# <u>Demand Response</u> -- Issue Paper in Preparation for the 5th Power Plan

## *Executive Summary*

This issue paper examines demand response in the retail market for electricity. It begins by explaining why demand response is important, why it has been deficient in the past, and how that deficiency has become more serious with the current electrical industry structure.

The paper then explains that "demand response," as it is used here, is not "conservation" as the Council has used the term. It discusses how the difference affects the kinds of policy goals we can consider.

The paper describes and evaluates the main options for increasing demand response. It begins with real-time pricing, which offers a number of advantages in principle, but faces a number of obstacles that rule out quick and widespread adoption. It examines time-of-use pricing, which faces somewhat fewer obstacles and offers somewhat less promise. The paper then moves to a number of forms of payment for reductions in use, which have been adopted fairly widely in our region and elsewhere. The payment for reductions options are more familiar and enjoy more acceptance, but have transactions costs and limited participant pools.

Next, the issue paper proposes to estimate the potential amount of demand response in the region, and the value of achieving that potential.

Finally, the paper invites comments on the issue in general and some aspects of the issue in particular.

## *Why are We Concerned with Demand Response?*

The region's electricity market has moved from a structure of regulated vertically integrated monopolies to a mixture of regulated and competitive components. The wholesale market, in spite of questions raised by the price volatility of 2000-2001, is generally agreed to have moved farthest towards competition. In contrast, the retail market remains mostly a regulated monopoly market. While we expect that we will see more changes in the electricity market, we can't predict the final form it will take. We do expect further change to be cautious, so that the fundamental mixture of relatively competitive wholesale market and mostly regulated retail market will persist at least for the next several years. While regulated load-serving entities may take a greater role in resource development than they have in the recent past, the wholesale market will still be an important factor at the margin.

Presently, producers of electricity, who sell into the wholesale market, generally see prices that reflect the marginal cost of production. When supplies are short, prices rise and producers expand supply. When supplies are ample, prices moderate. Producers cut back the operation of their most expensive units and review their plans to invest in new generating units.

But ultimate consumers of the electricity see retail market prices that are generally set by administrative ratemaking processes. These retail prices do not follow wholesale market prices except over the long run. The good news is that retail customers are buffered from the volatility of the wholesale market. The bad news is that retail customers have little incentive to respond to shortages and high wholesale prices (e.g. caused by extraordinary weather poor hydro conditions, by temporary generating or transmission outages or even market manipulations) by reducing demand for electricity. As a consequence, the market lacks one of the mechanisms necessary for moderating prices.

In a world of regulated monopoly utilities, poor retail market signals led to a power system that was inefficient but tolerable. Without much demand response, probably more generation, transmission and distribution facilities were built and operated than would have been otherwise been necessary. Utilities built the necessary facilities and were able to make returns on their investments so they stayed in business. The lights stayed on, but average costs were higher than they needed to be. Even if we ultimately move back to that traditional world, demand response would offer great benefit, by reducing the need for generating and distribution capacity that is used only a few hours each year.

But in the electricity industry we have now the potential benefits of demand response are even greater. We now rely on unregulated power producers to build many new generating plants. These producers have no obligation to build, and no assurance of making a return on investment. There is no guarantee they will find it worthwhile to build to the same reserve margins as we have enjoyed in the past.

Without demand response, the electricity market is lacking one the major factors that moderates prices in most other markets. Retail customers may be buffered in the short-run from the volatility of market. However, as the experience of the last couple of years has shown, the increased costs experienced by load-serving entities eventually make their way into retail rates.

We're wrestling with ways to maintain the reliability of the system and moderate the volatility of wholesale prices, without giving up the benefits of a competitive wholesale market. In our current situation, demand response can reduce the overall cost of the system, as in the past, and play a critical role in ensuring reliability and price stability as well.

## ***How is Demand Response Different from Conservation?***

We need to appreciate that what we mean by "demand response" is not "conservation." "Conservation," as the Council uses the term, is improvement in efficiency that reduces electricity use with no change in the level of service (e.g. warm house in winter, cold beer, light on the desktop). "Demand response," as the term is used here, is a change in the level or quality of service <u>that is chosen voluntarily by the consumer</u>, which reduces electricity use or shifts it to a different time. If the change in service were imposed on the consumer involuntarily we would call it "curtailment" and it would be evidence of an inadequate or unreliable power system.

There is an important implication of the difference between demand response and conservation. Since conservation leaves service unchanged, we can compare the costs of alternative ways of providing the service (e.g. conservation and generation) and estimate a cost-effective level of conservation in kilowatt-hours. The estimate will be somewhat uncertain because of the quality of data, but the conceptual process is straightforward -- that is, start with the cheapest conservation measures and add more measures until saving another kilowatt-hour costs as much as generating and delivering another kilowatt-hour. The total conservation measures at that point represent the cost-effective level of conservation. The Council's plans have used this level as the basis for efficiency standards or implementation targets.

But we can't set a kilowatt-hour target level for demand response, as we do for conservation. To estimate a cost-effective level of demand response in kilowatt-hours would require putting a value on the change in service level, which we don't know how to do.[1] We are left with assuming that each consumer's choice of service level is best for him, and would be best for the region as well if the consumer saw the region's cost of electricity. Instead of a policy goal specified in kilowatt-hours, we have a goal of identifying incentive mechanisms (e.g. prices paid or payments received) that will lead each consumer's chosen level of service to be best for the region as well. To the extent consumers see these incentives, their demand response to changing conditions will be appropriate for the region as a whole.

There are a number of mechanisms available, each with its own advantages and disadvantages. We don't expect any one of these mechanisms to be the best for every situation – it seems more likely that some combination of mechanisms will be a sensible strategy, particularly while we're still learning about their strengths and weaknesses. At the most general level, they can be categorized as price mechanisms and payments for reductions. We first examine pricing mechanisms.

## ***Price Mechanisms***

### *Real-time prices*

The goal of price mechanisms would be the reflection of actual marginal costs of electricity production and delivery in retail customers' *marginal* consumption decisions. One variation of such mechanisms is "real-time prices" -- prices based on the marginal cost of providing electricity for each hour. This does not mean that every kilowatt-hour they consume needs to be priced at marginal cost. But it does mean that rates would be structured in such a way that the customer receives a marginal price signal. Consumers

[1] We can calculate the cost of a changed level, but to calculate the value we would need to see into each consumer's head.

facing real-time prices are faced with the same costs as the power system for their marginal use, and in theory will make appropriate marginal use decisions.

*Experience*

Georgia Power has 1700 customers on real-time prices. These customers, who make up about 80 percent of Georgia Power's commercial and industrial load (ordinarily, about 5000 MW), have cut their load by more than 750 MW in some instances. The program applies real-time prices to <u>increases</u> or <u>decreases</u> from the customer's base level of use, but applies a much lower regulated rate to the base level of use itself. As a result, the total power bills don't vary in proportion to the variation of the real-time prices, but customers do have a "full strength" signal of the cost of an extra kilowatt-hour of use (and symmetrically, the value of a kilowatt-hour reduction in use).

Duke Power has a similar program that charges real-time prices to about 100 customers with about 1000 MW of load. Duke has observed reductions of 200 MW in these customers' load in response to hourly prices above 25 cents per kilowatt-hour.

Gulf Power offers a voluntary program for residential customers that includes prices that vary by time of day along with a programmable control for major electricity uses (space heating and cooling, water heating and pool pump, if present). While this program mostly falls in the "time-of-use pricing" category to be described next, it has an interesting component that is similar to real-time pricing--"Critical" price periods:

The Critical price (29 cents per kilowatt-hour) is set ahead of time, like the Low (3.5 cents), Medium (4.6 cents) and High (9.3 cents) prices, but unlike the other prices, the hours in which the Critical price applies are not predetermined. The customer knows that Critical price periods will total no more than 1 percent of the hours in the year, but not when those periods will be, until 24 hours ahead of time. Gulf Power helps customers program their responses to Critical periods ahead of time, although they can always change their response in the event.

Customers appear very satisfied by this Gulf Power program. Customers in the program reduced their load 44 percent during Critical periods, compared to a control group of nonparticipants.

*Assessment*

Real-time prices, if we can devise variations that are acceptable to regulators and customers, have the potential to reach many customers. Real-time prices can give these customers incentives that follow wholesale market costs very precisely every hour. Once established, real-time prices avoid the transaction costs of alternative mechanisms. For all of these reasons, the potential size of the demand response from real-time prices is probably larger than the other mechanisms examined here.

However, real-time prices have not been widely adopted for a number of reasons:

1. Most customers would need new metering and communication equipment in order to participate in real-time pricing. Currently, most customers' meters are only capable of measuring total use over the whole billing period (typically a month). Real-time prices would require meters that can measure usage in each hour. Also, some means of communicating prices that change each hour would be required. It's worth noting that more capable meters are also necessary for time-of-use metering, and such programs as short term buybacks and demand side reserves.
2. Currently, there is no source of credible and transparent real-time wholesale prices. Any application of real-time retail prices will need all parties' trust that the prices are fair representations of the wholesale market. The hourly prices from the California PX were used as the basis for some deals in our region until the PX was closed in early 2001, but prices from a market outside our region were regarded as less-than-ideal even while they were still available. Now the Cal PX is closed, and a credible regional source is needed. This is a problem that affects many of the other mechanisms for demand response[2] as well.
3. Some customers and regulators are concerned that real-time prices would result in big increases in electricity bills. While the argument can be made that such increases would be useful signals to consumers[3], the result could also be big decreases in bills. In either case, however, many customers and regulators are concerned with questions of unfair profits or unfair allocation of costs if real-time prices are adopted. The Council shares this concern.
4. Even if price increases and decreases balance over time, the greater volatility of real-time prices is a concern. Customers are concerned that more volatile prices will make it hard for them to plan their personal or business budgets. Regulators are concerned that more volatile prices will make it a nightmare to regulate utilities' profits at just and reasonable levels. The volatility is moderated if the real-time pricing applies only to marginal consumption, but it is still greater than what consumers are used to.
5. Some states' utility regulation legislation constrains the definition of rates (e.g. rates must be numerically fixed in advance, not variable based on an index or formula).

With time, some of these issues can probably be solved, making real-time prices more practical and more acceptable to customers and regulators:

Metering and communication technology has improved greatly. New meters not only offer hourly metering and two-way communication but also other features, such as automatic meter reading and the potential for the delivery of new services, that may make their adoption cost-effective.

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[2] For example, participation in short term buyback programs is enhanced when customers have confidence that their payments are based on a price impartially determined by the wholesale market rather than simply a payment the utility has decided to offer.

[3] For example, bills might rise for those customers whose use is concentrated in hours when power costs are high. While those customers would be unhappy about the change, their increased bills could be seen as an appropriate correction of a traditional misallocation of the costs of supplying them -- traditional rates shifted some of the cost of their service to other customers. Real-time prices would also increase the bills of all customers in years like 2000-2001, when wholesale costs for all hours went up dramatically. While customers are never happy to see bills rise, the advantage of such a prompt rise in prices would be a similarly prompt demand response, reducing overall purchases at high wholesale prices. This is a better result than the alternative of raising rates later to recover the utilities' wholesale purchase costs, after the costs have already been incurred.

Customers' and regulators' concerns with fairness and volatility may be relieved by such variations of real-time prices as the Georgia Power program. That program's blend of real-time rates applied to marginal use and regulated rates applied to base use was described earlier. Compared to application of real-time prices to the total use of the customer, this variation reduces the volatility of the total bill very significantly.

Concerns with fairness may also moderate as it is better understood that "conventional" rates have their own problems with fair allocation of costs among customers.

For the present, real-time prices are not widely used; they may become more widely used, but not in the very near future.

## *Time-of-use prices*

We could think of "time-of-use prices" -- prices that vary with time of day, day of the week or seasonally -- as an approximation of real-time prices. Time-of-use prices are generally based on the expected average costs of the pricing interval (e.g. 8 a.m. to 6 p.m. January weekdays).

*Experience*

Puget Sound Energy offered a time-of-use pricing option for residential and commercial customers. There are about 300,000 participants in the program. PSE's analysis indicates that this program reduced customers' loads during high costs periods by 5-6 percent. However, analysis showed that most customers paid slightly more under time-of-use pricing than they would have under conventional rates. PSE has ended the program, though a restructured program might be proposed later if careful analysis suggests it would be effective.

In Oregon, time-of-use pricing options have been offered to residential customers of Portland General Electric and PacifiCorp since March 1, 2002. So far about 2800 customers have signed up, and early measures of satisfaction are encouraging, but data are not yet available on any changes in their energy use patterns.

There have been many other time-of-use pricing programs elsewhere in the U.S. Rather than describe a number of examples, it should suffice to say that a study funded by the Electric Power Research Institute concluded that 25 years of studies indicated that "peak-period own-price elasticities range from -0.05 to -0.25 for residential customers, and -0.02 to -0.10 for commercial and industrial customers." Stripped of the jargon, this means that a time-of-use rate schedule that increases peak period rates by an assumed 10 percent would lead to a 0.5 to 2.5 percent reduction in residential peak use, and a 0.2 to 1.0 percent reduction in commercial and industrial peak use. While the assumed 10 percent rate increase is only illustrative, it is not exaggerated; PSE's peak time rates are about 10 percent higher than its average rates, and PGE's peak time rates are 67 percent higher than its average rates.

*Assessment*

While time-of-use prices, like real-time prices, require meters that measure usage over subintervals of the billing period, they have some advantages over real-time prices. A significant advantage of time-of-use rates is that customers know the prices in advance (usually for a year or more). This avoids the necessity of communication equipment to notify customers of price changes. It also makes bills more predictable, which is desirable to many customers and regulators.

A significant disadvantage, compared to real-time prices, is that prices set months or years in advance cannot do a very good job of reflecting the real-time events (e.g. heat waves, droughts and generator outages) that determine that actual cost of providing electricity. As a result, time-of-use pricing as it has usually been applied cannot provide efficient price signals at the times of greatest stress to the power system, when customers' response to efficient prices would be most useful. Variations in time-of-use pricing such as the Gulf Power "Critical Period" pricing, while they leave prices at preset levels, do allow utilities to match the timing of highest-price periods to the timing of shortages as they develop; these variations provide improved incentives for demand response.

Time-of-use prices will affect customers differently, depending on the customers' initial patterns of use and how much they respond to the prices by changing their patterns of use. While customers whose rates go up will be inclined to regard the change as unfair, regulators can mitigate such perceptions with careful rate design and making a clear connection between cost of service and rates.

## ***Payments for reductions***

### ***Buybacks***

Given the obstacles to widespread adoption of pricing mechanisms, utilities have set up alternative ways to encourage load reductions when supplies are tight. These alternatives offer customers payments for reducing their demand for electricity. In contrast with price mechanisms, which vary the cost of electricity to customers, these offers present the customers with varying prices they can receive as "sellers". Utilities have offered to pay customers for reducing their loads for specified periods of time, varying from hours to months or years.

#### *Short term buybacks*

Short-term programs can be thought of as load shifting (e.g. from a hot August afternoon to later the same day). Such shifting can make investment in a "peaking" generator[4] unnecessary. The total amount of electricity used may not decrease, and may even increase in some cases, but the overall cost of service is reduced mostly because of reduced investment in generators and the moderating effect on market prices. Short-term programs can be expected to be exercised and have value in most years, even when overall supplies of energy are plentiful.

[4] A generator that only runs at peak demands and is idle at other times.

Generally, utilities establish some standard conditions (e.g. minimum size of reduction, required metering and communication equipment, and demonstrated ability to reduce load on schedule) and sign up participants before exercising the program. Then, one or two days before the event:

1. The utility communicates (e.g. internet, fax, phone) to participating customers the amount of reduction it wants and the level of payment it is offering.
2. The participants respond with the amount of reduction they are willing to contribute for this event.
3. The utility decides which bids to accept and notifies the respondents of their reduction obligation.
4. The utility and respondents monitor their performance during the event, and compensation is based on that performance.

Generally participants are not penalized for not responding to an offer. However, once a participant has committed to make a reduction there is usually a penalty if the obligation is not met.

### *Experience*

B.C. Hydro offered a form of short-term buyback as a pilot program quite early -- in the winter of 1998-9. The utility offered payment to a small group of their largest customers for reductions in load. The offer was for a period of hours when export opportunities existed and B.C. Hydro had no other energy to export. Compensation was based on a "share the benefits" principle, sharing the difference between the customers' rates and the export price equally between B.C. Hydro and the customer.

The program was exercised once during the pilot phase, realizing about 200 MW of reduction. The overall evaluation of the program was positive and it has been adopted as a continuing program by B.C. Hydro.

Bonneville Power Administration, Portland General Electric and some other regional utilities offered another form of short-term buyback beginning in the summer of 2000. This program was called the Demand Exchange. The Demand Exchange was mostly limited to large industrial customers who had the necessary metering and communication equipment and who had demonstrated their ability to reduce load on call. An exception to the focus on large customers was the participation of Milton-Freewater Light and Power, a small municipal utility with about 4000 customers. Milton-Freewater participated by controlling the use cycles of a number of their customers' residential water heaters.

### *Assessment*

Both BPA and PGE regarded their Demand Exchange programs as successful. Between the two programs, participating customers represented nearly 1000 MW of potential reductions. Actual reductions sometimes exceeded 200 MW.

As the seriousness of the supply shortage of the 2000-2001 period became clearer, the participation in both utilities' Demand Exchange programs declined, but largely because customers who had been participating negotiated longer-term buybacks instead.

These programs require that customers have meters that can measure the usage during buyback periods. The programs also require that the utility and customer agree on a base level of electricity use from which reductions will be credited. The base level is relatively easy to set for industrial customers whose use is usually quite constant. It's more difficult to agree on base levels for other customers, whose "normal" use more variable because of weather or other unpredictable influences.

## *Longer-term buybacks*

Longer-term programs, in contrast to short term buybacks, generally result in an overall reduction of electricity use. They are appropriate when there is an overall shortage of electricity, rather than a shortage in peak generating capacity.

Most utility systems, comprised mostly of thermal generating plants, hardly ever face this situation. If they have enough generating capacity to meet their peak loads, they can usually get the fuel to run the capacity as much as necessary. The Pacific Northwest, however, relies on hydroelectric generating plants for about two-thirds of its electricity. In a bad water year we can find ourselves with generating capacity adequate for our peak loads, but without enough water (fuel) to provide the total electricity needed.

This was the situation in 2000-2001, and the longer-term buybacks that utilities negotiated with their customers were reasonable responses to the situation. We faced an unusually bad supply situation in those years, however. We shouldn't expect to see these longer term buybacks used often even here in the Pacific Northwest, and hardly ever in other regions with primarily thermal generating systems.

### *Experience*

As high wholesale prices and the drought in the Pacific Northwest continued, utilities began to negotiate longer-term reductions in load with their customers. BPA found the largest reductions, mostly in aluminum smelters but also in irrigated agriculture. Idaho Power, PGE, the Springfield Utility Board (SUB) and the Chelan Public Utility District negotiated longer-term reductions with large industrial customers. Idaho Power, Grant County Public Utility District and Avista Utilities negotiated longer-term reductions with irrigators. The total of these buybacks varied month to month but reached a peak of around 1,500 MW in the summer of 2001.

There were also "standing offer" buybacks offered by several utilities in 2001. Most of these offers were to pay varying amounts for reductions compared to the equivalent billing period in 2000. The general structure of these offers was a further savings on the bill if the reduction in use was more than some threshold. For example, a "20/20" offer gave an additional 20 percent off the bill if the customers' use was less than 80 percent of the corresponding billing period in 2000. Since the customer's bill was reduced more or less proportionally to his usage already, this amounted to roughly doubling his marginal incentive to save electricity. Utilities usually reported that many customers qualified for the discounts. However, attributing causation to the standing offers vs. quick-response conservation programs many utilities were running at the same time vs. governors' appeals for reductions, etc. is very difficult.

The Eugene Water and Electric Board had a standing offer that based its incentives more directly on current market prices. From April through September of 2001, 29 of EWEB's larger customers were paid for daily savings (compared to the corresponding day in 2000) based on the daily Mid-Columbia trading hub's quotes for on-peak and off-peak energy. Customers reduced their use of electricity by an average of 14 percent, and divided a total savings of $6.5 million with the utility.

*Assessment*

Generally, buybacks avoid some of the problems of price mechanisms, and they have been successful in achieving significant demand response. Utilities have been able to identify and reach contract agreements with many candidates who have the necessary metering and communication capability. . The notification, bidding and confirmation processes have worked. Utilities have achieved short term load reductions of over 200 MW. Longer-term reductions of up to 1,500 MW were achieved in 2001 when the focus changed because of the energy shortages of the 2000-2001 water year.

In principle, the marginal incentives for customers to reduce load should be equivalent, but buybacks have some limitations relative to price mechanisms. Buybacks generally impose transaction costs by requiring agreement on base levels of use, contracts, notification, and explicit compensation. The transaction costs mean that they tend to be offered to larger customers or easily organized groups; significant numbers of customers are left out. Transaction costs also mean that some marginally economic opportunities will be passed--there may be times when market prices are high enough to justify some reduction in load, but not high enough to justify incurring the transaction cost necessary to obtain the reduction through a buyback.

## *Demand side reserves*

Another option for achieving demand response is "demand side reserves," which can be characterized as options for buybacks.

The power system needs reserve resources to respond to unexpected problems (e.g. a generator outage or surge in demand) on short notice. Historically these resources were generating resources owned by the utility and their costs were simply included in the total costs to be recovered by the utility's regulated prices. Increasingly however, other parties provide reserves through contracts or an "ancillary services" market. In such cases, the reserves are compensated for standing ready to run and usually receive additional compensation for the energy produced if they are actually called to run.

The capacity to reduce load can provide much the same reserve service as the capacity to generate. The price at which the customer is willing to reduce load, and other conditions of his participation (e.g. how much notice he requires, maximum and/or minimum periods of reduction) will vary from customer to customer. In principle, customers could offer a differing amount of reserve each day depending on his business situation.

The California Independent System Operator administers an ancillary services market that has used demand side reserves in some cases. Their early experience has been that most load cannot be treated the same as generating reserve in every detail, but that demand side reserve can be useful. Analysis of their experience is continuing.

The metering and communication equipment requirements, and the need for an agreed-upon base level of use, are essentially the same for demand side reserve participants as for short term buyback participants. Demand side reserve programs may have a potential advantage to the extent that they can be added to an existing ancillary services market, compared to setting up stand-alone buyback programs.

### *Payments for reductions -- interruptible contracts*

Utilities have negotiated interruptible contracts with some customers for many years. An important example of these contracts was Bonneville Power Administration's arrangement with the Direct Service Industries, which allowed BPA to interrupt portions of the DSI load under various conditions. In the past, these contracts have usually been used to improve reliability by allowing the utility to cut some loads rather than suffer the collapse of the whole system. Those contracts were used very seldom. Now these contracts can be seen as an available response to price conditions as well as to reliability threats. We can expect that participants and utilities will pay close attention to the frequency and conditions of interruption in future contracts, and we can imagine a utility having a range of contract terms to meet the needs of different customers.

### *Payments for reductions -- direct control*

A particularly useful form of interruptible contract gives direct control of load to the utility. Part of BPA's historical interruption rights for DSI loads was under BPA direct control. Not all customers can afford to grant such control to the utility. Of those who can, some may only be willing to grant control over part of their loads. Direct control is more valuable to the utility, however, since it can have more confidence that loads will be reduced when needed, and on shorter notice. Advances in technology could mean expansion of direct control approaches. The ability to embed digital controls in residential and commercial appliances and equipment make it possible to, for example, set back thermostats somewhat during high cost periods. While the individual reductions are small, the aggregate effect can be large. Consumers typically have the ability to override the setbacks. Puget Sound Energy carried out a limited test of controlling thermostat setback. Most consumers were unaware that any setback had occurred. The adoption of advanced metering technologies for other reasons will facilitate the use of direct control.

## ***Summary of alternative mechanisms***

Table 1 summarizes the alternative mechanisms and some of their attributes. Staff has offered subjective evaluations of each mechanism to stimulate comment and discussion.

*Table 1:*

*Types of Demand Response Programs and Attributes*

| Type of Program | Primary Objective: Capacity or Energy? | Time span | Size of Potential Resource | Flexible for Customer? | Flexible for Utility? | Predictable, Reliable Resource for Utility? |
|---|---|---|---|---|---|---|
| Real-time Prices | Both | One hour to several hours | +++ (depending on extent applied) | ++ | ++ | - |
| Time-of-use Prices | Capacity | Several hours | ++ | ++ | -- | - |
| Short Term Buybacks | Capacity | Several hours (possibly more) | ++ | ++ | + | + (once customer committed) |
| Long Term Buybacks | Energy | Several months | + | -- | -- | +++ |
| Standing Offer (e.g. 20/20) | Energy | Several months | + | ++ | -- | - |
| Demand side reserves | Capacity | Hours or longer | + | ++ | ++ | + |
| Interruptible Contracts | Capacity | Hours or longer | + | -- | ++ | ++ |
| Direct Control | Capacity | Minutes, Hours or longer | + | --- | +++ | +++ |

For example, staff's evaluation suggests that time-of-use prices:

- have significant potential for load reduction, but somewhat less than real-time prices;
- have the primary objective of reducing capacity requirements;
- are flexible for the customer -- the customer can decide how to respond depending on his real time situation;
- are relatively inflexible for the utility -- it is committed to the price structure in advance for an extended period;
- is not a very predictable resource for the utility – customers' response may vary from one day to the next (although more experience may help the utility predict that response more accurately).

Or, long term buybacks:

- have significant potential for load reduction, but less than time-of-use prices;
- have the primary objective of reducing energy requirements;
- are relatively inflexible for both customer and utility (because they are both committed to the terms of the buyback over a long term)
- are a predictable resource for the utility (once the contract is signed).

## ***Potential benefits of demand response***

Does the improvement of demand response represent a significant resource in the Pacific Northwest? Is the effort required for an improvement worthwhile? We're proposing to estimate the potential size of the resource and its potential value as part of the analytical work of the 5th Power Plan.

### *Potential size of resource*

What does experience suggest about the potential demand response in the Pacific Northwest? The data don't support a precise estimate but even a rough estimate can be useful. We're interested both because we need to decide whether the topic merits more work, and because an estimate of demand response helps us project the future course of generation construction and electricity prices.

One way to arrive at a rough estimate is to use price elasticities that have been estimated based on response to real-time prices elsewhere. Though we don't expect to rely on real-time prices, other instruments can provide similar incentives[5], resulting in similar demand reductions.

Price elasticities have been estimated based on data from a number of American and other utilities. The elasticities vary from one customer group and program to another, from near zero to greater than -0.3. For example, we can conservatively assume:

1. a -0.05 elasticity as the lower bound of overall consumer responsiveness,

[5] For example, a customer with conventional electricity rate of $0.08/kWh might get a buyback offer of $0.20/kWh in a given hour. A real-time price of $0.28/kWh would offer a similar incentive to reduce use in that hour – in either case he is better off by $0.28 for each kWh reduction.

2. a \$50/ MWh average cost of electricity divided equally between energy cost and the cost of transmission and distribution,
3. a \$100/MWh cost of incremental energy at the hour of summer peak demand, and
4. a 30,000 MW regional load at that hour.

For these conditions, we can calculate a lower bound estimate of the amount of load reduction that could result from real-time prices to be 1,343 MW[6]. Actual responsiveness could be greater – actual prices seem quite likely to be higher on some occasions. In either of these cases, the load reduction will be more

As part of the analysis for the 5th Power Plan, this very rough estimate could be refined, although the basic conclusion to be drawn seems clear – even if this estimate is wrong by a factor of 2 or 3, the potential is significant, and demand response merits serious examination.

## *Value of the resource*

An estimate of the value of demand response to the power system must take interactions among generating plants into account. For example, one major benefit of demand response would be any reduction in generating capacity that is made possible. But that reduction will depend on the sharing of generating capacity among utilities across the western wholesale market. This sharing will vary depending on variation in weather-sensitive demand and variation in hydro conditions.

A preliminary analysis using GENESYS taking these interactions into account estimates that a marginal simple-cycle natural gas-fired turbine operates less than 100 hours per year, averaged across a 300-game representation of water and weather variability. At that number of hours of operation, the cost of the turbine's output is around \$1,000 per MWh. The power system could afford to pay up to that amount to avoid the necessity of building the generator by reducing load at the appropriate times. We need to expand on this analysis to test these conclusions and to expand on them, but between GENESYS and Aurora, the Council has the tools to do so.

## *Cost of the resource*

Demand response would also have costs. The form costs take would depend on the form of incentive chosen to stimulate demand response. In the case of price mechanisms, the costs fall on customers directly. In the case of compensated reductions such as buybacks, the costs are paid by the power system (but are ultimately collected from customers, of course). In addition, some forms of demand response might impose environmental costs (e.g. reducing load on the power system by using onsite generation that produces more emissions). A comprehensive accounting of costs would take the societal perspective and include both financial and environmental costs.

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[6] Using the convention that the percentage changes in demand and price are $\ln(D_2/D_1)$ and $\ln(P_2/P_1)$, respectively, we can calculate the new demand $D_2 = \exp(-0.05*\ln(125/50) + \ln(30{,}000)) = 28{,}657$ MW. The reduction from the initial peak demand of 30,000 MW is 1,343 MW.

## ***Questions for public comment***

The Council invites comments on this issue paper and the general topic of stimulation of demand response. In particular, the Council would appreciate detailed comments on the following questions:

1. Has the paper neglected any important alternative for encouraging demand response?
2. What advantages and drawbacks do you see for each of the mechanisms for stimulating demand response (real-time and time-of-use prices, buybacks, demand reserves, etc.) examined in the paper?
3. What variations of these mechanisms to you think offer particular advantages?
4. What combinations of these mechanisms to you think offer particular advantages?
5. What further analysis is needed to understand the relative advantages and limitations of the alternatives?
6. Are there additional sources of data that would help shed light on the costs and value of demand response?
7. How can the Council best cooperate with the region's regulatory bodies to study and encourage demand response?