BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 213

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In the Matter of	)
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In the Matter of IDAHO POWER COMPANY	)
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Request for a general rate revision.	)

RESPONSE TESTIMONY OBJECTING TO THE STIPULATION

OF THE

CITIZENS' UTILITY BOARD OF OREGON

January 19, 2010

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

I. Introduction.

The proposal by Staff and Idaho Power Company (The Company) to implement a summer seasonal rate applicable to the summer tailblock (for the sole purpose of discouraging residential air conditioning usage) is a proposal that CUB cannot support.[1] Such a proposal is patently unfair to residential customers. The proposal would result in the Company sending price signals to winter-peaking residential customers during the summer peak, when at the same time the Company is protecting summer-peaking irrigation customers from receiving accurate price signals through imposition of a heavy subsidy levy on other customer classes for support of irrigation customers. The contrast between the price signals being sent to these two groups of customers is stunning and it undercuts the stated logic of the Staff and Idaho Power Company's proposal. Staff has

[1] Stipulation at page 6, section 14.

stated that irrigators would suffer rate shock at increases above 27.96%, so what about this proposal's inequities and the rate shock that will be faced by winter-peaking residential customers if this proposal is implemented?

The proposal to require winter-peaking residential customers to pay higher summer rates is problematic for other reason too. Idaho Power Company is unable to isolate and bill for the summer season. Second, Idaho Power Company is asking to extend billing cycles to as long as 36 days. Third, it will be difficult for senior and low-income customers to manage these higher rates – notwithstanding the current economic down turn – without the development of better energy efficiency programs. Fourth, the rate increase is not in fact related to actual costs incurred by Idaho Power Company during the months when bills would be affected. Fifth, there is a lack of evidence to show that imposing the proposed price signals on winter-peaking residential customers will be effective in reducing peak energy consumption. The question that needs to be addressed, therefore, is whether this seasonal rate proposal fits with the OPUC's overall policy that balances the desire to send price signals with the need to protect vulnerable citizens.

CUB's testimony is divided into two sections. In the first section (CUB/100) I discuss CUB's position on seasonal rates and the broader issue of time-varying rates. In the second section (CUB/200) Gordon Feighner responds to the specifics of the Staff and Idaho Power Company proposal set forth in the Stipulation and the issues that proposal raises. We then offer CUB's own proposal for rate design and related issues.

II. Electric Service is a Monopoly and Regulation Must Incorporate Consumer Protection.

A. Electric service is an essential service that is provided by a monopoly.

These two elements (an essential service provided by a monopoly) go to the heart of CUB's concerns. Electric service is necessary and essential. People need it to cook food, light their homes, power their appliances, and provide heat in the winter and cooling in the summer. It is not a luxury and is not something any person should be expected to do without. While Staff's testimony suggests that the Commission should enact policies that discourage the use of refrigerated air conditioning, CUB notes that for the oldest, sickest and youngest amongst us, the provision of air conditioning on a hundred degree day can be the difference between minor discomfort, hospitalization and even death.

Electric service is provided by a monopoly. Customers have no choice as to the provider that sells them the electricity. If a customer does not like the cost, the pricing plans offered, or the perceived value, the customer cannot shop elsewhere due to the monopoly.

B. While the PUC is an economic regulator, it is also responsible for protecting consumers.

Economic analysis can predict how customers generally will react to various circumstances, but economic analysis tells us little about how an individual customer will act. Staff's testimony reflects the economist's view of consumer behavior. In opening testimony, Staff described the goal of seasonal pricing based on its potential to change behavior:

> As budgets tighten, households look for ways to cut their utility bills—by substituting more efficient appliances (including light bulbs), by making energy-efficiency-promoting capital investments in their domiciles, etc."[2]

CUB asked a data request to have the Staff explain how raising rates will cause capital investment on behalf of customers. The answer was partially based on Staff Witness Dr. Compton's personal experience:

> Staff made no such "claim that causing customers' budgets to tighten enables [emphasis added] them to make capital investments." The tightening of budgets due to elevated utility prices motivates, not enables, the making of capital investments that will serve as substitutes for electricity consumption. Basic economic theory holds that when the price of a particular good is elevated, the demand for substitutes for that good is also elevated. From my own experience, monthly mid-winter electricity bills around $180 in earlier years motivated this Staff person to invest in a heat pump system this year in hopes of achieving a substantial electric bill reduction. The heat pump is viewed as a substitute for excessive electricity consumption.[3]

CUB does not want to quibble with Staff concerning basic economic theory, but it is important to recognize that the response of a PhD economist (who has studied electric ratemaking for many years and has worked for the Utah and Oregon PUCs) to an energy price signal does not tell us much about how the wide range of less energy savvy customers will respond to the same price signals. This is the issue at the core of CUB's disagreement with Staff and the Company in this Docket. Basic economic theory predicts how markets overall will respond to pricing stimuli, but does not tell us about the impact on individual customers. While it is true that there are PhD economists who are utility customers in Oregon, it is also true that there are elderly couples dealing with dementia, young families dealing with sick children, families dealing with grief, households dealing with unemployment, and individuals dealing with mental illness. Customers have all

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[2] Staff/100/Compton/11
[3] CUB Exhibit 102, CUB Data Requests to Staff, # 6.

kinds of circumstances that may prevent them from reacting to “price signals” in the rational way predicted by economists.

Because electricity is necessary and is provided by a monopoly, utilities and regulators have to be concerned with customers’ individual circumstances. When a person is required to purchase a necessary product from a for-profit monopoly, everyone should be concerned as to how the most vulnerable citizens are affected by the policies put in place by regulators. While the parties involved in this docket may think of seasonal rates as a simple design that anyone can understand, the seasonal tailblock proposal is actually quite complicated and will likely create confusion for many who are not economists - and maybe even for some who are. Customers who make the effort to try to understand the higher tailblock may believe that the higher tailblock only applies to the June through August usage – this is how Staff describes the seasonal tailblock – when in fact it also affects usage in May and September. These customers may believe that is it okay to run their air conditioner a lot late in May or early in September because they believe these periods are not part of the higher priced block, but as we demonstrate in CUB/200, late May usage can potentially be billed almost entirely at the June rate. Many busy or otherwise distracted customers will simply ignore the notice of seasonal rates that they would receive prior to the rates taking effect. The bottom line is that many customers will only become aware of the existence and true effect of seasonal tailblock ratemaking when they receive their first bill after the implementation of this policy – a bill that will likely shock them enough to knock their socks off.

While an economist might only be concerned with whether a particular pricing regime efficiently allocates a product, consumer advocates and regulators also have a consumer protection mission. This mission requires both CUB and the OPUC to look deeply at rate design issues and consider how they will impact all customers – the educated, the uneducated, the vulnerable and the oblivious – all of whom purchase this product out of necessity.

III. CUB's Concerns with Time-Differentiated Rate Design

While Staff's rate design proposal is narrowly tailored to a small number of Eastern Oregon households with air conditioning, CUB's discussion in this section will go beyond the current proposal and discuss other time-varying forms of rate design such as time-of-use and critical peak pricing. There are a couple of reasons for this. First, the microeconomic theory that supports seasonal rates would suggest that time-of-use rates are superior to seasonal rates. Second, CUB has encountered several individuals on Staff and at utility companies who believe that seasonal rates are the first step towards dynamic pricing. Because docket UM 1415 has failed to identify an Oregon policy with regards to time-varying rates, CUB has significant fears that this is the first step towards rates with greater volatility and unreasonable price signals.

Rate design is not a new issue, but its dynamics may be morphing as smart meters change the issue by allowing for the easy implementation of different pricing structures. Over the years, CUB has weighed in on many utility proposals on rate design and has discussed the rate design issue with many customers. As a result, CUB has reached several conclusions as to the integration of consumer protection and rate design. Each CUB conclusion is based on CUB's knowledge that residential customers are not a homogenous group.

A. Most customers pay bills, not rates.

In this Idaho Power Company rate case, residential customer bills will, on average, go up more than 26%, which is one of the largest price signals that this Commission has ever sent residential customers. This large increase in rates will cause a similarly large increase in bills. Customers who pay the bills will feel the impact, and some customers will react by reducing their usage. Historically, we can see that weather-normalized usage declines after large bill increases. With or without seasonal rates, customers will be receiving a very large, very harsh price signal over the next year.

For many years, advocates of energy efficiency have made the argument that customers pay bills and not rates. It follows that if we can help customers lower their usage, we can lower their bills, even if rates are going up in the process. The truth of this statement that customers pay bills and not rates is also an important one for rate design purposes. I have found over the years that when I question customers about their utility bills, most customers know the approximate amount of their electric bills, but few know – even approximately – the rates that they are being charged. Most Oregon customers do not know that their rates change based on tiers of usage. Customers who do know that there are tiers of usage do not necessarily know whether the tiers increase in price or decrease in price as their usage increases.

It is clear to me that the most important price signal any customer receives is the total sum at the bottom of their bill each month, because that is the cost that they write on their check. While bills are impacted by weather conditions and usage, customers still have a pretty good sense of whether rates (and costs) are going up, or not going up, by the direction of their bills and bank balances.

Residential bills are slated to increase by an average of more than 26% in this docket. Staff and the Company have stated a preference that rates increase by 35% for customers with air conditioning. CUB does not believe that it is necessary to try to further increase bills as a way to shock customers into reducing their usage, as customers are going to be shocked enough. Usage will already come down because of the 26.3% increase in rates approved in this docket. Because bills are going up so significantly, customers are receiving strong price signals that encourage conservation, and there is little need to experiment with microeconomic theory.

B. Most customers don't like rate hikes.

Most customers don't like rate hikes. This is common sense. Utilities are required to notify customers when rates are going up, and while customers do not necessarily know what rate they are paying, they know that an increase in rates will increase their bill. Under Staff's proposal, it is guaranteed that rates will increase every June. While Staff argues (without supporting evidence) that customers in Utah and Idaho got used to this schedule, it doesn't mean that customers prefer these guaranteed annual rate increases.

C. Many customers prefer simplicity.

CUB believes that customers generally prefer simplicity in pricing. In competitive markets like wireless phones, there is much evidence showing that customers prefer plans where the pricing is simplified. So-called anytime minute plans now dominate the market, whereas a few years ago most companies were marketing plans that had different prices between weekday daytime usage and evenings and weekends.

Simplicity also serves the customer protection mission of CUB and the PUC. The more simplified we make rate design, the more likely the most vulnerable households will still understand it, and the less likely that those customers will be confused and misled. For many customers who do not understand the notice that explains the seasonal rates, a high bill will represent the unintended consequences of a complicated pricing policy rather than a rational economic decision that considers the new higher cost of air conditioning and compares that cost to the benefits obtained from turning on the air conditioning.

D. Customers are owners, not renters.

When economists advocate more dynamic pricing, whether it is seasonal rates, time-of-use, or critical peak pricing, the price that is often proposed as the correct price signal is the marginal cost, which represents the cost of producing (or purchasing) the next increment of energy. Short-term marginal costs often reflect the volatile wholesale market, while long-term marginal costs often reflect the cost of a gas combustion turbine, along with forecasts of natural gas prices. Short-term wholesale products are arguably the most volatile products in terms of price. Long-term natural gas forecasts tend to be volatile and inaccurate.

Much of the support for this marginal cost pricing comes from microeconomic theory and is based on the idea that markets will create a more efficient allocation of resources if they are priced at marginal cost. It should be noted that this was a favorite argument of the former owners of PGE, who a decade ago wanted to sell off all of that company’s generation and move all customers into an unformed retail market where they could receive price signals unconnected to historic utility investments.

Historically, large capital investments made by utility companies have been funded by customers. This regulatory bargain is based on the concept that utilities finance capital investment in power plants. Customers then pay the utility its capital investment plus a rate of return on that investment. Then, in exchange for customers paying for the costs and profits associated with an investment, the capital investment is dedicated to provide energy for customers for its useful life.

In this respect, customers have an equity share in the power supply of a utility. The analogy I make is that we are owners, not renters. My wife and I bought a house in the Hawthorne neighborhood of Portland more than a decade ago. Today our house payments are less than what it costs to rent a studio apartment in the neighborhood. It could be claimed that we are paying below the marginal cost of housing in our neighborhood, resulting in an uneconomic allocation of housing in our neighborhood, or at least a less-than-optimal result. This is not an uneconomic result, but instead reflects the economics of making a capital investment (purchasing a house) as an alternative to paying marginal costs. This is the same decision that has been made in utility planning to build new power supply, rather than rely on wholesale market purchases.

If customers have spent years paying for a utility's capital investments and profit on ratebase, with the expectation that the ratebase was, and is, dedicated to customers, then it is important that the ratebase be dedicated to customers when customers most need it (on hot and cold days when demand is greatest). The idea that rates should reflect embedded costs during the periods of the year where marginal costs may be below embedded costs, and should reflect marginal costs when those costs are higher than embedded costs, amounts to always charging customers for the highest-cost available option. While Staff has reduced the impact of this rate design by limiting the marginal costs to only being reflected in the tailblock rate, customers with higher usage may still be required to pay overall average power costs that are greater than Idaho Power's overall average power costs for that period of time (owned resources plus power purchases).

In a data request to Staff, CUB asked about the tailblock rate compared to Idaho Power Company's costs in each month that is affected by seasonal rates (May to September). The Staff response was to compare Idaho Power Company's marginal cost to the rate. Idaho Power Company's cost of power supply in the May-June, June-July, July-August, and August-September billing periods is not, however, the marginal cost, but reflects the Company's hydro and thermal generation costs, plus an increment that is purchased or sold into the market.

E. Tiered rates are not widely understood, but when coupled with energy efficiency programs can incent energy efficiency investment.

CUB is skeptical that customers fully understand tiered rates. Most customers do not know they have tiered rates, and do not know the structure of the tiering. In its Opening Testimony, Staff points out that CUB has supported tiered rates in the past.[4] This is true. Even though tiered rates violate the principle of simplicity, CUB has recognized that, when combined with good energy efficiency programs, tiered rates can have an important role to play in encouraging load reduction. While an individual customer may not understand tiered rates, when that customer gets an energy audit or other energy advice from the Energy Trust of Oregon (ETO), the customer's utility, or energy contractors, these professionals do understand the impact of tiered rates. When energy professionals work with customers to explore customer options for reducing usage, tiered rates allow these professionals to give customers good information about the choices they confront.

[4] UE 213/Staff/100/15.

These rates align the interest of the customer with the interest of the system as a whole, by aligning the least cost investment to the system with the least cost investment to the customer. While the customer's primary price signal is the monthly bill, tiered rates allow non-economically savvy customers to seek out good economic advice from energy efficiency professionals and tap into energy efficiency programs whose costs are lower than the cost of alternative power supply.

It is important, however, for the tiered rates to be linked with good energy efficiency programs and good energy audits. CUB's examination of Idaho Power Company's energy efficiency programs suggests that the residential energy efficiency programs available to customers may not be robust enough to support tiered rates in Oregon.

F. Energy efficiency programs should be a stronger focus than price signals.

CUB believes that tiered rates help to ensure that energy efficiency programs are based on the right economics, even when the overall price signal associated with utility bills (based on average rates rather than incremental tailblock rates) does not fully incent the right actions. The goal is to encourage customers to participate in energy efficiency programs. Staff disagrees. Staff views price signals as more important than energy efficiency programs, and has made little effort to investigate Idaho Power Company's Oregon energy efficiency programs:

> It is this Staff person's belief that, historically, concerns about high utility bills have been the greater factor in promoting energy efficiency via capital investments—including new-construction investments towards that end.[5]

[5] CUB Exhibit 102/CUB Data Requests to Staff, # 6.

> Staff regards weatherization advocacy, strictly construed, as being outside the scope of the current docket and/or Dr. Compton's participation therein.[6]

The debate over whether price signals or energy efficiency programs are more effective is largely irrelevant. Customers pay bills, and bills are going up dramatically. The price signal of higher bills is one that customers will receive from this rate case and will continue to receive as additional utility investments are made. Price signals are a given, and work best when there are energy efficiency programs to help manage demand. Critical Peak Pricing programs, for example, clearly work better when they are combined with enabling technologies like smart meters and programmable thermostats that can help customers manage demand more easily.[7]

Staff believes that raising bills more than just the 26% average increase will encourage customers to make capital investments, whereas for many customers rising bills actually make capital investments more difficult. Many customers simply cannot afford to make the economically-rational capital investments in energy efficiency products that microeconomic theory would suggest. Price signals work for those with capital to invest, whereas customers without capital need energy efficiency programs to assist them. If Staff's view is adopted, the focus will remain on price signals rather than efficiency programs. The Oregon households who can least afford the price signals will then be the most harmed, because they can least afford to respond to the price signals.

In this particular case, it is clear that residential customers will be seeing a strong price signal. It is less clear whether residential customers are being provided with all of

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[6] CUB Exhibit 102, CUB Data Requests to Staff, # 7.
[7] CUB Exhibit 103, Barbara Alexander , Smart Meters, Real Time Pricing, and Demand Response Programs: Implications for Low Income Electric Customers, p 33.

the energy efficiency programs necessary for them to cope with the price signals being sent.

IV. The results from time-differentiated rates suggest that such rate design is problematic from a consumer protection standpoint.

CUB wants to be upfront about its limited experience in regard to seasonal rates, time-of-use rates, critical peak pricing, and other forms of pricing that send signals to customers. This is why CUB has pushed for a docket where CUB could use intervenor funding to bring in a national expert to help stakeholders understand the impacts that these sorts of programs can have on residential customers. However, the evidence that we have seen from other states suggests that there are real concerns with mandating pricing plans in order to change behavior.

The results of pilots of various time-of-use rates raise several concerns:

A. The bulk of the energy savings comes from a relatively small segment of the participants.

Time differentiated rate programs can reduce peak energy usage. However, 80% of the peak energy savings in California Critical Peak Pricing Pilots came from just 30% of the participants.[8] This means that many households had little or no savings, and were likely impacted negatively by the peak-hour pricing. It is important to consider the impact of these programs on participants who do not alter their usage patterns. What are the bill impacts? Are people pushed into arrearage? Even if the programs are moving costs from one part of the year to another, as is done with seasonal rates, volatility in bills is a real

[8] IMPACT EVALUATION OF THE CALIFORNIA STATEWIDE PRICING PILOT, Charles River Associates, 2005;

problem for low-income households and others who live from paycheck to paycheck and have trouble handling unexpected bills.

B. Very little savings came from low income households.

In California, customers with incomes of 175% or less of the federal poverty guidelines are eligible for a rate discount. Many of these customers were included in the California Critical Peak Pricing pilot, and the results showed that there were "essentially zero" savings from these customers.[9]

C. College education makes a huge difference in customers' ability to respond to price signals.

The Charles River Associates study of California Critical Peak Pricing programs shows that people with a college degree on average reduced their energy usage by more than twice as much as people without college degrees.[10] While economists often think of customers as "super consumers" who process information and optimize economic decisions efficiently, many consumers don't have the educational background that would allow them to do this.

D. The bulk of the savings comes from higher income customers.

The Charles River Associates study shows that the response rate of families making $100,000 was significantly greater than the response rate of families making $40,000 in the California pilots.[11] This result makes sense, as college degrees can be associated with higher incomes, and fit with Staff's explicit goal of using price signals as a way to incent

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[9] CUB Exhibit 103, Barbara Alexander , Smart Meters, Real Time Pricing, and Demand Response Programs: Implications for Low Income Electric Customers, p. 32-33.

[11] IMPACT EVALUATION OF THE CALIFORNIA STATEWIDE PRICING PILOT, Charles River Associates, 2005

customers to make capital investments. But this is very troubling from a consumer protection standpoint. Low-income customers are often the least able to understand and respond to price signals and are the persons with the least financial ability to make capital investments. These customers will be forced to absorb price signals, which will serve to further reduce their standards of living. It also is important to note that the $40,000 figure used by Charles River to represent low or moderate income households, is greater than the medium household income in Ontario, Oregon.[12]

E. The programs are more successful when combined with enabling technology, not just price signals.

The California pilots also show that enabling technologies, such as programmable thermostats or technology that allows a utility to cycle appliances, greatly improve the performance of customers in time-of-use pricing plans.[13] If the goal is to provide customers with an incentive to reduce summer air conditioning use, it would seem that the price signals would work much better if they were combined with a program that offers customers programmable thermostats – particularly low-income customers who cannot make such an investment on their own. There is, however, no enabling technology being offered with this pricing proposal.

V. CUB's History on Rate Design.

CUB has been very involved in several cases where rate design and price signals were an issue.

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[12] CUB/200/Feighner/2

[13] CUB Exhibit 103, Barbara Alexander , Smart Meters, Real Time Pricing, and Demand Response Programs: Implications for Low Income Electric Customers, p.33.

A. Local Measured Service (LMS) for Telephone Customers.

CUB was created by voters in 1984 and got up and running in 1985, which coincided with PUC Commissioner Gene Maudlin's plan to implement mandatory local measured service (LMS) for all phone customers. Under his plan, rather than paying a flat monthly fee for local phone service, customers would be charged by the call, by the length of the call, by the distance of the call and by the time of day and day of the week of the call. At the time, Measured Service was offered as an optional service, but fewer than 10% of residential customers opted into measured service. Pacific Northwest Bell claimed that there were capacity issues associated with daytime calling, and it was therefore fair for customers to pay for what they used. CUB argued that the phone system was a sunk investment and that there was little or no incremental cost to a phone call.

Today, when unlimited VOIP calling plans to anywhere in the world can be had for a flat monthly fee, this debate about measured phone service seems ancient. CUB learned in this debate that customers overwhelmingly wanted simplicity in how their phone calls were priced. They did not want to worry about the time of day that they made a phone call, how long they were on the phone, or the distance that they were calling. Because Commissioner Maudlin seemed intent on enacting mandatory LMS, OSPIRG and the NFIB joined together in 1986 to put forth a ballot initiative to prohibit mandatory LMS. The voters supported the ban overwhelmingly, with more than 802,000 voters supporting it and just under 202,000 voters opposing it. It is rare that 80% of voters agree on anything.

B. Enron's customer choice proposal.

Many of the microeconomic arguments for seasonal rates and other forms of time-of-use rates are similar to the arguments that were made when Enron and PGE asked the Commission to allow the Company to divest of all generation assets and kick all customers out into a non-existent retail electric marketplace. CUB was told that moving customers to market rates would promote economic efficiency. Customers would receive price signals that reflected the real marginal costs of their usage, not an artificial history of inefficient utility decision-making. CUB was concerned with the volatility of deregulated rates, the likelihood of rate increases, the loss of Oregon customers' hydro endowment, the lack of adequate consumer protection, the addition of marketing and aggregation costs, and the lack of any demand from residential customers for a new, more complicated system of purchasing an essential service.

In CUB's surrebuttal testimony, CUB discussed its concerns with volatile market prices:

> PGE (PGE/1600/Schnitzer/12 argues that it is "not an especially sensible policy objective" to protect customers from market price volatility. CUB respectfully disagrees. We believe that it is sensible to protect customers from the sort of price volatility we have seen recently in the wholesale market and the Futures market. Current public policy requires that rates be "just and reasonable." While an economist from the Chicago School might argue that it is efficient for the market to send the right price signals to consumers during a severe cold spell or heat wave, we believe that it is not "just and reasonable" to put people's lives in danger by making their rates reflect the true price signals brought on by triple-digit heat or single-digit cold. How does Mr. Schnitzer's economic model input human discomfort or loss of life? Sometimes public policy and economic theory have different objectives. [14]

[14] UE 102/CUB/400/Jenks-Eisdorfer/7.

In CUB's Opening Testimony in that docket, we discussed our concerns about whether customers had the time or interest to optimize their economic decisions relating to this new electricity marketplace. The testimony quoted a book that discussed this issue:

> Economist Rober Kuttner, in his book <u>Everything for Sale: The Virtues and Limits of Markets</u>, discusses this problem:
>
> …economic decisions are often based on misinformation *ex ante*, and yield disappointment ex post. But as products and decisions proliferate, that prospect is a receding mirage: there are not enough hours in the day. As essayist Steven Waldman writes, "[S]pend the optimal amount of time on each decision and pretty soon you run out of life."
>
> Indeed, choice itself, one of the most prized trophies of the market system can become self-negating when taken to an extreme. The market model requires the informed consumer to hold the producer accountable. But an overwhelmed consumer cannot competently play that role. "The more choice available," Waldman writes," the more information a consumer must have to make a sensible selection. When overload occurs, many simply abandon the posture of rational Super-Consumer."[15]

C. Time of use rates.

CUB's alternative to Enron's deregulation was the creation of a portfolio of rate options for residential customers. These options would continue to be regulated and the base option (the default) would be the traditional service with the traditional pricing. CUB did support providing a time-of-use rate as an option for customers. Some customers have the ability to switch their usage to off-peak times, which reduces costs to the utility. By recognizing these cost savings, a utility can offer customers who switch usage to off-peak times a discount. Because most energy savings from time-varying rates come from a small subset of participants, it makes more sense to offer voluntary programs. If 70% of customers are not going to respond significantly to price signals, and many will be harmed by a program, it does not make sense to force the program on them.

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[15] UE 102/CUB/200/Jenks/6-7.

D. AMI.

CUB opposed PGE's plans to implement advanced metering infrastructure (AMI), first in UE 115 and later in UE 189. A large part of our concern was that it would lead to mandatory or default time-of-use or critical peak pricing plans:

> 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. 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 goal or an alternative," the Joint Testimony supporting the Stipulation is full of references to the importance of time-of-use pricing.[16]
>
> 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 time. 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:
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>> 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.
>>
>> With the ability to measure comes the ability to use price as the means to alleviate supply-demand imbalance.[17]

[16] UE 189/CUB/100/Jenks/10-11
[17] *Ibid*, page 14.

E. Critical Peak Pricing pilot.

CUB has not played a major role in PGE's Critical Peak Pricing pilot program. We believe that there may be a role for critical peak pricing as an optional program, but continue to be concerned about it as a mandatory or default program. CUB knows from discussions in workshops that there are employees of the PUC and various utilities who believe that the pilot is the first step towards making it a mandatory program.

In addition, CUB is not sure that another pilot provides a lot of useful information. There have been other critical peak pricing pilots around the country. These pilots have shown, as I have discussed above, that people with higher incomes, college degrees and enabling technologies can respond well to critical peak pricing, but other customers cannot. CUB reiterates its reservations about implementing a program that harms vulnerable households.

F. Seasonal rates / UE 197.

CUB joined Staff in opposing seasonal rates in the last Idaho Power Company Rate Case.[18] In this case, Staff has joined Idaho Power Company in supporting seasonal rates. In PGE's last rate case (UE 197), Staff proposed seasonal rates and CUB opposed them:

> The Staff proposed a new rate design which would add a seasonal summer block to residential customers. While we appreciate that the Staff did not propose full seasonal rates for residential customers, we still must oppose their proposal.
>
> Customers do not want time-of-use or seasonal rates. Customers have a time-of use option and it is not widely used. In other industries, such as wireless phones, we have seen customers move away from time differentiated rates. In a nutshell, most customers don't want to think about different rates for different usage patterns.
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> CUB has supported tiered rates. They have a long history in Oregon, going back to Oregon Fair Share's advocacy for Lifeline Rates in 1981. But

[18] UE 213/Staff/100/Compton/13

> these rates are constant and while they change with usage, they do not change from hour to hour or month to month. Quite frankly, we do not believe that the hassle is worth the result or the potential risk to customers. While economists like price signals, most customers are too busy in their daily lives to respond in a way so as to optimize each economic decision. But there will be some customers who will notice and will want an explanation each year when their rates change as we enter the summer months.
>
> If the Commission is inclined to add a third pricing block, we would recommend that such a block be done on an annual basis. This will allow these rates to be stable. It will remove the need to change prices an additional two times per year. The change in rates will only have the desired effect if it is well advertised so customers are aware of it. Having it be well-advertised, of course, will increase the amount of time that we, and the PUC, spend explaining to customers why their rates have changed.[19]

After filing surrebuttal testimony, PGE, CUB and ICNU agreed to a stipulation which asked the Commission to open a new docket to review this issue and ICNU's concerns with rate spread. These three parties specifically asked for a new docket to allow CUB to bring in an expert witness to address the issue of how these sorts of rate options impact customers. Staff opposed opening a new docket.

The Commission agreed with PGE, CUB, and ICNU, and in Order 08-585 ordered a new docket:

[19] UE 197/200/CUB/35.

> …parties representing a broad spectrum of customers agree with PGE that a separate proceeding, promptly undertaken, will enable the Commission to address the issues of cost allocation and rate design in an orderly and throughgoing manner.
>
> We agree. The instant proceeding has been characterized by the extraordinary number of unresolved issues, and it has been a particularly arduous process for the parties to create a record and advocate their positions with respect to them all. Adequate examination of important questions of rate spread and rate design deserves a separate proceeding that will enable the parties to prepare and put forward an evidentiary record worthy of the substance of the issue.
>
> A separate proceeding will be opened to address rate spread and rate design issue for PGE and its customers. In such a proceeding, we request the parties to also address how any resulting changes in rate design will be coordinated with the implementation of rate design options enabled by PGE's deployment of its Advanced Metering Infrastructure approved in Order No. 08-245.[20]

G. UM 1415.

Out of the Commission Order came docket UM 1415, which was supposed to investigate rate spread and rate design. Unfortunately, the proceedings of the docket never achieved CUB's expectations or the expectations of the Commission Order that established it.

CUB Exhibit 104 shows the official schedule that was established in that docket. There is no place in that schedule that allowed parties to put forward an evidentiary record worthy of the issues involved as ordered by the Commission. The docket started with some workshops on rate spread, but was supposed to later have a second phase on rate design. While workshops were eventually held on rate design, a schedule was never established that allowed for that phase. The docket became a series of informal workshops run by Staff, which had opposed the establishment of the docket.

[20] OPUC Order 08-585, page 3.

CUB recognizes now that CUB should have objected when it realized that Staff was not intending to allow the docket to move beyond workshops. CUB should have asked the ALJ to establish a schedule for testimony and evidence. CUB failed to do so, and thus CUB bears some responsibility for the failure of the UM 1415 docket to meet CUB's, and the Commission's, expectations. CUB continues to believe that there is a need for a testimony-laden docket to explore the implications of time-varying rates before the State of Oregon embarks on a new adventure in pricing experiments.

In UM 1415, CUB had intended to hire Barbara Alexander as an expert witness. Ms. Alexander wrote a report entitled Smart Meters, Real Time Pricing, And Demand Response Programs: Implications For Low Income Electric Customers (May 2007). While CUB had hoped to have her as a witness to discuss this issue and respond to specific Staff proposals, we did not have that opportunity. We have, however, attached sections of her report hereto as CUB Exhibit 103. CUB recognizes that her report is about time-of-use and critical peak pricing, not seasonal rates, but the economic theory to support seasonal rates is the same as the theory to support time of use and critical peak pricing. While CUB was unable to call Ms. Alexander as a witness in UM 1415, we believe that her views are relevant both in this docket and in future dockets where the Commission will consider time-varying rates.

H. Future Dockets.

As noted above, CUB still believes that the Commission should hear from Ms. Alexander or another expert, and should consider the implications of time-varying pricing before experimenting on Oregon customers. As things stand, rate design will not have a carefully considered record outside of a general rate case, and will be one of many issues that need to be addressed in any utility's general rate case. This structure makes things difficult for CUB, since Staff – not the utilities – are the primary proponent of time-varying rates, and Staff does not produce its argument until well into a rate case. This means that CUB could be obligated to spend tens of thousands of dollars on an expert witness in a case to discuss an issue that might not even be contested. CUB prefers not to risk intervenor funding in this way. Since customers pay for intervenor funding, it should be used judiciously.

Because of this concern, CUB asked Staff -at the last workshop in UM 1415 - whether Staff intended to push for seasonal rates in the upcoming rate cases of PGE and PacifiCorp. Staff informed CUB that, unlike in UE 197, Staff did not intend to press this issue in the PGE case, but might in the PacifiCorp case. Because of CUB's desire to hire an expert witness on this issue, we request that Staff inform all interested Parties in these dockets of Staff's intent to raise this issue in any rate case before the pre-hearing conference in that rate case takes place.

I. UE 213.

Instead of providing an opportunity to debate seasonal rate issues in a docket designed to look at rate spread and to build an appropriate seasonal rate record (as CUB contends is necessary), Staff took up the issue of seasonal rates in UE 213. Staff and the Company are well aware that CUB cannot afford to bring in a national expert witness to discuss the Staff's and Company's seasonal rate proposal in UE 213 where there is no provision for intervenor funding . This decision was unfortunate. CUB thinks that its hoped-for expert witness, Ms. Alexander, would have helped create a much better record around seasonal rates and other pricing programs that are enabled by AMI. CUB believes that Staff's case is largely built on assumptions about microeconomic theory. Receiving evidence-based testimony from a national expert about how such pricing would impact customers would have been very useful in debunking existing myths around this issue.

VI. Oregon's Regulatory Policy Regarding Rate Design

No energy utility in Oregon currently offers mandatory seasonal or time-of-use rates for residential customers. CUB believes that this is consistent with Oregon law and regulatory policy.

A. Minimizing Rate Changes.

Minimizing rate changes is a clear and long-standing policy in Oregon. It is one of the policy reasons that the Commission is allowed the authority to grant deferred accounting:

> Upon application of a utility or ratepayer or upon the commission's own motion and after public notice, opportunity for comment and a hearing if any party requests a hearing, the commission by order may authorize deferral of the following amounts for later incorporation in rates:
>
> …Identifiable utility expenses or revenues, the recovery or refund of which the commission finds should be deferred in order to minimize the frequency of rate changes…[21]

We have also seen this policy applied outside of deferred accounting. Numerous rate changes are regularly combined into a single event in order to minimize rate changes. For example, NW Natural has included a variety of rate changes that are timed to coincide with that Company's Purchased Gas Adjustment to avoid having several rate changes in a single year. Seasonal rates go against this policy by guaranteeing at least two rate changes each year.

[21] ORS 757.259(2)

ii. Equal pay plans.

Oregon utilities are required to offer equal pay plans that allow residential customers to spread their high winter heating bills or high summer cooling bills across the year to ease the difficulty of paying those bills.[22] The Commission has been a strong supporter of Equal Pay Programs and regularly promotes them when there is a large increase in rates that may cause customers difficulty with their high heating and cooling bills.

This case, with a residential rate increase of more than 26%, is exactly the kind of case that has led the Commission to promote equal pay. In 2008, when it looked like natural gas customers were facing significant rate hikes, the PUC released a toolkit to help customers. It included the following advice:

> Consumers should also consider taking advantage of bill payment plans, if offered by their local gas utility, to even out their monthly gas bills. These plans allow consumers to reduce their winter gas bills by paying more during other times of the year when gas consumption is normally much lower. Of course, unlike energy assistance programs, under a bill payment plan consumers are responsible for paying the full cost of gas purchased by the utility.[23]

This case is exactly the sort of situation that led the Commission to recommend that customers consider equal pay plans. However, combining seasonal rates, which are designed to increase the price signals of seasonal heating and cooling, with equal pay which will by design reduce that price signal by spreading the impact of higher seasonal rates across the entire billing year, makes little sense. Seasonal rates and equal pay programs work at cross purposes. In the situation where customers are being hit with a 26% rate increase, it is more important to promote the option of equal pay plans than it is to create even greater price signals.

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[22] OAR 860-021-0414, Equal-Payment Plans for Residential Electric and Gas Service

[23] PUC natural gas toolkit, http://www.puc.state.or.us/PUC/Nat_Gas_Tool_Kit_2008.pdf

B. SB 1149 requires cost-based rates.

As I have pointed out, many of the arguments here are similar to the arguments that the companies made regarding deregulation. It was in response to the Enron/PGE deregulation proposal that CUB and the PUC advocated for SB 1149, which established Oregon's current electric energy policy. That policy created choices such as a market option (time-of-use), but also mandated that customers continue to receive cost-of-service rates, as opposed to market rates. CUB believes that this law allows market-based rates as an option for customers, but requires cost-of-service rates as the default. Moving towards an explicit goal of aligning rates with marginal costs is a move away from the policy that SB 1149 established.

> (1) (a). Except as provided in this subsection, on and after March 1, 2002, an electric company shall provide all retail electricity consumers that are connected to the electric company's distribution system with a regulated, cost-of-service rate option.
>
> (b) The Public Utility Commission by order may waive the requirement of paragraph (a) of this subsection for any retail electricity consumer other than residential electricity consumers and small commercial electricity consumers…
>
> (2) Not later than March 1, 2002, each electric company shall provide each residential electricity consumer that is connected to its distribution system a portfolio of rate options. The portfolio shall include at least the following options:
>
> (a) A rate that reflects significant new renewable energy resources; and
>
> (b) A market-based rate.

A market based rate such as time-of-use pricing is required as an option for customers, but customers are required to be provided the option of traditional cost-of-service or embedded rates.

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

EMPLOYER: Citizens' Utility Board of Oregon

TITLE: Executive Director

ADDRESS: 610 SW Broadway, Suite 308
Portland, OR 97205

EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

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, Environment Oregon Research and Policy Center
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America

Oregon Public Utility Commission Staff Response
UE 213 – Citizens' Utility Board's First Set of Data Requests to OPUC
Dated December 24, 2009 – Due January 4, 2010

Data Request Nos. 1-14

Request No. 1: Staff/100/Compton/10 states that "If summer prices do not reflect that season s incremental cost allocation, customers in the other seasons will end up bearing some of the burden of the costs incurred to meet summer loads." Does Staff agree that since summer rates for irrigation customers do not reflect the incremental cost of service, customers in other classes and customers whose heavy-use periods do not occur during the summer are bearing some of the burden of the costs of irrigation service?

Response:

Yes, customers in all other schedules "are bearing some of the burden" of the costs of providing service to irrigation customers.

Request No. 2: Staff/100/Compton/11 states that "It would be unfair in the current instance for the heavy winter users to have to subsidize heavy summer users." Does Staff believe that it is fair for other users to subsidize irrigation customers?

Response:

In this circumstance, yes, due to the offsetting consideration that basing the rate spread strictly on costs would have resulted in an "untenably high" rate increase to the irrigation schedule.

Request No. 3: Staff/100/Compton/10 states that:
For some time, the trend nationally has been for residential customers to install refrigerated air conditioning. This trend has not reached completion in low-humidity, arid areas where less energy-intensive evaporative coolers have long been in use. There should be a strong summer-costs price signal in place so as to discourage refrigerated air conditioning use where the benefits do not exceed the additional electricity costs.

a. Please provide support for the statement that the benefits of refrigerated air conditioning do not exceed the additional electricity costs.

b. Does Staff believe that proper price signals will slow the adoption of refrigerated air conditioning in Idaho Power s Oregon service territory?

c. Has the introduction of summer seasonal rates slowed the trend towards refrigerated air conditioning in Idaho? If yes, please provide documentation. If no, please explain why not.

d. Has the introduction of summer seasonal rates slowed the trend towards refrigerated air conditioning in PacifiCorp s Utah service territory? If yes, please provide documentation. If no, please explain why not.

e. Does Staff believe that there are cases where the benefits of summer irrigation do not exceed the additional electricity costs?

Response:

a. Staff s testimony did not say that "the benefits of refrigerated air conditioning do not exceed the additional electricity costs." The statement instead referred to the role of an accurate price signal in *avoiding* the economically inefficient outcome where the costs of having and using refrigerated air conditioning exceed the benefits.

b. The microeconomic law of demand holds that as the price of something is elevated, the quantities demanded of that thing *and its complements* will be reduced. (In this example, electricity and refrigerated air conditioning are complementary goods.)

c. According to the economic law of demand, the introduction of the higher summer rate in Idaho would imply some degree of consumer response—how much I could only speculate.

d. As noted in Staff s testimony, the level of inversion in PacifiCorp s Utah residential summer rate was substantial. The law of demand would imply some degree of consumer response to the elevated price. To actually *measure* that degree would entail speculation as to what the increase in refrigerated air conditioning would have been absent the elevated price. Staff is not in a position to engage in such speculation.

e. Farmers will not, *a priori*, incur additional electricity costs on the margin if they believe the value of the increase in output consequent to incurring those costs will not equal or exceed them. *A posteriori*, unexpected crop failures or market downturns may result in incremental output values being beneath the additional electricity costs.

Request No. 4: Staff/100/Compton/10 states:
The older houses in Eastern Oregon are more likely to be heated with electricity relative to newer houses. Those same newer houses, and other homes occupied by more affluent residents, are also more likely to be cooled with refrigeration than are the older houses in that area. The result of failing to have electricity prices that reflect the seasonal cost differences would be to have the generally less affluent winter peaking customers subsidize the more affluent summer-peaking customers.
Please provide documentation to support the following statements:

a. “Older houses in Eastern Oregon are more likely to be heated with electricity relative to newer houses.”

i. Please define the year of construction before which Staff would consider a home to be “older.”

ii. What percentage of these older homes in Idaho Power s Oregon service territory are heated with electricity?

iii. What percentage of newer homes are heated with electricity?

iv. Please provide any available information showing the market share of primary fuel sources used to heat newer homes in Idaho Power s Oregon service territory.

b. “Newer homes and other homes occupied by more affluent residents are more likely to be cooled with refrigeration than are older homes.”

i. What percentage of newer homes are cooled with refrigerated air conditioning?

ii. What percentage of older homes are cooled with refrigerated air conditioning?

iii. What is the average income of households with refrigerated air conditioning vs. the average income of households that use evaporative cooling or other cooling methods?

Please provide household income figures or any other supporting information for the claim that winter peaking customers in Idaho Power s Oregon service territory are less affluent than summer peaking customers.
Response:

a. i. Natural gas came to Eastern Oregon in the 1950s. (Source: John Stolz of CNG.) If the experience in that area was similar to Utah s, all-electric homes were being built into the 1960s, after which virtually all homes in the urban centers were built with natural gas heating. “Older homes” would be those built before natural gas heating became the norm, i.e., built prior to the late 1960s.

ii. From the Company s response to Staff s Data Request No. 250, we learn that, “In the Western Region [which includes the Oregon territory], 43% of customers reported [„in late 2004] their primary heat source to be electricity.” Since virtually all newer homes in the more urban areas, i.e., those areas where natural gas is available, heat with natural gas,

one must conclude that most of the electrically heated homes are either older homes or, if newer, located in rural areas. Staff does not know the percentages.
iii. See response in a.ii.
iv. No such information is available to Staff (see above).

b. i. The very large majority. (See Response 5.c., below.)

ii. With a 72% overall penetration rate for refrigerated air conditioning (see Response 5.a., below), and a higher than 72% penetration rate for new homes, one must infer that the percentage of older homes with refrigerated air conditioning is well beneath the percentage of newer homes with refrigerated air conditioning.
iii. Staff possesses no knowledge regarding those averages. But because income correlates positively with both newness of housing (which is positively correlated with being equipped with refrigerated air conditioning) and with having replaced evaporative cooling with refrigerated air conditioning for any age of housing, one must infer that households with refrigerated air conditioning enjoy higher average incomes than are possessed by households that use evaporative cooling or other cooling methods.
Another indicator of the negative correlation between income and the use of evaporative cooling: Whereas only 9.2% of IPCO s customers, overall, use evaporative cooling, 31.7% of manufactured homes rely on that type of cooling. (Source: Page 10 of Idaho Power s Home Energy Survey of March, 2009.) Given the tendency of manufactured homes to be of lower value than conventional homes, and give the positive correlation between home value and income, one must infer again that households using evaporative cooling have lower income than do those using refrigerated air conditioning.

Request No. 5: For Idaho Power s Oregon service territory, please provide the following:

a. Support for the statement that “less energy-intensive” evaporative coolers are being replaced by refrigerated air conditioning (Staff/100/Compton/10)?

b. Identify the number of customers with evaporative coolers today versus 5 years ago.

c. Identify the number of customers with refrigerated air conditioning today versus 5 years ago.

Response:

a. From the Company s response to Staff s Data Request No. 251, we learn that, “In the Western Region [which includes the Oregon territory], 38% of customers reported [„in late 2004] having central air conditioning…with 34% of customers reporting owning one or more window or wall mounted air conditioning units.” With as much as a 72% penetration rate of refrigerated air conditioning, and given the extensive popularity of evaporative coolers in earlier times, it is inevitable that the former has replaced many of the latter.

b. I have no such specific information.

c. I have no such specific information. It has been my observation that the large majority (if not virtually all) of new housing that is equipped with central heating also have central air conditioning. (Lynn Anderson of the Idaho Commission Staff shares that observation.) The relatively high penetration rate mentioned above can be explained both by customers converting from evaporative coolers to refrigerated air conditioning and by virtue of the fact that most new housing is equipped with refrigerated air conditioning.

Request No. 6: Staff/100/Compton/11 states that "As budgets tighten, households look for ways to cut their utility bills—by substituting more efficient appliances (including light bulbs), by making energy-efficiency-promoting capital investments in their domiciles, etc."

a. Does Staff believe that most residential "energy-efficiency-promoting capital investments" are made in response to tight budgets, or to energy efficiency programs that offer incentives?

b. What evidence does Staff have to support the claim that causing customers budgets to tighten enables them to make capital investments?

Response:
General: The context of the quotation was for budgets to "tighten" due to electricity prices going up.

a. It is this Staff person s belief that, historically, concerns about high utility bills have been the greater factor in promoting energy efficiency via capital investments—including new-construction investments towards that end.

b. Staff made no such "claim that causing customers budgets to tighten *enables* [emphasis added] them to make capital investments." The tightening of budgets due to elevated utility prices *motivates*, not *enables*, the making of capital investments that will serve as substitutes for electricity consumption. Basic economic theory holds that when the price of a particular good is elevated, the demand for substitutes for that good is also elevated.

From my own experience, monthly mid-winter electricity bills around $180 in earlier years motivated this Staff person to invest in a heat pump system this year in hopes of achieving a substantial electric bill reduction. The heat pump is viewed as a substitute for excessive electricity consumption.

Request No. 7: Staff s testimony seems to reflect a desire to discourage the use of refrigerated air conditioning. Please explain why Staff is not advocating strengthening weatherization programs that will help to reduce both winter and summer peak loads in Idaho Power s Oregon service territory.

Response:

Staff regards weatherization advocacy, strictly construed, as being outside the scope of the current docket and/or Dr. Compton s participation therein.

Request No. 8: Does Staff support moving to time-of use rates for residential customers in Idaho Power s Oregon service territory?

Response:

No.

Request No. 9: Staff/100/Compton/18 states that customers generally "prefer a fixed monthly charge, *independent of usage."* Please provide support for this claim.

Response:

There are two major advantages to customers of having a monthly charge that is fixed in the sense that it is not affected by the level of usage: 1) there is no budgetary uncertainty; 2) incremental consumption is free. With those advantages in mind, it is no wonder that when telephone companies offered customers the choice of local measured service (i.e., with an incremental charge for every call/minute) versus unlimited, flat-rate local service, the overwhelming preference was for the flat-rate service. However, there is obviously a limit to how much customers will, individually, pay for the privilege of having those two advantages.

Request No. 10: Staff/100/Compton/18-19 states that June costs are “quite low.” How does the 8.3 cents/kWh summer tail block rate relate to Idaho s Power s costs in each of the following months:

a. May

b. June

c. July

d. August

e. September

Response:
Proposed Residential Marginal
Tail Block Rate Energy Cost

a. May 7¢ 4.3¢

b. June 8.3¢ 4.3¢

c. July 8.3¢ 13.9¢

d. August 8.3¢ 9.8¢

e. September 7¢ 6.9¢

Clarification: As shown in the table above, the 8.3 cents/kWh summer tail block rate only applies to the three summer months.
Marginal Energy Cost Source: Exhibit Idaho Power/802 Tatum/6. Note that to obtain full marginal power costs requires the addition of marginal costs for demand (generation, transmission and distribution) to marginal energy costs.

Request No. 11: Customer billing cycles do not correspond to calendar months. How are bills that overlap both seasonal billing periods treated? For example, if a customer is on a May 15 to June 14 billing cycle and experiences a hot weather event on May 20th, at what rate is the customer billed? Please provide the formula Staff proposes to use to calculate bills that overlap both periods.

Response:

Refer to the Company s response to CUB s Data Request Nos. 40 and 43 for examples of how Idaho Power calculates bills where the summer and non-summer seasons overlap. Staff will not be making an independent proposal on this subject in this docket.

Request No. 12: What is the proposed tailblock rate for irrigation customers in June, July, and August? How does this rate relate to Idaho Power s costs during those months?

Response:

Staff has yet to see a proposed tail block rate for irrigation customers. The average overall rate according to the stipulation (as indicated on line 32 of Exhibit Staff/102) is 5.4¢ per kWh. (That compares, respectively, to 6.455¢ and 3.592¢ for residential and large power [i.e., directly from transmission] customers.)

Request No. 13: Staff Exhibit 102 shows that a customer who has air conditioning and uses 1500 kWh per month in the summer will see an increase in summer rates of 31%, while an irrigation customer during the same month will see an average increase of 27%. This rate structure indicates that irrigation customers are being subsidized by other rate classes, as irrigation customers are generally summer peak users. Does Staff consider this to be an equitable and fair rate structure?

Response:

See Staff Response to question #2. Also, note from Exhibit Staff/102 that, respectively, the overall increases under the Stipulation are 26.30% for the residential class and 27.96% for the irrigation class.

Request No. 14:
Staff/100/Compton/15 states:
Having seasonal rates for Oregon s residential customers as well as for those in Idaho would itself eliminate the possible confusion to customers who reside in both jurisdictions and who wonder why rates for the same company were structured differently.

a. Please provide a count of the number of residential customers that are ratepayers in both Idaho Power s Oregon and Idaho service territories.

b. Does Staff believe that there is undue confusion regarding rates among residential customers who are ratepayers in multiple jurisdictions served by different electric utilities?

Response:
a. Staff has no such count, nor does the Company with any level of precision. Potentially "confused" customers in this regard would not be limited to customers who resided in both jurisdictions (with one of the domiciles possibly being a vacation home), but would apply to landlords with utility-furnished rentals in both states as well as anyone whose regular affairs took them on both sides of the state line and who paid attention to utility rates for whatever reason.
b. Staff referred to "possible confusion" as arising from having different rate structures imposed for the same kind of service by the *same* company. When a customer is served by two *different* companies there is not the same expectation regarding consistency as would be the case if the service came from the same company.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 213

In the Matter of	)
	)
IDAHO POWER COMPANY,	)
	)
Request for a General Rate Revision	)
	)

CUB EXHIBIT 103

EXHIBIT ACCOMPANYING TESTIMONY OF ROBERT JENKS

SMART METERS, REAL TIME PRICING, AND DEMAND RESPONSE PROGRAMS:
IMPLICATIONS FOR LOW INCOME ELECTRIC CUSTOMERS

BY BARBARA ALEXANDER - 2007

January 19, 2010

SMART METERS, REAL TIME PRICING, AND DEMAND RESPONSE PROGRAMS:

IMPLICATIONS FOR LOW INCOME ELECTRIC CUSTOMERS

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Revised: May 30, 2007

Barbara R. Alexander opened her own consulting practice in March 1996. From 1986-1996 she was the Director, Consumer Assistance Division, at the Maine Public Utilities Commission. Her special area of expertise has been the exploration of and recommendations for consumer protection, universal service programs, service quality, and consumer education policies to accompany the move to electric, natural gas, and telephone competition. She has authored "A Blueprint for Consumer Protection Issues in Retail Electric Competition" (Office of Energy and Renewable Energy, U.S. Department of Energy, October, 1998). In addition, she has published reports that address price volatility and consumer benefits associated with the provision of basic electric and natural gas service: "Managing Default Service to Provide Consumer Benefits in Restructured States: Avoiding Short Term Price Volatility" (2003), available at http://www.neaap.ncat.org_experts_index, and "Natural Gas Price Volatility: Regulatory Policies to Assure Affordable and Stable Gas Supply Prices for Residential Customers," (2004), available at http://www.ncat.org/liheap/news/Feb04/gaspricevol.htm. Most recently, Ms. Alexander has published an analysis of "red flag" issues associated with state consumer protection regulations, "Red Flags for Consumer Protection Policies Governing Essential Electric and Gas Utility Services: How to Avoid Adverse Impacts on Low Income Consumers" (October 2005), which is available at: http://www.liheap.ncat.org/pubs/balexanderconsstudy05.doc. Her clients include national consumer organizations, state public utility commissions, and state public advocates.

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The opinions and conclusions expressed in this report are
those of the author alone and do not represent
the views of Oak Ridge National Laboratory or the
U.S. Department of Energy

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SUMMARY OF FINDINGS AND RECOMMENDATIONS

The push to install more expensive smart meters (and their associated communication and data storage systems) and consider more "real time" or volatile electricity prices for residential electric customers has the potential for significant harm to many residential customers and particularly to limited income and payment troubled customers. Almost no jurisdiction has acknowledged the potential adverse impacts on these vulnerable customers who must have essential electricity service to assure household health and safety. Nor has any jurisdiction specifically ordered an analysis of proposals for dramatic changes in the pricing of electricity on limited income or payment troubled customers.

The repeated calls to link retail prices with short-term wholesale market hourly or day-ahead prices assumes economic validity of those price signals[1] and requires state regulators to promote the installation of more expensive meters and communication systems to achieve their rate design goals and objectives. Whether or not the rate designs are initially labeled "voluntary," the fact that more advanced meters are being installed or proposed for universal installation on a system-wide basis suggests that the "voluntary" label is temporary at best.

Finally, the more advanced meters with two-way communication systems carry significant implications for customer service, privacy, and consumer protection policies that have been viewed as either a benefit (as in the California Public Utilities Commission's analysis of the cost and benefits of the system-wide installation of smart meters) or completely ignored in terms of their possible adverse implications.

At a minimum, when faced with proposals to promote smart meters or any "real time" pricing proposal, advocates for limited income and payment troubled customers should call for an analysis of the impacts of the costs and the benefits to residential customers generally and more vulnerable lower income customers specifically. This analysis should reflect a bill impact analysis to pay for the new meters and communication systems at various usage levels, as well as a consideration of the consumer protection policies and programs that presently exist and that rely on personal contact and premise visits as a crucial aspect of the implementation of the notice and attempts to avoid disconnection of service.

It would be unfair and poor public policy to leap into new metering technology and new methods of pricing essential electricity service to residential customers without a careful analysis and access to factual information on the impacts of such proposals on customer bills and usage patterns. The lack of such information is particularly glaring for low income and payment troubled customers.

Rather than focus on passing through "real time price signals" to residential customers based on short term or spot market prices, representatives of limited income and payment troubled customers should consider reforms being adopted in some states that are designed to ensure long term price stability and long term lowest price for essential electricity service. These initiatives, often captured under the rubric of "portfolio management", require an analysis of the average price of electricity for the customer class and an acquisition strategy that is designed to dampen price volatility. As such, this approach is exactly the opposite of the recommendations of those who seek to pass through "real time" prices to residential customers that rely on wholesale spot market price changes. There are legitimate concerns that have been raised with the structure and operation of the current wholesale markets. These concerns point to the potential for market manipulation, lack of sufficient competition, and the structure of the market pricing mechanisms themselves. Wholesale market structure and pricing mechanisms are still being vigorously debated and to rely entirely on such immature and potentially "wrong" price signals to customers who rely on essential electricity services for minimum health and safety standards should raise red flags and longer term analysis prior to embarking on expensive new metering and rate design programs that appear linked to promoting more volatile pricing methods for residential customers.

Finally, advocates for limited income and payment troubled customers should ask for the development of the least expensive demand response programs that are likely to benefit all customers and focus on closely linking the demand response programs with those specific customer usage profiles that are likely to contribute to the objectives of the program in the most cost effective manner. Typically, this would require an analysis of simpler direct load control programs that reward the participating customer for a modest level of interruption or appliance cycling and are typically not intended to "punish" lower usage customers with higher prices at peak usage periods. Also, a rate design change to inclining block rates could send gradual price signals to all customers as their consumption increases. In addition, proponents of real time pricing programs often claim that the reduction in peak usage would assist in the ongoing efforts to reduce greenhouse gas emissions from power plants that contribute to global warming, on the grounds that reducing peak demand will reduce the need for new generation resources or reduce the need for reliance on gas-fired generation units, often the most expensive unit at the peak periods. However, logic suggests that shifting more usage to off peak periods would require an increased reliance on baseload generating plants which are typically coal-fired and nuclear generation. Any claims of environmental benefit should be carefully examined to determine whether most of the peak usage is just shifted to off peak hours, thus limiting any environmental benefits associated with these programs.

Any program that is aimed at residential customers in the form of a pilot program to test TOU or CPP options or rate designs should include identified low income customers with usage that is lower than average residential customers and analyze the impacts of such programs on those customers who do not or cannot take actions to avoid the higher peak prices. Finally, any pilot programs should require an independent evaluation that asks the hard questions about whether the program as designed or implemented can be rolled out to a sufficient number of residential customers to achieve its intended objective and at what cost.

It may be wiser to focus first on the very high use sub-class of such customers who typically have the financial ability to actually respond to peak prices and the usage profile that reflects the potential peak shaving or peak load reduction that is the intended purpose of such programs. Even with this subgroup, however, there may be serious obstacles to any requirement for real time pricing. For example, New York previously had a mandatory time of use rate for very high usage residential electric customers. Despite the presumed ability of very high usage customers to adapt to time of use rates, the program was so unpopular the state legislature amended the law to make any residential time of use program voluntary.[2] Maine's mandatory

TOU rate program, adopted at a time of price stability, was abandoned with a dramatic increase in electricity prices and the onset of electric restructuring. Puget Sound Energy in Washington abandoned a system-wide move to TOU pricing for residential customers when it became clear that the additional costs of the new communication and billing systems could not be avoided with average monthly bill savings.

Advocates for limited income and payment troubled customers should carefully examine proposals for "pilot" real time pricing programs, as well as utility proposals to install smart meters throughout its service territory. Such proposals should be examined in contested proceedings with a full airing of the proposed costs and benefits of such programs, , with a particular requirement that the impacts on lower income residential customers be undertaken. While utilities may seek to first install the smart meters (and obtain regulatory approval for cost recovery) without linking such meters to more volatile "real time" pricing options for residential customers, any such proposal should be reviewed with the understanding that more volatile pricing programs are sure to be offered and perhaps eventually mandated.

Appendix A contains suggested areas of concern and questions that should be asked and answered when considering the system-wide installation of smart meters and any suggestion that future benefits may be recouped by introducing more volatile real time pricing programs for residential customers. While the benefits of such meters and their communication systems may be justified for outage management, automatic meter reading and reductions in utility meter reading costs, more accurate bills, and their impact in allowing the utility to better integrate and manage its distribution system, the implications of these systems, particularly the more volatile pricing methods being promoted as part of the justification for smart meters in many states, for low income and payment troubled customers has not been fully explored or acknowledged.

INTRODUCTION

While electricity prices are increasing in many states due to the impacts of retail electric restructuring and higher fuel costs (particularly natural gas) used in electric generation power plants, another development is likely to have an even more significant impact on the ability of limited income and payment troubled customers to obtain and maintain essential electricity service. Federal policy, some state regulators, and advocates for "sending the proper price signals" to all customers support the installation of "smart meters" and changes in how electricity is priced. In some cases, customers will be offered the option of "time of use" or "critical" pricing programs that vary the price of electricity by the time of day or the volatile prices of a wholesale spot market. In other cases, customers will be offered the option of interrupting or reducing usage of key appliances in return for a bill credit or other means of rewarding the customer for taking actions in response to higher wholesale spot market prices. In some cases, regulators will order the mandatory installation and funding for new meters and communication technologies and make permanent changes in how electricity is priced. In general, the overall trend of these initiatives will be to raise electricity prices to pay for the new meters, installation and maintenance of the new meters, new communication facilities, new computers and software to receive and process the information from the meters, and new billing systems to implement the pricing changes. A move to make electricity prices more volatile (i.e., changing more frequently than in the past) and with more difference between "high" prices and "low" prices at different times of day or year would be a major break with longstanding state legislative and regulatory policies to stabilize rates of residential and small business consumers.

The purpose of this paper is to educate consumer advocates on the state and federal developments that are promoting "smart meters", "real time pricing", and "demand response" programs for residential customers and to highlight the potential concerns and impacts of these programs and policies on limited income and payment troubled residential customers.

By "limited income" I refer to residential customers whose household income qualifies the household for participation in one or more of a State's means-tested financial assistance programs, such as Low Income Home Energy Assistance Program (LIHEAP), Medicaid, Food Stamps, prescription drug assistance, WIC, telephone Lifeline, and similar programs. While most of these programs rely on a household income qualification that is at or below 150% of Federal Poverty Level, others use a slightly higher income qualification. In all cases, the programs are designed to assist households with insufficient income to meet their vital and essential needs for shelter, heat, electricity, medications, and food.

By "payment troubled" I refer to residential electric customers who demonstrate an inability to make regular monthly bill payments in full and who have frequent contacts with the utility concerning bill payments, enter into deferred payment plans, who frequently make only partial bill payments, or who need referrals to public assistance or charitable aid in response to notices of disconnection of service. These customers may have "limited income" but include those who are just above the more traditional definitions of poverty in many programs and who encounter bill payment difficulties.

In this paper I use the term "smart meter" to refer to a meter that has the capability to record and store information about a customer's electricity usage by time of day and is linked to a two-way communication system with the utility. In most cases, this requires a meter other than the typical mechanical meter already installed for most residential customer electricity services. These older meters are relatively inexpensive and reliable, but they only record continuous electricity usage with a mechanical dial. It is possible to "read" such meters more frequently (and thus obtain usage information at certain times of day), but this requires the installation of an additional communication system to access the meter reading several times a day. More typically, a "smart meter" is a new meter that has the capacity to store electricity usage according to various time periods or intervals that are programmed into the meter. In other words, the older meters are best thought of as an analog device and the newer meters as a digital device. While "smart meters" do not themselves require a two-way communication system to operate (i.e., the data they contain can be obtained with visual meter readings or by a one-way transmittal of data to the utility), typically such meters are also accompanied by a new communication technology that allows two-way communication between the meter and the utility by means of a high speed communication system that relies on radio or wireless communications, broadband power line transmission, or copper wire (telephone) communication devices.[3] A centralized database is maintained by the utility of continuous or frequent meter usage readings for each customer. This information can be used to issue customer bills, analyze usage profiles, and design and implement new electricity pricing programs. When the utility has direct contact with the customer's meter, the utility can also turn the meter on and off from a central location, i.e., start service and disconnect service without a premises visit.

The term "real time pricing" is used to describe how the more sophisticated or more detailed information derived from the smart meters is used to bill end use customers. This type of pricing is also referred to by its proponents as "dynamic pricing." Typically, smart meters are accompanied by a proposal to change the way in which electricity is priced on the customer's monthly bill. These electricity pricing programs (known in the regulatory world as "rate design") vary the price of electricity according to time of day or even every hour, charging more or less for electricity based on higher production costs, in states with vertically integrated utilities, or conditions in a wholesale electricity spot market in states where distribution utilities have divested their power plants and must purchase wholesale energy for retail customers. At its most basic, "real time pricing" means that a customer is charged more for electricity at peak periods when production costs or wholesale spot market prices increase (due to high demand and the need to turn on the most expensive generating resources) and less for off-peak periods when there is likely to be a larger surplus of electricity and lower demand (and when the least expensive baseload generating units are used). In regional wholesale markets, higher peak hour prices are also a reflection of transmission constraints and pockets in which there is insufficient transmission capacity to send otherwise available electricity to customers.

The most typical type of dynamic or real time pricing programs that are being proposed and discussed in state proceedings include:

- **Time of Use or TOU** rates in which the customer's meter records usage by hour and charge different prices for different times of day. The TOU rates usually change once or twice per year (winter and summer) and, at a minimum reflect two time periods, peak and off-peak, but sometimes also include a "shoulder" price that is midway between the two extremes.
- **Real Time Pricing or RTP** rates in which the customer's meter records usage by hour and charges a different rate for each hour depending on movements in the wholesale spot market.
- **Critical Peak Pricing or CPP** rates in which some hours of the year during particularly high peak prices are charged a very high price. This option can be implemented with either TOU or CPP rate programs. The hours in question are

typically fewer than 1% of the hours per year and the customer is notified at least one day in advance.

By "demand response" programs, I mean programs operated by utilities or wholesale market participants in which there is an organized effort to obtain a lower demand on the electricity system (i.e., reduce usage) so as to reduce the level of the peak period or to shift usage to lower peak periods. Proponents of demand response programs often suggest that properly designed programs can substitute for building new generation or lower prices for all customers if the usage at the peak period is reduced because of the significant impact that peak period prices have on the average price of electricity charged to all customers. Demand response programs are generally of two types: (1) the use of time of use or critical peak pricing programs to require the customer to pay more for electricity based on peak and non-peak system information so that the higher price acts as a signal to reduce usage; or (2) the use of customer credits or other incentives to allow the utility to directly control the use or load of a particular appliance (such as air conditioning) during the most extreme peak load conditions, typically 20-30 hours per year. A variation would enable the customer to adjust or shut off home appliances remotely, via internet or other means, when prices rise above certain levels.

Why should limited income and payment troubled customers be concerned about these developments? As will be discussed further in this paper, the system wide installation of smart meters and the promotion of more volatile pricing alternatives for basic electricity service, as well as the design of some demand response programs, raise important issues for customers who have difficulty making regular bill payments and whose household income may not support higher bills in some months in return for lower bills in other months. In some cases, these concerns are similar to those shared by all residential customers, but the impacts of these concerns resonate more deeply with customers who have difficulty making regular monthly payments based on current and rising electricity prices. Since electricity is vital to household and community health and safety, any development that may reduce the affordability of electricity or subject the monthly amount necessary to pay for such services to potentially significant volatility should be viewed with suspicion and alarm.

First, the installation of smart meters and the new communications and data management systems required to implement the new pricing programs, the design and implementation of new billing options with changes to the utility's customer service and accounting software, as well as the consumer education and communication programs that will be required, are likely to result in higher rates or prices for all customers. Even assuming investment in this technology has the potential for lower prices in the long run, most utilities will not choose or agree to absorb these additional costs in the short run. As part of the rate recovery proposals that are likely to accompany proposals for advanced meters is a suggestion that higher meter costs should be paid for with higher fixed monthly customer charges. Any rate increase is likely to have a more significantly adverse impact in the form of higher monthly bills on limited income and payment troubled customers, but higher fixed monthly charges have a more adverse impact on lower use customers where the fixed charges represent a higher percentage of the total monthly bill.

Second, the theory of more volatile pricing and "sending the proper price signal" assumes the spot market price is correct and reflects the marginal or incremental cost for electricity. The use of smart meters and dynamic or real time pricing means that electricity is not being bought with the objective of price stability or long term management of a diverse portfolio of contracts and energy management services. In other words the meters and the new pricing trends attempt to institutionalize the wholesale spot market as the method of acquiring and pricing electricity. This reliance on the spot market to buy electricity for residential (and small commercial) customers is directly contrary to initiatives in some restructuring states to adopt long term planning and portfolio management of electricity service and avoid the short term wholesale market ups and downs.[4]

Third, the use of more dynamic pricing methods assumes that every customer has the ability to respond to hourly or daily price signals. This ability is obviously easier for higher usage residential, commercial, or industrial customers who have greater flexibility for reduction or shifting the usage away from expensive peak hours and taking advantage of the option to lower bills and experience benefits. For example, an industrial customer could alter production patterns and operations to use electricity during lower cost periods. Some residential customers could lower the thermostat (for controls of home heating, home cooling, hot water, or pool pumps) at peak periods.

These options are not as easily available to customers with a fairly constant usage profile or who use such a low level of electricity that there is not a great deal of elasticity in their ability to reduce or shift usage, at least without suffering some potential discomfort or harm to health. Such may be the case with many residential customers and is more likely the case with limited income and payment troubled residential customers who typically use less electricity than their higher income neighbors.[5] The penetration of more energy intensive appliances is lower for limited income customers than for higher income customers. On average, limited income customers reside in housing units that are typically smaller in size and require less electricity to light, heat, or cool. This is true even though many limited income and payment troubled customers live in structures that are older and not properly insulated and often rely on older and less energy efficient appliances. However, those customers with poorly insulated dwellings, in need of repairs, or who rely on less efficient and older appliances, are the least able to fix these problems and take actions to reduce their energy usage due to their limited income. Also, low income renters may lack control over appliances provided by landlords, *e.g.,* inefficient heating systems, refrigerators or hot water heaters. These factors suggest that limited income and payment troubled customers are not as likely to be able to take actions in response to price signals that are available to higher income customers, such as investments in structural repairs, weatherization, upgrading appliances; purchasing energy savings control devices, etc. The only practical option available to these customers is to do without or make changes in their lifestyle or family schedules to avoid using electricity at certain times of the day, even when that may adversely impact their health. Finally, older consumers may need a constant level of heat or cooling to maintain a safe body temperature and "doing without" in the middle of a heat wave in order to avoid higher bills may result in dire health and safety consequences.

Crucial to any analysis of the impact of more volatile pricing programs on low income customers is the definition of "peak" period or hours by the local utility. If the peak electricity periods and the times of day in which electricity is likely to be priced the highest (early morning and late afternoon/early evening) are also those times of the day when most families must prepare meals (breakfast and dinner), provide heat (and cooling in warmer climates) and hot water for themselves and their children for baths and other household cleaning chores, the potential for adverse impact is higher. TVs and lights are operating when families are home, not in school, and not at work. While it is certainly possible to "teach" customers to do their laundry and operate dish washers after 8 PM, the bulk of electricity usage is not likely to be dramatically shifted for households when most of the usage relates to necessary tasks. Elderly customers and households with small children need to maintain a level heating and cooling temperature to avoid potentially dangerous health conditions. If the peak or critical hours typically fall in the summer afternoon a residential customers is at work, the ability to reduce air conditioning usage by increasing the home temperature may not adversely impact health and safety, although any such program should pay careful attention to the impact on elderly or other vulnerable residential customers who are at home and may rely on air conditioning to avoid adverse health consequences due to hyperthermia or who are suffering illness and other medical conditions that require cooling in hot weather and additional heat in cold weather.

When electricity prices are volatile, it may be more difficult for households with limited or fixed incomes to plan and accommodate significant changes in monthly expenditures. For example, limited income households are not necessarily benefited if the <u>average</u> annual electricity bill is lower when relying on higher peak period prices during some months of the year and lower than standard rates in other months or times of the year. If the size of any monthly bill is driven by high peak period prices or frequent critical peak hours, the unexpected expense can throw a customer into the nonpaying and collection cycle. Utility payment plans are unlikely to provide a solution when the bill is unaffordable unless the customer can shift the higher than normal bill into pay periods that correspond with lower bills. Any typical payment plan offered by utilities requires the customer to make a downpayment on the overdue amount and make regular monthly payments on the arrears balance along with the future monthly bills in full. While some claim that budget payment plans are useful tools for blunting fluctuations in bills, they are designed to average seasonal variations in a customer's <u>consumption</u> over the year and work best when prices are fairly constant. For a heating customer, the use of a budget payment plan shifts some of the winter bills impacts to the lower use summer bills. This payment option would blunt the intended impact of making customers "see" the higher prices at times of the wholesale system peak and respond to those high prices in real time. The use of TOU and CPP pricing makes the calculation of estimated future bills for a 12 month period more difficult and perhaps impossible. Furthermore, some utilities will not allow a customer in arrears to enter into a budget or levelized payment plan.

Fourth, the reliance on more volatile pricing options for residential service and the resulting impact on customer bills may have an unforeseen impact on the policies and delivery mechanisms with existing energy assistance programs. For example, the use of TOU or CPP options may result in higher overdue amounts, thus triggering more frequent requests for assistance and for higher amounts. If utilities can remotely disconnect service with such systems without the need for a field visit - and the possibility of a field payment, this is likely to increase the volume of disconnections, with the accompanying impacts on customers, communities, and social service agencies. Another impact may be the expansion of those who may have managed to "make do" under the prior method of charging for electricity prices but now require emergency financial assistance.

Finally, the installation of smart meters and their accompanying communication systems will allow utilities to remotely read, energize, and disconnect service. A likely result will be the increase in the volume of disconnections because such automated systems avoid the need to schedule field personnel and premise visits. Most utilities do not actually disconnect all those customers eligible for disconnection in any week or month due to operational constraints and the need to prioritize such field work with other operational obligations. Premise visits and "truck rolls" are expensive and often result in utilities making choices about the volume or type of disconnections that occur at any time. Also, field payments are sometimes made to forestall termination when the disconnection is being made or the field worker is made aware of a potential medical emergency that leads to a delay while the occupant obtains the necessary confirmation from a medical professional. When access to the meter can be accomplished remotely, utilities will not need to prioritize disconnections based on the amount overdue, for example, unless they choose to do so for other reasons. Furthermore, the elimination of the need for premise visits to effectuate the disconnection carries significant implications for current regulations in effect in many states that require the utility to attempt personal contact with the customer prior to disconnection in order to determine if a medical emergency is present or offer payment arrangements. As a result, reliance on remotely controlled meters is likely to result in a degradation of consumer protection and customer service compared to current practices.

Does this mean that any demand response program or TOU or CPP pricing option should always be opposed as harmful to limited income or payment troubled customers?

Not necessarily, because the "devil is in the details." The programs that are most likely to have a positive impact, i.e., lower customer bills and contribute to lowering peak usage at a modest system-wide cost, are those that are referred to as "direct load control" demand response programs. In such programs, the customer's appliance, typically an air conditioner, or a thermostat that governs the home heating and cooling system, is directly hooked into the utility's communication system and interrupted or cycled on and off for a few hours during critical peak periods. In return, the customer who chooses to participate may enjoy a near invisible impact on household comfort, the benefit of reduced usage on the monthly bill, and a customer reward or credit provided as an incentive to participate in the demand response program. Several examples of this type of program are described later in this paper. This type of program does not necessarily require advanced metering and the investment in the direct communication equipment is typically modest and far less than the savings seen by the utility in their management of peak usage. However, some proponents of these programs point to the more efficient use of advanced metering and the use of "smart" thermostats coupled with two-way communication systems as necessary for a more widespread use of direct load control programs. It is possible that a direct load control program may result in more targeted system-wide peak reduction benefits with fewer of the adverse potential associated with "real time" pricing that is being promoted by some policymakers, but the question still remains whether the costs and benefits of "smart meter" installation for all customers can or should be justified based on a more targeted program to only a subset of all customers.

It is also possible to construct a CPP option that results in customer bill savings if the there is a highly supervised customer communication and interaction program that links the advent of high peak usage prices with actions that the customer can easily implement without adverse impacts on household activities or health. Unlike the program in which the utility directly controls the customer's appliance or thermostat on certain peak hours, the CPP option requires the customer to take actions to reduce usage or shift usage to avoid the extremely high prices charged at a "critical peak" period. If the frequency of such CPP events is relatively low and the customer communication and education aspects of the program are well designed and successful, this type of program can be implemented without adverse impacts on health and safety, assuming the customers participating in the program have the ability, knowledge, and economic wherewithal to avoid usage or shift usage during these high price hours.

Rate options, such as TOU and RTP, in which all customer hours are designed to reflect short term wholesale market prices and pass through spot market prices, are more likely to be of questionable value and may pose significant bill impacts on limited income customers. Very little research has been done on the widespread costs, bill impacts, usage patterns, and system benefits of these programs, yet they are being widely discussed and promoted in many states.

WHY ARE "SMART METERS" BEING PROMOTED AND WHO IS PROMOTING THIS CHANGE IN HOW ELECTRIC SERVICE IS PRICED?

When the U.S. Congress enacted the Energy Policy Act of 2005,[6] most observers focused on the provisions that contained directives for energy efficiency, renewable resources, tax breaks and initiatives for coal, oil, and nuclear energy, new federal authority to ensure more reliable transmission systems, as well as the repeal of the Public Utility Holding Company Act of 1935. But buried in Subtitle E of Title XII (Electricity) are several amendments to the Public Utility Regulatory Policies Act of 1978 (PURPA). Sections 1251, 1252, and 1254 of the 2005 Energy Policy Act amend the "Retail Regulatory Policies for Electric Utilities (Title I) of PURPA by adding new federal policies[7] that are applicable to state regulation of electric utilities. Section 1252 contains a new "smart metering" standard. The standard requires that each electric utility offer to each of its customer classes and to individual customers upon request a "time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level." The time-based schedule "shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology…."

The statute also sets forth the types of time-based rate schedules that may be offered, including "time of use pricing (TOU)" in which prices are broken into two or three time periods and are fixed for some period, but which may change twice per year; "critical peak pricing" (CPP) in which TOU pricing is used except for a few hours per year in which the utility can increase peak prices to a substantially higher level to reflect wholesale market conditions; "real time prices" (RTP) in which prices are provided to the end use customer to reflect the actual or real wholesale market conditions on an hourly or daily basis, typically with a very short notification of forthcoming price changes; and the use of credits for customers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.[8]

Under PURPA, the federal government appears to directly regulate or set standards for electric utilities. But, another section of PURPA defers to state authority over retail electric service and requires state regulators to "consider" the federal standards within one year of the enactment of the federal standard and complete the determination of its consideration within two years of the enactment of the federal standard, i.e., August 2007 based on the 2005 Energy Policy Act's enactment date.[9] If the state does not complete its determination within this time frame, PURPA then requires the state to consider and determine the federal standard at the time of the utility's next base rate case. A state can avoid any new determination entirely if it has already implemented the standard or a comparable standard, if the state regulator has considered the same or comparable standard within the previous three years before enactment, or the state's legislature has voted on the implementation of the standard or a comparable standard within the previous three years before enactment. The apparent reason for the ultimate deference to the states is that regulation of such matters traditionally is a matter of state concern and has not been preempted. Indeed, the PURPA requirement that a state must consider the original PURPA agenda was narrowly upheld by the Supreme Court in a divided opinion.[10]

The result of the new amendments and the PURPA language is that there is now a clear federal standard that supports "smart meters" and the exploration of the new pricing methods such as TOU, CPP, and RTP for all customer classes. While state regulators and nonregulated (electric cooperatives or publicly owned) electric utilities are not required to offer all customer classes the option of these new meters and alternative electric pricing methods, the fact that states are required to conduct an analysis of these options means that the proponents of this new federal policy will be eager to participate in state proceedings and argue for these policies and programs. Whether representatives of residential customers generally or limited income and payment troubled customers will be at the table is a legitimate concern.

Why do the proponents of smart meters, TOU, CPP, and RTP push for these changes in the way electricity is priced? At its core, the simple explanation is that economists believe that prices for resources should be set so that those who consume the resources will reflect when the resource is scarce and when the resource is plentiful. Under the classic economic theory, a scarce resource should reflect a high enough price to drive the providers of the resource to invest in new capacity or find a new way to satisfy customer wants and needs through technological innovation or substitution of another product. When electricity is priced to reflect the average cost of all the generation units and all the times of day in which electricity is used, the impact of the most expensive generating unit and the time of day when prices are higher due to the highest level of demand (the peak), is not seen by end use customers. Proponents say they do not see the "real" price of electricity and cannot make decisions about their usage to reflect the peaks and valleys in electricity prices. Under this theory, consumers who see the "real" price of electricity will alter usage patterns or reduce usage during the most expensive periods. Alternatively, those who must use electricity at the most expensive times will pay the "real" price and investors in new generation facilities will see the potential for profits if new generation is produced to serve this need. When generation unit prices and times are averaged, those who need to see the potential for a profit on new merchant power investment may not be paid enough to generate such investment. When a vertically integrated utility sees that it is paying higher prices for running less efficient peakers in more hours, or that capacity reserve margins are shrinking, it may take those price and reliability signals into account and may build new capacity, or take other action to reduce load, through DSM programs, or shift peak usage through rate design changes. In contrast, most end users lack power to address a peak price signal by building a new baseload plant.

This economic theory has been used in the context of electric utility regulation for many years, and there are many instances of time of day or seasonally differentiated rates under conventional regulation in states that do not have spot markets. The full import of this approach was muted with traditional regulation in which the utility was allowed to recover the costs of higher priced or more expensive generation and average that price with lower cost generation in its total generation portfolio. However, in jurisdictions where restructuring occurred, many utilities no longer own generation and they rely almost exclusively on the wholesale market for generation. Regulators are now allowing those wholesale prices to be passed through to retail customers, after transitional retail rate freezes or price caps expire. In the restructured states, an independent owner of generation without long term contracts that assure recovery of costs and a return of and on capital may not be able to recoup the costs of new generation and make a profit if it depends on selling in spot markets, all of which have constraints on charging very high scarcity prices at key peak periods.

This promotion of new metering technology and alternative pricing methods for electricity service also resonates with those who seek to make sure that prices are set to reflect the costs that are caused by the particular customer class or sub-class. For example, these proponents argue that if the reason why peak usage occurs is primarily due to residential and small commercial usage late in the afternoon or early evening, those customer classes should pay the higher prices associated with that usage. If a large commercial or industrial customer can shift usage to off peak periods or operate a night shift to make their widgets, they should pay the lowest price for electricity. Some refer to this as a reduction in "cross subsidies" which can occur between different customer classes and within a customer class, if total revenue from one of the classes does not cover the incremental cost of serving them.

Other proponents of smart meters and new pricing methods also suggest that these innovations allow utilities and other market participants to better manage the electricity grid to make more electricity available at certain key times or reduce the need for investment in new transmission or generation facilities. This can be accomplished by monitoring usage patterns in greater detail and taking actions at the wholesale level to assure that the transmission system and the dispatching of various generation units is more closely matched to actual need or used as a means of triggering interruption programs or events to prevent blackouts and reduced reliability generally. These programs are typically called "demand response" programs because they are intended to target the reduction in demand or a shift in demand usage in response to peak prices and wholesale market conditions. In states where vertically integrated utilities still own generation, new generation, transmission, or demand response mechanisms, or a combination of them, can be used in conjunction with rate design changes to achieve the desired level of system efficiency and balance of supply and demand.

Finally, proponents of smart meters and new pricing methods emphasize the potential for improved customer service by allowing the utility to read meters remotely (and eliminate meter readers and the issuance of estimated bills) and issue accurate bills, program new billing changes and pricing options into meters and offering these optional programs to customers, detect and respond to meter tampering and energy theft, and improve collection activities by allowing meters and services to be remotely started or disconnected without premise visits or personal contact at the customer's residence. Data mining of such electricity usage data could indicate when customers get up in the morning, whether they use electricity during working hours, when they leave and return, whether and when they use significant air conditioning or other motors, whether they are home weekends, whether they have been terminated for nonpayment, when they take vacations, etc. Utility handling of customer usage data has been considered in telecommunications regulation, with the general result that customer proprietary network information (CPNI) obtained by the utility as a result of the customers usage generally is to be protected from release to any third parties, and must not be released without consent, subpoena or warrant. Privacy implications from gathering customer real time electricity usage data are largely ignored and need to be addressed.

The following quotes and excerpts from national publications reveal a wide ranging support for the installation of smart meters and, more importantly, the more volatile pricing methods that will be possible as a result of the new metering and communication systems:

- Rates that are based on highly averaged costs blur the price signals to customers, and result in an inefficient allocation of resources, referred to by economists as "deadweight loss" to society. These deadweight losses have been well known for many years but there is still a need to "break away from uniform rates and substitute rates based more accurately on cost." The benefit of smart metering is that it makes it more feasible to price electricity at its real cost through time. This, in turn, can lead to the elimination (or, more realistically, the reduction) in deadweight losses, thereby promoting social welfare.[11]

- In response to a question concerning moving to an energy-only pricing in the wholesale market and eliminating locational marginal pricing, "We can get rid of every bit of that tomorrow, if every state will allow the full floating price every five minutes to be reflected in the customer's bill." Further, "Up and until the time that states will allow retail customers to see the real-time prices, and pay the real-time prices, you're forced to create square-peg/round-hole solutions; to create surrogates for scarcity pricing."[12]

- The automated collection of advanced or "interval" energy use data is necessary to enable energy market participants to more closely match energy supply with demand. Balancing energy supply and demand will become increasingly important to making the new competitive energy marketplace work in a cost effective and reliability manner. By collecting more advanced metering data, a utility can build a body of knowledge to develop an entirely new portfolio of dynamic rate structures and incentive programs, real-time pricing packages and interruptible rates that can be targeted to specific customers to significantly improve load management capabilities and reduce peak demand when distribution system conditions become critical.[13]

- With the appropriate remote control technology, the utility—via the call center—will be able to process connect and disconnect requests the same day, and without a truck roll. Further, delinquent accounts can be monitored and address—and service disconnected—without lag time between service order generation and its execution at the customer location. This ability to connect and disconnect remotely while reducing the required number of truck rolls has the ability to significantly reduce these operating costs.[14]

- The Demand Response and Advanced Metering Coalition emphasizes the importance of "customer control over their energy bill" in promoting smart meters and new pricing programs. DRAM states that residential customers "are better at managing their energy budgets; they have what economists call a higher price elasticity of demand" and such customers "deserve the same chance to lower their bills as businesses."[15]

- At the present time, because of price caps and rate protocols, prices don't rise high enough to provide adequate signals. It's always a good idea to provide consumers with better price signals, so they can increase or decrease consumption accordingly. But if you give consumers prices that are wrong or too low, they won't react to those prices. Until you integrate the system-operation protocols with prices and demand-response system, you won't get the incentives you need.[16]

- Although demand response programs can provide benefits, they face three main barriers to their introduction and expansion: (1) state regulations that shield customers from short-term price fluctuations; the absence of equipment installed at customers' sites required for participation; and (3) customers' limited awareness of programs and their potential benefits.[17]

Implicit in real time pricing strategies is a shift away from the longstanding traditional utility responsibility, still incorporated in the statutes of most states, to provide adequate service upon demand at reasonable, predictable prices, and toward a new regime in which utilities and regulators expect customers to react to system inadequacies or deficiencies by using less or paying more.

The Federal Energy Regulatory Commission (FERC) has completed a recent survey of all states in the use of smart meters, alternative pricing methods, and demand response programs.[18] Based on the results of this survey, FERC reported that there is only a 6% penetration of advanced metering on a national level, but the penetration rate for such meters varies by type of utility and region. For example, 13% of the rural electric cooperatives have installed advanced meters. The highest level of advanced meter installation occurs in Pennsylvania, Wisconsin, Connecticut, Kentucky, Idaho, Maine, Missouri, and Arkansas. Nationally, only 5% of customers are on some form of time-based rates or incentive-based rates that relate to peak usage periods.

FERC has stated its desire to promote and encourage demand response programs and the wider use of advanced meters. In this Report, FERC identified the following regulatory barriers to increased use of demand response and peak pricing programs:

- There is a failure to link wholesale markets and wholesale prices with how retail prices appear on customer bills.
- Utilities have disincentives to promote demand response generally because it may reduce utility sales and its revenues and profits are linked to selling more electricity.
- There is no clear policy concerning the incentives to stimulate utility investment in advanced meters and new communication and data management systems and cost recovery mechanisms have not yet been resolved.
- The business case to demonstrate that benefits exceed the costs for the widespread installation of advanced meters, new communication and data management systems has not yet been made.

- There are State-level barriers to more widespread adoption of demand response programs and the use of some pricing methods in the form of state law and policy that protects some customers from being exposed to volatile prices.
- There is not yet a resolution of how to link the wholesale markets to retail rates and prices, specifically the difficulty in linking actions taken by retail end use customers with wholesale market payments.
- The third parties or new market participants who seek to promote advanced meters need more assurance of longer term funding to expand their ability to market and produce the new meters and communications software.
- There is insufficient market transparency and access to data on prices in the wholesale market.
- There is a need for better coordination of federal-state jurisdictions to coordinate policy initiatives between the retail and wholesale markets.

Implicit in FERC's analysis is an assumption that wholesale spot market prices are a correct economic signal. Many economists would identify marginal <u>cost</u> as an appropriate pricing signal, but the wholesale markets are based on sellers' demands, not their costs. FERC apparently assumes that spot market prices approach incremental cost, but that assumption is not universally accepted. There is a growing body of academic and technical study showing that auction pricing of goods such is highly susceptible to market manipulation and overcharging.[19] If spot market prices are inflated due to strategic bidding, or are subject to manipulation, or for other reasons do not reflect incremental cost, as many contend, then the price signals for end use customers will be incorrect. Closing manufacturing plants, sending shifts of workers home on hot days, inefficient investment signals, or subjection of low income households to considerable hardship and suffering all could flow from unthinking transmission of deeply flawed spot market price signals to end use customers.

CALIFORNIA SMART METER PROGRAM: A SYSTEM WIDE INVESTMENT AND COMMITMENT TO ADVANCED METERS, ALTERNATIVE PRICING OPTIONS, AND DEMAND RESPONSE PROGRAMS

While there is little "progress" as yet made in the widespread installation of smart or advanced meters and the use of more volatile pricing methods for residential customers, no State has taken more dramatic steps than those undertaken or planned in California. The State's Energy Action Plan identifies several key action items with regard to Demand Response, including the proposals to adopt advanced metering by the large electric utilities, educate Californians about the time-sensitivity of energy use and how they can participate in demand response programs, and incorporate demand response appropriately and consistently into the planning protocols of the California PUC, the California Energy Commission and the wholesale market administrator. As early as 2001, California had already rolled-out interval meters for large customers with usage in excess of 200 kW and the placement of those customers on time-of-use tariffs. Starting in 2003, the investor owned electric utilities were ordered to develop new demand response programs and tariffs for customers as well as expand existing emergency triggered programs. At the same time, California adopted an aggressive long-term dynamic pricing goal for the utilities equal to 5% of the projected system peak demand in 2007.

In a Report[20] to the California Legislature by the California Energy Commission in October 2003, these potential adverse impacts of real-time, critical peak, and other dynamic pricing scenarios on some customers were noted:

> Dynamic pricing can more accurately charge customers for their cost of service than do existing fixed rates. As a result, customers subsidized under current rates are most likely to pay more under dynamic pricing. In particular, any customer that uses more energy during peak periods than the average customer, and who cannot or will not shift their usage in response to price signals, is likely to pay more under dynamic pricing. Most customers should not be protected from paying the real cost of purchasing and delivering

electricity to their homes. Truly "disadvantaged" customers, i.e., low income and medical necessity customers could be provided with an explicit subsidy if the dynamic rates actually result in higher bills for them.

A fixed monthly charge for interval meters may increase bills for some low-usage customers. Options to ensure protection of these customers include the following:

- Require that the costs of new interval meters be recovered through volumetric energy rates rather than fixed charges.
- Provide customers below a certain usage level with a credit or subsidy.
- Do not provide interval meters to low-usage customers.

In this Report, the California Energy Commission also challenged the notion that low use or low income customers would necessarily be harmed by dynamic pricing. Using a simulation analysis, the Commission analyzed the impact of a 5 percent shift in usage from on to off-peak and another scenario with no shift in usage for customers using less than 350 kWh per month and reported that the resulting average monthly bill would be at least $1.00 lower under critical peak pricing compared to existing standard rates (which, in California, are already tiered to reflect significantly higher prices for increased usage). At the time of this Report, the Commission reported that the range of costs and benefits for installing the necessary advanced metering and communication systems for California's investor owned electric utilities ranged from a net benefit of $6.91 per meter per month to a net cost of -$2.45/meter/month.

In 2003-2004, California conducted statewide pilot programs for residential customers and tested a variety of pricing and demand response options.[21] Customers were solicited to participate in the program based on geographic and demographic diversity. Specifically, three pricing options were tested: (1) a traditional TOU where the price during the peak period was 70% higher than the standard rate and about twice the value of the price during the off-peak period; (2) a CPP tariff in which the peak period price during a small number of critical days was about five times higher than the standard rate and about six times higher than the off-peak price, but with a fixed critical period and day ahead notification; and (3) a CPP tariff similar to (2), but where the peak period on critical days was variable. The Commission had approved the pricing pilots with certain constraints, namely,

- experimental rates had to be revenue neutral for the class-average customer over a calendar year,
- the rates could not change the bill of low and high users by more than 5% in either direction, and
- participating customers must be provided with the opportunity to reduce their bills by 10% if they reduced or shifted peak usage by 30%.

These constraints resulted in using rates that would rely on a high price ratio in the summer and a low price ratio in the winter so that the annual revenue neutrality obligation could be met. Finally, it is important to consider that low income electric customers in California are already provided a 20% rate discount under the CARE program. The CARE program of low income discounts is funded through the Public Benefits Charge by all customers and is available to customers with household income of 175% of federal poverty guidelines or less. The penetration of this program among eligible low income households is very high among all California utilities, and over 90% at Southern California Edison.

The evaluation of these pricing programs for residential customers found that the use of TOU prices alone reduced consumption by 6%, but the authors noted that this may be due in part to the "modest" nature of the differential in the pilot TOU prices between peak and off peak periods. Indeed, the impact of time of use rates on residential consumption in general "almost completely disappeared" by the second year. However, the use of CPP or critical peak pricing reduced usage on Critical Peak days by 13-16%, thus showing that those customers with the largest energy usage (particularly those with central air conditioning) could have a potentially significant impact on usage during expensive peak periods. Finally, the pilot programs found that usage reduction (27%) significantly improved with installation of "smart thermostat," that is, the use of a module in the customer's home that enabled the customer or the utility to program cooling usage based on network conditions. However, since California law appears to prohibit the use of CPP for residential customers on a mandatory basis[22], it is not clear how these results can be translated into system-wide cost effective programs at this time.

Most importantly for the implications of such pricing methods for limited income customers, the impact evaluation of the California Statewide Pricing Pilot[9] found that "the elasticity of substitution for CARE [low-income discount] customers is essentially zero."[23]

All of California's investor owned electric utilities have filed proposals for the installation of advanced meters and associated communication systems throughout their service territories with the California PUC. In July 2006, California PUC approved PG&E's proposal to replace all electric and gas meters with "smart meter" technology over five years at a price tag of $1.6 billion.[24] This initiative (and the similar plans proposed by Southern California Edison and San Diego Gas & Electric that are still pending before the PUC) is a direct result of a statewide policy to rely on smart meters and demand response programs to reduce peak load in an attempt to reduce electricity prices and the need to construct expensive new generation facilities. However, the PUC's decision did not mandate that residential customers take electricity under a demand response tariff. Rather, TOU price plans will continue to be available on a voluntary basis to such customers. The Commission stated its objective to promote TOU pricing for residential customers and will require ratepayers to fund education programs to this end in addition to the cost of the meters and ancillary communication and data management systems. It should be noted that current California law prohibits the use of Critical Peak Pricing for residential customers, but the PUC also approved a new voluntary CPP price option that will be offered to residential customers for certain summer peak usage hours. This CPP tariff is likely to price electricity as high as 60 cents/kWh during certain summer peak afternoon hours.

The new meters were evaluated as beneficial over a 20-year pay back period and the PUC rejected the arguments of the primary consumer intervener that the proposed level of investment and type of meter architecture proposed by PG&E was not cost effective for the residential class and that a more modest and targeted investment should be approved at this time. However, the Commission acknowledged that the primary benefits identified in the proposal were not related to demand response savings, but savings related to the use of remote meter reading, remote connection/disconnection, and outage management. The Commission's analysis also relied heavily on the proposed CPP option to have an impact on actual demand reduction during peak periods. The Commission found that 90% of the costs associated with the metering initiative would be recovered through operational savings and only 10% through demand response benefits.

eDockets

Docket Summary | *Return to Search Page* | *eFiling*

Docket No: UM 1415 **Docket Name:** INVESTIGATION INTO COST METHODS FOR USE IN DEVELOPING ELECTRIC RATE SPREADS

Print Summary

See also: UE 197

In the Matter of the PUBLIC UTILITY COMMISSION OF OREGON Staff Investigation into Cost Methods for Use in Developing Electric Rate Spreads. (See UE 197, Order No. 08-585, ordering paragraph 3.)

Filing Date: 1/30/2009

Case Manager: GEORGE COMPTON **Phone:** **Email:** george.compton@state.or.us

Law Judge: ALLAN ARLOW **Phone:** (503) 378-3511

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ACTIONS | SERVICE LIST | **SCHEDULE**

Date/Time	Event	Description
7/8/2009	STAFF WORKSHOP	
4/22/2009	OTHER EVENT	Workshop
3/17/2009	OTHER EVENT	Workshop
2/20/2009 9:30:00 AM	CONFERENCE	Notice of Prehearing Conference served electronically on 2/5/09 and via U.S. Mail on 2/6/09 to UM 1415 and UE 197 Service Lists, Electric List, and Gas List.
	Location: MAIN HEARING ROOM - PUC 550 CAPITOL ST NE , SALEM, OR, OR	

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 213

In the Matter of	)	REDACTED
	)	RESPONSE TESTIMONY OF
IDAHO POWER COMPANY,	)	OBJECTING TO STIPULATION
	)	THE CITIZENS' UTILITY BOARD
Request for a General Rate Revision	)	OF OREGON

My name is Gordon Feighner, and my qualifications are listed in CUB Exhibit 201.

I. Introduction

Idaho Power and the PUC staff have put forth a proposal in this docket to implement a seasonal rate structure for residential customers beginning in 2010. This structure would consist of two seasons, summer and non-summer, with summer rates being in effect from June 1 to August 31 each year. Rates will be charged in two tiers, with the first block covering the first 1,000 kWh of energy used per month, and the second block covering all energy used above 1,000 kWh each month. Rates for the non-summer period will be 6.0832 c/kWh in the first block and 6.99551 c/kWh in the second block, while rates for the summer period will be 6.0832c/kWh in the first block and 8.3123 c/kWh in the second block.[1]

CUB does not object in principal to Idaho Power's request for a rate hike, though CUB notes for the record that a rate hike of more than 26% for residential customers will create considerable rate shock and hardship. Idaho Power provides service in a relatively poor part of Oregon. Median household income in Ontario is $35,661, well below the state median household income of $50,166.[2] Information provided by the Company in this docket indicates that the new overall rate structure will bring rates closer in line with the Company's cost of service for its Oregon service territory. But CUB points to two major issues in this new rate structure that will have detrimental effects on residential ratepayers. The first is the subsidy to irrigation customers and the second is application of seasonal rates to residential customers as a way to promote energy efficiency.

II. Irrigation Subsidy.

Under the new proposed rate structure, the residential customer class will be billed at 103 percent of the class's cost of service. The irrigation customer class will, on the other hand, only be paying 75% of the irrigation class's cost of service. Thus, irrigation customers will be subsidized, with their rate of increase being limited to 27.96%. Adding insult to injury for the residential customers is the fact that residential customers will be contributing to the irrigation customer class subsidy, even though the residential customers will be suffering through their own 26.3% rate hike – an increase of nearly the same percentage. According to Staff, irrigation customers must be subsidized, and their rates limited to a 27.96% increase, because raising their rates in order to send correct

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[1] UE 213 / Staff / 103 / Compton / 1.
[2] http://www.city-data.com/city/Ontario-Oregon.html.

price signals "would have resulted in an "untenably high" rate increase to the irrigation schedule".[3] Staff, however, seems to show no such concern for residential customers who will suffer an almost identical rate increase. In fact, Staff finds it "encouraging" that residential rate payers may complain about their large rate hikes:

> No one likes to see customers who are distressed. But as an economist concerned about conservation and economic efficiency, I take some encouragement in observing customers paying attention to price signals, even if it is "only" to complain.[4]

The bottom line is that while the percentage overall rate increase above the actual cost of service may be small, CUB objects vehemently to residential customer rates being structured to subsidize the rates of others (primarily irrigation customers) when residential customers are already suffering an equally large rate hike.

CUB is not proposing an additional rate increase for irrigation customers. This is because CUB thinks the Commission's concerns about rate shock are valid concerns for all customers, regardless of customer class. CUB does, however, believe that it is important to begin removing the subsidies provided to irrigators.

Because Idaho Power's Oregon rate cases are infrequent, the resulting rate increases in these cases tend to be large. The large size of the increases make it difficult to make much movement towards cost of service pricing for irrigation customers without causing rate shock. CUB is therefore proposing that the Commission direct Idaho Power to use the smaller rate increases and decreases that occur in the PCAM to begin to unwind this subsidy.

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[3] CUB Exhibit 102 / Jenks / 2.
[4] Staff / 100 / Compton / 12.

III. Seasonal Rates

CUB believes that the seasonal rate structure proposed in this case will result in confusion and additional rate shock for residential customers, and may not function to reduce peak loads as much as the Company is likely anticipating. CUB instead argues for making energy efficiency programs a much more integral part of Idaho Power's load management strategy in Oregon.

CUB does not understand the Staff desire to institute seasonal rates for residential customers on top of the huge increase in rates that residential customers will already receive. CUB's confusion emanates from prior statements by Staff to the effect that the threshold for rate shock for irrigation customers is 27.96 %. If Staff believes that rate shock for irrigation customers begins at 27.96% then how can Staff design a seasonal rate structure for residential customers that will cause rate shock to residential customers who use more than 1000 kWh/month in the summer? Customers' bills, not their rates, are the primary price signal. With a 26.3% price increase, residential customers are already receiving one heck of a price signal without the institution of seasonal rates.

A. Residential customers do not drive the summer peak.

It is important to recognize that residential customers are not the main driver of Idaho Power's summer seasonal peaks, although they – like all customer classes – contribute to these peaks. Figure 1 shows total monthly systemwide energy consumption of Idaho Power's residential and irrigation customers over the period 2004-2008. Residential customers clearly experience annual peak consumption in the winter months, with smaller peak events in the summer months. Irrigation customers, however, use energy almost exclusively in the summer and can be therefore considered to be driving marginal consumption during summer peaks. CUB acknowledges that irrigation customers are also subject to tiered and seasonal rates. These rates can, however, be considered to be almost one and the same, as the vast majority of energy consumption for irrigators occurs during the June-August period. In addition, because of the heavy subsidy, irrigation customers' seasonal rates are not designed to bring "marginal cost" price signals to them.

BEGIN CONFIDENTIAL MATERIAL

Figure 1. Monthly systemwide energy usage (kWh) by customer class, 2004-2008.[5]

CONFIDENTIAL – SUBJECT TO PROTECTIVE ORDER

This chart demonstrates that irrigation customers have a summer peak that is approximately [redacted] kWh, which is similar to the residential customer class's summer usage. Residential customers' year-round base usage is above [redacted] kWh, so their summer peak is best described as being approximately [redacted] kWh, or [redacted] of the irrigators' peak.

There is a strong argument that residential customers drive winter peak, but the case that residential customers are significant drivers of summer peak simply isn't supported.

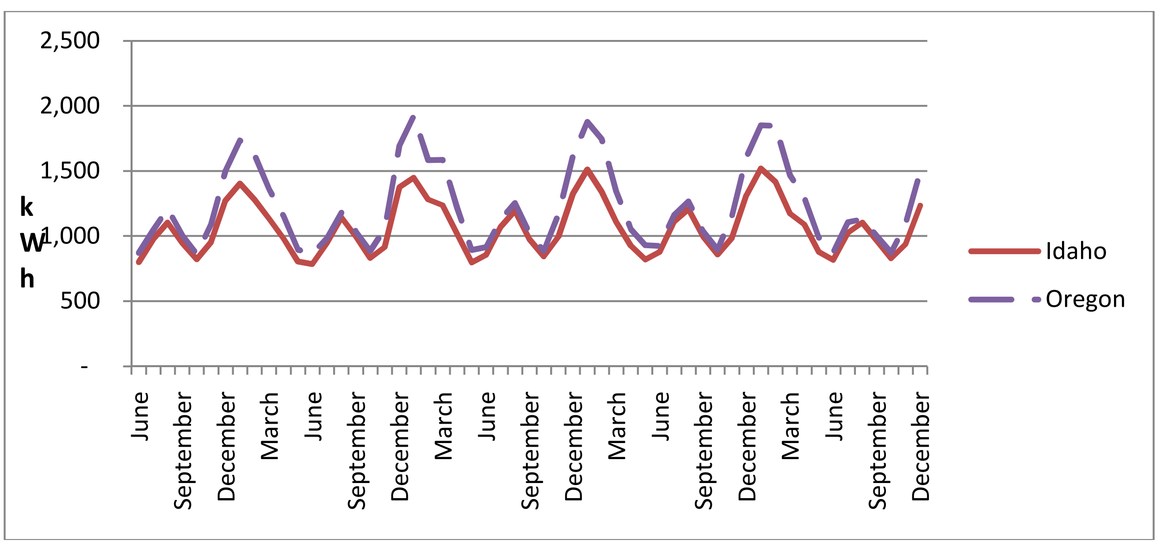
END CONFIDENTIAL MATERIAL

[5] Source: CUB / Exhibit 205.

B. There is no evidence that seasonal rates reduce consumption.

Neither Idaho Power nor Staff have provided any empirical evidence that seasonal rates actually reduce average or peak energy consumption among residential customers. Figure 2 shows the average monthly energy usage of residential customers in Idaho Power's Oregon and Idaho service territories over the past five years, since seasonal rates took effect for Idaho customers. While Oregon customers clearly use more energy on average in the winter, the figures show that customers in both service territories have consistently increasing patterns of usage in all months of the year. This trend indicates that seasonal rates are not having a significant impact in terms of reducing summer energy usage among Idaho residential customers. It is difficult to see how seasonal rates in Oregon would somehow have a different result.

Figure 2. Monthly residential energy usage by state, 2004-2008.[6]



[6] Source: CUB / Exhibit 206.

In addition, there is no evidence in Staff's testimony that seasonal rates will actually reduce demand. Staff claims that this will happen because laws of economics "imply" that it will happen:

> According to the economic law of demand, the introduction of the higher summer rate in Idaho would imply some degree of consumer response—how much I could only speculate.
>
> As noted in Staff's testimony, the level of inversion in PacifiCorp's Utah residential summer rate was substantial. The law of demand would imply some degree of consumer response to the elevated price. To actually *measure* that degree would entail speculation as to what the increase in refrigerated air conditioning would have been absent the elevated price. Staff is not in a position to engage in such speculation.[7]

Seasonal rate design is about shifting cost recovery from one rate period (non-summer) to another (summer), so economic theory would suggest that there would be consumer response (an increase in usage) during the non-summer period. This could be seen in fewer customers investing in weatherizing their homes to reduce their true peak in winter. Because weatherization reduces both heating and cooling load, this consumer response might actually result in increased summer usage. Indeed, Figure 2 offers little evidence that seasonal rates have an impact on residential usage in either winter or summer.

C. Lack of correlation between rates and marginal energy costs.

A further argument against Idaho Power's seasonal rate structure proposal, and one that holds the most weight from a financial perspective, is the lack of a direct correlation between the tailblock price assessed and the marginal cost of service. Oregon has a long history of requiring electric companies to analyze the marginal cost of service, though historically this analysis has been primarily used for rate spread purposes. As rates reflect

[7] CUB Exhibit 102 / Jenks / 3.

the actual cost of service, not the marginal cost of service, we have traditionally not used marginal cost as the basis for rate design. The energy cost figures for the residential customer class provided in Idaho Power/802/Tatum/6 (which Staff used to develop its marginal costs for rate design purposes) show that the Company's marginal energy costs for residential customers are higher in July (13.9 cents/kWh) and August (9.8 cent/kWh) than in other months. The Company's costs in June (4.3 cents/kWh), are actually below the annual average (6.69 cents/kWh) and below the marginal cost of energy in November (6.83 cents/kWh), December (7.31 cents/kWh) and January (7.21 cents/kWh). It is difficult to support Idaho Power's position that seasonal rates are meant to reflect the Company's higher energy costs in the summer months when June marginal energy costs are below the annual average and below several other months. If the goal of seasonal rates is to send price signals, then the May and June tailblock should be below the annual average, not significantly above, and the winter tail block should be higher.

If reducing peak energy usage is key to reining in marginal energy costs, it seems that some sort of time-sensitive demand-side management would be a much better fit than a structure that will affect nearly half of all residential ratepayers during the months of June, July and August. Instead, both the Company and Staff argue in favor of implementing seasonal rates on a schedule that fits with a nominal definition of the "summer" months, even though there is little empirical basis for such a major change in the rate structure.[8,9] CUB maintains that rates should remain at the same level throughout the year, and that Idaho Power should increase its efforts to reduce peak demand through energy efficiency measures.

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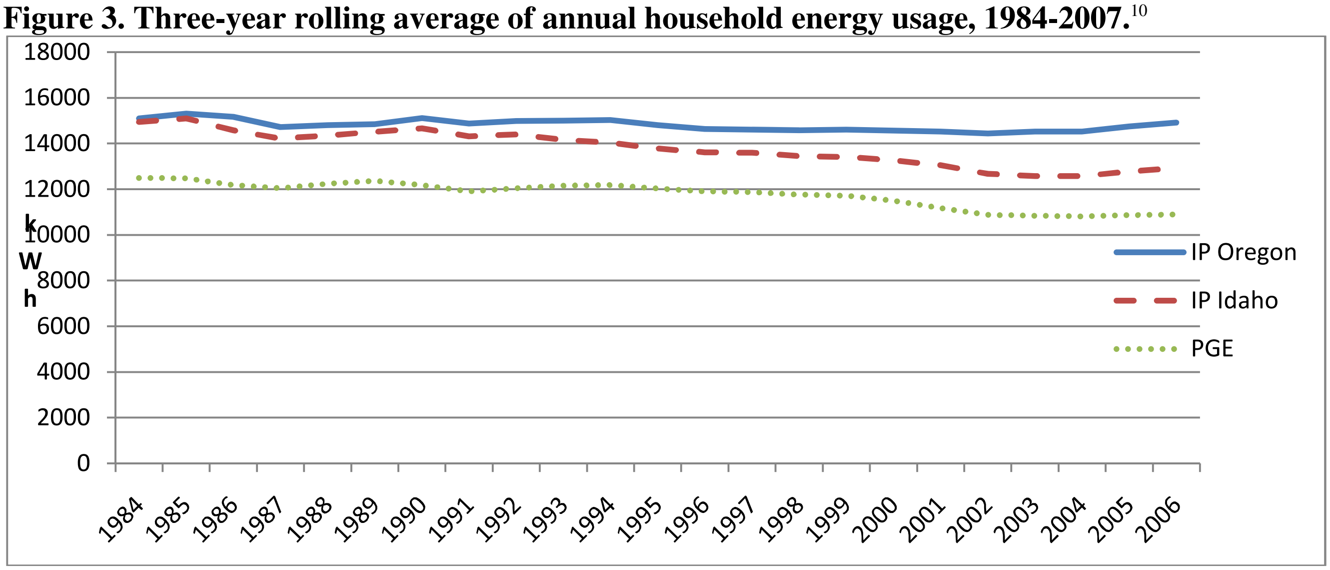
[8] UE 213 / Staff / 100 / Compton / 19.
[9] UE 213 / Idaho Power / 900 / Waites / 5.

IV. Energy Efficiency

Energy efficiency is a proven, cost-effective method for reducing both peak loads and overall demand. Idaho Power appears to have had a decent amount of success in implementing energy efficiency programs in its Idaho service territory, but has achieved poor results in its Oregon service territory. Figure 3 plots the three-year rolling average of annual household energy usage for Idaho Power's Oregon and Idaho service areas, as well as for Portland General Electric customers, over the past 25 years. Energy usage has remained roughly flat for Idaho Power's Oregon customers, whereas PGE and Idaho Power's Idaho customers have both managed to significantly reduce average consumption over this period. These results indicate a lack of Company effort and expenditures on residential energy efficiency programs in Oregon, as well as a shifting of program dollars away from residential customers and towards programs that improve efficiency for other customer classes.

Figure 3. Three-year rolling average of annual household energy usage, 1984-2007.[10]



[10] From CUB / Exhibit 207.

CUB Exhibits202 and 203show the amount of customer contributions towards energy efficiency programs and the amount spent on these programs. In each of the past five years Oregon residential customers have contributed roughly 35% of the total funds to Idaho Power's Oregon Energy Efficiency Rider (Rate Schedule 91). Of this contribution, only 16% has been spent by the Company on energy efficiency programs aimed at residential customers. This is a paltry return on investment for residential customers, and contrasts greatly with the return seen by irrigation customers. Irrigation customers have contributed only 7% of total funds over the life of the program, yet have received over 41% of the expenditures. Clearly this is another case of irrigation customers being the favored class.

CUB Exhibit 204 shows the number of participants in the Company's energy efficiency programs in Oregon and Idaho. The number of Oregon participants in most of these programs is minute compared to Idaho participants, even considering the difference in the size of the Company's service territory in the two states.[11] This disparity, while not surprising given the funding gap between the two states shown in Exhibit 204, seems to indicate that Idaho Power is taking an approach to demand management in Oregon that is more stick than carrot. For example, the A/C Cool Credit program, while apparently successful in Idaho with over 31,000 participants (8% of all households), has only a few hundred participants in Oregon (2% of all households).[12] This is a very useful program for reducing peak summer loads, which is ostensibly the Company's goal in introducing

[11] 2008 statistics from the Company show that there are over 390,000 residential customers in Idaho and about 13,500 residential customers in Oregon. This equates to roughly 29 Idaho customers for every Oregon customer.
[12] CUB / Exhibit 204 / Feighner / 1.

seasonal rates in Oregon. CUB believes that the Company should ramp up its efforts to encourage Oregon customers to participate in the program.

A/C Cool Credit is not the only program that is being underutilized. The Oregon Residential Weatherization program – which would reduce both winter and summer peak loads – has been offered since at least 2005, yet has only had eight total participants in its history. Other programs, such as appliance rebates and subsidies for compact fluorescent bulbs, were moderately more successful, but still lagged significantly behind the success these programs see in Idaho. CUB does not necessarily expect to see equal percentages of customers participating in all programs in the two jurisdictions, but the disparity in many programs far exceeds the ratio of Idaho to Oregon customers and suggests that the Company is not making the same effort to promote residential energy efficiency programs in Oregon as it does in Idaho.

CUB has stated that tiered rates only make sense when combined with robust energy efficiency programs.[13] The evidence suggests that residential energy efficiency programs for Idaho Power's Oregon customers lag behind Idaho customers. This would explain why Oregon residential usage is flat, while Idaho's is declining.

Staff testified that the goal of the summer tailblock was to incent customers to make capital investments in energy efficiency:

> As budgets tighten, households look for ways to cut their utility bills – by substituting more efficient appliances (including light bulbs), by making energy-efficiency-promoting capital investments in their domiciles.[14]

CUB does not believe that causing customers financial pain will necessarily provide an incentive for them to make capital investments in energy efficiency. Many of

[13] CUB / 100 / Jenks / 12.
[14] Staff / 100 / Compton / 11.

those suffering the financial pain will, for that very reason, not have any money to invest in home energy efficiency upgrades. It makes more sense to improve Idaho Power's residential energy efficiency programs and to provide customers the opportunity to reduce their usage. If Idaho Power has trouble promoting residential energy efficiency programs in its Oregon service territory, CUB would propose that they be turned over to the Energy Trust of Oregon (ETO), which already runs similar programs for Cascade Natural Gas in some of the same territory.

CUB also recognizes that there is a different level of accountability for Idaho Power on energy efficiency as compared to the ETO. The ETO makes quarterly presentations to the Commission and is held accountable for its results. At a minimum, Idaho Power's efficiency programs should have an identical accountability structure as that of the ETO.

CUB recommends that the PUC open an investigation into Idaho Power energy efficiency programs in Oregon to determine why they are not operated at the same level as Idaho programs. This investigation should consider whether these programs should be run by the ETO and what accountability structure should be put in place.

V. Billing Cycle Timing

Another consideration when implementing a seasonal rate structure is the timing of the billing cycle. Very few customers will have their billing cycles perfectly coincide with the June 1 through August 31 period that constitutes the summer seasonal rate period. The vast majority of customers will have this period spread across four billing cycles – May-June, June-July, July-August, and August-September. The May-June and August-September bills would be pro-rated to reflect the portion of the cycle that falls under the summer rate structure. The pro-rating formula is ostensibly fair, but it does not include a weather adjustment and therefore assumes that consumer behavior is, on average, the same across each day in the billing cycle.

CUB believes there are a number of issues that may arise during overlapping billing cycles which will result in circumstances that are unfavorable to customers. In the event of a heat wave that runs from May 28-31, for example, customers may be using energy at a rate considerably higher than normal to cool their homes. Even though these customers will be told by Idaho Power that the summer billing cycle does not begin until June 1, the vast majority of billing cycles will include these four days in the "June" cycle. Since the majority of residential customers use more than 1000 kWh per month in both May and June, each marginal kWh that is used during the May heat spell will be billed at the higher rate. This is inequitable to customers because 1) they are likely under the impression that May usage is strictly billed at non-summer rates, and 2) the Company will be collecting a premium on rates assessed outside of the summer period in which it is attempting to send price signals to reduce its peak loads.

CUB studied data related to the historic temperatures at the Ontario Airport.[15] Heat spells that raise temperatures into the 90s have happened during May in each of the last 5 years. In 2002, temperatures were over 100 degrees in May. CUB's concern is that if there is hot weather in May, each Oregon customer with air conditioning will be billed at a different rate for their air conditioning, depending upon their billing cycle. This situation will cause confusion among customers.

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[15] http://www.wunderground.com/history/airport/KONO/2008/5/24/MonthlyHistory.html?req_city=NA&req_state=NA&req_statename=NA.

VI. Billing Cycle Length

The situation described above may also be exacerbated by Idaho Power's request to change the definition of a "Billing Period" in Rule B.[16] Rule B currently defines a normal billing period as 30 days, but provides the Company with the flexibility to consider any period between 27 and 33 days as a normal billing period. Idaho Power is seeking to extend this flexibility to make the normal billing period up to 36 days long without pro-rating any associated charges. This rule change would have the potential to be harmful to customers in all months, as the residential rate structure is tiered. Larger impacts, however, would likely be felt in the summer months, as the difference between the two rate blocks is significantly higher during this period.

The potential for a customer to have what should normally be a 30-day billing cycle extended by an additional six days would increase the length of the billing cycle by up to 20%. Since average household usage in June and July is greater than 1,000 kWh, all usage in the longer billing cycle will be billed at the tailblock rate. Customers who have normal usage at or just below the break point for the lower rate tier may end up having a significant portion of their normal usage billed at the tailblock rate, even though their daily usage may not change.

For example, a customer may use 1,000 kWh during 30 days of the July billing period. If that customer's daily usage remains the same, an additional 200 kWh will be billed at the tailblock rate, costing the customer $16.62. If the billing cycle were a normal 30 days, the charge for these 200 kWh would only be $12.16. This customer would therefore pay an additional $4.46 in rates simply because his meter was not read in a

[16] UE 213 / Idaho Power / 1200 / Youngblood / 6.

timely manner. Even if customers are assured that there will be 12 billing cycles per year on their accounts, there are many possible situations in which the longer billing cycle could result in a much higher tailblock bill than would normally occur, without any change in customer behavior.

It is CUB's understanding that Idaho Power's new AMI meters should have the capability to render this consideration moot, as customers will be able to choose their billing date and receive a bill for 30 or 31 days of service each month. However, the Company attests that the problem will still exist even when AMI is fully implemented.[17] If this statement is correct, it opens up the question of the value of AMI to customers, but that is a discussion for another day. In the meantime, CUB contends that Rule B should remain unchanged with regard to the definition of the length of the normal billing cycle. If the Commission decides to grant Idaho Power's request to lengthen the billing cycle, the Commission should require the Company to prorate the tired rates into daily rates that are then multiplied by the number of days in the billing cycle.

VII. CUB Recommendations

CUB makes the following recommendations in resolution of this docket. While some of these recommendations may seem to go beyond rate design, CUB believes that these recommendations need to be addressed, since rate design in this docket is explicitly linked to a desire to promote conservation, and rate design is also directly impacted by billing cycles.

[17] UE 213 / Idaho Power / 1200 / Youngblood / 6.

A. The Commission should reject the staff rate design and instead maintain one rate structure for the entire year.

There is little evidence on the record to show that charging higher rates in the summer and lower rates during the rest of the year will yield significant benefits for Idaho Power customers, even if doing so yields significant benefits for the Company. But there is evidence, as demonstrated by CUB, that the proposed rate design will increase the rate shock that is inherent in a case with a 26.3% increase in residential rates. Additionally, there is evidence that this rate design will increase rate volatility, will guarantee that rates will go up at least once per year, will create confusion for customers whose billing periods do not line up with the high rate season, will potentially cause hardship for customers who struggle with their bills, and will likely lead to overcharging customers who have billing periods that are longer than 31 days.

B. The Commission should reject Idaho Power's proposal to raise the monthly residential base charge from $4.50 to $8.00. Instead, it should allow Idaho Power to increase the customer charge by $1.25.

One of the mysteries in this case has been the purpose of raising the base charge for residential customers. If the Company and the Staff have an explicit goal of increasing price signals to residential customers, then increasing the base charge for residential customers runs counter to this goal. Instead, moving millions of dollars from variable rates to fixed monthly charges will actually reduce the price signals received by customers.

Increasing the base charge for residential customers will have a disproportionately high impact on customers with low monthly usage, who will receive rate increases that are significantly greater than the average customer. Because of the huge rate hike associated with this case, CUB believes that the best goal is to spread the increase out as equally as possible, so few customers will receive increases that are much above 26.3%. To accomplish this objective, CUB recommends that the increase to the base charge be limited to $1.25, which is a 27.8% increase.

C. The Commission should adopt the following rate design for residential customers.

CUB recommends that Idaho Power maintain its current structure in rate design, with the first 300 kWh priced at one rate and the additional priced at a higher rate. CUB recommends that after raising the customer charge by $1.25, the remaining revenue requirement should be spread so that both rate blocks receive the same percentage increase.

CUB is not suggesting that it believes that this is an ideal structure, or that 300 kWh per month is the best place to tier the rates. – CUB would generally support Staff's proposal to increase the separation point between tiers to 1000 kWh per month. However, because of the size of this increase, CUB believes it is more reasonable to spread the increase out in an equal manner to all customers. Changing the rate design from the current structure guarantees that some residential customers will see increases that are greater than 26.3%. CUB strongly recommends against this change and the consequent result. A redesign of Idaho Power's rate structure should be postponed until a time when it can be commenced and completed outside of a rate case where its effects are sure to be serious rate shock and significant harm to customers.

D. The Commission should open an investigation into Idaho Power's residential energy efficiency programs.

Idaho Power's per-capita residential load has remained essentially flat in its Oregon service territory over the past 25 years, whereas Idaho Power's Idaho service territory and PGE's service territory have seen significant reductions in per-capita usage. Idaho Power's participation rates for its residential energy efficiency programs in Oregon are below that of its programs in Idaho. Energy efficiency programs are critical to helping customers deal with costs that are increasing by 26.3%. These programs can also go a long way towards helping Idaho Power deal with its summer peaking costs.

The Commission should launch an investigation, formal or informal, into Idaho Power's energy efficiency programs to determine if more can be done to help residential customers reduce their energy usage. Specifically, such an investigation should look at the reasons for the disparity between Idaho customers' and Oregon customers' participation rates, should compare the results of Idaho Power's programs with the programs operated by the Energy Trust of Oregon (ETO) of other utilities, and should consider whether the current accountability structure is sufficient. If the ETO programs are found to produce superior results, then the Commission should consider requiring Idaho Power to turn its programs over to the ETO, which already operates Cascade Natural Gas Corporation's programs in this service territory.

E. The Commission should order Idaho Power to promote the option of Equal Pay to residential customers.

Typically, when rates are going up by more than 25%, the Commission and the utility will work to ensure that customers are well informed of their option to convert to equal pay plans, where the high cost of winter heating or summer cooling is spread throughout the year. Because such a program runs counter to Idaho Power's desire to send strong price signals in the summer, we are concerned that Idaho Power may not want to promote these programs. The Commission order in this case should make clear that Idaho Power has a responsibility to help customers manage the rate shock associated with the case by promoting equal pay as an option for customers.

F. The Commission should order that the PCAM be used to bring irrigation customers closer to their cost of service.

One of the most troubling aspects of this case was the different treatment that Idaho Power gives residential customers as compared to irrigation customers. Irrigation customers are the primary source of Idaho Power's summer peak loads. If the Company seriously believes that price signals are an appropriate way to reduce summer demand, then it is necessary to reduce the heavy subsidy for irrigation customers and send stronger price signals to these users. Unfortunately, Idaho Power does not file rate cases in Oregon very often. In a case like this one, where the overall rate increase is high, the Commission policy that protects customers against rate shock prevents the kind of rate hike that is necessary to bring irrigators up to their actual cost-of-service. Throughout most of the 1990s, residential customers regularly received an increase of two or three times greater than the system average in order to bring them closer to their actual cost-of-service. In this case, the Company and Staff have stated that such a practice is not possible without creating rate shock for irrigators.

CUB is not arguing here that irrigators should get a larger increase. CUB agrees with the Commission policy that works to avoid rate shock to any class of customers.

However, the infrequency of Idaho Power's rate cases, coupled with the large size of the consequent irate hikes, results in a policy that locks in the status quo and the subsidies to irrigators and prevents significant policy changes during rate cases.

CUB believes the logical solution to this issue would be to order that the PCAM be used to move towards a fair allocation of costs between classes of customers. When the PCAM has a rate decrease, that decrease should only go to customers who are paying more than 90% of their class cost of service. Where there is a rate increase in a PCAM, if the increase is less than 10%, customers whose rates are paying less than 90% of their class cost of service would get two times the overall increase. The excess amount created by increasing the rate hike or avoiding the refund should be spread to other classes in proportion to the subsidy that they pay to irrigators.

WITNESS QUALIFICATION STATEMENT

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WORK EXPERIENCE: I have previously provided testimony in dockets UE 196, UE 204, UE 207, UE 210, UM 1355 and UM 1431. Between 2004 and 2008, I worked for the US Environmental Protection Agency and the City of Portland Bureau of Environmental Services, conducting economic and environmental analyses on a number of projects. In January 2009 I joined the Citizens' Utility Board of Oregon as a Utility Analyst and began conducting research and analysis on behalf of CUB.

Idaho Power Company
UE 213 CUB Data Requests No. 38a and 38b

Consolidated Totals - Funding by Customer Class - 2005-2009*

Customer Class	Oregon Rider Funding	% of Oregon Rider Total	Idaho Rider Funding	% of Idaho Rider Total	Total Funding Received	% of Total
Residential	$ 552,055	35%	$ 24,751,316	45%	$ 25,303,371	45%
Commercial	$ 424,413	27%	$ 14,524,588	26%	$ 14,949,001	26%
Industrial	$ 481,414	31%	$ 8,131,363	15%	$ 8,612,777	15%
Irrigation	$ 107,808	7%	$ 7,824,116	14%	$ 7,931,924	14%
Funding Sub-Totals	$ 1,565,691	100%	$ 55,231,383	100%	$ 56,797,073	100%
Accrued Interest	*$ 80,010*		*$ 415,868*		*$ 496,115*	
Funding Totals (2005-2009*)	**$ 1,645,701**		**$ 55,647,251**		**$ 57,293,189**	

***2009 (Jan-Sept)**

2009 (January - September 2009)

Customer Class	Oregon Rider Funding	% of Total	Idaho Rider Funding	% of Total	Total Funding Received	% of Total
Residential	$ 105,259	36%	$ 8,285,853	44%	$ 8,391,113	44%
Commercial	$ 79,007	27%	$ 4,657,396	25%	$ 4,736,403	25%
Industrial	$ 82,962	28%	$ 2,475,162	13%	$ 2,558,124	13%
Irrigation	$ 24,848	9%	$ 3,335,979	18%	$ 3,360,827	18%
Sub-Total	$ 292,077	100%	$ 18,754,390	100%	$ 19,046,467	100%
Accrued Interest	*$ (2,950)*		*$ (97,626)*		*$ (100,577)*	
al Funding by Customer Class	**$ 289,126**		**$ 18,656,764**		**$ 18,945,890**	

2008

Customer Class	Oregon Rider Funding	% of Total	Idaho Rider Funding	% of Total	Total Funding Received	% of Total
Residential	$ 138,065	36%	$ 5,980,444	44%	$ 6,118,508	44%
Commercial	$ 105,573	27%	$ 3,574,145	26%	$ 3,679,718	27%
Industrial	$ 115,414	30%	$ 1,955,057	14%	$ 2,070,471	15%
Irrigation	$ 28,328	7%	$ 1,982,144	15%	$ 2,010,472	14%
Sub-Total	$ 387,380	100.00%	$ 13,491,789	104.50%	$ 13,879,169	104.37%
Accrued Interest	*$ 24,222*		*$ (36,906)*		*$ (12,684)*	
al Funding by Customer Class	**$ 411,602**		**$ 13,454,883**		**$ 13,866,485**	

Idaho Power Company
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2007

Customer Class	Oregon Rider Funding	% of Total	Idaho Rider Funding	% of Total	Total Funding Received	% of Total
Residential	$ 136,425	35%	$ 4,027,610	46%	$ 4,164,035	45%
Commercial	$ 105,578	27%	$ 2,434,132	28%	$ 2,539,710	28%
Industrial	$ 123,025	31%	$ 1,389,096	16%	$ 1,512,121	16%
Irrigation	$ 27,931	7%	$ 936,470	11%	$ 964,400	11%
Sub-Total	$ 392,959	100.00%	$ 8,787,308	100.00%	$ 9,180,267	100.00%
Accrued Interest	*$ 32,723*		*$ 248,764*		*$ 281,487*	
al Funding by Customer Class	**$ 425,683**		**$ 9,036,072**		**$ 9,461,754**	

2006

Customer Class	Oregon Rider Funding	% of Total	Idaho Rider Funding	% of Total	Total Funding Received	% of Total
Residential	$ 136,380	35%	$ 3,905,081	46%	$ 4,041,461	46%
Commercial	$ 105,172	27%	$ 2,325,213	28%	$ 2,430,385	28%
Industrial	$ 126,963	32%	$ 1,357,958	16%	$ 1,484,921	17%
Irrigation	$ 23,017	6%	$ 847,917	10%	$ 870,934	10%
Sub-Total	$ 391,532	100.00%	$ 8,436,169	100.00%	$ 8,827,701	100.00%
Accrued Interest	*$ 22,540*		*$ 196,367*		*$ 218,907*	
al Funding by Customer Class	**$ 414,073**		**$ 8,632,535**		**$ 9,046,608**	

2005

Customer Class	Oregon Rider Funding	% of Total	Idaho Rider Funding	% of Total	Total Funding Received	% of Total
Residential	$ 35,926	35%	$ 2,552,328	44%	$ 2,588,254	44%
Commercial	$ 29,083	29%	$ 1,533,702	27%	$ 1,562,786	27%
Industrial	$ 33,049	32%	$ 954,090	17%	$ 987,139	17%
Irrigation	$ 3,684	4%	$ 721,608	13%	$ 725,292	12%
Sub-Total	$ 101,742	100.00%	$ 5,761,727	100.00%	$ 5,863,470	100.00%
Accrued Interest	*$ 3,475*		*$ 105,270*		*$ 108,745*	
al Funding by Customer Class	**$ 105,218**		**$ 5,866,997**		**$ 5,972,215**	

Idaho Power Company
UE 213 CUB Data Requests No. 38c and 38d

Total 2005-2009* DSM Expenses by Funding Source (Dollars)

Sector/Program	Idaho Rider	% Idaho Rider Total	Oregon Rider	% Oregon Rider Total	Idaho Power Funds	% IPC Total	Total	% Total
Energy Efficiency/Demand Response								
Residential	$ 18,049,842	25.5%	$ 397,912	16.1%	$ 6,582,193	87.0%	$ 25,029,947	31.0%
Commercial/Industrial	23,508,554	33.3%	711,535	28.9%	102,292	1.4%	24,322,381	30.1%
Irrigation	22,747,297	32.2%	1,031,306	41.8%	392,120	5.2%	24,170,723	29.9%
Total Energy Efficiency/Demand Response	64,305,693		2,140,753		7,076,605		73,523,051	
NEEA	3,744,224	5.3%	197,064	8.0%	26,078	0.3%	3,967,366	4.9%
Other Programs and Activities	377,608	0.5%	16,675	0.7%	49,656	0.7%	443,939	0.6%
Indirect Program Expenses	2,251,866	3.2%	111,620	4.5%	416,763	5.5%	2,780,249	3.4%
Total DSM Expenses by Funding Source	$ 70,679,391	100%	$ 2,466,112	100%	$ 7,569,102	100%	$ 80,714,605	100%

***2009 (Jan-Sept)**

2009 Q1-Q3 DSM Expenses by Funding Source (Dollars)

Sector/Program	Idaho Rider	% Idaho Rider Total	Oregon Rider	% Oregon Rider Total	Idaho Power Funds	% IPC Total	Total	% Total
Energy Efficiency/Demand Response								
Residential	$ 5,211,920	20.9%	$ 227,434	19.5%	$ 1,017,946	83.9%	$ 6,457,300	23.6%
Commercial/Industrial	7,855,455	31.5%	305,931	26.3%	10,559	0.9%	8,171,945	29.9%
Irrigation	10,641,164	42.7%	566,807	48.6%	86,471	7.1%	11,294,442	41.4%
Total Energy Efficiency/Demand Response	23,708,539		1,100,172		1,114,976		25,923,687	
NEEA	688,434	2.8%	36,233	3.1%			724,667	2.7%
Other Programs and Activities	101,235	0.41%	6,000	0.51%	8,276	0.68%	115,511	0.42%
Indirect Program Expenses	434,656	1.7%	22,870	2.0%	89,495	7.38%	547,021	2.0%
Total DSM Expenses by Funding Source	$ 24,932,864	100%	$ 1,165,275	100%	$ 1,212,747	100%	$ 27,310,886	100%

2008 DSM Expenses by Funding Source (Dollars)

Sector/Program	Idaho Rider	% Idaho Rider Total	Oregon Rider	% Oregon Rider Total	Idaho Power Funds	% IPC Total	Total	% Total
Energy Efficiency/Demand Response								
Residential	$ 5,787,360	30.7%	$ 126,989	20.3%	$ 1,429,177	85.0%	$ 7,343,526	34.7%
Commercial/Industrial	7,974,823	42.2%	190,596	30.5%	29,052	1.7%	8,194,471	38.7%
Irrigation	3,252,815	17.2%	210,846	33.7%	71,881	4.3%	3,535,542	16.7%
Total Energy Efficiency/Demand Response	17,014,998		528,431		1,530,110		19,073,539	
NEEA	894,913	4.7%	47,101	7.5%	-		942,014	4.4%
Other Programs and Activities	158,502	0.84%	6,945	1.11%	25,265	1.50%	190,712	0.90%
Indirect Program Expenses	811,863	4.3%	42,523	6.8%	125,919	7.49%	980,305	4.6%
Total DSM Expenses by Funding Source	$ 18,880,276	100%	$ 625,000	100%	$ 1,681,294	100%	$ 21,186,570	100%

Idaho Power Company
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2007 DSM Expenses by Funding Source (Dollars)

Sector/Program	Idaho Rider	% Idaho Rider Total	Oregon Rider	% Oregon Rider Total	Idaho Power Funds	% IPC Total	Total	% Total
Energy Efficiency/Demand Response								
Residential	$ 4,194,448	31.1%	$ 35,742	8.7%	$ 1,329,732	85.0%	$ 5,559,922	36.0%
Commercial/Industrial	4,399,335	32.6%	$ 147,528	36.1%	24,252	1.5%	4,571,115	29.6%
Irrigation	3,401,222	25.2%	148,671	36.3%	67,950	4.3%	3,617,843	23.4%
Total Energy Efficiency/Demand Response	11,995,005		331,941		1,421,934		13,748,880	
NEEA	846,898	6.3%	44,574	10.9%	1,868	0.1%	893,340	5.8%
Other Programs and Activities	68,424	0.51%	2,758	0.67%	2,235	0.14%	73,417	0.47%
Indirect Program Expenses	577,133	4.3%	29,915	7.3%	139,006	8.88%	746,054	4.8%
Total DSM Expenses by Funding Source	$ 13,487,460	100%	$ 409,188	100%	$ 1,565,043	100%	$ 15,461,691	100%

2006 DSM Expenses by Funding Source (Dollars)

Sector/Program	Idaho Rider	% Idaho Rider Total	Oregon Rider	% Oregon Rider Total	Idaho Power Funds	% IPC Total	Total	% Total
Energy Efficiency/Demand Response								
Residential	$ 1,817,824	20.6%	$ 7,396	3.1%	$ 1,392,132	87.7%	$ 3,217,352	30.2%
Commercial/Industrial	1,965,431	22.2%	61,933	26.3%	28,058	1.8%	2,055,422	19.3%
Irrigation	3,912,692	44.2%	104,982	44.6%	86,364	5.4%	4,104,038	38.5%
Total Energy Efficiency/Demand Response	7,695,947		174,311		1,506,554		9,376,812	
NEEA	872,570	9.9%	45,925	19.5%	11,960	0.0075	930,455	8.7%
Other Programs and Activities	19,081	0.22%	972	0.41%	7,686	0.48%	27,739	0.26%
Indirect Program Expenses	257,315	2.9%	13,968	5.9%	60,682	3.82%	331,965	3.1%
Total DSM Expenses by Funding Source	$ 8,844,913	100%	$ 235,176	100%	$ 1,586,882	100%	$ 10,666,971	100%

2005 DSM Expenses by Funding Source (Dollars)

Sector/Program	Idaho Rider	% Idaho Rider Total	Oregon Rider	% Oregon Rider Total	Idaho Power Funds	% IPC Total	Total	% Total
Energy Efficiency/Demand Response								
Residential	$ 1,038,290	22.9%	$ 351	1.1%	$ 1,413,206	92.8%	$ 2,451,847	40.3%
Commercial/Industrial	1,313,510	29.0%	5,547	17.6%	10,371	0.7%	1,329,428	21.8%
Irrigation	1,539,404	34.0%		0.0%	79,454	5.2%	1,618,858	26.6%
Total Energy Efficiency/Demand Response	3,891,204		5,898		1,503,031		5,400,133	
NEEA	441,409	9.7%	23,231	73.8%	12,250	0.008	476,890	7.8%
Other Programs and Activities	30,366	0.67%	-	0.00%	6,194	0.41%	36,560	0.60%
Indirect Program Expenses	170,899	3.8%	2,344	7.4%	1,661	0.11%	174,904	2.9%
Total DSM Expenses by Funding Source	$ 4,533,878	100%	$ 31,473	100%	$ 1,523,136	100%	$ 6,088,487	100%

Idaho Power Company
UE 213 CUB Data Requests No. 38e and 38f

2005-2009 Energy Efficiency Program Participants

January 1, 2005 - September 30, 2009

Sector/Program	Year	Unit	Idaho	Oregon	Total
Energy Efficiency/Demand Response					
Residential					
A/C Cool Credit					
	2005	*Homes*	2,369	0	2,369
	2006	*Homes*	5,369	0	5,369
	2007	*Homes*	13,692	0	13,692
	2008	*Homes*	20,067	128	20,195
	2009	*Homes*	31,397	325	31,722
			0.08	0.02	
Ductless Heat Pump Pilot					
	2009	*Homes*	34	4	38
Energy Efficient Lighting					
	2005	*CFLs*	43,760		43,760
	2006	*CFLs*	173,260	5,254	178,514
	2007	*CFLs*	216,265	3,474	219,739
	2008	*CFLs*	433,519	2,715	436,234
	2009	*CFLs*	369,016	5,715	374,731
Energy House Calls					
	2005	*Homes*	874	17	891
	2006	*Homes*	790	29	819
	2007	*Homes*	653	47	700
	2008	*Homes*	1,021	78	1,099
	2009	*Homes*	563	155	718
ENERGY STAR® Homes Northwest					
	2005	*Homes*	200	0	200
	2006	*Homes*	439	0	439
	2007	*Homes*	303	0	303
	2008	*Homes*	254	0	254
	2009	*Homes*	299	0	299
Heating & Cooling Efficiency					
	2006	*Homes*	0	0	0
	2007	*Homes*	4	0	4
	2008	*Homes*	340	19	359
	2009	*Homes*	281	2	283
Home Improvement					
	2008	*Homes*	282	0	282
	2009	*Homes*	379	0	379
Home Products					
	2007	*Appliances/Fixtures*	0	0	0
	2008	*Appliances/Fixtures*	2,979	55	3,034
	2009	*Appliances/Fixtures*	6,334	116	6,450
Oregon Residential Weatherization					
	2005	*Homes*	0	4	4
	2006	*Homes*	0	0	0
	2007	*Homes*	0	1	1
	2008	*Homes*	0	3	3
	2009	*Homes*	0	0	0

Sector/Program	Year	Unit	Idaho	Oregon	Total
Rebate Advantage					
	2005	*Homes*	87	11	98
	2006	*Homes*	88	14	102
	2007	*Homes*	99	24	123
	2008	*Homes*	90	17	107
	2009	*Homes*	26	3	29
See Ya Later Refrigerator					
	2009	*Refrigerators*	850	12	862
WAQC					
	2005	*Homes/Non-profits*	570	28	598
	2006	*Homes/Non-profits*	540	0	540
	2007	*Homes/Non-profits*	397	11	408
	2008	*Homes/Non-profits*	439	13	452
	2009	*Homes/Non-profits*	329	10	339
Weatherization Solutions for Eligible Customers					
	2008	*Homes*	16	0	16
	2009	*Homes*	18	0	18
Residential Total					
	2005		**47,860**	**60**	**47,920**
	2006		**180,486**	**5,297**	**185,783**
	2007		**231,413**	**3,557**	**234,970**
	2008		**459,007**	**3,028**	**462,035**
	2009		**409,526**	**6,342**	**415,868**
Commercial					
Building Efficiency					
	2005	*Projects*	12	0	12
	2006	*Projects*	39	1	40
	2007	*Projects*	22	0	22
	2008	*Projects*	54	6	60
	2009	*Projects*	48	0	48
Easy Upgrades					
	2007	*Projects*	98	6	104
	2008	*Projects*	659	26	685
	2009	*Projects*	827	28	855
FlexPeak Management					
	2009	*Customers*	22	0	22
Holiday Lighting					
	2008	*Projects*	14	0	14
	2009	*Projects*	20	0	20
Oregon Commercial Audit					
	2005	*Audits*	0	7	7
	2006	*Audits*	0	6	6
	2007	*Audits*	0	8	8
	2008	*Audits*	0	0	0
	2009	*Audits*	0	20	20
Oregon School Efficiency					
	2005	*Projects*	0	0	0
	2006	*Projects*	0	6	6

Sector/Program	Year	Unit	Idaho	Oregon	Total
Commercial Total					
	2005		**12**	**7**	**19**
	2006		**39**	**13**	**52**
	2007		**120**	**14**	**134**
	2008		**727**	**32**	**759**
	2009		**917**	**48**	**965**
Industrial					
Custom Efficiency					
	2005	*Projects*	24	0	24
	2006	*Projects*	40	0	40
	2007	*Projects*	48	1	49
	2008	*Projects*	96	4	100
	2009	*Projects*	83	11	94
Industrial Total					
	2005		**24**	**0**	**24**
	2006		**40**	**0**	**40**
	2007		**48**	**1**	**49**
	2008		**96**	**4**	**100**
	2009		**83**	**11**	**94**
Irrigation					
Irrigation Efficiency Rewards					
	2005	*Projects*	38	0	38
	2006	*Projects*	543	16	559
	2007	*Projects*	801	15	816
	2008	*Projects*	916	45	961
	2009	*Projects*	749	37	786
Irrigation Peak Rewards					
	2005	*Service points*	894	0	894
	2006	*Service points*	893	13	906
	2007	*Service points*	925	22	947
	2008	*Service points*	883	14	897
	2009	*Service points*	1,476	36	1,512
Irrigation Total					
	2005		**932**	**0**	**932**
	2006		**1,436**	**29**	**1,465**
	2007		**1,726**	**37**	**1,763**
	2008		**1,799**	**59**	**1,858**
	2009		**2,225**	**73**	**2,298**
Total Participants					
	2005		**48,828**	**67**	**48,895**
	2006		**182,001**	**5,339**	**187,340**
	2007		**233,307**	**3,609**	**236,916**
	2008		**461,629**	**3,123**	**464,752**
	2009		**412,751**	**6,474**	**419,225**
	Total		**1,338,516**	**18,612**	**1,357,128**

CUB EXHIBIT 205 IS CONFIDENTIAL

SUBJECT TO PROTECTIVE ORDER

Attachment - Response CUB DR 14

Monthly Residential Usage

2004

	January	February	March	April	May	June	July	August	September	October	November	December	January
Idaho						278,128,605	339,605,552	383,243,208	328,269,454	285,196,793	331,336,481	442,261,528	506199634
						801	978	1,103	945	821	954	1,273	1404.222196
Oregon						11,382,711	13,655,713	15,852,651	13,151,218	11,269,110	14,289,676	19,648,025	22772870
						870.37	1,044.17	1,212.16	1,005.60	861.68	1,092.65	1,502.37	1735.86935

2005

	January	February	March	April	May	June	July	August	September	October	November	December	Avg Monthly Usage
Idaho	506,199,634	461,252,347	408,285,168	353,757,511	289,931,423	282,678,719	341,780,496	412,495,770	359,384,624	299,456,538	330,003,124	495,351,033	378,381,366
	1,404	1,280	1,133	981	804	784	948	1,144	997	831	915	1,374	
Oregon	22,772,870	21,295,167	17,839,232	15,150,453	11,756,978	11,324,676	12,917,152	15,497,722	13,591,991	11,617,603	13,845,315	22,227,668	15,819,736
	1,735.87	1,623.23	1,359.80	1,154.85	896.18	863.23	984.61	1,181.32	1,036.05	885.56	1,055.36	1,694.31	

2006

	January	February	March	April	May	June	July	August	September	October	November	December	Avg Monthly Usage
Idaho	542,256,628	479,564,784	463,458,719	381,773,365	298,831,143	321,018,018	400,378,182	447,538,708	365,751,234	316,254,852	373,300,878	496,763,991	407,240,875
	1,447.84	1,280.45	1,237.45	1,019.35	797.89	857.13	1,069.02	1,194.94	976.57	844.41	996.73	1,326.38	
Oregon	25,334,222	20,872,541	20,893,377	16,079,087	11,770,517	12,067,181	14,840,713	16,515,001	13,448,393	11,669,934	15,407,486	21,298,295	16,683,062
	1,922.17	1,583.65	1,585.23	1,219.96	893.06	915.57	1,126.00	1,253.03	1,020.36	885.43	1,169.01	1,615.96	

2007

	January	February	March	April	May	June	July	August	September	October	November	December	Avg Monthly Usage
Idaho	580,998,277	514,606,033	425,590,246	355,513,090	314,881,186	337,194,443	426,578,902	463,872,089	382,847,131	330,078,189	378,525,441	504,317,513	417,916,878
	1,513.04	1,340.14	1,108.33	925.83	820.02	878.13	1,110.90	1,208.02	997.02	859.59	985.76	1,313.35	
Oregon	24,966,551	23,190,746	17,874,398	13,988,526	12,362,236	12,286,542	15,435,588	16,838,004	13,776,351	11,894,188	15,352,798	21,353,109	16,609,920
	1,878.31	1,744.71	1,344.75	1,052.40	930.05	924.36	1,161.27	1,266.78	1,036.44	894.84	1,155.04	1,606.46	

2008

	January	February	March	April	May	June	July	August	September	October	November	December	Avg Monthly Usage
Idaho	593,556,135	553,197,468	458,154,512	426,084,869	343,396,926	319,448,339	401,143,203	431,891,539	377,428,418	324,299,533	366,215,693	482,084,760	423,075,116
per cap	1,518.60	1,415.34	1,172.18	1,090.13	878.57	817.30	1,026.32	1,104.99	965.64	829.71	936.96	1,233.40	
Oregon	25,000,898	24,951,259	19,830,986	17,500,463	13,349,329	11,769,369	14,962,181	15,241,256	13,519,168	11,809,061	14,751,877	20,247,720	16,911,131
per cap	1,849.73	1,846.05	1,467.22	1,294.80	987.67	870.77	1,107.00	1,127.65	1,000.23	873.71	1,091.44	1,498.06	

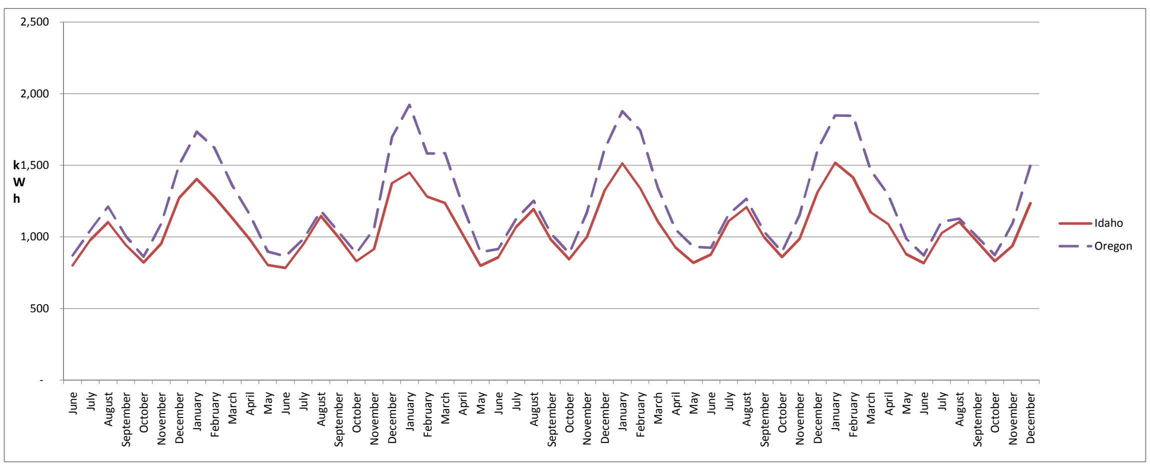
2009

	January	February	March	April	May	June	July	August	September	October	November	December	Avg Monthly Usage
Idaho	591,775,224	521,700,702	460,164,049	406,955,942	321,942,831	330,396,750	372,005,502	429,796,413					429,342,177
	(0.30)	(6.04)	0.44	(4.70)	(6.66)	3.31	(7.83)	(0.49)					
Oregon	26,379,052	23,626,503	20,239,197	16,519,853	12,348,912	12,139,543	13,170,258	15,506,164					17,491,185
	5.22	(5.61)	2.02	(5.94)	(8.10)	3.05	(13.61)	1.71					

Note: Idaho usage includes Idaho's Residential time variant rate schedules. The Company currently has a total of 128 customers on these rates.

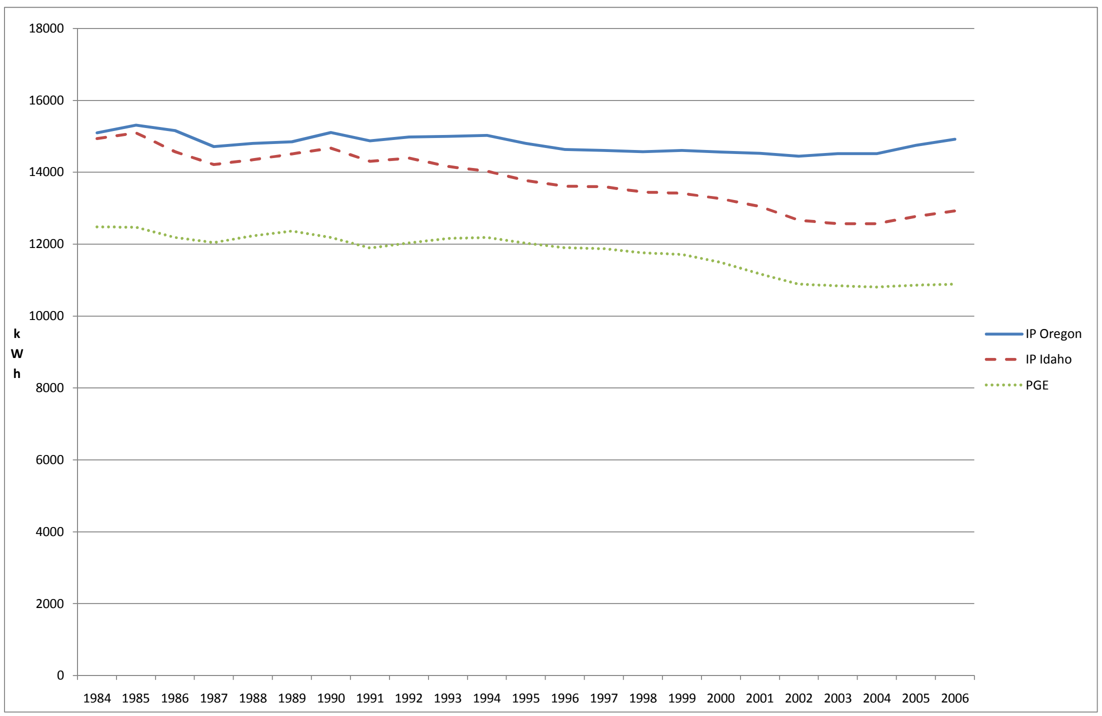
341,148,803

14,178,443



Residential Energy Usage by Utility Territory, 1983-2007.

	Idaho Power Oregon Territory				Idaho Power ID Territory				PGE			
Year	demand	customers	Per Capita Demand	3 Yr Rolling Average	demand	customers	Per Capita Demand	3 Yr Rolling Average	demand	customers	Per Capita Demand	3 Yr Rolling Average
1983			14282		2935247	208859	14054				12027	
1984			15413	15098	3248580	211799	15338	14938			12644	12484
1985			15598	15308	3304941	214289	15423	15094			12781	12471
1986			14913	15162	3139525	216218	14520	14577			11987	12186
1987			14974	14715	3006086	218042	13787	14219			11791	12040
1988			14259	14800			*14349*	14349			12343	12234
1989			15168	14847	3318827	222582	14911	14509			12568	12363
1990			15115	15105	3243278	227308	14268	14667			12178	12185
1991			15031	14872	3443581	232329	14822	14305			11810	11896
1992			14469	14985	3301720	238822	13825	14397			11699	12039
1993			15456	15001	3596561	247272	14545	14162			12608	12157
1994			15078	15025	3623642	256721	14115	14029			12163	12183
1995			14542	14807	3569829	265895	13426	13775			11778	12028
1996			14801	14635	3788331	274842	13784	13612			12143	11905
1997			14562	14607	3856951	283073	13625	13602			11795	11874
1998			14459	14575	3905835	291557	13396	13448			11683	11760
1999			14704	14610	4011527	301113	13322	13418			11802	11716
2000			14666	14567	4203268	310559	13535	13267			11663	11489
2001	185344	12933	14331	14525	4117128	318076	12944	13047	7080228	643596	11001	11176
2002	188991	12965	14577	14445	4197803	331482	12664	12671	7058334	649674	10864	10883
2003	188301	13052	14427	14519	4238675	341652	12406	12569	7098730	658232	10785	10840
2004	190343	13078	14554	14520	4389994	347384	12637	12573	7270118	668830	10870	10807
2005	191252	13119	14578	14753	4569023	360484	12675	12770	7322964	680093	10768	10861
2006	199383	13180	15128	14917	4868384	374527	12999	12922	7572788	691931	10944	10888
2007	199962	13292	15044		5027204	383993	13092		7688285	701952	10953	
				14799.93489				13779.05758				11759.34916



UE 213 – CERTIFICATE OF SERVICE

I hereby certify that, on this 19th day of January 2010, 2010, I served the foregoing **RESPONSE TESTIMONY OBJECTING TO THE STIPULATION OF THE CITIZENS' UTILITY BOARD OF OREGON** in docket UE 213 upon each party listed in the UE 213 OPUC Service List by email and, where paper service is not waived, by U.S. mail, postage prepaid, and upon the Commission by email and by sending an original and five copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

(W denotes waiver of paper service)

(C denotes service of Confidential material authorized)

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