

# Chapter 5: Demand Response

Summary of Key Findings .....	1
Demand Response in the Fifth Power Plan.....	2
Progress Since the Fifth Power Plan.....	3
Demand Response in the Sixth Power Plan.....	3
Estimation of Available Demand Response .....	3
Demand Response Assumptions.....	5
Studies of Potential .....	5
Experience.....	6
Council Assumptions .....	8
Caveats for Demand Response Assumptions .....	11
Ongoing Analysis with the Regional Portfolio Model .....	11
Pricing Structure .....	12
Providing Ancillary Services with Demand Response .....	12
Contingency Reserves.....	13
Regulation and Load Following.....	13

## SUMMARY OF KEY FINDINGS

The Council’s definition of demand response (DR) is a voluntary and temporary change in consumers’ use of electricity when the power system is stressed. The change in use is usually a reduction, although there are situations in which an increase in use would relieve stress on the power system and would qualify as DR.

Demand response could provide value to our power system in four forms. It can provide a form of peaking capacity by reducing load a few hours a year at peak load. It can provide contingency reserves, standing ready to interrupt load if unscheduled generation outages occur. Some demand response could provide flexibility reserves (e.g. load following) by decreasing or increasing load as needed to accommodate small errors in scheduling in virtually all hours of the year. Finally, some demand response could absorb and store energy when its cost is low and return the energy to the system a few hours later when its value is higher.

This plan assumes, based on experience in the region and elsewhere, that the achievable technical potential for demand response in the region is around 5 percent of peak load over the 20-year plan horizon. The plan assumes 1,500 to 1,700 megawatts of load reductions in the winter and summer, respectively, and 2,500 to 2,700 of load reductions together with dispatchable standby generation. This achievable technical potential was included in analysis by the Council’s regional portfolio model<sup>1</sup> to determine how much demand response is included in the preferred resource portfolios identified by the model.

The region still lacks the experience with demand response to construct a detailed and comprehensive estimate of its potential. To make that estimate possible, the region will need to conduct a range of pilot programs involving demand response. These pilots should pursue two general objectives, research and development/demonstration.

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<sup>1</sup> See Chapter 9 for a description of this analysis.

“Research pilot programs” should explore areas that have not been tried before. These pilot programs should be regarded as programs to buy essential information. They should not be designed or evaluated based on how cost effective each pilot is on a stand-alone basis, but rather based on how much the information gained from each pilot will contribute to a long run demand response strategy that is cost effective overall. Ideally regional utilities and regulators will coordinate these research pilots to avoid duplication of effort. Regulators should allow cost recovery of pilots that contribute to such a strategy.

The region should also pursue “development and demonstration pilot programs” that are designed to test acquisition strategies and customers’ reactions to demand response programs that have been proven elsewhere. These pilots will allow the region to move to full-scale acquisition of some elements of demand response while the research pilots expand the potential by adding new elements. The development and demonstration pilots should be designed and evaluated with cost effectiveness in mind, but with the recognition that the product of these pilots includes experience that can make the acquisition program more cost effective.

Both the research pilots and the development and demonstration pilots should include projects to test the practicality of demand response as a source of ancillary services.

## **DEMAND RESPONSE IN THE FIFTH POWER PLAN**

The Council first took up demand response as a potential resource<sup>2</sup> in its Fifth Power Plan.<sup>3</sup> The Fifth Plan explained that concern with demand response rises from the mismatch between power system costs and consumers’ prices. While power system costs vary widely from hour to hour as demand and supply circumstances change, consumers generally see prices that change very little in the short term. The result of this mismatch is higher consumption at high cost times, and lower consumption at low cost times, than is optimal. The ultimate result of the mismatch of costs and prices is that the power system needs to build more peaking capacity than is optimal, and uses base load generation less than is optimal. Programs and policies to encourage demand response are efforts to correct these distortions.

The Fifth Plan described pricing and program options to encourage demand response, made a very rough estimate of 2,000 MW of demand response that might be available in the Pacific Northwest over the 2005-2025 period, and described some estimates of the cost effectiveness of demand response. The Plan concluded with an Action Plan to advance the state of knowledge of demand response.

The Fifth Power Plan’s treatment of demand response is laid out in more detail in Appendix H of this plan, with references to relevant parts of the Fifth Plan.

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<sup>2</sup> According to the strict legal definitions of the Northwest Power Act, demand response is probably not a “resource” but a component of “reserves.” For ease of exposition, the Plan refers to demand response as a resource in the sense of the general definition of the word - “a source of supply or support.”

<sup>3</sup> The Fifth Power Plan is posted at <http://www.nwcouncil.org/energy/powerplan/5/Default.htm>, with Chapter 4 on DR at [http://www.nwcouncil.org/energy/powerplan/5/\(04\)%20Demand%20Response.pdf](http://www.nwcouncil.org/energy/powerplan/5/(04)%20Demand%20Response.pdf) and Appendix H on DR at [http://www.nwcouncil.org/energy/powerplan/5/Appendix%20H%20\(Demand%20Response\).pdf](http://www.nwcouncil.org/energy/powerplan/5/Appendix%20H%20(Demand%20Response).pdf)

## ***Progress Since the Fifth Power Plan***

Since the release of the Fifth Plan, the region has made progress on several fronts. Idaho Power, PacifiCorp and Portland General Electric have expanded existing demand response programs. Portland General Electric and Idaho Power have begun to install advanced metering for all their customers, which facilitates demand response programs and enables time-sensitive pricing. Many utilities in the region are now treating demand response as an alternative to peaking generation in their integrated resource plans.

The Council and the Regulatory Assistance Project (RAP) have worked together to coordinate the Pacific Northwest Demand Response Project (PNDRP), composed of parties interested in the stimulation of demand response in the region. The initial focus of PNDRP has been on three primary issues; defining cost effectiveness of demand response, discussing a role for pricing, and considering the transmission and distribution system costs that can be avoided by demand response.

PNDRP adopted guidelines for cost effectiveness evaluation that are included in Appendices H-1 and H-2. Agreement on these guidelines is a major accomplishment by the region. These cost effectiveness guidelines provide an initial valuation framework for demand response resources and should be considered as a screening tool by state commissions and utilities in the Pacific Northwest. PNDRP has begun the consideration of price structures encouraging demand response.

The Council has extended its analysis of demand response, examining the effect of the cost structure of demand response (i.e. high fixed cost/low variable cost as compared to low fixed cost/high variable cost) on its attractiveness in resource portfolios. This analysis takes into account the benefits of demand response in reducing risk, which other analyses tend to overlook.

The region's system operators have also become increasingly concerned with the system's ability to achieve minute-to-minute balancing of increasingly peaky demands for electricity against generating resources that include increasing amounts of variable generation such as wind. Demand response is recognized as a potential source of some of the "ancillary services" necessary for this balancing.

These areas of progress are covered in more detail in Appendix H.

## **DEMAND RESPONSE IN THE SIXTH POWER PLAN**

### ***Estimation of Available Demand Response***

The region has gained much experience in the estimation of conservation potential over the last 30 years but demand response analysis is still in its infancy. For conservation the general approach has been to compile a comprehensive list of conservation measures, analyze their costs and effects, and arrange them in order of increasing cost per kilowatt-hour. Given the resulting

supply curve, planners can identify all conservation measures that cost less than the marginal generating resource.<sup>4</sup>

Estimating demand response potential using a similar approach makes perfect sense, and it is the Council's strategy. However, demand response presents some unique problems to this approach. Some of the features that make estimating a supply curve for demand response more complex than estimating one for conservation are listed below and treated in more detail in Appendix H.

- The amount of available demand response varies with season, time of day, and power system conditions. For example, on an August afternoon customers can accept higher temperatures to reduce air-conditioning load, but that response is not available when there is little or no air-conditioning load, such as the cool night hours in most months.
- Demand response can provide a variety of services to the power system (e.g. peak load service, contingency reserves, regulation, load following) as described in Appendix H. Each of these services will have its own supply, which will vary over time. To estimate a supply curve for demand response to help meet peak load, we must consider whether some of the same customers and actions will be providing contingency reserves or load-following services as well -- otherwise we run the risk of counting the same actions twice in separate supply curves.
- The costs of demand response are more complex than those of conservation. The costs of conservation are generally fixed, as are the amount and schedule of energy savings. In contrast, demand response often comes with fixed and variable cost components, and requires a "dispatch" decision (by the utility or the customer) to reduce energy use at a particular time. The variable cost of demand response is the major factor in that decision.
- Displaying demand response in the normal cost vs. quantity format of a supply curve requires some sort of aggregation of the fixed and variable costs into a single measure, such as the "average cost per megawatt of a demand response program that operates 100 hours per year." But a supply curve displaying such aggregated costs may distort critical information about a demand response program. In this example, depending on the variable cost of the program, it may or may not make sense to operate it the assumed 100 hours per year.
- Estimates of conservation potential have usually depended on understanding the performance of "hardware" such as insulation and machinery, predictable through an engineering analysis. Estimates of demand response, on the other hand, depend more on understanding the behavior of consumers exchanging comfort or convenience for compensation. This behavior is not so predictable without actual experience, which so far is quite limited.
- The economics of demand response will be powerfully influenced by technological change, particularly the development of "Smart Grid" technologies,<sup>5</sup> which promise to make more and cheaper demand response available. Such technological change is impossible to predict in specifics, but it seems inevitable that there will be significant

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<sup>4</sup> The methodology for estimating conservation potential is described in more detail in Appendix E.

<sup>5</sup> See Appendix K

change over the next 20 years, and that the change will make demand response more attractive.

## ***Demand Response Assumptions***

With the limited experience available now, a balance must be struck between the precision and the comprehensiveness of estimates of potential demand response. Precise estimates need to be limited to customers, end uses, and incentives where there is experience. These estimates necessarily exclude some possibilities that are virtually certain to have significant demand potential, eventually. Comprehensive estimates avoid this tendency to underestimate potential by including possibilities where there is less experience, and the estimates are therefore less precise.

Each of these approaches has its place. An estimate for a near-term implementation plan must focus on the “precise” end of this spectrum. An estimate for a long run planning strategy, such as the Council’s, should focus on the “comprehensive” end. The long-term goal should be to expand experience with various forms of demand response to the point that a precise estimate of available demand response is also comprehensive. It’s fair to say this goal has been reached in the estimation of conservation potential, but has not yet been reached for demand response, at least for the region as a whole.

### **Studies of Potential**

With these caveats about the limitations of estimating potential demand response based on limited experience, the regional discussions and analysis since the Fifth Power Plan have advanced our understanding of the resource. In the Northwest, studies of potential have been contracted by the Bonneville Power Administration, PacifiCorp, Portland General Electric, and Puget Sound Energy.

Global Energy Partners and The Brattle Group performed Bonneville’s study. The study estimated demand response available through 2020 and included direct load control of residential and small commercial customers, an “Emergency Demand Response”<sup>6</sup> program for medium and large commercial and industrial customers, capacity market options,<sup>7</sup> customers’ participation in a market for ancillary services, and two pricing options. The study estimated potential demand response for each of these options. The estimates took each option alone, with no attempt to estimate the interactions among them -- as a result, adding the estimates together risks double counting some demand response.

Council staff extended this study’s results for direct load control, emergency demand response, and capacity market options proportionally to the entire region by assuming that these programs did not double count potential so that they could be summed. The upper end of the range of regional estimates resulting from this extension amounted to about 1.4% of peak load in the winter and 2.2% of peak load in the summer in 2020.

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<sup>6</sup> Customers are offered payment for load reductions during system events, but are not penalized if their usage does not change.

<sup>7</sup> Customers are paid to commit to reduce loads when required by the power system, and receive additional payment when they are actually called to reduce load.

Puget Sound Energy (PSE) commissioned a study by Cadmus in 2009 that is still being revised. Preliminary results indicate that about demand response equal to about 3 percent of 2029 forecast peak load will be available.

The studies of demand response potential for PacifiCorp and Portland General Electric had not been completed at the time the Draft Sixth Power Plan was released, but are expected soon. Their results may be available in time to include in the final version of the Sixth Power Plan.

## Experience

In addition to estimates of demand response available in the future, there is considerable experience around the country with demand response that has been acquired or is in the last stages of acquisition by utilities and system operators. This experience gives some idea of the total amount of demand response that can be expected when utilities pursue it aggressively over a period of time. Table 5-1 shows some of this experience. It also shows some scheduled increases in demand response over the next few years; these schedules are based on expansion of existing programs or signed contracts that make the utilities quite confident that the scheduled demand response will be realized.

In the Pacific Northwest, PacifiCorp has been quite active in acquiring demand response. By 2009, PacifiCorp expected to have over 500 megawatts of demand response, including direct load control of air conditioning and irrigation, dispatchable standby generation, and interruptible load. PacifiCorp also calls on demand buy back and “Power Forward.”<sup>8</sup> These last two components are considered non-firm resources, but have combined to provide reductions in the 100 to 200 megawatts range in addition to the 500 megawatts of firm megawatts. The demand response, compared to PacifiCorp’s forecasted peak load of 9,800 megawatts for 2009, means that PacifiCorp has more than 5 percent of peak load in firm demand response, and another 1-2 percent in non-firm demand response.

Idaho Power had about 60 megawatts of demand response in 2008, made up of direct load control of residential air conditioning and timers on irrigation pumps. The company is committed to achieving a total of 307 megawatts by 2013, pending the expected approval of this plan by the Idaho Public Utility Commission. This level of demand response would be accomplished by converting much of their irrigation demand response to dispatchable<sup>9</sup> and adding demand response from the commercial and industrial sectors. This level would be 8.1 percent of their projected peak demand in 2013 of 3,800 megawatts. In the longer run the company is planning on reaching 500 megawatts of demand response by 2021, which would make demand response equal to 11.4 percent of its 2021 forecasted peak demand of about 4,400 megawatts.

Portland General Electric had 53 MW of dispatchable standby generation in place in 2009 and expects to have 125 megawatts in place by 2012. PGE is using it to provide contingency reserve, which only operates when another resource is unexpectedly unavailable. This means that while this generation is licensed to operate 400 hours per year, it actually operates a much smaller

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<sup>8</sup> Power Forward is a program coordinated with the governor’s office in Utah that makes public service announcements asking for voluntary reductions from the general public when the power system is stressed. Estimated response varies, but has been as much as 100 megawatts.

<sup>9</sup> Instead of having reductions on fixed schedules, some customers on Monday, some on Tuesday, etc., the company would be able to call on all of the participating customers at the same time when the need arises.

number of hours per year. PGE also has received responses from a Request for Proposals (RFP) asking for proposals to provide demand response up to 50 megawatts by 2012. These responses make the company confident that it can actually secure 50 megawatts of new demand response by 2012. Finally, PGE has 10 megawatts of interruptible contracts with industrial customers. The sum of these three components, 185 megawatts, is equal to 4.1 percent of the company's projected peak load of 4500 megawatts in 2012.

Elsewhere in the country, the New York Independent System Operator (NYISO) has been enlisting and using demand response in its operations for several years. The NYISO currently has about 2,300 megawatts of demand response participating in their programs. About 2,000 megawatts of that total are subject to significant penalties if they don't deliver promised reductions when called upon, so should be considered firm resources. About 300 megawatts of the total are voluntary and are better counted as nonfirm, although the typical response of these resources is around 70 percent, according to NYISO staff. The 2,000 megawatts of firm demand response amounts to about 5.9 percent of the NYISO's expected 2009 peak load of 34,059 megawatts. Adding the expected 70 percent of the 300 megawatts of non firm demand response would raise the expected total demand response to 2,210 megawatts, or 6.5 percent of peak load.

The New England Independent System Operator (ISO) cites 1,678 megawatts of demand response without dispatchable standby generation and 2278 megawatts of demand response with dispatchable standby generation in 2007. These figures are 6.1 and 8.3 percent of the ISO's average weather summer peak load of 27,400 megawatts, (winter 22,775 megawatts).<sup>10</sup>

PJM Interconnection is a Regional Transmission Organization that manages a wholesale market and the high-voltage transmission system for 13 mid-Atlantic Coast and Midwest states and the District of Columbia. PJM estimates 4460 megawatts of demand response in its control area in 2008 compared to a forecasted peak load of 137,950 megawatts<sup>11</sup> or about 3.2 percent of peak load. There may be some demand response in the utilities of states that have been recently added to PJM (Illinois, Ohio, Michigan, and Kentucky) that is not included in this total.

California dispatched 1,200 MW of interruptible load on July 13, 2006 to help meet a record peak load of 50,270 MW. California had 1,200 megawatts more of DR available if it had been needed.<sup>12</sup> The 2,400 megawatts of total demand response used and available amounted to 4.8 percent of actual peak load. By 2011 the three investor-owned utilities expect to have at least 3,500 megawatts of demand response available, or 6.5 percent of the California Energy Commission's forecast of the three utilities' peak loads total for 2011 (53,665 megawatts).<sup>13</sup>

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<sup>10</sup>[http://www.iso-ne.com/trans/rsp/2008/rsp08\\_final\\_101608\\_public\\_version.pdf](http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf) Table 5-7 page 47, Table 5-8 page 49, and Table 3-3 pg 25

<sup>11</sup> <http://www.pjm.com/documents/~media/documents/presentations/pjm-summer-2008-reliability-assessment.ashx>

<sup>12</sup> "Harnessing the Power of Demand How ISOs and RTOs Are Integrating Demand Response into Wholesale Electricity Markets" Markets Committee of the ISO/RTO Council October 16, 2007

<sup>13</sup> The California Energy Commission's forecast of the three utilities peak demands can be found at <http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF>, in the Form 4 table for each utility.

**Table 5-1: Demand Response Achieved by System Operator**

System Operator	Year Achieved/ Scheduled	Demand Response as % of Peak Load (Achieved/Scheduled)
PacifiCorp	2009	5.1
Idaho Power	2008/2013	1.9/8.1
Portland General Electric	2009/2012	1.4/4.1
New York ISO	2009	5.9 firm, 6.5 expected
New England ISO	2007	8.3
PJM	2008	3.2
California ISO	2006/2011	4.8/6.5

### Council Assumptions

Based on these study results and experience elsewhere, the Council adopted cost and availability assumptions for several demand response programs. For this analysis of long-term planning strategies, the assumptions lean more toward the comprehensive end of the “precise/comprehensive” spectrum. These assumptions were used in the regional portfolio model to analyze the impact on expected system costs and risk of alternative resource strategies. Accordingly, they can be regarded as achievable technical potential, with the portfolio model analysis determining the programs and amounts that are cost- and risk- effective.<sup>14</sup>

The Council based its assumptions in part on the evidence that demand response of at least 5 percent of peak load has been accomplished by a number of utilities and system operators in periods of five to ten years, so that accomplishing a similar level of total demand response over 20 years in our region is reasonable. The total assumed potential brackets the 5 percent level, depending on whether the dispatchable standby generation is included or not. Without dispatchable standby generation, the assumed potential is 1,500 megawatts in the winter and 1,700 megawatts in the summer (about 3.8 percent and 4.3 percent of the forecast 40,000 megawatt peak load forecast for 2030, respectively). With dispatchable standby generation the totals are 2,500 megawatts in the winter and 2,700 megawatts in the summer, or 6.3 percent and 6.8 percent of forecast peak load, respectively.

The assumptions are summarized in Table 5-2. Three further points are worth making about these assumptions: First, they include demand response that has already been achieved, amounting to more than 160 MW by 2009. Second, they include announced plans to acquire demand response by regional utilities amounting to more than 350 MW. Finally, these assumptions are used as long run assumptions for the portfolio model, and are not targets for short run utility implementation planning. Targets for implementation result from the portfolio analysis and a strategy to accumulate experience with demand response, described in the Action Items of this chapter, the Implementation Plan and in Chapter 9.

<sup>14</sup> For more information about the working of the portfolio model, see Chapter 8.

**Table 5-2: Demand Response Assumptions**

Program	MW	Fixed Cost	Variable Cost (hours/year limit)	Season available
<b>Air Conditioning (Direct Control)</b>	200	\$60/kW-year	100 hours/year	Summer
<b>Irrigation</b>	200	\$60/kW-year	100 hours/year	Summer
<b>Space heat/Water heat (Direct Control)</b>	200	\$100/kW-year	50 hours/year	Winter
<b>Aggregators (Commercial)</b>	450	\$70/kW-year	\$150/MWh 80 hours/year	Summer + Winter
<b>Interruptible Contracts</b>	450	\$80/kW-year	40 hours/year	Summer + Winter
<b>Demand Buyback</b>	400	\$10/kW-year	\$150/MWh	All year
<b>Dispatchable Standby Generation</b>	1,000	\$20-\$40/kW-year	\$175-300/MWh	All year

The resource programs are described below.

**Direct load control for air conditioning.** Direct control of air conditioners, by cycling or thermostat adjustment, is one of the most common DR programs across the country, and is most attractive in areas where electricity load peaks in the summer. The Pacific Northwest as a whole is still winter-peaking, but new forecasts show the region's summer peak load growing faster than winter peak load. PacifiCorp's Rocky Mountain Power division and Idaho Power already face summer-peaking load. The two utilities have acquired and exercised more than 100 peak megawatts of demand response from direct control of air conditioning. Most of those 100 megawatts are outside the Council's planning region, in Utah. The assumption for the portfolio model analysis is that there will be 200 megawatts of this resource in the region by 2030. Based on PacifiCorp's experience, the resource is assumed to cost \$60 per kilowatt a year and to be limited to 100 hours per summer.

**Irrigation.** PacifiCorp and Idaho Power are currently reducing irrigation load by nearly 100 megawatts by scheduling controls. Both utilities are in the process of modifying their programs to give them more control of the resource, increasing the load reduction available when the utilities need it. There is significant irrigation load elsewhere in the region as well. The assumption for the portfolio model analysis is that 200 megawatts of irrigation DR will be available by 2030. Based on PacifiCorp's experience, this resource is assumed to cost \$60 per kilowatt a year, limited to 100 hours per summer. Since the adoption of these assumptions for the draft plan, the Council has learned that the planned acquisition of demand response from irrigation by Idaho Power alone would exceed 200 megawatts. Experience this summer should support the revision of this assumption before the release of the final version of the Sixth Plan.

**Direct load control of space heat and water heat.** While there has been some experience with direct control of water heating in the region, experience with direct control of space heating is limited. The assumption for the portfolio model analysis is 200 megawatts, at \$100 per kilowatt a year for a maximum of 50 hours per winter. These assumptions are informed by the Global Energy and Brattle Group study for Bonneville. The megawatt assumption is about half the study's estimate for residential and commercial direct control programs when the study's most optimistic result is extended from Bonneville's customers to the whole region.

**Aggregators.** Increasingly, aggregators facilitate demand response by acting as middlemen between utilities or system operators on the one hand and the ultimate users of electricity on the other. These aggregators are known by a variety of titles such as “demand response service providers” for the independent system operators in New York and New England and “curtailment service providers” for the regional transmission organization in the Mid-Atlantic states (PJM). Aggregators could recruit demand response from loads already described here, in which case aggregators would not add to the total of available demand response. But in the Council’s analysis, aggregators are assumed to achieve additional demand response by recruiting commercial and small industrial load that is not otherwise captured. This resource is assumed to be 450 megawatts. The assumed fixed costs of \$70 a kilowatt per year and variable costs of \$150 per megawatt hour are based on conversations with aggregators. The resource is assumed available for a maximum of 80 hours during the winter or summer.

**Interruptible contracts.** Interruptible contracts offer rate discounts to customers who agree to have their electrical service interrupted under defined circumstances. This is an old mechanism for reducing load in emergencies, although in some cases it became a de facto discount with no expectation that the utility would ever actually interrupt service. These contracts are usually arranged with industrial customers, and PacifiCorp has about 300 megawatts of interruptible load under such contracts. The assumption for the portfolio analysis is that 450 megawatts will be available by 2030 at a fixed cost of \$80 a kilowatt per year, limited to 40 hours a year. The costs of existing interruptible contracts are considered proprietary, so the Council’s cost assumption is based on conversations with aggregators.

**Demand buyback.** Utilities with demand buyback programs offer to pay customers for reducing load for hours-long periods on a day-ahead basis. Early in the 2000-2001 energy crisis, Portland General Electric conducted a demand buyback program and had significant participation. Other utilities were developing similar programs, but the idea of buying back power for several hours a day was overtaken by high prices in all hours, and deals were made that bought back power for months rather than hours.<sup>15</sup> Since 2001, the most active buyback program has been PacifiCorp’s program. Buyback programs still exist elsewhere in principle, but have not been maintained in a ready-to-use state. While this option could be replaced by expanded aggregator programs, the assumption for the Council’s portfolio model analysis is that demand buyback programs with customers who deal directly with utilities (not through aggregators) could amount to 400 megawatts by 2030, at fixed costs of \$10 a kilowatt per year and variable costs of \$150 per megawatt hour available all year. These cost assumptions are based on the experience of Portland General Electric with its Demand Exchange program in 2000-2001.

**Dispatchable standby generation.** This resource is composed of emergency generators in office buildings, hospitals, and other facilities that need electric power even when the grid is down. The generators can also be used by utilities to provide contingent reserves, an ancillary service. Ancillary services are not simulated in the portfolio model, but dispatchable standby generation is nevertheless a form of demand response that has significant potential and cannot be overlooked. Portland General Electric has pursued this resource aggressively, taking over the maintenance and testing of the generators in exchange for the right to dispatch them as reserves when needed. PGE has 53 megawatts of dispatchable standby generation available in early 2009, and plans to have 125 megawatts by 2012. This potential will grow over time as more

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<sup>15</sup> These longer-term buybacks were predominantly from Direct Service Industries (DSIs).

facilities with emergency generation are built and existing facilities are brought into the program. The Council assumes that at least 300 megawatts would be available in PGE’s service territory by 2030, and that the rest of the region will have at least twice as much, for a total of about 1,000 megawatts by 2030. Based on Portland General Electric’s program, cost assumptions are \$20-\$40 per kilowatt per year fixed cost and \$175-\$300 per megawatt hour variable cost, available all year.

The dispatchable standby generation component is expected to be used for contingency reserves, which cannot be represented in the regional portfolio model. The other programs were simulated in the portfolio model, with schedules based<sup>16</sup> on those in Table 5-3. The air conditioning and irrigation programs were treated as one program, since their costs and dispatch constraints were identical. That program, the space and water heating program, the aggregator’s component, and the interruptible contracts component were modeled similarly.

**Table 5-3: Schedule of Demand Response Programs in the Regional Portfolio Model (MW)**

	2009	2011	2013	2015	2017	2019	2021	2023	2025	2027	2029
<b>AC and Irrigation</b>	100	200	230	260	290	320	350	380	400	400	400
<b>Space and Water Heat</b>		10	20	30	40	50	70	90	120	160	200
<b>Aggregators</b>		20	60	100	150	200	250	300	350	400	450
<b>Interruptible Contracts</b>		50	100	150	200	250	300	350	400	450	450
<b>Demand Buyback</b>	70	100	130	160	190	220	250	290	340	370	400

### **Caveats for Demand Response Assumptions**

While the Council regards these assumptions as reasonable for the region as a whole, each utility service area has its own characteristics that determine the demand response available and the programs most cost effective in that area. Further, while the allocation of the total potential to individual components is reasonable, more experience could well support changes in the allocation. For example, ALCOA has offered to provide reserves as part of its proposed contract with Bonneville that could provide from about 15 MW to over 300 MW of demand response, depending on how much aluminum production capacity is operating and the level of compensation.<sup>17</sup> Cold storage facilities for food are estimated to use about 140 MWa of energy in the region and could be interrupted briefly without compromising the quality and safety of food. As the region gains more experience the Council will revise these assumptions.

### **Ongoing Analysis with the Regional Portfolio Model**

The portfolio model analysis described in Chapter 9 did not include demand response options in the “efficient frontier,” although some demand response options were included in portfolios that were quite close. The Council continues to regard demand response as a resource with

<sup>16</sup> Because of computer run time considerations, the schedules were treated as ten-year blocks. The portfolio model tried various combinations of these blocks to determine which combinations appeared in portfolios on the efficient frontier (see Appendix H). 200 MW of AC and irrigation were assumed adopted in all portfolios to reflect the level of program already adopted by PacifiCorp and Idaho Power, and the 400 MW demand buyback resource was assumed adopted in all portfolios based on its very low fixed costs. The remaining resources were modeled as “optional” i.e. the portfolio model could include them or not in trial portfolios.

<sup>17</sup> See Appendix H for details on the range of demand response potential from this possibility.

significant potential to reduce the cost and risk of a reliable power system. The Action Plan includes further work with the portfolio model to better reflect and estimate the value of demand response. The Action Plan also includes work to understand the potential of demand response to provide ancillary services; this latter work will need to use other approaches, since the portfolio model does not simulate the within-the-hour operation of the power system.

### ***Pricing Structure***

The Council is not making assumptions now about the amount of demand response that might be available from pricing structures. There is no doubt that time-sensitive prices can reduce load at appropriate times, but the region does not yet appear to be ready for general adoption of these pricing structures. While hourly meters are becoming more common, most residential customers don't yet have them, which makes time-of-day pricing, critical peak pricing, peak time rebates, and real time prices unavailable to those customers for the time being. Many in the region are concerned that some customers will experience big bill increases with different pricing structures. There is also the potential for double counting between demand response programs and any pricing structure initiatives.

The Pacific Northwest Demand Response Project, co-sponsored by the Council and the Regulatory Assistance Project (see Appendix H) is taking up the subject of pricing structures as a means of achieving demand response in the spring of 2009. In addition, Idaho Power and Portland General Electric are launching pilot projects for time-sensitive electricity prices, which can be expected to provide valuable experience not only for those utilities but the region as a whole.

### ***Providing Ancillary Services with Demand Response***

Demand response has usually been regarded as an alternative to generation at peak load (or at least near peak load), which occur a few hours per year. Because demand response for this purpose is only needed a few hours a year, customers need to reduce their usage for only a few hours a year. The load whose reduction provides such demand response need not be year-round load, as long as the load is present during hours when system load is at or near peaks (the most familiar example is air conditioning load for summer-peaking systems).

But demand response can do more than help meet peak load. It can help provide ancillary services such as "contingency reserves" and "regulation and load following." Historically ancillary services have not been considered a problem in the Pacific Northwest, but as loads have grown, and especially as wind generation has increased, power system planners and operators have become more concerned about ancillary services (see Chapter 11). Not all demand response can provide such services, since they have different requirements than meeting peak load.

Ancillary services are not simulated in the Council's portfolio model, so the potential value of demand response in this area will not be captured in the model's analysis. Nevertheless, the potential cannot be ignored, and the subject should be pursued as one of the demand response action items.

## Contingency Reserves

In some respects providing contingency reserves with demand response is similar to meeting peak loads with demand response. In both cases load reductions of a few hours per year are likely to meet the system need.<sup>18</sup>

But in other respects providing contingency reserves requires somewhat different demand response than meeting peak loads. To provide contingency reserves during non-peak load hours, demand response will require reductions in end use loads that are present in those hours. For example, residential space heating cannot provide reserves in the summer; residential air conditioning cannot provide reserves in the winter; but commercial lighting and residential water heating can provide contingency reserves throughout the year.

## Regulation and Load Following

Providing regulation and load following with demand response presents new requirements, compared to serving peak loads. Regulation is provided by generators that automatically respond to relatively small but quite rapid (in seconds) variations in power system loads and generation. Load following is provided by larger and slower adjustment in generator output in response to differences between the amount of prescheduled generation and the amount of load that actually occurs. Regulation and load following are needed in virtually every hour of the year, and require that generation be able to both increase and decrease.

Many customers who would be willing to provide demand response for meeting peak loads will not be available for regulation or load following. Providing regulation or load following with demand response would involve decreasing or increasing loads in virtually every hour.<sup>19</sup> Customers who are willing and able to decrease and increase use when the power system needs it will be harder to recruit than those who are willing and able only to decrease loads. Even if customers are asked only to decrease loads, many of them who could participate in, for example, a 100 hour per year demand response program that helps meet peak loads, will not be able participate in a load following program that requires thousands of actions per year.

While demand response that can provide regulation or load following will be a subset of all possible demand response, there may well be a useful amount. What kinds of loads make good candidates for this kind of demand response?

One example would be pumping for municipal water systems. Such systems don't pump continuously -- they fill reservoirs from which water is provided to customers as needed. The schedule of pumping can be quite flexible, as long as the reservoir level remains somewhere between specified minimum and maximum levels. For such a load, the water utility could specify the total amount of pumping for the next 24 hours based on its customers' expected usage, and allow the power system to vary the pumping over the period to help meet variation in the power system's loads (and variation of wind generation), as long as the total daily pumping

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<sup>18</sup> Contingency reserves are only called to operate when unexpected problems make the regularly scheduled resource unavailable, which occurs infrequently. Further, utilities are required to restore reserves within 105 minutes, so that the reserves' hours of operation per occurrence are limited. The result is that actual calls on contingency reserves are likely to be a few hours per year.

<sup>19</sup> It may be possible to achieve an equivalent effect by a combination of loads that can make reductions when necessary together with generation that can make reductions when necessary. One such combination could be DR and wind machines.

requirement is satisfied. Presently, accomplishing this degree of coordination between the power system and its customers is probably not practical, but with the Smart Grid's promise of cheaper metering and communication and more automated control, it could become so.

Another example is the charging load for plug-in hybrid cars (PHEVs). Many parties have suggested this possibility, and the general outline of these cars' potential interaction with the power system is common to most proposals -- the PHEVs' individual batteries together act as a large storage battery for the power system whenever they are connected to the grid, at home, at work or elsewhere. This aggregate battery accepts electricity when the cost of electricity is low (e.g. at night) and gives electricity back to the system when the cost is high (e.g. hot afternoons or during cold snaps). The Smart Grid could coordinate<sup>20</sup> this exchange.<sup>21</sup>

Domestic water heating is yet another example of a load that could be managed to provide regulation or load following to the power system. In this case we have enough information to make a rough estimate of how much flexible reserve could be available.<sup>22</sup> Current estimates of the region's total number of electric water heaters run in the 3.4 million range. If each of these heaters has heating elements of 4,500 watts, the total connected load is about 15,300 megawatt. Of course water heaters are not all on at the same time, but load shape estimates suggest that the total water heating load on the system ranges from about 400 megawatts to about 5,300 megawatts, depending on the season, day and hour.

In normal operation water heaters' heating elements come on almost immediately when hot water is taken from the tank, to heat the replacement (cold) water coming into the tank. But if the elements don't come on immediately, the water in the tank is stratified, hot at the top and cold at the bottom. Opening a hot water faucet continues to get hot water from the top of the tank until the original charge of hot water in the tank is gone. This means that heating the replacement water can be delayed (reducing loads) for some time without depriving water users of hot water. Based on the load shape estimates cited above, the maximum available reduction ranges from about 400 to about 5,300 megawatts, depending on when it is needed.

But to provide regulation or load following, reductions aren't sufficient -- loads need also to be increased when the power system needs it. An example of such a condition is 4:00 AM during the spring runoff, when demand for electricity is low, river flows cannot be reduced, not much non-hydro generation is operating, and winds are increasing. System operators have too much energy and few good options -- they can cut hydro generation by increasing spill, which loses revenue and can hurt fish, or they can require wind machine operators to feather their rotors, losing both market revenue and production tax credits.

Water heating can help absorb this temporary surplus of energy and make productive use of it. Water heating loads can be increased up to the maximum connected load, but the duration of the increase will be limited by the rise in water temperature above its normal setting that we allow. If, for example, we allow the temperature to rise from 120 degrees F to 135 degrees F, 3.4 million 50 gallon water heaters can accept 6,198 megawatt hours of energy, store it (at the cost

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<sup>20</sup> A common assumption is that this coordination includes a requirement that the charge in the PHEV's battery at the end of the day is sufficient to get home. Even if requirement is not met, however, PHEVs have the ability to charge their own batteries, so they are not stranded.

<sup>21</sup> A more detailed description of how PHEVs could contribute to the power system is at Appendix K-1

<sup>22</sup> More details of the potential for water heating as a source of ancillary services is in Appendix K.

of roughly 24 megawatt hours per hour higher standby losses) and return it to the system in the form of a reduction in hot water heating requirement in a later hour.<sup>23</sup>

There are other loads that have some sort of reservoir of “product,” a reservoir whose contents can vary within an acceptable range. The “product” might be crushed rock, compressed and cooled air (in the process of air separation), stored ice (for commercial building air conditioning), pulped wood for paper making, or the like. This reservoir of “product” could allow the electricity customer to tolerate variation in his rate of electricity use to provide ancillary services to the power system, assuming that the customer receives adequate compensation.

There is an industrial plant in Texas that provides 10 megawatts of regulation to the Electricity Reliability Council of Texas (ERCOT) the independent system operator of the Texas interconnected power system. ERCOT’s rules keep plant information confidential, but it is understood that the plant’s process is electrochemical, and that its unique situation makes unlikely that many other plants could provide regulation to the power system.

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<sup>23</sup> This rise could result from an increase in load of 6198 MW for an hour, or an increase in load of 3099 MW for two hours, etc.