time-varying prices.

The SPP experimental design included control groups that stayed on the standard tariff and treatment groups that were placed on the new rates. Treatment customers were divided into subgroups that faced different price levels so that statistical relationships between energy use by rate period and prices could be estimated. These statistical relationships, referred to as demand models in the economics literature, were used to estimate demand response impacts for the average prices used in the SPP. Importantly, they can also be used to estimate the impact of other prices that are within a reasonable range of those tested. Most of the demand models also allow the analyst to adjust the magnitude of price responsiveness to account for variation in climate and the saturation of central air conditioning. Thus, demand response impact estimates can be developed for customer segments with characteristics that differ from those included in the experiment.

The demand system estimated for each tariff consisted of two equations. One equation predicts daily energy use as a function of daily price and other factors. The second equation predicts the share of daily energy use by rate period. This type of demand system is commonly used in empirical analysis of energy consumption.

II. Residential Customer Response

Three rate treatments were examined for residential customers: CPP-F, CPP-V and TOU. The CPP-F and TOU rates were implemented among a statewide sample of customers. The sample size for the CPP-F treatment was much larger than for the TOU treatment and the results are more robust. The CPP-V rate was implemented only in the SDG&E service territory.

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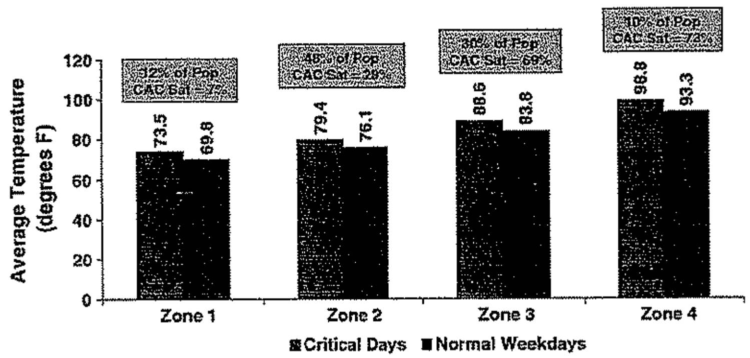

Figure 1: Population, Air Conditioning Saturations and Average Temperature by Climate Zone

A. CPP-F impacts

A key focus of the SPP was to assess the impact of dynamic tariffs. Estimated impacts varied by day type: critical days (when the highest prices are in effect); normal weekdays (when lower peak prices are in effect); and weekends (which have the same prices as off-peak weekday periods). They also varied across California's diverse climate zones, where, as seen in **Figure 1**, average temperatures and central air conditioning (CAC) saturations differ significantly.

Figure 2 summarizes the impact of the average CPP-F prices on energy use during the peak period on critical and normal weekdays. Statewide, the estimated average reduction in peak-period energy use on critical days was 13.1 percent.[5] Impacts varied across climate zones, from a low of −7.6 percent in the relatively cool climate of zone 1 (which includes San Francisco) to a high of −15.8 percent in the hot climate of zone 4 (which includes Palm Springs and the Central Valley city of Bakersfield). The average impact on normal weekdays was −4.7 percent, with a range across climate zones from −2.2 percent to −6.5 percent.

Other key findings for the CPP-F rate include:

- Differences in peak-period reductions on critical days across the two summers, 2003 and 2004, were not statistically significant.
- Differences in impacts across critical days when two or three critical days are called in a row (as might occur during a heat wave) were not statistically significant.
- Average peak-period impacts on critical days were greater during the hot summer months of July through September (−14.4 percent) than during the milder summer months of May, June, and October (−8.1 percent).
- Peak-period reductions on normal weekdays were lower in the winter (−3.9 percent) than in the summer (−4.7 percent), and lower during the milder winter months of November, March, and April (−0.7 percent) than during the colder winter months of December, January, and February (−4.7 percent).
- There was essentially no change in total energy use across the entire year based on average SPP prices. That is, the reduction in energy use during high-price periods was almost exactly offset by increases in energy use during off-peak periods.

Understanding how price responsiveness varies with differences in selected customer characteristics can be useful from both a policy and marketing perspective. For example, if high users are more responsive than low users, different tariffs might be targeted at each customer segment in order to maximize demand response and/or minimize implementation costs. If spa owners are more responsive than households that do not have spas, it may be possible to improve overall demand response from a

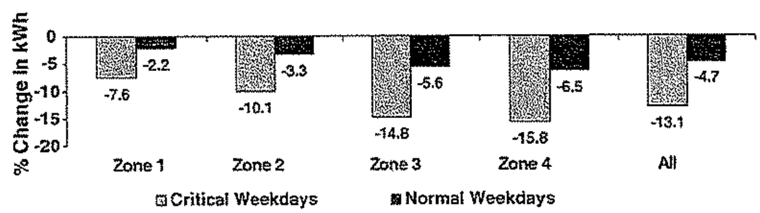

Figure 2: Percent Change in Residential Summer Peak-Period Energy Use (Avg. CPP-F Prices/Avg. 2003/2004 Weather)

Table 1: Percent Impact on Energy Use by Rate Period on Critical Days Given a Change in Customer Characteristics

Variable	Customer Characteristic	Peak Period	Off-Peak Period	Daily Period
None	Average	−13.06	2.04	−2.37
Central A/C	Yes	−17.43	3.21	−2.82
	No	−8.05	0.68	−1.87
Average daily use	200 percent of average	−14.70	1.77	−3.04
	50 percent of average	−12.15	2.21	−1.99
Spa	Yes	−15.84	3.53	−2.13
	No	−12.94	1.93	−2.41
Electric cooking	Yes	−11.53	0.32	−3.14
	No	−14.09	3.16	−1.87
Persons per household	Four	−12.13	1.51	−2.47
	Two	−13.99	2.46	−2.35
Annual income	$100,000	−16.15	2.99	−2.60
	$40,000	−10.92	1.68	−2.00
Housing type	Single family	−13.98	2.72	−2.16
	Multi-family	−11.78	0.43	−3.14
# Bedrooms	Four	−15.67	2.12	−3.07
	Two	−11.59	2.01	−1.96
College education	Graduate	−18.52	3.69	−2.79
	Did not graduate	−8.56	0.93	−1.84

voluntary program by targeting spa owners.

Table 1 shows how average customer impacts by rate period on critical days varied with differences in selected customer characteristics. As seen, air conditioning ownership had a very significant influence on demand response, with critical day, peak-period reductions being more than twice as large for households with air conditioning than for those without. Whether or not the head of the household has a college education has a similar influence to that of air conditioning ownership. Households where the head has a college education were roughly twice as responsive as households where the head did not have a college education. Income is also an influential characteristic, with higher-income households being more responsive. Obviously, college education and income are highly correlated. Average daily energy use, spa ownership and number of bedrooms were all positively correlated with responsiveness, while persons per household and electric cooking were negatively correlated with demand response. Single-family households were more price responsive than multiple-family households.

As previously mentioned, demand models are versatile policy tools that can be used not only to estimate the impact of the specific rates that were tested in the pilot but also to predict the impact of rates not included in the pilot. As indicated above, demand models can also predict how impacts vary with customer characteristics.

Figures 3 and 4 show how the percent reduction in peak-period energy use on critical days varied with changes in the peak-period price (when everything else is held constant). The curves indicate that the reduction in peak-period energy use increases as prices increase, but at a diminishing rate. Figure 3 shows that reductions are greater in percentage terms in hotter climate zones, where air conditioning saturations are high, than in cooler zones. It should be noted that the difference in the absolute value of the peak-period reduction would be even greater than the difference in the percentage reduction as average use prior to the demand change is much larger in hotter climate zones than in cooler ones. Figure 4 shows that peak-period reductions are greater in the inner summer months of July, August, and September than in the outer summer months of May, June, and October. We believe the greater responsiveness in the inner summer is due primarily to the influence of central air conditioning.

The impacts shown in Figures 3 and 4 are driven more by the relationship between the initial average price and price in each rate period under the alternative rate more than they

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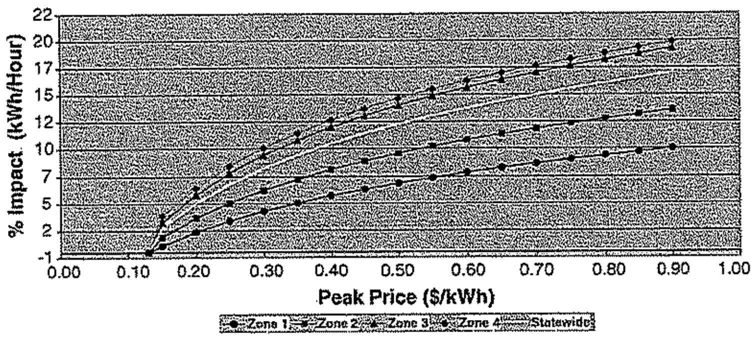

Figure 3: Percent Reduction in Peak-Period Energy Use on Critical Days, Average Summer, 2003/2004

are by the absolute levels of prices. In the SPP, the average price for customers on the standard rate was roughly 13 ¢/kWh, the average peak-period price on critical days was roughly 59 ¢/kWh and the average off-peak price was 9 ¢/kWh. If, instead, the average standard price were, say, 7 ¢/kWh, a critical peak price of roughly 32 ¢/kWh combined with an off-peak price of around 5 ¢/kWh would produce approximately the same impact as that found in the SPP. Thus, the SPP demand models can be used to predict the impact of dynamic pricing in other regions of North America and possibly in other developed economies, once adjustments are made for climatic conditions and customer characteristics.

B. TOU impacts

As previously mentioned, in addition to the CPP-F tariff, the SPP also examined traditional TOU rates. The reduction in peak-period energy use resulting from a TOU rate in the inner summer of 2003 equaled −5.9 percent. This 2003 value is comparable to the estimate for the CPP-F tariff on normal weekdays when prices were similar to those for the TOU treatment. However, in 2004, the TOU rate impact (−0.6 percent) almost completely disappeared.

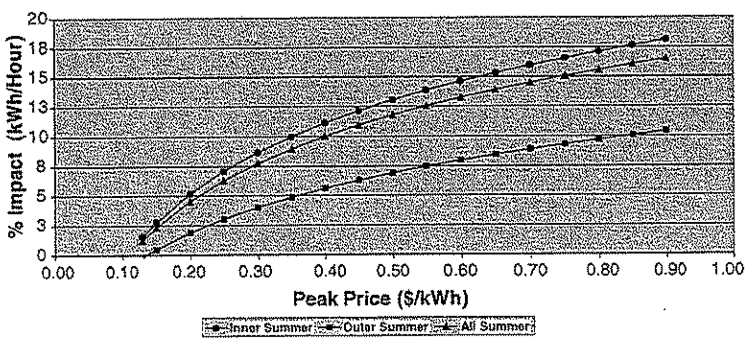

Figure 4: Percent Reduction in Peak-Period Energy Use on Critical Days, Inner Summer, Outer Summer, Average Summer

TOU winter impacts were comparable to the normal weekday winter impacts for the CPP-F rate.

Drawing firm conclusions about the impact of TOU rates from the SPP is somewhat complicated by the fact that the TOU sample sizes were small relative to the CPP-F sample sizes.[6] Small sample sizes are more easily influenced by outliers and changes in the sample composition over time than are larger samples. Further complicating the estimation of the daily energy equation (one of the two equations underlying the impact estimates) is that variation in daily prices over time was quite small for the TOU rate, making it difficult to obtain precise estimates of daily price responsiveness.[7] In short, we don't have as much confidence in the TOU results as we do the CPP-F results. Indeed, an argument could be made that the normal weekday elasticities from the CPP-F treatment may be better predictors of the influence of TOU rates on energy demand than are the TOU price elasticity estimates. On the other hand, if the TOU results are accurate, they have very important policy implications, since they indicate that the relatively modest TOU prices tested in this experiment do not have sustainable impacts across the two summers.

C. CPP-V impacts

The residential CPP-V rate was tested between two different populations, both within the SDG&E service territory.

Track A customers were drawn from a population of customers with average summer energy use exceeding 600 kWh per month. The saturation of central air conditioning among the Track A treatment group was roughly 80 percent, much higher than among the general population, and average income was also much higher. Track A customers were given a choice of having an enabling technology installed free of charge to facilitate demand response. About two-thirds of the participants took one of three technology options[8] and about half of those selected a smart thermostat.

Track C customers were recruited from a sample of customers that had previously volunteered for a Smart Thermostat pilot.[9] All Track C customers had smart thermostats and central air conditioning.

Key findings for the CPP-V rate treatments include:

• The reduction in peak-period energy use for Track A customers on critical days equaled almost 16 percent, which is about 25 percent higher than the CPP-F rate average.

• The peak-period reduction for Track C customers equaled roughly 27 percent. About two-thirds of this reduction can be attributed to the smart thermostat and the remainder to price-induced behavioral changes.

Although comparisons between Track A and Track C CPP-V treatments and between the CPP-V and CPP-F treatments must be made carefully due to differences in sample composition, the Track C results suggest that impacts are significantly larger with enabling technology than without it. The 27 percent average impact for the Track C, CPP-V treatment is roughly double the 13 percent impact for the CPP-F rate for the average summer. It is also substantially larger than the

Track A, CPP-V treatment impact, where only some customers took advantage of the technology offer.

D. Residential summary

Table 2[10] summarizes the key findings from the SPP with regard to reductions in peak-period energy use resulting from the various tariff options tested. The most robust and generalizable results were for the CPP-F rate. TOU rate impacts varied across years and are suspect due to sample size limitations and other factors. Although the Track C, CPP-V results are more difficult to generalize to the overall population, they provide useful insight into the incremental impact of prices and enabling technology.

It is interesting to compare the results obtained from the SPP with those that have been found elsewhere. Dozens of studies on the impact of time-varying rates have been conducted over the years, although many of them are quite dated.[11] Very few previous studies examined dynamic rates, which were a key focus of the SPP. Making comparisons across studies is very difficult because of differences in methodology, differences in the characteristics of underlying populations and differences in price levels and other factors. Ignoring such complexities, a simple comparison shows that the SPP estimates of price responsiveness in California are at the low end of the range reported in the literature.

One study, conducted in the early 1980s by the Electric Power Research Institute,[12] allows for a more careful comparison between the SPP results and estimates based on five of the best-designed TOU rate experiments that were conducted in the late 1970s.[13] The EPRI study used a similar demand model specification to the one underlying the SPP, making it easier to estimate the impact of SPP prices using the price responsiveness measures from the EPRI study. Using these earlier model parameters along with average SPP prices, the estimated peak-period reduction on critical days is roughly 70 percent greater than the estimated value from the SPP (i.e., −22.5 percent versus −13.1 percent).

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Table 2: Summary of Average Summer Peak-Period Impacts by Treatment Type for Residential Customers

Treatment	Day Type	Avg. Price (¢/kWh)	Impacts	Comments
Track A CPP-F	Critical weekday	$P = 59$ OP = 9 $D = 23$ $C = 13$	−13.1 percent average summer −14.4 percent inner summer −8.1 percent outer summer −4.7 percent average summer	No statistically significant difference for inner summer between 2003 and 2004 (differences across the two years can not be estimated for the outer summer or the average summer).
	Normal weekday	$P = 22$ OP = 9 $D = 12$ $C = 13$	−5.5 percent inner summer −2.3 percent outer summer	Difference between critical and normal days is primarily due to price differences and secondarily to differences in weather.
Track A TOU	All weekdays	$P = 22$ OP = 10 $D = 13$ $C = 13$	−5.9 percent inner summer 2003 −0.6 percent inner summer 2004 −4.2 percent outer summer 2003/2004	Results are suspect because of the small sample size and observed variation in underlying model coefficients across the two summers. Recommend using normal weekday CPP-F model to predict for TOU rate.
Track A CPP-V	Critical weekday	$P = 65$ OP = 10 $D = 23$ $C = 14$	−15.8 percent average summer 2004 Represents average across households with and without enabling technology —could not separate price and technology impacts	Not directly comparable to CPP-F results due to differences in population (CAC saturation for CPP-V treatment group twice that of CPP-F; CPP-V average income much higher; 2/3 of CPP-V customers had enabling tech; all households located in SDG&E service territory).
	Normal weekday	$P = 24$ OP = 10 $D = 14$ $C = 14$	−6.7 percent average summer 2004	See above comments about population differences.
Track C CPP-V	Critical weekday	Same as for Track A	−27.2 percent combined tech and price impact for average summer 2003/2004 −16.9 percent impact for tech only −11.9 percent incremental impact of price over and above tech impact	Not directly comparable to Track A results due to population differences (all Track C customers are single family households with CAC located in SDG&E service territory). Some evidence that impacts fell between 2003 and 2004.
	Normal weekday	Same as for Track A	−4.5 percent average summer 2003/2004	See above comments about population differences.

Based on these comparisons, it would appear that price responsiveness in California today is less than it was in California and elsewhere a quarter century ago. This is not surprising in light of the significant conservation and load management programs that were implemented in the last 25 years. Actions taken by many consumers following the energy crises of 2000 and 2001 may also have reduced the ability or willingness of California's customers to further reduce energy use. Nevertheless, it is also very clear from the SPP that there still remains a significant amount of demand response that can be achieved through TOU and dynamic pricing.

III. Commercial and Industrial Customer Response

CPP-V and TOU tariffs were also tested for small and medium C&I customers with billing demands under 200 kW. These tariffs were only tested in the SCE service territory. The C&I population was segmented into two groups, customers with peak demands less than 20 kW (LT20) and customers with peak demands between 20 and 200 kW (GT20). The CPP-V tariff was implemented between two population samples. The Track A sample was recruited from the general population while the Track C sample was drawn from a pre-existing Smart Thermostat pilot. All Track C customers had central air conditioning and smart thermostats. Most Track A customers had central air conditioning but only about half selected the smart thermostat technology option. In light of these and other differences, direct comparisons between Track A and Track C results must be made carefully.

For the Track A, CPP-V treatment, key findings include:

- LT20 customers had a very small but statistically significant demand response, with the average peak-period reduction on critical weekdays equal to 6.0 percent.
- The peak-period reduction on normal weekdays for LT20 customers was roughly 1.5 percent.
- GT20 customers showed a larger percent reduction in peak-period energy use on critical weekdays (−9.1 percent) than did LT20 customers.
- Reductions in peak-period energy use on normal weekdays for GT20 customers equaled 2.4 percent.

Key findings for the Track C, CPP-V treatment include:

- LT20 customers reduced peak-period energy use on critical weekdays by 14.3 percent. All of this reduction was due to the enabling technology. That is, this customer segment did not have any incremental price response.
- GT20 customers reduced peak-period energy use on critical weekdays by 13.8 percent. Roughly 80 percent of this reduction is attributable to the enabling technology.

For the C&I TOU rate treatment, demand response and peak-period impacts varied significantly between summer 2003 and summer 2004. In 2003, price was not statistically significant for the LT20 customer segment. However, price was significant in 2004 and the estimated reduction in peak-period energy use equaled almost 7 percent. Price was statistically significant in both summers for the GT20 segment. Peak period impacts in 2003 equaled −4.0 percent and in 2004 equaled −8.6 percent. These results should be viewed cautiously, however, in light of the small sample size and significant variation in the underlying model coefficients across summers.

Table 3 summarizes the key findings for the C&I analysis. The Track C, CPP-V results suggest that technology could have a relatively significant influence on demand response in the C&I sector, although this population was not representative of the overall population of C&I customers. Demand response among the smallest segment (LT20) was quite small in most instances.

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Table 3: Summary of Average Summer Peak-Period Impacts by Treatment Type for C&I Customers

Treatment/ Customer Segment	Day Type	Avg. Price (¢/kWh)	Impacts	Comments
Track A TOU LT20	All weekdays	$P = 28$ OP = 12 $D = 18$ $C = 18$	−0.3 percent in 2003 −6.8 percent in 2004	The 2003 value was not statistically significant. Small sample size and variation in underlying model coefficients across summers suggest estimates may be suspect. Recommend using normal weekday CPP-F model to predict for TOU rate.
Track A TOU GT20	All weekdays	$P = 23$ OP = 12 $D = 16$ $C = 15$	−3.9 percent in 2003 −8.6 percent in 2004	The difference between 2003 and 2004 was statistically significant. Same caveat as described above for LT20 customers.
Track A CPP-V LT20	Critical weekday	$P = 81$ OP = 12 $D = 30$ $C = 17$	−6.1 percent in 2004	This treatment was not implemented in 2003. Price responsiveness measure was small but statistically significant.
	Normal weekday	$P = 20$ OP = 12 $D = 15$ $C = 17$	−1.5 percent in 2004	Same comments as above.
Track A CPP-V	Critical weekday	$P = 66$ OP = 11 $D = 24$ $C = 15$	−9.1 percent in 2004	This treatment was not implemented in 2003. This segment was more price responsive than LT20 customers.
	Normal weekday	$P = 18$ OP = 12 $D = 14$ $C = 15$	−2.4 percent in 2004	Same comments as above.
Track C CPP-V LT20	Critical weekday	$P = 87$ OP = 12 $D = 33$ $C = 18$	−14.3 percent combined tech and price impact for average summer 2003/2004 −18.2 percent for tech alone +4.5 percent incremental impact of price over and above tech impact	The tech only impact was higher than the combined price/tech impact, indicating that price did not provide any incremental impact for this customer segment.
	Normal weekday	$P = 21$ OP = 12 $D = 16$ $C = 18$	+1.1 in average summer 2003/2004	The estimate was not statistically significant, additional evidence that this customer segment was not price responsive.

Table 3: *(Continued)*

Treatment/ Customer Segment	Day Type	Avg. Price (¢/kWh)	Impacts	Comments
Track C CPP-V GT20	Critical weekday	$P = 71$ $OP = 11$ $D = 24$ $C = 15$	−13.8 percent combined tech and price impact for average summer 2003/2004 −11.0 percent for tech alone −3.2 percent incremental impact of price over and above tech impact	Incremental impact of price over technology declined by roughly 75 percent between 2003 and 2004. GT20 participants used significantly less electricity on average than the average control group.
	Normal weekday	$P = 19$ $OP = 11$ $D = 14$ $C = 15$	−0.9 percent in average summer 2003/2004	Same comments as above.

Responsiveness was greater for GT20 customers than it was for LT20 customers.

IV. Conclusions

California's Statewide Pricing Pilot has demonstrated conclusively that residential and small to medium C&I customers reduce peak-period energy use in response to time varying prices. Price responsiveness varies with climate zone, season, air conditioning ownership, and other customer characteristics. Traditional TOU rates with a peak-to-off-peak price ratio of around 2 to 1 produce peak-period reductions in the 5 percent range for residential customers whereas critical peak prices with ratios in the 5 to 1 and 10 to 1 range produce reductions between 8 and 15 percent with no enabling technology and between 25 and 30 percent with enabling technology.

A series of demand models have been developed using the SPP data that can be used to predict the impact of other prices than those used in the pilot. Equally important, these models can be used to predict the impact of dynamic pricing in other regions of North America and possibly in other developed economies, once adjustments are made for climatic conditions and customer characteristics.

As indicated at the beginning of this article, one of the key reasons for implementing the SPP was to develop estimates of demand response that could be used by California's major utilities to assess the net benefits of wide scale deployment of the Advanced Metering Infrastructure (AMI) required to implement time-varying rates.[14] In March of this year, PG&E, SCE and SDG&E filed preliminary business cases for AMI. Investment costs, operational savings, and demand response benefits vary significantly across the three utilities, as they would for any other utility exploring such a policy. Not surprisingly, the preliminary conclusions and recommendations of each utility also vary.

PG&E found that, in spite of an investment with a present value of revenue requirements equal to roughly $2 billion to replace the Company's 9.3 million gas and electric meters, the demand response benefits outweighed the net costs (equal to roughly $410 million after netting out operational savings) under several potentially achievable assumptions about opt-in participation for dynamic rate programs. SDG&E concluded that such an investment was also attractive, but only if a dynamic rate were implemented on an opt-out basis (that is, customers were placed on the rate as the default option and allowed to switch to a fully hedged, flat or tiered rate

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alternative). SCE came to yet a different conclusion, namely that the demand response benefits were not sufficient to offset the cost of AMI given current technology and costs, but that the net benefits could be positive if additional functionality could be added to the AMI infrastructure at reasonable cost. The company requested funding from the CPUC to help design and develop a new meter that would achieve this goal. These disparate analyses and conclusions highlight both the potential benefits of dynamic pricing and advanced metering as well as the importance of doing the detailed analysis required to determine whether such policies are sensible in light of the unique costs, savings and customer characteristics of each utility.■

Endnotes:

1. Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E).

2. In March of this year, each utility filed updates of preliminary business cases that were originally filed in Oct. 2004 comparing the costs and benefits of advanced metering and pricing reform under various pricing and meter deployment strategies. The results of the SPP were used, in part, to estimate the contribution of demand response to the net benefit calculations for these filings.

3. This article is adapted from the executive summary of our report, *Impact Evaluation of the California Statewide Pricing Pilot, Final Report*, Mar. 16, 2005, that was submitted to Working Group 3. The report can be found at http://www.energy.ca.gov/demandresponse/documents/index.html.

4. See Tables 2 and 3 for a summary of the average prices associated with the experiment.

5. The statewide impact estimate of −13.1 percent has a 95 percent confidence band of ±1 percentage point. This means that there is a 95 percent probability that the actual reduction in peak-period energy use on critical days based on average SPP prices would fall between 12.1 and 14.1 percent.

6. Samples had been optimized using Bayesian techniques to be larger when there would be more value to the information that would be generated. Since there was a large literature on TOU rates and a comparatively small literature on CPP rates, and since CPP rates were likely to be more cost-effective than TOU rates, larger samples were allocated to the CPP cells and smaller ones to the TOU cells.

7. Daily prices varied much more for the CPP-F tariff than the TOU tariff because of the higher prices on critical days with the CPP-F rate.

8. The three options offered were a smart thermostat, an automated water heater control and an automated swimming pool pump control.

9. The Smart Thermostat pilot was an outgrowth of Assembly Bill 970, which was passed in the aftermath of California's energy crisis of 2000–2001.

10. P = peak period price; OP = off-peak price; D = daily price; C = control group price.

11. See Chris S. King and Sanjoy Chatterjee, *Predicting California Demand Response*, Pub. Util. Fortnightly, July 1, 2003.

12. Results from the EPRI study are summarized in Douglas Caves, Laurits Christensen and Joseph Herriges, *Consistency of Residential Customer Response in Time-of-Use Electricity Pricing Experiments*, J. Econometrics 16 (1984), at 179–203.

13. These included two experiments in southern California and single experiments in Connecticut, North Carolina, and Wisconsin.

14. See Ahmad Faruqui and Stephen S. George, *The Value of Dynamic Pricing in Mass Markets*, Elec. J., July 2002, at 45.

❖ *Meetings of Interest* ❖

Conference	*Date*	*Place*	*Sponsor*	*Contact*
Spinning Green Energy into Gold	May 25, 2005	Mechanicsburg, PA	PennFuture	717-214-7920
International Hydrogen Energy Congress	July 13–15, 2005	Istanbul	Hydrogen Energy Forum	http://www.ihec2005.com/
Energy 2005: The Solutions Network	Aug. 14–17, 2005	Long Beach, CA	U.S. Department of Energy	http://www.energy2005.ee.doe.gov/
Air Quality V: Mercury, Trace Elements, SO_3, and Particulate Matter	Sept. 19–21, 2005	Arlington, VA	Energy & Environmental Research Center	(701) 777-5246

Excerpts From: "Time of Use Rate Option."
Lisa Schwartz Presentation to Portfolio Options Committee May 9, 2007.

Slide 6:

Evaluation (cont.)

- **PacifiCorp's 2005 evaluation**
  - Benefit/cost ratio of 0.23
  - Estimated $889,000 in subsidies from 2002 through 2004, after accounting for benefits. Assuming no new participants, attrition and continuing load research, the company estimated $870,000 (2004$) in subsidies would be required from 2002 to 2010.
  - Estimated about 10,000 enrollments would be needed for the program to be cost-effective under current metering and data collection strategies
- **Commission staff's perspective**
  - Programs are not cost-effective with one-off installation of special meters. Mass meter installation and automated data collection are needed to make time-varying pricing for small customers cost-effective.
  - Cost-effectiveness of programs is highly dependent on participation rates

Slide 12:

Context (cont.)

- **PGE's advanced metering filing**
  - PGE filed a tariff requesting cost recovery for advanced metering infrastructure (AMI) during the deployment period (Docket UE 189).
  - AMI makes it inexpensive and easy to offer time-varying rates to all customers.
  - Additional enabling technology (e.g., programmable communicating thermostats and appliance controls that receive price signals) are needed to increase participation and load reductions.
  - PGE plans to file a Critical Peak Pricing (CPP) experimental tariff for residential customers in October 2007. The proposed design would discount basic rates during months (or days) CPP events are called (initially, day-ahead notice). The CPP price would be far higher than the basic rate.

CERTIFICATE OF SERVICE

I hereby certify that on this 21st day of December, 2007, I served the foregoing Response Testimony of the Citizens' Utility Board of Oregon in docket UE 189 upon each party listed below, by email and, where paper service is not waived, by U.S. mail, postage prepaid, and upon the Commission by email and by sending 2 copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

Respectfully submitted,

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The Citizens' Utility Board of Oregon

W=Waive Paper service, C=Confidential, HC=Highly Confidential

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