# Demand Response Programs for Oregon Utilities

Public Utility
Commission

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## INTRODUCTION

Facing unprecedented wholesale prices and looming shortages in Western power markets in 2000-01, Portland General Electric, PacifiCorp and Idaho Power put programs in place that reduced demand in order to maintain system reliability and rein in high-cost power purchases. The programs achieved sizable load reductions by paying customers to reduce electricity use during peak hours or over a month or season.

Today, only demand buyback programs for large customers remain, though they are not active at current wholesale prices. Other programs now in place that reduce peak demand rely on retail prices that change over time. They include optional time-of-use pricing for residential and small business customers, a market-based daily pricing choice for nonresidential customers, and on- and off-peak pricing for some large customers.

These programs are a good start toward using demand response to improve reliability, reduce delivered energy costs, and keep customers' rates down and more stable. But more can be done to tap its potential to reduce loads when supplies are tight as well as help meet ongoing needs for peak capacity, thereby reducing investments in power plants and distribution upgrades and easing congestion on the region's transmission grid.

This report reviews demand response tools that can help utilities meet peak electricity needs, documents the results of the demand response programs Oregon utilities have offered and assesses their effectiveness. The report then makes recommendations for future programs.

Though not the focus of this paper, alternative energy suppliers that serve Oregon's nonresidential customers in the future likely will provide demand response for the wholesale market — by passing through real-time prices for usage above a set level and including demand buyback provisions for times of high prices. As control area operators, the utilities may call on direct access customers to curtail loads in the event of a system contingency.

## TYPES OF DEMAND RESPONSE PROGRAMS

Utilities have used a wide variety of approaches to encourage customers to reduce or shift demand for power during system emergencies, energy and capacity shortages, and periods of high market prices and to make the best use of generation, transmission and distribution assets. Independent system operators (ISOs) also offer demand response programs, to improve system reliability, avoid outages and ease transmission congestion.

Demand response programs generally fall into two categories: 1) rate structures that give customers a price signal reflecting the marginal costs of electricity production (and sometimes delivery) and 2) payments for reducing load when supplies are tight. Other programs offer non-monetary benefits. Following are pricing, payment and other options for achieving demand response:[1,2,3]

### PRICING OPTIONS

A report funded by the Electric Power Research Institute[4] (EPRI) found "overwhelming evidence" from dozens of studies that all customer classes respond in modest but significant and consistent ways to time-varying electricity prices. Responses vary widely, depending on electricity usage levels, appliance ownership or electricity intensity of operations, ability to shift loads to off-peak times, on-site generation and other factors.

Time-varying rates may be voluntary or mandatory. Unlike payment options, pricing options require no utility-paid incentives.

Pricing may be "dynamic," where prices or time periods change on short notice in response to changes in supply and demand. Or pricing and time periods may vary throughout the day or seasonally but are fixed and known in advance. Real-time pricing and critical-peak pricing are examples of dynamic rates; traditional time-of-use rates have fixed prices and time periods.

Time-of-use rates have commonly been used for 25 years for all types of customers, and some utilities have recently added a critical-peak rate. Many also have offered real-time pricing for large customers, some for more than 10 years. However, many have operated as pilot programs or have had limited participation.

#### Real-Time Pricing

Real-time pricing allows prices to be adjusted frequently to reflect real-time system conditions. Prices typically change hourly, with hour-ahead or day-ahead notice. Prices may be based on actual trading in wholesale markets, a statistical model that forecasts real-time wholesale prices

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[1] Western Governors' Association, *Demand Response Programs: An Overview*, Sept. 26, 2002.

[2] Severin Borenstein, Michael Jaske and Arthur Rosenfeld, *Dynamic Pricing, Advanced Metering and Demand Response in Electricity,* Center for the Study of Energy Markets, CSEM WP 105, October 2002.

[3] Ken Corum, *Demand Response: Issue Paper in Preparation for the Fifth Power Plan*, Northwest Power Planning Council, Dec. 2002.

[4] *Customer Response to Electricity Prices: Information to Support Wholesale Price Forecasting and Market Analysis*, EPRI, Palo Alto, CA: 2001. 1005945.

or a forecast of avoided generation costs. Customers can reduce load or move load from high-price hours to other hours of the same day or to other days.

Not every kilowatt-hour must be priced in real-time. Some utilities charge real-time prices only for usage above an historical baseline, reducing the customer's price risk and the utility's risk of revenue loss. Customers also may be able to adjust how much of their baseline load is charged at hourly prices.

Real-time pricing reduces ongoing capacity requirements and provides energy reductions during periods of high prices — during system emergencies or when supplies are otherwise tight.

Programs typically target large commercial and industrial customers. Among programs with sizable participation today are Georgia Power, Duke Power (North Carolina), Niagara Mohawk (New York) and utility and marketer-led programs in the United Kingdom. (See Table 1.) Other utilities offering real-time pricing for large customers include Southern California Edison, XCel Energy (MidWest), Tennessee Valley Authority, Pacific Gas and Electric and British Columbia Hydro and Power Authority.

Georgia Power has offered real-time pricing since 1992. It has the highest level of participation and is the most extensively analyzed program in the U.S. (See Appendix A.)

**Table 1. Sampling of Real-Time Pricing Programs**[5]

| Program | Customers | Peak Reduction | Pricing | Elasticity Estimate[6] | Available Since |
|---|---|---|---|---|---|
| Georgia Power | 1,500 | 1,000 MW[7] | Hourly | 0.01 to 0.19 | 1990 |
| Duke Power | 100 | 200 MW[8] | Hourly | 0.00 to 0.07 | 1997 |
| Niagara Mohawk | 38[9] | 18 MW | Hourly | 0.10 to 0.20 | 1988 |
| Midlands (U.K. utility) | 340 | NA | Half-hourly | 0.07 to 0.35 | 1990 |
| Marketer-run programs in U.K. | 520 | NA | Half-hourly | 0.00 to 0.86 | 1990 |

## Time-of-Use Rates

[5] Most information in this table is from the *Report of Working Group 2 on Dynamic Tariff and Program Proposals*, Nov. 15, 2002, prepared for California Public Utilities Commission Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response and Dynamic Pricing, R.02-06-001. Peak reductions are from other sources, noted below.

[6] Price elasticity of demand, a ratio of the percent change in amount purchased to the percent change in price. For example, an elasticity of 0.10 means that the consumer will purchase 10 percent less electricity in response to a 100 percent higher price.

[7] Mike O 'Sheasy, Christensen and Associates, "Real Time Pricing at Georgia Power Company," Appendix A in Severin Borenstein, Michael Jaske and Arthur Rosenfeld, *Dynamic Pricing, Advanced Metering and Demand Response in Electricity,* Center for the Study of Energy Markets, CSEM WP 105, October 2002.

[8] Steven Braithwait, Christensen and Associates, "Real Time Pricing and Demand Response: Five Basic Facts About Power Markets and Real Time Pricing," presentation at California Energy Commission Demand Response Workshop, March 15, 2002. The combined load of participating customers is about 1,000 MW. Reduction is about 20 percent of expected load in response to prices above 25¢ per kWh.

[9] C. Goldman, Lawrence Berkeley National Laboratory, cites 250 Niagara Mohawk customers with peak demand greater than 2 MW are on real-time pricing tariffs, in *Price-Responsive Load Programs*, prepared for New England Demand Response Initiative, March 25, 2002.

Time-of-use rates are an approximation of real-time prices. They are generally based on the expected average costs of each part of the day and typically vary by season. Prices are higher during peak times and lower during off-peak times. Rates are fixed for set time periods throughout the week, rather than based on real-time prices in the marketplace. Time-of-use rates may apply to energy or demand charges, or both. The primary objective of time-of-use rates is to reduce capacity requirements. They also shift energy requirements from higher priced to lower priced hours.

A significant advantage of time-of-use rates over real-time pricing is that prices are fixed for months or a year in advance (or longer), making bills more predictable. In addition, no communication equipment is needed to notify customers of price changes, and the required meters are less costly than for real-time pricing or critical-peak pricing. (However, it may be prudent to install meters capable of measuring and storing at least hourly data to allow flexibility for future rate designs.) A significant disadvantage, however, is that prices and pricing periods set in advance cannot reflect real-time events, including cold snaps, heat waves, droughts and generator outages. So time-of-use rates cannot provide accurate price signals to consumers at times of greatest stress to the power system, when customers' response to actual power costs would be most useful.

The EPRI study concluded that an on-peak time-of-use rate 10 percent higher than the average rate leads to a reduction in peak use for residential customers ranging from 0.5 percent to 2.5 percent. (Rates 100 percent higher would lead to reductions of 5 percent to 25 percent.) For commercial and industrial customers, a 10 percent higher peak price reduces peak use by 0.2 percent to 1.0 percent.[10]

Time-of-use pricing has been used for 25 years, and most utilities in the U.S. offer or require it at least for large customers. Many utilities also offer a time-of-use option for residential and small nonresidential customers. Puget Sound Energy recently terminated its widespread program for residential and small business customers after it reduced the difference between on- and off-peak rates and added a monthly meter charge. Residential participants consumed 5 percent to 6 percent less electricity during peak demand hours than consumers paying flat rates. (See Appendix A.)

**Critical-Peak Pricing**

Critical-peak pricing is a hybrid of time-of-use and real-time pricing. For nearly all hours of the year, the utility charges fixed time-of-use rates for preset periods — on-, mid- and off-peak. But for a limited number of hours (or days) each year — during extreme supply conditions as they develop — the utility declares a very high price. The "super-peak" price may be fixed or variable. The customer finds out when the utility will charge the super-peak price shortly before it's in effect. Adding a critical-peak price to time-of-use rates allows the utility to reduce on-peak hours and/or rates.

Critical-peak pricing combines the predictability of time-of-use rates with very limited use of a real-time market signal to customers when generation and delivery impose the greatest costs — and increased demand response provides the most benefit.

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[10] Data are for voluntary programs, where customers might be expected to be more price-responsive than a typical customer, though some programs have very high participation rates.

Critical-peak pricing requires investments in specialized time-of-use meters with a fourth register or meters that can measure and store hourly data, as well as a customer notification system. The utility can install technology to set customers' energy-consuming equipment automatically to levels they've preprogrammed for each pricing period to make it easy for them to participate and benefit.

Recent estimates of the overall economic benefit of critical-peak pricing for small customers of three utilities, including two winter peaking utilities, show it can be far larger than for traditional time-of-use rates and direct load control alone using all cost-effectiveness tests. The results further show that residential consumers have far more potential to shift load and provide economic value than do small business customers.[11]

Several utilities in the U.S. and Europe offer critical-peak pricing options, targeting small or large customers. Gulf Power's program for residential customers combines critical-peak pricing with automatic control technology. (See Appendix A.) Southern California Edison has offered a program for many years for large customers. Electricite de France's Tempo program uses a two-period time-of-use rate that varies depending on the type of day (high-, moderately- and low-priced), with day-ahead notice.

## PAYMENT PROGRAMS

Payment programs provide utility-paid incentives for load curtailments at times the utility specifies. Utilities in Oregon and throughout the West reached agreements with many customers to reduce loads in exchange for payment during the energy shortages of 2000-01.

### Demand Buyback

Demand buyback allows the customer to choose on any particular day at the utility's request to curtail electricity use for a specified period of time and price. Curtailments reduce the need for peak generation and delivery, reducing purchases during high-priced hours, delaying the need to invest in peaking generators and moderating market prices. The overall cost of service is reduced, so long as the cost of buying any additional energy used during non-peak hours is taken into account in the program design or there are sufficient safeguards preventing customers from shifting load.

Customers must have meters that measure usage at least hourly during buyback periods, and the utility and customer must agree on a base level of usage from which reductions will be credited.

Demand buyback programs were used successfully throughout the West during the 2000-01 energy shortage. In the Northwest, BPA and the utilities achieved short-term load reductions of more than 200 MW.[12] The New York ISO ran a demand buyback program in summer 2001 that achieved up to 400 MW of curtailment (3 percent of total load).[13] In summer 2002, New York

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[11] Ahmad Faruqui and Stephen S. George, Charles River Associates, "The Value of Dynamic Pricing in Mass Markets," *The Electricity Journal*, July 2002.

[12] Corum.

[13] Christensen & Associates, presentation at California Energy Commission demand response workshop, March 15, 2002.

ISO's emergency demand response program achieved a peak savings of 668 MW on average.[14] Cinergy runs a large program in the Midwest with a high participation rate among a wide range of customer sizes. BPA is conducting a pilot demand exchange program on the Olympic Peninsula to determine how well this approach works for meeting short-term needs for peak transmission capacity.

**Longer-Term Buybacks**

Longer-term buybacks are for customers who agree to reduce their load over longer periods — typically several months or more. They include negotiated reductions with industrial customers as well as "standing offer" tariffs for customers who reduce loads compared to baseline usage in exchange for a credit on their monthly bill.

Longer-term buybacks are designed primarily to reduce energy use during long-term shortages. The long-term buybacks that Bonneville Power Administration and investor-owned utilities negotiated with Northwest industrial customers reached a peak curtailment of about 1,500 MW in summer 2001.[15]

**Demand Bidding**

Demand bidding is a variation of demand buyback. The customer proposes a bid to curtail energy use instead of the utility setting a predetermined price. Some programs impose penalties for nonperformance. California utilities, ISO-New England, New York ISO and Pennsylvania, New Jersey, Maryland (PJM) ISO have offered such programs. Results have been modest, in part because the programs were new. Other barriers included high thresholds for minimum bids, cost of required software to participate, concerns about penalties, low benefit expectations, and the long time between curtailments and payments.[16]

**Interruptible Rates**

Interruptible rates are for industrial or large commercial customers willing to have their operations interrupted by the utility — in whole or in part — for a few hours or a shift. Depending on the rate design, these programs may be a pricing or payment option. The utility may offer a discounted demand charge in exchange for the right to interrupt service for a portion of the customer's load. Or the utility may charge a lower rate most of the time than other customers and a high rate during shortages. Customers also may be compensated through fixed monthly payments and payments per event for reductions below specified levels.

The contract spells out the maximum number of times each year the utility can call for interruptions and their maximum length, the amount of advance notice it must provide, and penalties for nonperformance during any event.

Interruptible rates are common in the U.S. California utilities, for example, have offered interruptible tariffs since the mid-1980s. However, the electricity crisis of 2000-01 demonstrated their potential shortcomings. Although the utilities had been paying industrial and large commercial customers more than $220 million a year for interruption rights, many of the participants did not interrupt their loads as required during the

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[14] Neenan Associates, Lawrence Berkeley National Laboratory and Pacific Northwest National Laboratory, *How and Why Customers Respond to Electric Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance*, prepared for New York ISO and NYSERDA, January 2003.

[15] Corum.

[16] Goldman.

shortages. A compliance rate of 60 percent to 70 percent achieved about 1,200 MW of load reduction instead of the 1,800 MW under contract. In addition, many customers dropped out of the programs as soon as they could, once they realized the utilities would exercise their contractual rights under emergency conditions.[17]

Long-term contracts for load interruption are one way utilities and other electricity providers can participate in PJM's load management program, which provides credits for installed capability. (Other ways are direct-load control and on-site generation.) If end-users fail to perform, PJM can impose a penalty on the utility comparable to the charge for failure to meet the installed capability requirement. Almost 2,000 MW of load reduction (roughly half from interruptible contracts and on-site generation and half from residential and small commercial direct-load control) qualify for PJM installed capability. The program was called upon six times during the summer of 1999 and not at all during the summer of 2000. In 2001, the combination of interruptible contracts, direct-load control and on-site generation provided 1,800 MW of load relief.[18]

Some utilities, including the Tennessee Valley Authority, have included an interruptibility requirement in real-time pricing tariffs.

**Demand Reserves**

Demand reserves are focused on the ancillary services market. They are similar to contracts for capacity reserves standing ready to run, but they reduce capacity needs. Customers get regular payments for agreeing to reduce loads, for hours or longer, when the utility calls on them. The California Power Authority, for example, is using load reduction by end users to provide demand reserves in the wholesale market for non-spinning or replacement reserves. It also is using load reduction as a call option — as energy supplied in day ahead, hour ahead or supplementary energy markets during critical demand times or when market prices are high. The utilities contract with the agency for the demand reserves in the same way they buy peaking capacity.

**Direct Load Control**

Direct load control allows the utility to remotely turn off, turn down or cycle energy-consuming equipment for short periods of time in response to capacity and energy shortages or high prices. The utility provides incentives for signing up, incentives per curtailment event or lower energy rates (in which case it would be a pricing program). Other implementation costs include communication and control equipment and software. Utilities may use direct load control in conjunction with time-of-use or critical-peak pricing, without offering incentives.

No utility in the Northwest has implemented a large-scale load control program. However, many utilities elsewhere have for many years used radio technology to cycle home appliances on and off remotely, mostly to control air conditioning. Some utilities also have controlled water and space heating. New technology allows more precise control.

Prior to PGE initiating its own pilot program, it hired XENERGY (now KEMA, Inc.) to conduct a survey of 12 utilities in the U.S. with load control programs. Nine of the utilities used direct load control for water heating, nine controlled for air conditioning, and two controlled for space heating. For water heating control, capacity savings ranged from 0.175 kW to 0.5 kW per

[17] Eric Hirst and Richard Cowart, *Demand Side Resources and Reliability*, prepared for New England Demand Response Initiative, March 20, 2002.

[18] *Ibid*.

household on average, and customer participation ranged from 2 percent to 10 percent. Air-conditioning load control achieved reductions between 1 kW and 1.8 kW per household. Space heating reductions for customers of two utilities were 3.33 kW and 5.1 kW on average. (The programs took place in cold climates, and customers were required to have backup heating systems.) Incentives for participation in utility load control included free control equipment, monthly fixed payments, monthly payments based on load reduction or lower energy rates.[19]

Under PJM's Active Load Management program, utilities use direct load control of residential equipment (as well as interruptible contracts and generation at customer sites) to receive installed capability credits, which reduce their costs of installed generating capacity.[20]

## OTHER PROGRAMS

Programs also may offer non-monetary incentives:

**Blackout Protection**
Large customers may be exempt from rotating outages in exchange for reducing loads during critical periods for the utility system. They receive no other compensation. Utilities in California offered such a program during summer 2001, and Oregon utilities now offer this option.

**Dispatchable Standby Generation**
Some utilities use backup generation at customer sites to help meet peak capacity needs. The utility may provide interconnection for parallel operation with the electric grid, take care of maintenance and pay for fuel. Or the utility may provide compensation for the right to use the generator for a limited number of hours during the year.

In California, for example, San Diego Gas & Electric pays customers on a kilowatt-hour basis to run backup generators during all rolling outages. The New York ISO enrolled 150 MW of standby generation for its emergency demand reduction program.

Having on-site generation also helps customers participate in other demand response programs, including real-time pricing and demand-side reserves. Some 15 percent of the ISO's load reduction in summer 2001 was accompanied by on-site generation. New England ISO achieved 14 MW of its load curtailment in summer 2001 from operation of backup generators.[21]

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[19] XENERGY, Residential Direct Load Control Program Survey conducted for PGE, 2002.
[20] Goldman.
[21] Hirst and Cowart.

## DEMAND RESPONSE PROGRAMS IN OREGON

Oregon's investor-owned electric utilities have offered a wide variety of demand response programs in recent years. An attachment to this report (Table 2) presents results of programs active during the energy shortages in 2000-01. Altogether, the programs achieved maximum load reductions exceeding 335 MW — more than half the size of a typical new power plant. Also included in the table are demand response programs established since that time.

Following are descriptions and detailed results of these programs as well as additional time-differentiated rates and pilot programs underway. The deployment status and costs of advanced meters also are covered because they are necessary for most demand response programs. Findings from demand response programs offered elsewhere are in Appendix B. Appendix C sets out principles for designing demand response programs.

### PRICING OPTIONS

#### Daily Pricing Option for Nonresidential Customers

PGE and PacifiCorp offer daily pricing[22] for nonresidential customers through market rate options introduced with electric industry restructuring in March 2002. PGE also offers monthly pricing and quarterly pricing (prices fixed for each month) for customers over 30 kW.

The daily pricing option is a step toward real-time pricing. However, prices aren't posted until the day after they are in effect, and they are differentiated only by fixed on- and off-peak periods, not hour by hour.

Twenty-six PacifiCorp customers (28 metered accounts) are enrolled in the daily rate for 2003, accounting for 2 aMW to 3 aMW of load. Some 123 PGE accounts representing 90 aMW to 95 aMW (6 percent to 7 percent of eligible loads) opted out of the cost-of-service rate for the year. PGE customers may shift between daily, monthly and quarterly pricing options. In January 2003, for example, about half of those accounts were on the daily option.

Customers must enroll in a utility market rate if they want the option to choose an alternative electricity supplier later in the year. Some customers choosing the daily pricing option did so only for this purpose and may not intend to respond to price changes. Neither do customers that chose daily pricing simply because they hope it will beat the utility's cost-of-service rate.

#### On- and Off-peak Pricing for Large Customers

PGE incorporates on-peak and off-peak pricing for energy in its cost-of-service rate for large customers (facility capacity greater than 1 MW). The on-peak rate is about a penny more per kilowatt-hour than the off-peak rate. About 250 customers are on this schedule.

#### Time-of-Use Pricing for Residential and Small Business Customers

PGE and PacifiCorp offer residential and small nonresidential customers a time-of-use rate with three pricing periods — on-, mid- and off-peak. Rates and hours vary slightly between the heating and cooling seasons. The option began in March 2002. About 3,700 customers are enrolled. Nearly nine out of 10 participants are residential customers.[23]

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[22] Price is based on the Dow Jones Mid-Columbia daily on-peak and off-peak electricity firm price index.
[23] As of May 2003.

Customers can enroll at any time, and the minimum term is one year. For the first 12 months of enrollment, a price guarantee protects participants from paying more than 10 percent above what they would have paid on the Basic Service rate (not including the monthly meter charge), so long as they remain enrolled for the full term. They receive a credit for any payment beyond that at the end of the 12-month term. [24]

PacifiCorp's on-peak rates are about 4.5¢ per kWh more than off-peak rates for residential customers and about 5.1¢ more for small nonresidential customers. PGE's on-peak rate for residential customers is about 5¢ more per kWh than the off-peak rate. The difference in on- and off-peak rates for small nonresidential customers is about 4.7¢ per kWh.

A monthly fee helps offset the cost of the meter. Except for about 100 load research participants with 15-minute interval meters, PacifiCorp uses standard time-of-use meters that store data for on-, mid- and off-peak periods. PGE's meters store hourly data. The monthly meter fee for all PacifiCorp participants is $1.50 per month. PGE's monthly meter fee is $2 for residential participants, $2.35 for small businesses with single-phase service and $4.25 for three-phase service.

*Results of PGE's Time-of-Use Program*[25]
In the first 10 months of the program, residential customers in PGE's time-of-use program paid 24¢ *more* per month on average than they would have paid on Basic Service. The typical business customer, however, is saving on the program — $4.28 per month on average. The following table also shows the average savings when the meter charge is not included in the calculation.

**Table 3. Average Participant Savings for PGE's Time-of-Use Program**

| | **Average monthly savings*** | |
|---|---|---|
| | *Including meter charge* | *Not including meter charge* |
| Residential | -$0.24** | $1.76 |
| Small business | $4.28 | $7.27 |

*Based on cumulative savings from April 2002 to February 2003. Customers entered and left the program throughout the period.
**Bill increase

The following tables show how many customers are saving under the program depending on whether the meter charge is taken into account and, looking only at those who saved, their average savings. The most any residential customer saved in a month was $47.13; the most a business saved was $156.05.

[24] PGE lets customers quit the program before their term is completed, but they forfeit the price guarantee.
[25] PGE responses to PUC data request, April 1, 2003. Data are preliminary and for the period April 2002 through February 2003. Savings are compared to what customers would have paid on the Basic Service rate. The monthly meter charge is included in the data except where noted.

**Table 4. Customers Saving on PGE's Time-of-Use Program, Including Meter Charge**

| | **Percent of participants who saved** | **Average monthly bill savings for those who saved** |
|---|---|---|
| Residential | 39% | $2.74 |
| Small business | 50% | $12.73 |

**Table 5. Customers Saving on PGE's Time-of-Use Program*, Not* Including Meter Charge**

| | **Percent of participants who are saving** | **Average monthly savings** (for those who saved) |
|---|---|---|
| Residential | 79% | $2.83 |
| Small nonresidential | 80% | $10.26 |

Among residential participants who are *not* saving on the time-of-use option, the average monthly loss was $2.09 — *about the same amount as the meter charge*. Business participants who are not saving paid $4.04 more per month on average. The greatest loss in any month was $96.51 for residential participants and $32.30 for business participants, not including the customer guarantee payment.[26]

Because time-of-use meters are not in place until customers begin participating in the program, we do not know how much energy they used in each time period prior to enrollment. Thus we do not know the actual peak energy savings of the program. However, we have sample data from control groups that show the differences in usage patterns between time-of-use participants and nonparticipants.[27]

The data show that time-of-use participants use less electricity during on- and mid-peak periods and more in off-peak periods. From April 2002 through February 2003, 18.3 percent of residential participants' energy use was during on-peak hours, vs. 20.6 percent for the average customer. Among small businesses, 16.3 percent of participants' energy use was during on-peak hours, vs. 20.3 percent for the class.[28]

Generally, the differences in usage patterns are greatest during months when electricity use is high — when customers have the greatest opportunity to reduce loads and when demand response is needed the most.

[26] Customers receive a credit for any loss that exceeds 10 percent above what they would have paid on Basic Service, not including meter charges. Actual customer losses under the program are determined at the end of the 12-month term.

[27] Some customers may choose the time-of-use program because they have better-than-average load profiles — less on-peak and more off-peak energy use. These "free riders" may be able to save on the program without changing their usage pattern and affect the load profile of their time-of-use customer class.

[28] PGE presentation to the Portfolio Advisory Committee, April 23, 2003.

**Table 6. Energy Use Patterns of PGE Residential Customers – Selected Months**

| | | On-Peak | Mid-Peak | Off-Peak |
|---|---|---|---|---|
| July 2002 | TOU participants | 16% | 41% | 43% |
| | Average customer | 18% | 43% | 40% |
| January 2003 | TOU participants | 21% | 35% | 45% |
| | Average customer | 25% | 37% | 38% |

The differences in usage patterns are more striking for small business customers, especially the portion of power consumed on-peak during the summer and fall.

**Table 7. Energy Use Patterns of PGE Small Business Customers – Selected Months**

| | | On-Peak | Mid-Peak | Off-Peak |
|---|---|---|---|---|
| June 2002 | TOU participants | 13% | 36% | 52% |
| | Average customer | 20% | 47% | 34% |
| July 2002 | TOU participants | 13% | 36% | 51% |
| | Average customer | 18% | 45% | 37% |
| August 2002 | TOU participants | 14% | 38% | 49% |
| | Average customer | 20% | 47% | 33% |
| September 2002 | TOU participants | 13% | 36% | 51% |
| | Average customer | 19% | 47% | 35% |
| October 2002 | TOU participants | 15% | 39% | 47% |
| | Average customer | 19% | 46% | 36% |
| January 2003 | TOU participants | 20% | 30% | 50% |
| | Average customer | 22% | 40% | 38% |

Residential time-of-use customers used about the same amount of energy as the average customer in their class (906 kWh per month on average vs. 889 kWh). But business participants used far more energy than nonparticipants: 2,018 kWh per month on average vs. 1,491 kWh per month for the class.

PGE sent participants written materials on several occasions with tips on shifting energy use from on-peak hours and a brochure on reading their time-of-use meter. In October 2002, the company sent a six-month comparison of the customer's bills on time-of-use versus what they would have been on the Basic Service rate. PGE later sent a $20 rebate coupon for a qualifying water heater timer.

Half of the participants reported taking two or three actions to reduce on-peak energy use, and half are taking four or more actions to do so. The most commonly cited actions are doing laundry on Sundays and running dishwashers later in the evenings.[29]

[29] PGE presentation to the Portfolio Advisory Committee, Nov. 18, 2002, based on a survey of time-of-use customers by Market Decisions Corp., May 2002.

PGE expects that customers will improve their load shifting as they gain experience. The company estimates that it will achieve a 0.73 MW capacity reduction from initial customer participation in the time-of-use option and a reduction of 13.45 MW by 2007 after expanding the program.[30]

*Results of PacifiCorp's Time-of-Use Program*[31]

Residential customers in PacifiCorp's time-of-use program paid 10¢ *more* per month on average than they would have paid on Basic Service. Businesses are saving on the program, however — about $3 per month on average for commercial customers and 82¢ per month for irrigators. The following table also shows the average savings when the meter charge is not included in the calculation.

**Table 8. Average Participant Savings for PacifiCorp's Time-of-Use Program**

| | **Average monthly savings*** | |
|---|---|---|
| | *Including meter charge* | *Not including meter charge* |
| Residential | -$0.10** | $0.94 |
| Commercial | $3.02 | $3.82 |
| Irrigation | $0.82 | $1.75 |

*Based on cumulative savings from March 2002 to February 2003. Customers entered the program throughout the period.
**Bill increase.

The table below shows how many participants saved under the program and, looking only at those who saved, their average savings. The most any residential customer saved in a month was $63.87, the most a commercial customer saved was $79.24, and the most an irrigator saved was $218.55.

**Table 9. Customers Saving on PacifiCorp's Time-of-Use Program**[32]

| | **Percent of participants who are saving*** | **Average monthly savings** (for those who saved) |
|---|---|---|
| **Residential** | 33% (47%) | $3.10 |
| **Commercial** | 75% (91%) | $4.33 |
| **Irrigation** | 46% (62%) | $3.47 |

*In parentheses are participants saving if the meter charge is not included.

For residential participants who are *not* saving on the time-of-use option, average monthly losses were $1.69. Commercial participants who did not save paid 86¢ more per month on

[30] PGE, *2002 Integrated Resource Plan*, August 2002.

[31] PacifiCorp responses to PUC data request, April 2, 2003. Data are for the period March 2002 through February 2003. Savings are compared to what customers would have paid on the Basic Service rate. The $1.50 monthly meter charge is included in the data except where noted. Commercial and irrigation customers are saving more in part because time-of-use rates inadvertently were based on the average rate paid by all customers in those classes, including those with demands exceeding 30 kW that have much of their usage billed at the cheaper tail-block rate.

[32] Compared to what they would have paid on the Basic Service rate. The monthly meter charge is $1.50 for all participants.

average, and irrigation customers paid $1.46 more. The greatest monthly loss for a residential participant was $17.59, for a commercial customer $41.93 and for an irrigator $90.73.[33]

Overall, time-of-use participants used less electricity during on- and mid-peak periods and more in off-peak periods, compared to their customer classes as a whole. The differences in usage patterns between participants and nonparticipants were far larger for small businesses, though time-of-use customers had significantly smaller loads than average. For the first year of the program, 21 percent of residential participants' energy use was during on-peak hours, vs. 23 percent for the average customer. Among small businesses, 19 percent of participants' energy use was during on-peak hours, vs. 23 percent for the class.[34]

**Table 10. Energy Use Patterns of PacifiCorp Residential Customers**

| | | On-Peak | Mid-Peak | Off-Peak |
|---|---|---|---|---|
| October 2002 | TOU participants | 14% | 45% | 41% |
| | Average customer | 14% | 49% | 37% |
| November 2002 | TOU participants | 20% | 33% | 46% |
| | Average customer | 24% | 34% | 42% |
| December 2002 | TOU participants | 22% | 33% | 45% |
| | Average customer | 25% | 38% | 37% |
| January 2003 | TOU participants | 24% | 34% | 42% |
| | Average customer | 25% | 36% | 39% |
| February 2003 | TOU participants | 24% | 34% | 42% |
| | Average customer | 27% | 37% | 36% |

**Table 11. Energy Use Patterns of PacifiCorp Commercial Customers**

| | | On-Peak | Mid-Peak | Off-Peak |
|---|---|---|---|---|
| October 2002 | TOU participants | 13% | 43% | 44% |
| | Average customer | 14% | 49% | 37% |
| November 2002 | TOU participants | 18% | 34% | 48% |
| | Average customer | 24% | 34% | 42% |
| December 2002 | TOU participants | 20% | 34% | 46% |
| | Average customer | 25% | 38% | 37% |
| January 2003 | TOU participants | 21% | 36% | 43% |
| | Average customer | 25% | 36% | 39% |
| February 2003 | TOU participants | 21% | 35% | 44% |
| | Average customer | 27% | 37% | 36% |

[33] Not including any guarantee payments. At the end of their 12-month term, customers receive a credit for any loss that exceeds 10 percent above what they would have paid on Basic Service, not including meter charges. Of the 269 residential customers who have been on the program for 12 months, 19 percent qualified for the customer guarantee. Their average credit for the year was $8.72.

[34] Heather Qualey, PacifiCorp, presentation to the Portfolio Advisory Committee, April 23, 2003.

Nearly nine in 10 participating households say they have made changes in when they use electricity as a result of the program, most commonly when they do laundry and dishes. (At the time of the survey, the utility had not yet run the program during peak heating months, so customers did not report heating-related changes.) Forty percent of businesses have made changes. Other findings are reported in Appendix D.[35]

**Seasonal Pricing for Households and Small Businesses**[36]
PacifiCorp offers residential and small business customers another time-dependent option called Seasonal Flux. Energy rates change monthly based on seasonal demand and are published in advance for the year. In 2003, Seasonal Flux energy rates for January-February and August-December are slightly higher than for Basic Service. Rates are slightly lower than Basic Service all other months. Rates are lowest in May and highest in December, with a maximum variance of only 0.3¢ per kWh from Basic Service rates.

There's an annual signup deadline, and the minimum term is one year (10 months in 2002). Some 1,071 residential customers and 33 small business customers are enrolled in the Seasonal Flux option for 2003, down somewhat from participation in 2002.

All commercial customers, nearly all residential customers and most irrigation customers (81 percent) on Seasonal Flux saved money, compared to being on Basic Service, during the period March through December 2002. But average savings were small:

**Table 12. Seasonal Flux Bill Savings**

| | Average savings over the entire 10-month period |
|---|---|
| Residential | $4.14 |
| Commercial | $8.54 |
| Irrigation | $17.61 |

The savings range was large. The lowest monthly savings for all customer classes was 1¢. The highest was $24.84 for residential, $30.51 for commercial and $94.81 for irrigation participants. The largest monthly loss for any residential customer was $5.98 and for irrigation customers $64.10.

A third of residential participants said they made changes in how they use electricity; fewer businesses have done so. The most common actions households took to reduce use during high-priced months were installing energy-efficient lights, turning off lights when not in use and turning down heaters.[37]

However, the program did not reduce energy use among residential and commercial participants during two of the three highest-price (peak usage) months. PacifiCorp recommends discontinuing the program for 2004.

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[35] Market Decisions Corp., *Time of Use Program Evaluation for PacifiCorp*, December 2002, based on a survey of PacifiCorp customers in October-November 2002.
[36] PacifiCorp responses to PUC data request, April 2, 2003.
[37] Market Decisions Corp., Seasonal Flux Program Evaluation for PacifiCorp, December 2002, based on a telephone survey conducted in October-November 2002.

**Table 13. Seasonal Flux Energy Savings**

| | Change in average participant's energy use from 2001 to 2002* | | |
|---|---|---|---|
| | July | August | September |
| Residential | 15 kWh | 98 kWh | -16 kWh |
| Commercial | 85 kWh | 92 kWh | -53 kWh |
| Irrigation | -42 kWh | -87 kWh | -435 kWh |

*Positive numbers indicate an *increase* in energy use. Residential and commercial usage was adjusted for weather. The effect of the program on irrigation energy usage is unknown because data are not weather-normalized.

## PAYMENT PROGRAMS

### Demand Buyback

PGE, PacifiCorp and Idaho Power all had programs in place during the energy shortages of 2000-01 for large customers that were willing to reduce their energy use by turning off large power-consuming equipment. The utility determined the times and prices, based on prevailing market rates. The hourly credit rate is the amount the utility is willing to pay for load reduction (about half the avoided wholesale purchase cost) minus the customer's normal energy rate. The credit rate varies depending on how much advance notice the customer needs before it reduces loads.

The utility primarily uses a secure Web site to notify the customer of an event opportunity and for the customer to respond. The utility shares the cost savings from avoided spot market purchases or the net revenues of selling the energy in the wholesale market.

After the buyback event, the utility verifies the load reduction using the load measured each hour at the interval meter and the customer's average energy use for each hour during the preceding 14 days. The utility may remove from the program customers that do not meet their pledged reductions. In addition, PacifiCorp may require reimbursement for enrollment costs. During extended buyback events, PGE may charge customers the daily on-peak price plus a premium for the difference between their pledge amount and their actual curtailment.

Although PacifiCorp participants agreed not to shift load curtailed during a buyback event to other times, or to other facilities served by the utility, some did nonetheless. Instead of prohibiting load shifting, PGE's tariff allows the company to quote a different buyback price for participants who shift load by more than 50 percent of the pledge amount the day before or after a buyback event (or any day of an extended buy back event).

Buyback programs were active in 2000 and the first half of 2001. When the Federal Energy Regulatory Commission (FERC) set a price cap for the Western wholesale power market of $92 per MWh in June 2001, the programs were no longer economic. FERC's "soft" price cap is now set at $250 and if spot market prices escalate, the programs can once again help reduce utility power costs.

*PGE*
PGE's Demand Buy Back Program began in July 2000. During the time the program was active, only customers with at least 1,000 kW account facility capacity and 5,000 kW aggregate facility capacity were eligible to participate. PGE later opened the program to customers able to reduce demand at least 250 kW at each metered location.

PGE called 122 events through May 2001, totaling 1,728 hours. Customers participated in 84 percent of those hours, reducing energy use during those periods by a total of 87,532 MWh.

The greatest number of exchange hours occurred in April 2001, followed in order by December 2000, March 2001 and January 2001. The largest energy curtailments occurred in December 2000 and April 2001. The greatest load reduction in any hour was 157.8 MW.

Eight customers participated, receiving payments totaling about $11.3 million. The average payment was $129 per MWh. Net power cost savings are estimated at $26.2 million.[38]

The 24 customers currently enrolled in the program have the potential to reduce load up to an estimated 135 MW.[39] They range in size from 1 MW to 110 MW, with the average size about 16 MW. Sixteen of them signed up after the first FERC price cap went into effect, so they have not yet had the opportunity to participate. The average size of customers that participated in exchange events is about 40 MW.

*PacifiCorp*
PacifiCorp's Energy Exchange Program for customers with a monthly demand of 1 MW or more began in December 2000. Of the 215 metered loads that qualify, 44 participated in an exchange event. Their loads range from 1 MW to 76 MW, and they identified a total of 213 MW of loads they could curtail.

The utility called more than 250 exchange events from December 2000 to August 2001, over more than 5,200 hours. Customers participated in more than 60 percent of those hours, reducing total load on the utility's system by as much as 67.2 MW. Individual customers curtailed loads up to 17.4 MW. Combined energy use reductions during the period exceeded 38,000 MWh.

Customers curtailed loads the greatest number of hours in April and May 2001. Curtailments were highest in May, with energy reductions exceeding 12,000 MWh.

Customer payments totaled nearly $4.2 million, with an average payment of $108 per MWh. The utility estimates power cost savings of $2.1 million, not including lost revenues.

Some 144 customers remain enrolled in the program.

*Idaho Power*
Idaho Power's Energy Buy Back Program went into effect in March 2001, but has never been used. One customer with an estimated 6 MW of potential load reduction enrolled in the program. When FERC established a market price cap in the West in June 2001, spot market prices dropped below levels that made the program economic.

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[38] Not adjusting for any lost revenues or increased usage during non-buyback hours.
[39] Reflects reductions in customer operations since the program was active in 2001.

To participate, customers must commit to reduce their load by at least 1 MW at a single metering point. The tariff limits service to 10 customers, but there are currently only six Oregon customers whose loads would make them eligible for the program.

**Longer-Term Buybacks**

*Negotiated Buybacks*

PGE negotiated longer-term buyback contracts with two large customers during the 2001 energy shortage for a total of 56 MW of load reduction. One contract began in April that year, the other in May. Both were in place through September. Contract prices were fixed for the period, based on forward price curves at the time they were put in place.

PGE called 170 curtailment events over 2,608 hours, reducing energy use 108,664 MWh during those periods. Participants received payments totaling $19.6 million, averaging $180 per MWh curtailed. PGE projected net power cost savings of about $21 million based on forward market prices.[40] With the unexpected drop in spot market prices for power, the long-term buybacks appear to have netted a loss of about $9 million.[41] Because even a small amount of demand response may reduce market prices, utility power costs absent these long-term curtailments, and therefore actual losses or benefits, are unknown.

PacifiCorp had agreements with three large customers for buybacks lasting longer than one week during the period March through September 2001. The duration of events ranged from less than a month to several months. Customers reduced loads under the contracts up to a total of 35.1 MW. Curtailments spanned 4,704 hours, reducing energy use 61,385.1 MWh. Participants received about $12.3 million in payments, averaging $200 per MWh curtailed. Payments for committed reductions were based on projected high power prices. Actual power prices were far lower. The utility estimates net losses (not including lost revenues) of about $7 million, absent any effects of the curtailments on market prices.[42]

*Irrigation Buybacks*

PacifiCorp offered an Irrigation Curtailment Program during the 2001 season (May through November) for customers with a total pumping load of at least 16 kW. The utility disconnected pumps for participating customers in exchange for monthly payments of 12.5 cents per kilowatt-hour curtailed. Customers were required to certify that reductions would not be offset at other PacifiCorp connections.

Curtailed load was calculated using the customer's average monthly energy use for irrigation during the previous five years. For customers with less than five years of usage records, the utility used the average historical usage to date and compared it with average usage for similar pumping operations. An excess consumption rate of 25 cents per kilowatt-hour was in place for energy use in violation of program requirements.

Some 328 customers participated, 13 percent of those eligible. Energy savings totaled 20,636 MWh. Payments to customers totaled about $2.6 million. The Mid-C market price at the start of the program was about $210 per MWh. By June, after FERC's price cap went into effect, the price plummeted to about $60 per MWh, bottoming out at $27 in September. Irrigators,

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[40] Not accounting for any lost revenues or increased usage during non-buyback hours.

[41] PUC staff estimate based on average monthly on-peak firm mid-C prices, per PGE. Mid-C prices may not reflect actual PGE power costs. Does not include lost revenues.

[42] PacifiCorp estimate based on hourly non-firm mid-C prices.

however, were guaranteed $125 per MWh for the entire season so they could plan their operations. So the utility paid about $1.5 million more than the energy savings were worth.

Idaho Power offered a similar program. Customers willing to reduce energy use by at least 100,000 kWh received a payment of 15 cents per kWh curtailed. Participants were not allowed to offset committed reductions by increasing consumption at other facilities served by the utility.

Load reduction was based on the customer's average monthly energy use for irrigation during the previous five years. The utility paid customers monthly for 75 percent of the measured energy reduction (so long as the customer achieved at least 95 percent of the pledged amount). The utility withheld payment for the remaining 25 percent reduction until the end of the irrigation season and it confirmed fulfillment of all contract provisions. The rate for excess consumption was 30 cents per kWh.

Of the 66 Oregon customers eligible for the program, 17 participated. Size ranged from 0.7 MW to 7.7 MW, with an average size of about 1 MW. Energy savings totaled more than 16,000 MWh. Savings peaked in July at about 3,600 MWh. The utility paid customers an incentive of $150 per MWh, totaling some $2.3 million.

When the program was approved, the forecasted market price for energy during the irrigation season was about $300 per MWh. Faced with a summer deficit, Idaho Power pursued the program as an alternative to forward month purchases. Shortly after the utility started the program, market prices decreased significantly below the $150 per MWh incentive. Had Idaho Power left its summer deficit uncovered, the utility ultimately could have made these purchases at a lower cost.

*Residential Curtailment Program*
PacifiCorp offered a voluntary curtailment program for residential customers from June through September 2001. The 20/20 Customer Challenge Program offered a 10 percent discount on monthly bills for customers using at least 10 percent less electricity compared to the same period during the prior year (at the same location). Customers received a 20 percent discount if they reduced electricity use during the month by at least 20 percent. The program required no enrollment or special meters.

An evaluation by Quantec for PacifiCorp included the following findings for Oregon:

- An average of 115,598 customers participated per month — some 27 percent of residential customers.
- Participants saved 108 kWh on average, or $7.48, over the summer. Customer credits totaled about $3.5 million.
- The program reduced energy use by 50,000 MWh.
- On average, the program saved 19 MW during peak hours (66 MW regionwide).
- The value of the energy savings was $2.2 million – far below projected savings based on forecasted energy prices.
- Lost revenues (which were recoverable from ratepayers through a power cost adjustment) totaled $3 million.
- Administrative costs were low, in large part because there was no signup procedure and the utility kept marketing costs low.
- The program was cost-effective from a Total Resource Cost perspective, but not from a utility or ratepayer test, because of the unexpected drop in market prices. If prices turned out as expected when the utility designed the program, the program would have been highly cost-effective under all of these tests.

**Interruptible Rates**
None of the Oregon utilities offers interruptible rates. However, PGE has a long-standing special contract with an industrial customer that contains a provision allowing the utility to curtail most of the customer's load in the event of imminent or actual system emergencies or capacity deficiencies.[43] PacifiCorp is proposing in Utah an interruptible rate with monthly capacity payments, energy payments during curtailment events and penalties for noncompliance.

**Direct Load Control**
PGE began a load control pilot program in January 2003 to reduce residential demand during peak hours. The utility tested separately control of electric water heating and space heating in 75-80 homes each. Equipment installed in the home allowed the utility to set back space heat temperatures a few degrees for two to three hours during peak periods on the coldest days. Customers were able to override utility control at their thermostat or via the Internet. PGE shut off water heaters at times of peak utility demand every weekday. Customers could override water heating curtailments on the Internet.

The focus of the pilot program was acceptance of utility control of water and space heating where customers can override it. The goal was to determine if enough peak load can be economically shifted so the utility can defer or avoid construction of peaking plants or avoid high-cost power purchases. Results are not yet available.

PacifiCorp is developing an air conditioning control program for residential and small commercial customers in Utah. The estimated load reduction is 90 MW from 90,000 participants within three years.

PGE believes that 5,000 customers with combined space and water heating load control could achieve an estimated peak reduction of 4.9 MW by the end of 2004.[44] In 10 years, PGE estimates that peak capacity reductions from such a program could reach 60 MW.[45]

## OTHER PROGRAMS

**Blackout Protection**
PGE and PacifiCorp offer a voluntary load curtailment program for large customers that allows them to avoid rotating outages during short-term system emergencies in exchange for reducing loads during those times by up to 15 percent. The utilities provide no other compensation. The program lets participants protect their vital operations, while all customers benefit from eliminating outages.

The minimum term is one year, and the utility must approve the customer's curtailment plan annually. The baseline for determining the required load reduction is generally the customer's average hourly electricity use for 14 typical days during the period leading up to the curtailment event.

Customers must reduce their loads during every curtailment event the utility calls. Load reductions must begin within 30 minutes of notification. There are financial penalties for failing

[43] Jim Lobdell, PGE, Winter Contingency Plan Presentation to the Oregon PUC, Dec. 2, 2002, and personal communication with Doug Kuns, PGE.
[44] PGE, *2002 Integrated Resource Plan*, August 2002.
[45] PGE, Response to comments on its Integrated Resource Plan Supplement, April 2003.

to meet the required reduction by the specified time or to maintain the reduction for the entire event. The utility can remove customers from the program for continued failure to meet requirements.

PacifiCorp's tariff began in February 2002. Customers are eligible if monthly demand the past year exceeded 4 MW at least once and they are served on a dedicated feeder. At the time the tariff began, the utility estimated there were 20 eligible sites, for total potential savings of 2.5 million kWh per month.

PGE's tariff began September 2002 for customers with a monthly demand of at least 1 MW. The utility estimates that about a dozen customers may sign up for the program in the future, with potential load reduction totaling 50 MW.

Though customers expressed interest in a blackout protection program before tariffs were put in place, none is yet participating. That's likely because the risk of outages has been low, and programs have not been in place long.

**Dispatchable Standby Generation**[46,47]

Dispatchable standby generation is one of two primary resources PGE is planning to rely on in the next 10 years to meet capacity needs above baseload. (Seasonal exchange with California is the other one.)

The program is for customers with generators 1 MW and larger that agree to allow PGE to use them up to 400 hours per year. PGE expects to use them 200 hours to 300 hours a year. Customers most likely to participate are in the high-tech, medical or telecommunications industry with backup generation for critical operations.

The utility reconfigures the grid connection to make the generator dispatchable, maintains the unit and pays for all fuel. When PGE needs peak capacity resources, it requests operation of the generators, then starts and monitors their performance. The unit supplies the customer's facility first. Any excess capacity is sent to the grid. If the utility system has an outage while the generator is in parallel operation, the connecting breaker trips and the generator continues to supply the customer.

All generators currently in the program are fueled with diesel. PGE installs oxidation catalysts on all new generators, requires use of low-sulfur diesel and recommends the installation of low-NOx engines. PGE is studying dual-fuel conversion packages, which allow the use of natural gas to reduce emissions.

PGE has generators at four customer sites on line for a total of 9.75 MW, with 10.6 MW more at two additional sites scheduled to come on line in 2003 and 2004. Another 7 MW to 9 MW of generation is in contract negotiations. PGE has identified a total of 130 MW of potential from existing standby generators and believes it could acquire up to 100 MW of dispatchable standby generation under the program by 2007.

Initial capital investment is $150 per kW to interconnect existing generators to the grid; $100 per kW to interconnect new generators. PGE cites an effective reservation fee of $20 per kW per year, with estimated fuel costs of $60 per MWh (2003$).

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[46] PGE, *2002 Integrated Resource Plan*, August 2002.
[47] PGE, Advice No. 03-2, Dispatchable Standby Generation, Jan. 30, 2003.

The utility tests the generators monthly, but has not yet called on them to meet capacity needs because of mild winter weather and stable wholesale prices.

## ADVANCED METERS AND COMMUNICATIONS

### PGE's Medium and Large Customers[48]

Some 3,220 of PGE's nonresidential customers already have the interval meters needed for dynamic pricing. That includes most customers with loads greater than 300 kW (all with loads over 1 MW) and 40 percent with loads between 100 kW and 300 kW, in particular those with meters inside buildings in downtown Portland. A thousand of the meters track data in 30-minute intervals; the remainder uses a 15-minute interval for billing. Another 600 meters will be installed in the next few months, completing the conversion of meters for loads over 300 kW.

PGE is installing a network meter reading system to remotely read its meters. When completed, the system will consist of powerline carriers connected to substations, a two-way wireless network in urban areas, and cellular and land-based telecommunications technologies elsewhere. The major component of the wireless network has not yet been installed.

About two-thirds of the company's interval meters are already part of the network system. PGE collects data daily for 1,800 meters and weekly for 420 meters. (The meters that are read weekly support daily data collection, but in some cases there would be additional cellular telephone charges.) The additional 600 interval meters coming on line in the next several months will be read remotely each day. When PGE finds a radio network solution for some 1,500 remaining loads greater than 100 kW, it will install new meters and communication equipment over a 12- to 18-month period.

PGE cites its cost for a basic commercial meter with capability to record interval data at about $320, plus an additional $100 for installation. Installation costs are lower for meters for smaller commercial loads — about $30 to $50. To read the meters remotely, and more frequently than monthly, the utility can install a meter with a modem for $700. Where a standard meter already is in place, the utility may be able to simply add a modem. But the customer would need to bring a phone line close to the meter at a cost of $100 to $350 and pay monthly charges for an additional phone line if an existing line could not be used. An alternative that saves the customer these costs is a $950 meter with a built-in communication system (plus an installation cost of $75).

PGE estimated total costs of the network meter reading system, including additional meters, hardware and software, at $25.4 million.[49]

### PacifiCorp's Medium and Large Customers[50]

PacifiCorp has installed 15-minute interval meters that are read remotely for all accounts 200 kW and larger, some 1,425 customers. The meters were installed recently, between 2000 and 2002, replacing 30-minute interval meters. The utility collects usage data by dedicated telephone lines or cellular telephone. Data collection is weekly from customers 1 MW and larger, nearly 250 accounts. Collection is monthly from the other remotely read meters.

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[48] PGE responses to PUC data request, Feb. 21, 2003.
[49] PGE, UE-115 Revenue Requirement Workpapers, Oct. 2, 2000.
[50] PacifiCorp responses to PUC data request, March 11, 2003.

The meters cost $1,604 on average: $425 for the meter itself, $398 for installation, $625 for cell phone charges and $156 for the capital surcharge.

Except for load research studies and direct access customers, PacifiCorp has no plans at this time to increase the number of meters read remotely. However, the utility is developing a strategy for automated meter reading.

PacifiCorp is converting remaining 30-minute demand meters for smaller nonresidential customers (under 200 kW) to 15-minute demand through its regular testing program. The meters are not read remotely.

**Advanced Meters for Small Customers**
The nearly 4,000 residential and small business customers of PGE and PacifiCorp on the time-of-use rate also have meters that track usage in more detail. PGE's meters record usage hourly; PacifiCorp uses standard time-of-use meters that record data for on-, mid- and off-peak periods, except for about 100 load research participants with 15-minute interval meters. The meters are not read remotely.

The utilities deploy the meters one at a time, as customers enroll in the time-of-use option. Following are the installed costs the utilities cite for the meters they provide. Mass deployment of the meters would reduce installed costs per unit.

**Table 7. Installed Meter Costs for Time of Use Customers**[51,52]

| | Portland General Electric | PacifiCorp |
|---|---|---|
| Residential | $120.89 | $277.43 |
| Small commercial single-phase | $140.69 | $277.43 |
| Small commercial three-phase | $252.85 | Cost not cited |

[51] PGE, Advice No. 01-20, Nov. 1, 2001. Meters store hourly data. The equipment alone costs $80 for residential customers, $104 for commercial single-phase meters, and $240 for three-phase meters. Installation is about $50. Total cost includes a credit for redeploying the existing standard meter: $7.19 for residential, $13.53 for single-phase small commercial and $49.50 for three-phase.

[52] PacifiCorp responses to PUC data request, June 4, 2001. Meters store data in on-, mid- and off-peak intervals. The meter cost is $102.16. Most of the remaining cost is installation. No credit was given for redeploying the standard meter.

## EVALUATION OF OREGON DEMAND RESPONSE PROGRAMS

PUC staff concludes the following based on analysis of information from the utilities and staff interviews with large customers.

1. **The voluntary demand response programs Oregon utilities operated during the energy shortages in 2000-01 were successful, for the most part.**

   They substantially reduced energy use and peak demand, helped avoid outages throughout the West, reduced utility power purchases at high market prices, and allowed the utilities to sell power on the market at high prices.

   Further, a wide variety of customer types and sizes were willing and able to curtail loads in exchange for payments or credits. The largest customers in Oregon had the greatest opportunity to participate. Many participated in short-term energy buybacks, and a few signed long-term curtailment agreements, receiving payments in exchange for reducing loads at the utilities' request. Hundreds of irrigation customers signed season-long agreements to curtail pumping. And when PacifiCorp gave residential customers the opportunity to receive credits all summer long by using at least 10 percent less energy than the prior summer, a quarter of their Oregon customers did so.

   However, the long-term agreements appear to have increased utility costs. They locked-in rates for customer credits for several months based on high forecasted market rates, just before FERC set a price cap in the Western wholesale market and prices fell. On the other hand, we do not know to what extent the long-term buybacks reduced market prices and therefore provided ratepayer benefits.

2. **Oregon missed out on some of the benefits of the demand response programs because they were not in place before the energy shortages began.**

   The quicker demand response can reduce loads during system contingencies or periods of high market prices, the more benefits it can provide. Oregon put a number of demand response programs in place quickly in response to the 2000-01 energy shortage. Even so, by the time some programs were in place — PacifiCorp's 20/20 Customer Challenge and Idaho Power's Energy Buy Back, for example — the opportunity to achieve the greatest savings from load reductions (or any savings at all) had already passed.

   Even after programs are designed and approved, it takes time for utilities to put them in place and for customers to understand how they work, determine whether and how they can benefit by participating, and make the necessary changes in their homes or business operations. Demand response programs should always be in place to provide load reductions immediately when needed.

3. **The energy buyback programs for large customers provided the vast majority of the savings, but in today's market and as currently designed their usefulness is limited.**

   First, the market price has to be very high to draw participation in buyback events. With current forecasts of market prices and FERC's soft price cap in place in the West, we are unlikely to see any time soon the prices we saw in 2000-01.

Second, savings were shared 50/50 between the utility and the customer, and the customer's regular energy rate was deducted from that. The smaller the customer's share of savings, the higher the market price must be to make participation worthwhile. Changes in the utilities' programs now allow them to vary the percentage of savings offered to customers through their price quotes. The utilities likely would need to increase the customer's share of savings to achieve much load response under these programs today.

Third, only large customers can participate. PacifiCorp limits the program to customers with a monthly demand of 1 MW or more; PGE requires a minimum 250 kW reduction each hour during a buyback event.

Further, some customers may not have participated, or participated less often, because of the program design. Some believe the program does not provide a fair share of the savings. They believe they should get a larger share of the savings because they're taking all the risk (of reduced operations) and paying for the utility's peak demand capability through monthly charges. (The utility, however, takes the risk that wholesale prices will be lower than expected.) Or customers think the utility got more than half the savings because the participants' regular energy rate was deducted from their share of the savings. Some customers also don't like the utility having all the control — deciding when to call buyback events and at what price. Determination of baselines from which curtailments are measured also was an issue.

4. **Large customers want a variety of options, even for different facilities owned by the same company.**

   Large customers want as many choices as possible, so they can choose the program best suited to each of their facilities. Even within a program, they want flexibility — for example, to participate with only a portion of their load and to make adjustments in participating loads over time. Further, some customers want programs that they can participate in day-in, day-out. Others want programs they can choose to participate in on a day-to-day basis, not long-term. Utilities may be able to significantly increase demand response by offering a greater variety of programs.

5. **Most demand response programs in Oregon as currently designed do not have as much planning value for the utilities as physical peaking resources.**

   PGE and PacifiCorp don't give much capacity value in their Integrated Resource Plans for demand response programs where they don't have full control over the curtailment. Redesigned and new programs — and longer-term experience — are needed for the utilities to count on load curtailments as they would a peaking plant.

6. **Only a small share of nonresidential customers — accounting for a small share of load — has chosen a dynamic pricing option in the first year the utilities offered one. The rate option was not designed to provide demand response. New options are needed to achieve greater and more timely load reductions in response to supply shortages and high market prices and for efficient operation of the utility system.**

   Since March 2002, all nonresidential customers have had a daily pricing option with on- and off-peak prices that change each day. Participation levels remain low.

The daily pricing option was designed to meet the energy needs of nonresidential customers who do not choose an alternative electricity supplier, not to provide demand response. Most participants are PGE customers, many of whom simply hope to beat the utility's cost-of-service rates, which have risen steeply. Some are hoping market prices fall and there's an economic opportunity to choose an alternative supplier later in the year, and they must opt out of the cost-of-service rate to do so. Some participants do not even get the daily prices, which are available only by subscription for a fee. Demand response does not appear to be in the picture.

The number one reason customers choose real-time pricing is to save money: Over time, the average rate is lower than under flat pricing. Second is to have more control over their energy costs. However, only customers willing and able to shift loads and manage the short-term risk typically will be interested. Further, they want some assurance that their potential bill savings are likely to outweigh the risk of paying more than they would on flat rates. They also want to mitigate the risk as much as possible.

The daily pricing option does not include features that help customers manage risk — for example, application of real-time prices only to usage above the customer's historic baseline, credits for reducing usage below the baseline during times of high market prices, and availability of hedging tools to cap risk. Customers also may need assistance with investing in energy management systems to shift loads to lower-priced hours. That frees them from having to manually turn off lights, adjust temperature settings and turn off particular equipment. Some may need on-site generation to power vital operations when prices are high.

In addition, the wholesale price index that the daily pricing option is based on is published the day after. Customers don't know what prices are currently in effect, although they may reduce or shift demand during the peak period based on the previous day's prices. Further, on- and off-peak periods are fixed, so prices do not vary hourly.

A real-time pricing option with day-ahead notice of exact prices may increase participation and demand response, and hourly prices may give businesses more flexibility in scheduling operations. Utilities would need to target customers most likely to benefit, provide them with the information and technical assistance they need to decide whether they should participate, and develop a design that reduces risk.

7. **Participation among small customers in the time-of-use rate is increasing, but still low. Improvements are needed to maintain and increase participation.**

Residential and small business customers have been able to choose a time-of-use rate since March 2002. It has great potential, but needs improvement.

Only about 40 percent of PGE's residential participants and half of participating small businesses are saving money compared to what they would have paid on Basic Service, after accounting for the additional meter charge. That's despite half of them taking two or three actions to reduce on-peak energy use and half taking four or more actions to do so.

PacifiCorp participants are faring about the same: Only a third of the households, three-fourths of commercial customers and about half the irrigators have reduced their energy bills. That's despite nine in 10 participating households and about 40 percent of businesses reporting they have made changes in when they use electricity.

Two parts of the rate design can be changed to increase savings for those customers taking action to reduce on-peak energy use:

First is the meter charge that all time-of-use participants pay. It was set to cover at least some of the cost of the more expensive meter that the utilities need for tracking energy consumption by time of use — in part because of uncertainty over how much savings the program would provide for the utility system. However, the intent was to not charge so much that it would discourage participation or make it too difficult for participants to save money.

For PGE customers, the fee is $2 for residential service, $2.35 for small nonresidential single-phase service and $4.25 for three-phase service. All PacifiCorp participants pay a monthly meter fee of $1.50.

PGE’s meter fee for residential participants pays off the installed meter cost in five years. PacifiCorp's meter costs are far higher and the meter fee is lower, so the customer makes a smaller contribution toward the payback. Any utility system savings from the time-of-use program shortens that payback time.

Monthly meter fees may be set too high. Time-of-use customers should not have to bear the entire cost of the meters because their load shifting reduces utility costs for energy, capacity, distribution and transmission.

Second are the energy rates. The intent of the design was that customers matching the average usage pattern for their class (percent of use in on-, mid- and off-peak periods) would have the same energy costs as they would on Basic Service if they don’t shift usage. They wouldn't have any rate savings to cover the additional meter charge.

PGE’s on-peak rates are about 2-1/2 times the off-peak rates, and its mid-peak rates are the same as its Basic Service rates. Coupled with the meter charge, the result is that the average residential customer who shifts even 20 percent of on-peak usage (equally to mid- and off-peak hours) pays *more* on the time-of-use rate than on Basic Service. And that amount of load shifting is likely far more than is possible for most households, especially without automated load control.

PGE's mid-peak rates may be set too high and on-peak rates too low. First, capacity costs for energy should be included only in on-peak rates. Second, only on-peak hours cause incremental costs for distribution and transmission, because they are the only hours during which existing systems may be inadequate. So theoretically, these incremental costs should be assigned only to peak hours. However, tiered distribution and transmission rates might be confusing for customers in combination with unbundled rates for electricity services. Another alternative is eliminating the mid-peak period and increasing the number of off-peak hours.

PacifiCorp’s on-peak rate for residential time-of-use customers is four times the off-peak rate, and its mid-peak rate is lower than its Basic Service rate for usage up to 1,000 kWh a month. Its higher Basic Service rate for additional usage makes the time-of-use rate attractive for high-usage households.[53] In fact, residential participants that match the average usage pattern and use 1,500 kWh or more per month save on the time-of-use rate

[53]PacifiCorp adopted inclining block rates for residential customers in October 2001.

*without reducing usage during on-peak hours*. And a typical household (1,000 kWh per month) that shifts a whopping 50 percent of its usage from on-peak hours (equally to mid- and off-peak periods) pays more on the time-of-use rate compared to what it would pay on Basic Service, including meter charges. Even if there were no meter charges, the typical household would not save under current time-of-use rates after shifting 30 percent of its on-peak usage.

Because of PacifiCorp's inclining block rates for basic residential service, a major redesign of the time-of-use rate is needed in order for the typical household to have a reasonable opportunity to save money and to reduce free ridership for high-usage households.

Direct utility control of heating and cooling loads is a further improvement for the time-of-use rate that would reduce participants' risk. At the same time, it would make participation easier and the resulting demand response more reliable for the utilities.

Another possible improvement is adding a critical-peak price. In conjunction with utility load control, critical-peak pricing would allow a reduction in the number of on-peak hours and/or the on-peak rate. It also would give the utility a way to achieve greater demand response during system contingencies, when it needs it the most.

8. **Oregon utilities do not offer any rate options that allow customers to respond to real-time changes in prices. These options are working well elsewhere.**

All large PGE customers (over 1 MW demand) have on- and off-peak energy rates, but rates are flat and time periods are fixed. So customers cannot respond to real-time changes in supply and demand. Nonresidential customers on the daily pricing option do not know rates ahead of time, and time-of-use rates for small customers do not change in response to daily changes in supply and demand or utility power costs.

Variations on real-time and critical-peak pricing are working well in several areas of the U.S. and Europe. Key to their success are features that minimize bill volatility.[54] Utilities have devised real-time rate designs that do so and at the same time give customers billing credits for shifting load from high-price hours.

Automatic controls and, for nonresidential customers, financial tools further reduce risk. Consumer education and technical assistance also are needed for programs to succeed.

For two-part real-time pricing, baseline determination and flexibility to adjust baselines over time are important issues. Because there is no third-party index for day-ahead, hourly power prices in the Northwest, the utilities would need to determine them based on projected market prices.

[54]Though it should be recognized that real-time pricing may actually *reduce* bill volatility. Under fixed rates, utilities raise rates *later* to recover higher-than-expected power costs — if a power cost adjustment is in place. If an adjustment is not in place, the utility may apply for a deferral for the higher power costs or file a rate case to try to recover them. Real-time pricing provides a *prompt* rise in retail prices in response to tight supplies, causing a prompt demand response. That reduces utility power purchases at high wholesale prices (or allows the utility to sell curtailed energy at high prices) and helps dampen market prices. (From Corum, in part)

9. **Most customers on the Seasonal Flux rate are saving money, but the savings are negligible. Overall, participants used more energy during peak-use months than before they were on the option.**

   Nearly all customers on PacifiCorp's Seasonal Flux rate are saving money so far, compared to what they would have paid on Basic Service. But savings are negligible because the difference between the rates is very small. Further, residential and business participants used more energy during two of the three highest use, highest price months compared to how much they used the year before (after adjusting for weather differences).

   A third of residential participants say they made changes in how they use electricity during high-priced months; fewer businesses have done so. However, providing an option that doesn't provide much savings for participants and doesn't reduce utility costs may unnecessarily complicate consumer choices.

10. **Most types of demand response programs require advanced meters and communication technology. Much progress has recently been made, but much work remains to be done.**

    Most customers' meters are capable of measuring electricity use only over the whole billing period. Most demand response programs require meters that can measure usage and store data at least for each hour. Programs also may require two-way communication for utility control of loads, to verify reductions, to provide customers with timely data on their energy use or notify them of changing prices.

    Which meter and communication systems are needed to support demand response programs depends on the information needs of the programs, rate structures, timing of data retrieval and communication requirements.[55] The closer to real-time curtailments can be verified, the more valuable they are for meeting needs for capacity and ancillary services. Advanced meter costs also depend on the number being installed. Low levels of deployment significantly raise per-customer costs.

    The meter and communication systems that are needed for some demand response programs enable automated meter reading. The many benefits of automated meter reading can help make adoption of advanced metering cost-effective.

[55] Frederick Weston and Jim Lazar, Regulatory Assistance Project, *Metering and Retail Pricing*, prepared for the New England Demand Response Initiative, May 1, 2002.

## RECOMMENDATIONS

The utilities should maintain a variety of demand response programs — with sufficient customer enrollment — that they can tap immediately during short-term system contingencies and extended shortages to minimize outages, reduce exposure to high market prices (or take advantage of them), and make the best use of generating, distribution and transmission assets.

Programs should be tailored to the wide range of customer needs, and customers should have a variety of options for contributing to load reductions when needed. However, the utilities should approach any long-term fixed payments for demand response cautiously.

Following are recommendations for Portland General Electric and PacifiCorp to improve demand response programs already in place and to introduce new efforts that allow all ratepayers to participate more fully in demand response. In a forthcoming report, PUC staff will make recommendations for removing barriers to distributed generation. The ability to generate power on site is an important factor for some customers in whether they can participate in demand response programs.

PUC staff also will ask PacifiCorp to evaluate whether its energy rates for large customers should be differentiated by on- and off-peak periods. PacifiCorp recommends discontinuing the Seasonal Flux program after 2003, and the full Portfolio Advisory Committee agrees.

1. **The utilities' Integrated Resource Plans should evaluate demand response programs on par with other options for meeting energy and capacity needs. The Commission should add to the issues list for its investigation into least cost planning requirements (UM 1056): How should demand response be explicitly included in least cost planning on par with other options for meeting energy and capacity needs?**

   Loads and generators providing comparable services should be treated equally in the utilities' Integrated Resource Plans, and expected load reductions from demand response programs should be taken into account in load forecasts. To the extent that North American Electric Reliability Council and Western Electricity Coordinating Council rules allow loads to provide reliability services, the utilities also should evaluate the cost-effectiveness of using appropriate demand response resources to help meet installed capability requirements.

2. **The utilities should provide to the Commission by Dec. 31, 2003, an assessment of demand response potential by market segment, barriers to development and recommended actions.**

   The assessment should evaluate by market sector what customers need to participate in demand response, the types of programs that are tailored to meet those needs, barriers to successful programs, and actions required to overcome barriers. The utilities also should estimate the potential load reduction by market sector from each type of program. The assessment should cover the range of possible programs for all customer classes, from those that give the utility direct control over the curtailment, including automated control of heating and cooling loads, to those that allow customers to respond to prices, whether they are fixed (time-of-use rates) or change with supply and demand (critical-peak and real-time pricing variants). Where the utilities have not had experience, they should consider results from other utilities and how they might apply to their customer loads.

3. **The utilities should bring forward by Sept. 30, 2003, for the Commission's consideration at least one voluntary real-time hourly or critical-peak pricing tariff beginning Jan. 1, 2004, for nonresidential customers with a demand of 200 kW or greater.**

   More than one rate option may be needed to address the needs of customers with different loads, load patterns and abilities to shift business operations. The tariff(s) should be approved enough in advance of the utility's notification deadline for the cost-of-service rate so customers understand all their options for 2004. The utilities should provide for the Commission's consideration an estimate of the costs of the proposed program and an analysis of utility costs that may be avoided.

   Among the programs the utilities should consider is Georgia Power's two-part real-time pricing option with historical usage billed at the cost-of-service rate and deviations billed or credited at hourly prices posted a day ahead. The rate design reduces bill volatility, and customers can buy price protection products to further reduce risk. The utilities should consider customer needs for notification, automated load control, continuing education and technical assistance.

4. **The utilities should bring forward by Sept. 30, 2003, for the Commission's approval a program to expand their direct load control efforts for small customers in Oregon beginning Jan. 1, 2004. The utilities also should consider testing critical-peak pricing for customers that choose utility load control.**

   PGE tested direct load control of residential water heating and space heating loads in winter 2003. PacifiCorp is developing an air-conditioning load control program for residential and small commercial customers in Utah, with an estimated load reduction of 90 MW from 90,000 participants in three years.

   The utilities should expand these efforts in Oregon in 2004. Further, the utilities should consider whether to test critical-peak pricing under their load control programs. Automated control makes it easier for customers to participate in such a pricing option. And unlike traditional time-of-use rates, critical-peak pricing allows customers to respond to system contingencies, so it has greater potential benefits for the utility system. Further, adding a critical-peak price to the time-of-use option would allow the utilities to reduce on-peak hours and/or the on-peak rate. Any critical-peak pricing option must provide advance notification to customers of critical-peak events. It also must specify limits on the number of hours per event and total event hours.

   The utilities should provide an analysis for the Commission's consideration of the proposed program's costs as well as the estimated avoided costs for the utility system. Evaluation of the program should include energy and capacity savings, bill savings for participants, actual program costs, customer override of load control and customer satisfaction. The utilities also should estimate the long-term cost savings for the utility system from reducing the need for peaking plants, power purchases, and distribution and transmission upgrades.

5. **The Commission should open an investigation to identify policies that facilitate the adoption of more advanced meters, communication technology and automated meter reading.**

Advanced meters, communication technology and automated data collection are needed to get the most benefit from demand response. The utilities have made much progress in these areas in the last few years.

Among the issues the proceeding should look at are the following:

- What purposes will advanced metering and communications serve in the near term and longer term?
- What are the benefits of advanced metering and communications? In addition to the benefits from being able to expand demand response programs, the proceeding should assess the value of greater settlement accuracy, more accurate assignment of costs to customers, tools for better management of loads, automatic outage reporting, improved load profiling and better support for rate design. The proceeding also should consider the potential for lower meter reading costs if the meters can be read remotely and increased competition for nonresidential customers (and at lower cost from mass deployment) by having the meters already in place for service by aggregators and alternative energy suppliers.
- What size customers should have more advanced meters and communications?
- What type of meters and communication systems are the most cost-effective and preserve flexibility for future rate options and services?
- What are the costs, and do the benefits outweigh them?
- How can mass deployment reduce costs?
- Is automated meter reading cost-effective in the utility's service area?
- Where should automated meter reading be deployed?
- How should we pay for more advanced meters and automated meter reading, and who should receive the benefits?
- Are there opportunities for joint meter reading — for electricity and natural gas, for example?

6. **The Commission should determine whether time-of-use energy rates should be redesigned and meter charges reduced.**

The Portfolio Advisory Committee will make its recommendations to the Commission for the time-of-use option by July 1, 2003. The Commission will consider them at a subsequent public meeting.

At that time, the Commission should determine whether monthly meter charges should be reduced. It also should assess whether PGE's mid-peak rates should be lower and on-peak rates increased to maintain the same average rates. That would encourage more shifting from on-peak hours and make it easier for customers to save when they do so. Alternatively, PGE could propose other rate changes, such as eliminating the mid-peak period and increasing the number of off-peak hours. For PacifiCorp, the Commission should consider a new time-of-use rate design for residential customers that is compatible with inclining block rates. One option is a simple credit (or charge) to the customer's Basic Service bill for usage below (above) an on-peak allowance. The allowance would be the customer's total energy use for the billing period times the percent of energy used on-peak by the average residential customer (usage typical for that month or on an annual basis).

To assist the Commission in its evaluation, the utilities should provide by July 1, 2003, an analysis showing the effects on participants' bills of any changes the Committee or the utility proposes. The analysis should test a variety of load shifting levels for both average-usage and high-usage customers. The analysis also should compare the resulting bills with what those customers would pay under current time-of-use rates and what they would pay under Basic Service. Further, the analysis should estimate the utility cost savings from reductions in on-peak usage.

## Appendix A
## MODEL DEMAND RESPONSE PROGRAMS

The following demand response programs have been among the most successful in reducing peak demand for power.

**Georgia Power Real-Time Pricing for Nonresidential Customers**[56,57,58]
Georgia Power's real-time pricing programs for large customers are the largest and most successful in the country. More than 1,600 customers were participating as of June 2002, representing 5,000 MW of peak demand. The utility's real-time pricing options are credited with peak demand reductions of up to 1,000 MW, or 5 percent of system peak.

The most popular program is a day-ahead, two-part tariff. Customers pay a fixed rate (differentiated by on- and off-peak hours) for their baseline energy use, based on historical load prior to going on the tariff, and hourly prices for deviations. When customers use less energy than their baseline, they receive a credit at the hourly real-time price (the utility's marginal cost). When they use more, they pay the real-time price for the additional energy they use that hour.

The utility determines hourly prices based on its forecasted cost of incremental generation, plus a risk adder. Customers can get hourly prices on the company's Web site by about 4 p.m. for the following day. Prices for Saturday through Monday are available the previous Friday, except when there is a high risk of outages.

The utility develops the customer baseline load using a complete calendar year of either customer-specific hourly firm-load data or monthly billing determinant data that represents the typical consumption pattern and level for that type of facility. Customers can keep their traditional bills by holding their loads to the traditional load shape, and the utility recovers its embedded revenue requirements through the baseline portion of the bill.

Commercial and industrial customers with a minimum peak demand of 250 kW are eligible. Participating customers run the gamut from small to large. An administrative fee of $155 per month for customers over 1,000 kW and $175 per month for smaller customers covers billing, administrative and communication costs.

A few very large customers are participating in another of Georgia Power's real-time pricing programs. It uses hour-ahead prices, with notice 70 minutes in advance of the hour. The fee is $850 per month to cover the higher billing, administrative and communication costs. In general, these customers are the most price-responsive.

The utility offers an additional product that allows customers to adjust their baseline energy use on an annual basis after seeing the utility's expected *day-ahead* prices for the forthcoming year. The customer can raise its baseline to ensure against the possibility of higher-than-expected prices or lower it to reap the benefits of lower-than-expected prices. The administrative fee is $175 per month for customers greater than 1,000 kW and $195 per month for smaller

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[56] O'Sheasy.
[57] Braithwait.
[58] www.georgiapower.com

customers. There's a similar option allowing customers to adjust their baseline up or down annually after seeing forecasted *hour-ahead* prices. The administrative fee is $870 per month.

*Price Responsiveness*
Industrial customers on *hour-ahead* prices have shown great price-responsiveness: When the hourly price is 20¢ per kWh, customers cut demand by 20 percent. Prices of 50¢ per kWh lead to load reductions of 30 percent. Industrial customers on *day-ahead* pricing are less responsive, reducing load by 10 percent at a price of 20¢ per kWh — still a significant reduction. Customers in this group had previously been on a curtailable service contract and had no on-site generation.

For commercial accounts that switched from curtailable service to day-ahead pricing, loads tend to *increase* as price goes up at prices below about 10¢ per kWh. That's because price and temperature are typically correlated (in this case, higher temperatures increase air conditioning loads). By 23¢ per kWh, price response overcomes the temperature effect. And by 50¢ per kWh, demand decreases by 5 percent to 10 percent (though data are limited).

Industries that are best suited to load shifting, including warehouses, pipelines, water and sanitation, are most price-responsive. At the low end of the range are industries that are not electricity intensive.

*Price Protection Products*
Georgia Power offers price protection products that allow customers to manage the risk and volatility of real-time prices for all or a part of their load above their baseline, up to the total amount above baseline the prior year. About 10 percent of customers on real-time pricing had price protection contracts in place as of June 2002 — considerably fewer than prior years, largely because prices were expected to be less volatile.

Contracts are for a specific timeframe, quantity and price. They clear at the end of the billing period based on the difference in the contract price and the actual average real-time price. Because price protection products are financial instruments with fixed quantity components not directly related to the actual metered load during the billing period, the customer's incentive to respond to real-time prices remains intact regardless of the amount of load contracted.

Price protection products include the following:
- A *Price Cap* is a ceiling guarantee on the average real-time price over a specific time period. Customers are protected against the average real-time price above the cap. Customers pay an up-front premium.
- A *Contract for Differences* is a fixed price guarantee for the average real-time price over a specific time period. No up-front premium is required.
- A *Collar* is a cap and floor on the average real-time price over a specific time period. Each cap price has a floor price associated with it. No up-front premium is required.
- An *Index Swap* ties a real-time swap price to a commodity price index. If the commodity price decreases, the swap price decreases. If the commodity price increases, the swap price increases.
- An *Index Cap* ties a real-time price cap to a commodity price index. If the commodity price decreases, the cap price decreases. If the commodity price increases, the cap price increases.

**Gulf Power Critical-Peak Pricing for Residential Customers**[59,60]

Gulf Power in Pensacola, Fla., began offering its voluntary GoodCents Select℠ program for residential customers in March 2000, following a successful pilot project. It combines advanced metering, communication technology, automated control of energy-using systems and critical-peak pricing.

Gulf Power can call the "super-peak" price any time with at least 30 minutes' notice for up to 1 percent of hours in a year (88 hours). The utility typically gives one-hour's notice. The utility called the super-peak price a few times during the first summer, in 2000. No critical periods were declared during summer 2001. Eleven events totaling 12 hours were called in 2002.

Time-of-use periods vary between winter and summer, but prices are the same: 4.2¢ per kWh off-peak, 5.4¢ per kWh mid-peak and 10¢ per kWh on-peak. The super-peak price is 30.9¢ per kWh. The mid-peak price is lower than the standard residential rate of 6.3 cents per kWh. Thus, time-of-use prices are lower than the standard residential rate 87 percent of the time: 28 percent of hours are off-peak, 59 percent are mid-peak, 12 percent are on-peak, and up to 1 percent are super-peak.

Customers get a programmable thermostat to set their preferred temperature settings for heating and cooling as well as whether the heating or cooling system, water heater or pool pump run during each time period. The utility also installs controls for water heaters, pools and spas.

Communication equipment in the home sends the critical-peak price signal using commercial paging. The equipment also sends a signal to the thermostat to provide automatic control. The utility uses the communication equipment, paging and the customer's phone line for automated meter reading. The utility expects in the future to add Internet access to energy use profiles and for remote management of thermostat settings.

Participants pay about $5 a month, which offsets about 60 percent of the program's costs. Gulf Power and the Florida Public Service Commission agreed that participating customers should pay only part of the cost because all ratepayers benefit from participants reducing the utility's need for peak power and using the company's generating resources more efficiently. The minimum term is one year, unless the customer requests termination within the first 30 days.

Gulf Power cites the following results:

- Average demand reduction of 2.1 kW per household during on-peak periods in summer, 2.7 kW in winter — a 22 percent reduction compared to a control group
- Average demand reduction of 2.75 kW per household during critical periods — a 41 percent reduction

The typical participant uses 20,000 kWh per year — more than the typical Gulf Power residential customer. Average energy savings per household is 1,433 kWh per year. Together with savings from shifting load to off-peak hours, the average household saves $187 a year, or 14.9 percent, on its annual electric bill.

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[59] Brian White, Gulf Power Co., presentation at California Energy Commission Demand Response Workshop, March 15, 2002, and personal communication, Jan. 7, 2003.

[60] www.gulfpower.com

The program has a 96 percent satisfaction rating, the highest ever for a Gulf Power program. Nearly 4,000 households are now participating. The utility expects about 10 percent of its residential customers, 40,000 to 50,000, to sign up for the program within 10 years.

The utility used to offer a standard time-of-use option with no super-peak price and no control equipment. Because the standard option had a longer off-peak period and a lower off-peak price, consumers could have saved even more on that rate — if only they installed control equipment to help them manage loads. But hardly any customers enrolled in the schedule, indicating that consumers were disinclined to do so. The utility discontinued the standard time-of-use rate in June 2002. According to Gulf Power, customers place a much higher value on the GoodCents Select program because of the convenience and automation benefits, including a fully debugged control system installed by the utility.

**Puget Sound Energy Time-of-Use Pricing for Mass Markets**[61,62]
Puget Sound Energy in Bellevue, Wash., widely deployed residential time-of-use metering and pricing in 2000, during the Western energy crisis. Small businesses also participated.

At its peak, some 268,000 customers participated in the program. Puget Sound Energy used an opt-out approach, assigning all eligible customers to the rate option unless they told the utility they did not want to participate. The utility provided daily usage information by time period on its Web site for each customer. Customers also received a detailed report with each utility bill.

A recent analysis using 14 months of data found that even with mild price signals, residential customers overall responded with typical price elasticities found in other time-of-use programs. Generally, customers were able to shift their on-peak energy use more in the winter than in the summer and more in the evening peak period than during the morning peak.

All-electric customers shifted the most energy use (in kWh) out of the morning peak hours during winter and the least during summer, compared to customers with only electric water heating or all-gas heating. All-electric customers also shifted the most energy use out of the evening peak hours in the late winter/early spring and the least in the summer and fall. Customers with electric water heating (but not electric space heating) shifted more during the evening peak hours than other types of customers from late fall through mid-winter.

For customers in single-family homes, those with electric water heating only consistently met or exceeded a 5-percent shift during peak evening hours, except in summer. All-gas, single-family home customers were consistently at that level or higher (in spring and summer) and were able to shift a greater percentage of their energy use out of all on-peak and mid-peak periods compared to other customers. Over all types of housing, the shift from on-peak periods generally ranged during the year between 6 percent and 8 percent for all-gas customers, 5 percent and 7 percent for electric water heating customers, and 3 percent and 5 percent for all-electric customers.

The program was designed to give customers an incentive to shift some of their power use to off-peak times. Throughout most of the program, most participants paid less than they would have on flat rates. The program was changed in July 2002. The difference between on- and off-

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[61] Puget Sound Energy news releases, Oct. 24 and Nov. 6, 2002.

[62] Eric Englert, Puget Sound Energy, *Residential Demand Response With Mass-Market Time-of-Use Electric Rates: An Analysis of Selected Segments of the Residential Class*, presented at the Western Load Research Association Spring Meeting, April 2003.

peak prices was reduced to only 1.4¢ per kWh, giving customers little incentive to shift their power use. A $1 monthly fee also was added to help pay for metering and data collection costs.

After that, bills for most participants were slightly higher than they would have been on flat rates. On average, residential customers paid 80¢ a month more from July through September 2002 than they would have under flat rates. The average small business paid $1.16 more per month during that period. As a result, Puget Sound Energy ended the program ahead of schedule in November 2002. The utility will consider offering a modified program after analyzing the results of a review that will be completed by summer 2003.

## Appendix B
## LESSONS FROM DEMAND RESPONSE PROGRAMS ELSEWHERE[63,64,65]

Among the conclusions that researchers have drawn from demand response programs offered by utilities and ISOs throughout the U.S. and Europe:

- All customer classes respond in modest but significant and consistent ways to time-varying electricity prices or curtailment incentives.

- The most successful utility programs are characterized by:
  - A much greater degree of customer education and hand-holding, including energy audits and help in reducing energy use and demand
  - A variety of forward-contracting options, including day-ahead and term events
  - Sharing of savings between the utility and customers
  - A broad array of options, including emergency and price-responsive load programs, offered under a single program brand
  - Verification and settlement of load curtailments using customer-specific baselines (historic usage levels against which actual load is measured to determine reductions)

- Many industrial customers can shift or curtail load for a period of time and still maintain their basic operations. Certain types of customers are more likely to shift load than others, particularly those with on-site generation, energy costs that are a sizable percentage of total operating costs, and those with flexible or non-continuous production processes. However, several utilities have found that other innovative customers are willing to shift loads. Still, most of the short-term load response comes from a relatively small number of customers.

- Industrial customers form the backbone of most programs, but participation by commercial and institutional customers is increasing. A recent sample of programs nationwide found that about half of participants are industrial customers (including steel mills, pulp and paper mills and cement plants), about a quarter are commercial customers, and the rest are institutional and small manufacturers. Wider participation is necessary to achieve the full potential of demand response.

- About 80 percent of participants in price-responsive load programs have demands greater than 500 kW. This is in large part due to the minimum size or curtailment level required to participate under the program. Aggregation or lower curtailment thresholds are needed to tap other customer markets.

- Incentives that well exceed bill savings from curtailing loads are required for sizable response. Alternatively, smaller payments for curtailment events may be coupled with upfront reservation or capacity payments. Programs that only pay participants when the

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[63] Goldman.
[64] Ahmad Faruqui, Joe Hughes and Melanie Mauldin, *Real-Time Pricing In California: R&D Issues and Needs*, California Energy Commission, Oct. 28, 2001.
[65] Charles A. Goldman, Joseph H. Eto and Galen L. Barbose, Lawrence Berkeley National Laboratory, *California Customer Load Reductions During the Electricity Crisis: Did They Help to Keep the Lights On?*, LBNL-49733, May 2002.

utility calls a curtailment event may not elicit sufficient enrollment unless curtailment payments are very high.

- Most programs are new, and curtailment levels have been relatively low because low wholesale electricity prices throughout most of the country have induced few participants to bid. Further, most programs are voluntary, with no standing commitment and no penalties for nonperformance.

- Customers on interruptible rates abandon them when utilities really need them — when they repeatedly call high prices or curtailments during prolonged shortages — even after receiving reservation fees for years.

- Too many and frequently changing programs confuse customers and limit participation.

- While backup generators at customer sites are an important demand response resource, most are diesel-powered and their use is limited to relatively few hours a year. However, that limit may meet or exceed the number of super-peak hours. Some programs allow only non-diesel generators to participate. Environmental impacts can be mitigated through purchases of pollutant allowances.

- Programs designed for system emergencies provide a pathway to transition to those designed for ongoing economic efficiency. Customers get experience with how much price volatility and risk they can handle, and at least some of the enabling technology gets installed — metering, communication, monitoring, notification and automated load control equipment.

- Traditional load management programs that utilities have offered may not be well suited for restructured electricity markets. Programs should be redesigned long before an electricity crisis so that retail customer loads can participate directly in bulk power markets and respond to high prices or system contingencies.

Utilities have devised several solutions to reduce bill volatility for large customers on real-time pricing:

- For real-time rates that apply to all of the customer's usage, utilities have set price caps. For programs with differently priced days, utilities have limited the number of high- and low-priced days. Utilities also have developed two-part rates, with flat rates for the customer's historical usage levels and real-time pricing applied as a debit or credit to deviations. That not only limits the customer's risk, but also the risk of revenue loss to the utility. Customers that use less electricity than their baseline during a high-priced hour get a credit at the hourly price. If they use more, they pay for the additional amount at the hourly price.

Among the findings from time-of-use and critical-peak pricing programs for small customers:[66,67,68]

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[66] Brian White, Gulf Power, presentation at California Energy Commission workshop on demand response, March 15, 2002.

[67] Faruqui and George.

[68] Puget Sound Energy.

- Residential customers with a large number of appliances and higher usage levels are most responsive to time-varying electricity prices.

- Residential customers have much greater potential to shift load and reap economic benefits than do small commercial customers.

- Dynamic pricing shows far greater potential to generate economic value than a traditional time-of-use rate.

- Residential customers value the convenience of utility-installed controls for energy-consuming equipment and direct utility load control. The technology increases load reductions possible through dynamic pricing and can make it largely painless to consumers.

## Appendix C
## DESIGN PRINCIPLES FOR DEMAND RESPONSE PROGRAMS[69]

- Programs should be designed to minimize overall costs for ratepayers.
- Utilities should pay the lowest incentive levels required to achieve load reductions.
- The level and timing of payments should be sufficient to achieve the required level of load reduction.
- Programs should attract and retain sufficient participation and achieve meaningful load reductions.
- Participants and non-participants should share the benefits.
- Program design and participation should be as simple as possible.
- Program offerings should be stable to minimize customer confusion and build participation.
- Customers should have the technical assistance and technology they need to achieve their full potential for cost-effective load reduction.
- Customers should be able to predict their costs for participating and their resulting electricity bills and paybacks.

[69] Based in part on Ren Orans, Snuller Price, Debra Lloyd, Tom Foley and Eric Hirst, *Expansion of BPA Transmission Planning Capabilities*, prepared for Bonneville Power Administration - Transmission Business Line, November 2001.

## Appendix D
## PACIFICORP SURVEY ON ITS TIME-OF-USE OPTION IN OREGON[70]

A telephone survey of PacifiCorp customers in October and November 2002 found that nearly nine of 10 households participating in the time-of-use option say they have made changes in when they use electricity, most commonly when they do laundry and dishes. (The utility had not yet run the program during peak heating months, so heating-related changes are not yet captured.) Forty percent of businesses say they have made changes. Nonparticipants also were surveyed. Among the other findings:

- Residential participants took three actions to reduce on-peak energy use on average; business participants took only one.
- Residential customers give the time-of-use program a rating of 6.8 (on a scale of 0 to 10); small nonresidential customers rated it at 6.9. Saving on energy bills is the main reason for being satisfied with the program. Having more control over electricity costs was another reason, according to 14 percent of residential participants and 9 percent of small nonresidential enrolled in the program. That also ranked high as a motivator for taking part in the program.
- Conversely, customers who are not satisfied with the program say not saving money is the main reason. Inconvenience is another.
- Among nonparticipants, 34 percent of residential customers and 46 percent of business customers cited lack of awareness of the program as a main reason for not enrolling. Other factors include inability to change usage behavior and thinking they would not save money on the option. Being able to minimize the risk of participating was cited as an important motivator.
- The majority of residential (86 percent) and business (90 percent) participants thought it would be "very" or "somewhat" easy to save money on the time-of-use option when they signed up for it.
- Fifty-seven percent of residential customers planned to continue with the program beyond their initial 12-month term. (The remainder was split between not planning to continue and not knowing whether they would do so.) Three-fourths of business participants planned to continue.
- Forty-one percent of nonparticipating residential customers and 29 percent of nonparticipating business customers say they are likely to participate in the program. A majority of nonparticipants say more information to help evaluate whether the program would work for them might motivate them to enroll.
- Fifty-five percent of residential participants work the day shift. About one-third are not employed (some are retired). Education is the main demographic difference between participants and nonparticipants: About half of participants have a college degree, compared to about a quarter of nonparticipants. Most have electric space heating (65 percent) and water heating (71 percent). Nearly half have air-conditioning.
- Among business participants, 25 percent are farmers/irrigators and 15 percent are retailers. About half have electric space heating, 65 percent have electric water heating and nearly half have air-conditioning.

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[70]Market Decisions Corp., *Time of Use Program Evaluation for PacifiCorp*, December 2002.

**Table 2**
**Demand Response Programs Offered in Oregon by Investor-Owned Utilities**

| Program | Utility | Targeted customers | No. of active participants | Energy reduction (MWh)[1] | Max. capacity savings (MW) | Average payment per MWh | Est. net savings for utility[2] | Period offered |
|---|---|---|---|---|---|---|---|---|
| Demand Buy Back (next day) | PGE | Can reduce demand by 250 kW or more | 8 | 87,532 | 157.8 | $129 | $26.2 million | Ongoing; active July 2000-May 2001 |
| Energy Exchange (events lasting 1 week or less) | PacifiCorp | Monthly demand ≥1 MW | 44 | 38,761 | 67.2 | $108 | $2.1 million | Ongoing; active Dec. 2000 - Aug. 2001 |
| Energy Buy Back | Idaho Power | Can reduce load by 1 MW or more | 0[3] | 0 | 0 | 0 | 0 | Since June 2001 |
| Longer-term negotiated buybacks | PGE | Largest customers | 2 | 108,664 | 56.0 | $180 | (-$9 million)[4] | April-Sept. 2001 |
| Longer-term negotiated buybacks | PacifiCorp | Largest customers | 3 | 61,385 | 35.1 | $200 | (-$7.6 million)[5] | Dec. 2000 and March-Sept. 2001 |
| Irrigation Curtailment | PacifiCorp | Irrigators with a pumping load ≥16 kW at a single meter | 328 | 20,636 | Unknown[6] | $125[7] | (-$1.5 million) | May-Nov. 2001 |
| Irrigation Buy Back | Idaho Power | Irrigators committed to reduce energy use ≥100,000 kWh over season | 17 | 16,287 | Unknown[6] | $150[7] | Not available[8] | April-Nov. 2001 |
| 20/20 Customer Challenge | PacifiCorp | Residential customers | 115,598[9] | 49,824 | 19.1 | $69 | (-$1.4 million) | June-Sept. 2001 |
| Blackout Protection | PGE | Monthly demand ≥ 1 MW; must be able to reduce demand by 15% during every event | 0[10] | 0 | 0 | NA[11] | 0 | Since Sept. 2002 |
| Blackout Protection | PacifiCorp | Monthly demand ≥4 MW; must be able to reduce demand by 15% during every event | 0[10] | 0 | 0 | NA[11] | 0 | Since Feb. 2002 |
| Dispatchable Standby Generation | PGE | Own generators ≥1 MW | 5 | NA[12] | NA | See note[13] | Not available | Since April 2000 |
| Optional time-of-use rate | PGE and PacifiCorp | Residential and small business customers (≤30 kW) | About 3,700 | NA | Unknown | NA[14] | Unknown | Since March 2002 |

[1]Savings during energy shortage of 2000-01, not including any load shifting.
[2]Not including lost revenue.
[3]The program got underway just before power prices dropped, so the utility didn't call any events.
[4]PUC staff estimate based on average monthly prices for firm peak power at mid-C, per PGE.
[5]PacifiCorp estimate based on hourly mid-C prices for non-firm power.
[6]Program was designed for energy savings, not capacity savings. Many irrigation meters do not measure demand.
[7]Guaranteed payment during the entire irrigation season.
[8]The program increased power costs because of an unexpected drop in market prices.
[9]Average number of customers participating per month.
[10]No customers had signed up by year-end 2002.
[11]Not applicable. Customers avoid rolling blackouts but receive no payments.
[12]Projected savings of systems under contract to date is about 2,000 MWh (9.75 MW * 200 hr) during a year with significant peaking needs. Generators have not yet been used under the program because of mild winter weather and stable wholesale prices.
[13]PGE estimates an effective reservation fee of $20/kW for making the generator dispatchable and for maintenance. Estimated fuel costs are $60 per MWh.
[14]Energy rates are lower during off-peak hours and higher during on-peak hours.