

The background of the page is a scenic landscape. At the top, a large, snow-capped mountain peak rises against a clear blue sky. Below the mountain is a dense forest of evergreen trees. In the foreground, a vast field of purple flowers, likely lupines, stretches across the bottom half of the image. A yellow line graph with multiple peaks is overlaid on the bottom right portion of the purple flower field.

The Fifth Northwest Electric Power and Conservation Plan



Executive Summary

Background

The Northwest is unique in how it plans its energy future. Through the Northwest Power and Conservation Council's power plan, strategies to ensure the economy and adequacy of the power system are developed in an open forum where the public can voice its opinion. Why is this so important? With the building of the region's first mainstem Columbia River dams in the 1930s, the Northwest would have access to inexpensive electricity for many years.

But by the 1960s, increased demand led energy planners to believe that hydropower-generating resources would soon be unable to keep up with the demand for electricity. In the 1970s, the federal Bonneville Power Administration and the region's public and investor-owned utilities embarked on an effort to build major new generating resources, including several nuclear power plants. Many of these projects proved to be hugely expensive. As a consequence, retail

rates skyrocketed, demand for electricity plummeted and, although several of the projects were abandoned, the Northwest continues to pay the debt that was incurred.

Amidst the turmoil caused by this massive planning failure, Congress enacted the 1980 Pacific Northwest Electric Power Planning and Conservation Act authorizing the states of Idaho, Montana, Oregon, and Washington to form the Council as an "interstate compact" agency. The Act requires the Council periodically to develop a 20-year power plan to assure the region of an adequate, efficient, economical, and reliable power system and to develop a fish and wildlife program to protect, mitigate, and enhance fish and wildlife affected by the dams. As the Council embarked on its first plan, the lesson it drew from the experience of the 1970s and early 1980s was that the future can turn out very differently than expected. Planning must take this uncertainty into account.

*Wheat fields near Spangle,
Washington.*



The Fifth Power Plan

This is the Council's fifth regional power plan. Like the first, it comes on the heels of a major crisis in the region's power system – the electricity crisis of 2000-2001. That crisis was the result of several adverse trends and events: Uncertainty created by efforts to deregulate the power industry; a corresponding de-emphasis on planning; several years of under-investment in generation and conservation; a deeply flawed electricity market design in Califor-

nia; unethical and illegal actions by some of the participants in that market, and the second-worst water year in the Northwest's hydrological record. While the causes were different, the results of this crisis were much the same as the one preceding the first Council plan – skyrocketing retail rates that struck a major blow to the regional economy.

The lessons for this plan are similar to those of the first. The future is uncertain. Plans and policies must be developed that allow the region to manage this uncertainty and the risks it entails. Many of the uncertainties we now face are familiar – uncertainty about demand for electricity, hydro conditions, and forced outages of major power plants. Other uncertainties are new or have greater importance. The increased role of gas-fired generation and changes in the nature of the natural gas industry mean uncertainty and volatility of gas prices are significant factors. Increasing concerns about global climate change pose new uncertainties for resource choices. The wholesale electric power market is still important, and is also uncertain and volatile.

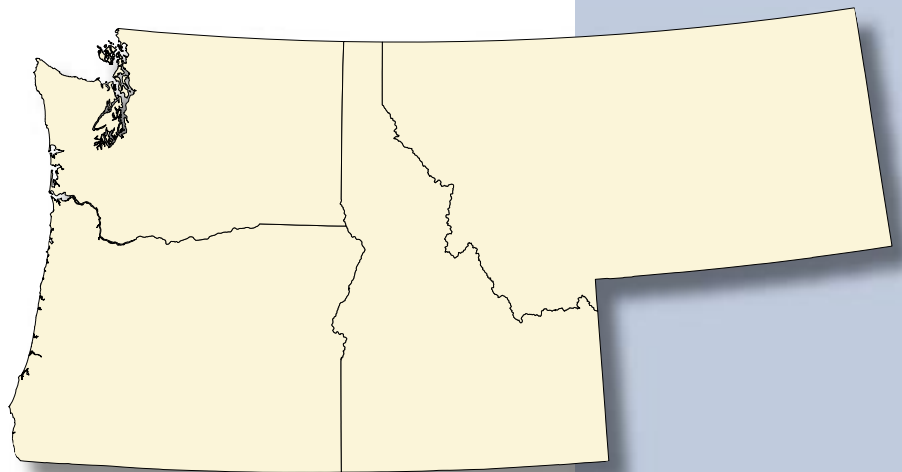
The environment for this plan also is changed. It is no longer a world composed of the Bonneville Power Administration and regulated public and investor-owned utilities. It is now a mix of regulated and unregulated elements. From a physical standpoint, the region currently has a modest generation surplus under critical-water conditions. That surplus is the result of reduced demand that has not yet returned to pre-crisis levels and a significant amount of new generation, most of which was built by independent power producers (IPPs). But the region's individual utilities currently are in deficit. The IPP generation is available to the region but, unless purchased for the long term, it

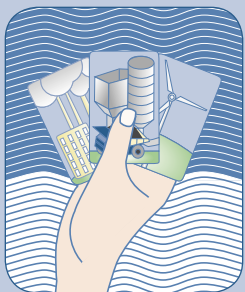
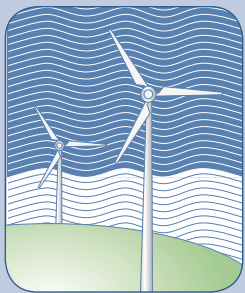
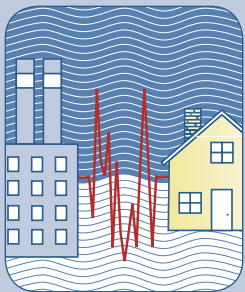
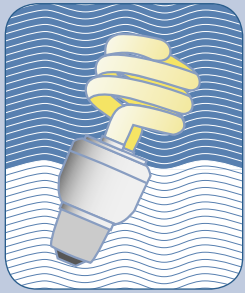


will be sold at market prices. The role of the IPPs in the region's electricity future is unclear.

In addition, those making resource decisions may be a more varied group than in the past. If proposed changes to Bonneville's role in power supply go forward, many smaller public utilities may be making resource decisions in addition to Bonneville, the investor-owned utilities, and the larger public utilities. However, until those changes are in place, there is uncertainty regarding who will acquire new resources for many public utility customers.

The challenge for this plan is two-fold. First, it must provide a flexible resource strategy that can perform well under the expanded and intensified range of future uncertainties. Second, the plan must address key policy issues that affect the region's ability to assure an adequate, efficient, economical, and reliable power system. These issues include: Standards for resource adequacy; planning, funding, and operation of transmission; the interaction of fish and wildlife and power, and the future role of the Bonneville Power Administration in power supply. In the plan the Council assesses these issues and recommends actions to help regional entities resolve them in the months ahead. Through a rigorous examination of various energy options and a healthy willingness to question given assumptions, the Council believes its new power plan offers sound guidance on how the region can secure its energy future.





Recommendations

Conservation

The Council recommends that the region increase and sustain its efforts to secure cost-effective conservation immediately. The Council's analysis shows that improved energy efficiency costs less than construction of new generation and provides a hedge against market, fuel, and environmental risks. To achieve these benefits fully, however, stable and sustained investment in conservation is necessary. Although conservation may result in small rate increases in the short term, it can reduce both cost and risk in the long term. The targets are ambitious but achievable - 700 average megawatts between 2005 and 2009, and 2,500 average megawatts during the 20-year planning period.

Demand Response

The Council also recommends developing demand-response programs - agreements between utilities and customers to reduce demand for power during periods of high prices and limited supply. The Council recommends developing 500 megawatts of demand response between 2005 and 2009 and larger amounts thereafter. Demand response has proven helpful in stabilizing electricity prices and in preventing outages. The Council's analysis shows that although it will probably be used infrequently, demand response reduces both cost and risk compared to developing additional generation.

Wind

The plan incorporates more than 1,100 megawatts of wind generation capacity between 2005 and 2014 from state system-benefits-charge

programs and current utility integrated-resource plans. Beyond that, additional wind generation figures prominently in the next decade. However, the economics of this wind resource is affected by a number of assumptions: Continuation of production tax credits for several years; possible future controls on green house gas emissions; decreasing production costs; the ability to integrate intermittent wind into the existing power system at reasonable costs, and the availability of large areas for development with access to transmission at moderate costs. During the next five years, the power plan calls for gathering more experience and information about the performance and cost of wind resources within the regional power system. To be most useful, these projects should be sited in geographically diverse wind-resource areas. In addition, project developers and operators will need to be willing to share information about the projects. This can be done in ways that do not adversely affect their commercial interests.

Prepare for New Power Plants

This plan defines a schedule of options for development of generating resources. Options mean completed siting and permitting for the amounts and types of power generation identified in the plan. Optioning is a risk-management strategy. With siting and permitting completed, actual construction can be undertaken with a minimum of lead-time when conditions warrant. Conversely, if the projects prove not to be needed, the expended costs are relatively small.

The Council believes the region should secure options (sites and permits) to be able to begin constructing new wind-generating resources as early as 2010 with up to 5,000 megawatts

of capacity to be developed through the end of the 20-year planning period. The Council also analyzed both conventional coal-steam generation and coal-gasification power plants. Recent information indicates that coal-gasification generation has entered the early stage of commercial availability. The analysis indicates that use of coal-gasification power plants lowers the expected cost and risk compared to the use of conventional coal-generation technology and that these plants emit lower levels of pollutants, including carbon dioxide.

The plan calls for being prepared to begin construction, if needed, of coal-gasification generation by the beginning of 2012. However, the analysis is predicated on the further commercialization of coal-gasification technology. If commercialization fails to advance as forecast and other estimates underlying the plan do not change significantly, 400 megawatts of conventional coal-fired capacity could be needed by 2013. This would require preconstruction development to commence by mid-2007 so construction could begin as early as 2010. To provide for this contingency, the Council will issue an assessment of the progress of commercialization of coal-gasification combined-cycle technology and other estimates underlying the plan by 2007. The Council recognizes that individual utilities may find it necessary to acquire additional generation before the target dates in this plan. Commitment to coal-gasification technology for near-term acquisitions may be premature.

Later in the 20-year planning period, some additional gas-fired generation may be needed. Needed transmission upgrades should be identified so all of these resources can be built and brought

on line quickly when required. If major transmission upgrades are needed, pre-construction planning, siting, and permitting will have to begin well before actual construction of the power plants.

The Power Plan and Utility Integrated Resource Plans

The Council recognizes that a plan developed from a regional perspective cannot fully reflect the situation of each individual utility in the region. There can be legitimate reasons for individual utility plans to differ from this plan in resource choices or resource timing. However, the Council's plan serves as an important independent, objective source of information on the region's power system and the resource choices it faces. The plan also provides strategic insights that have broad applicability. For example, this plan demonstrates the value of sustained investment in conservation as opposed

to the up-and-down pattern of investment followed in the past. It also suggests that in many situations during the next few years, reliance on market purchases, much of which could be supplied by in-region IPPs, can be a lower-cost and lower-risk option than immediate construction of new power plants. In addition, the method used to evaluate uncertainty and risk in this plan is one that can and should be applied in individual utility planning.

Pelicans on the Snake River.



Key Policy Issues

With respect to the Bonneville Power Administration's role, the Council recommends that the agency sell electricity from the existing Federal Columbia River Power System to eligible customers at cost. Customers that request more power than the existing system can provide should be required to pay the additional cost. The Council recommends that Bonneville implement this change through new long-term contracts to be offered by 2007. The Council also believes that Bonneville must continue its commitment to support conservation, renewable energy, and fish and wildlife mitigation.

The Council's two main responsibilities, fish and wildlife mitigation and power planning, are closely linked. The Council's power plan and fish and wildlife program attempt to meet the requirements of both the power system and fish and wildlife recovery as effectively and efficiently as possible. For the region to achieve these objectives, it is important that planning for both power and fish and wildlife are coordinated. Outside of the Council, however, no clear process exists for integrated long-term planning. The Council proposes to improve the coordination between fish and wildlife and power planning and decisionmaking.

An adequate power system has a high probability of being able to maintain service when the region experiences a poor water year, unexpected load growth, or the failure of some new resources to perform as planned. The power plan includes analysis that evaluates alternative regional adequacy standards and their interaction with the Western system. The Council is committed to working with regional utilities and regulators to develop a standard that will assure an adequate power supply while being fair and equitable to all parties.

Adequate transmission is key to any of the new generating resources identified in this plan. The move toward deregulation and expansion of wholesale electricity markets, along with changes in technology, has altered the character of the traditional transmission system. Questions of how to plan for, build, pay for, and manage the region's transmission system effectively are becoming critically important. Efforts to establish an organization to assess the long-term requirements of the transmission system and a mechanism to encourage investments to meet those requirements have been pursued for several years with little success. The Council supports and is an active participant in regional efforts to resolve these problems and believes that the time for resolving these issues is growing short. If current efforts do not succeed by the end of 2005, the Council is committed to seeking alternative means of resolving these transmission issues.

Recommended Action Items: Next Five Years

The Council's power plan will be reviewed and revised at least every five years. The actions that the region takes now and during the next few years will determine the success of this plan. The key actions are:

- 1) Develop resources now that can reduce cost and risk to the region
 - 700 average megawatts of conservation, 2005 - 2009
 - 500 megawatts of demand response, 2005 - 2009
 - Secure cost-effective cogeneration and renewable energy projects
 - Develop cost-effective generating resources when needed
- 2) Prepare to construct additional resources
 - Develop and maintain an inventory of ready-to-construct projects
 - Resolve uncertainties associated with large-scale wind development
 - Encourage use of state-of-the-art generating technology when siting and permitting projects
 - Plan for needed transmission and work toward better integration of resource and transmission planning
 - Improve utilization of available transmission capacity
- 3) Confirm the availability and cost of additional resources that promise cost- and risk-mitigation benefits
 - Coal gasification with carbon sequestration
 - Oil sands cogeneration
 - Energy-storage technologies
 - Demonstration of renewable and high-efficiency generation with Northwest potential
- 4) Establish the policy framework to ensure the ability to develop needed resources
 - Carry out a process to establish adequacy targets for the Northwest and the rest of the Western system
 - Work through the Grid West, Regional Representatives Group process to address emerging transmission issues by the end of 2005. If necessary, pursue alternative approaches to resolve issues
 - Revise the role of the Bonneville Power Administration in power supply, consistent with the Council's May 2004 recommendations
- 5) Monitor key indicators that could signal changes in plans
 - Periodically report on the regional load-resource situation and indicate whether there is a need to accelerate or slow resource-development activities
 - Monitor conservation development and be prepared to intensify efforts or develop alternative resources, if necessary
 - Monitor efforts to resolve uncertainties regarding the cost and availability of wind generation and prepare to develop alternatives, if necessary
 - Monitor climate-change science and policy for developments that would affect resource choices
 - Prepare a biennial monitoring report and revise elements of the power plan as necessary
 - Monitor progress in implementing the changes recommended for Bonneville's future role in power supply

Overview

Background

The Northwest Power and Conservation Council is required to develop a 20-year power plan under the Pacific Northwest Electric Power Planning and Conservation Act to assure the region of an adequate, efficient, economical, and reliable power system. The power plan is updated every five years. To accomplish the goals of the Act, the plan addresses future uncertainties; identifies realistic resource alternatives; analyzes the costs and risks that arise from the interaction of resource choices and uncertain futures; and lays out a flexible strategy for managing those costs and risks.

Like the Council's first power plan, released in 1983, this plan follows on the heels of a major crisis in the region's power system. The Council's first plan was developed in the aftermath of the effort to plan and build several large nuclear and coal-fired power plants, and the failure to anticipate the nearly disastrous effect the costs of those plants would have on consumer rates, the region's economy, and electricity demand.

This plan has been developed in the aftermath of the Western electricity crisis of 2000-2001. The causes of this crisis included the failure to develop adequate resources, the failure to anticipate the price volatility that short supplies might create, the failure to put in place effective market rules and mechanisms, and the unethical and illegal manipulation of the market by some participants. The effect, however, was much the same. Retail rates in the region soared and demand plummeted. The impact on the region's economy from 2000 through 2002 was at least \$2.5 billion, and as much as \$6 billion in increased power-purchase costs and foregone economic activity. These impacts linger today.

Both crises underscore the importance of evaluating potential risks as accurately and fully as possible. Although planners cannot predict the future, anticipating alternative outcomes and developing strategies to address changing circumstances are critical elements to any sound planning effort.

The Council's past power plans always dealt with a variety of unknowns – year-to-year uncertainty about hydroelectric generation, uncertainty about future demand for electricity, and uncertainty about fuel prices. Planning today must cope with these and other uncertainties. Gas-fired generation, which has relatively low capital



costs and a short lead-time to build, has reduced capital risk. But such generation is more vulnerable to fuel-cost risk as gas prices have become less certain. Possible climate-change mitigation policies could pose a significant risk for generating technologies using carbon-intensive fuels. To what degree and when such policies will be implemented is unclear.

Some renewable energy technologies, such as wind, though capital-intensive, have short construction lead-times and provide a hedge against fuel price and climate-change risk. But it is uncertain whether current trends of decreasing costs for wind generation will continue or whether integration into the power system of this intermittent resource will prove significantly more expensive as more wind generation is built. Another factor is electricity market-price risk. It is tempting to think that future electricity markets will be orderly and predictable but volatile gas prices and hydroelectric generation, as well as the behavior of market participants, can translate into volatility in electricity markets.

The Northwest is part of a complex, highly interconnected power system linking the region and the rest of Western North America. As a consequence, the region is always subject, to some degree, to the effects of the actions of others. The power system has many different kinds of participants, a mix of regulated and competitive elements, and fragmented rules, regulations, responsibilities, and authorities. Attempting to isolate the region from the rest of this system would be difficult and very costly, but inherent in the status quo are significant uncertainty and risk that must be recognized and managed.

The Council's power plan provides guidance to the region in two areas. First, it addresses key policy issues that need to be resolved to help reduce uncertainty and clarify responsibilities for electricity supply and transmission adequacy and reliability. Second, the plan provides a detailed analysis of alternative resource strategies and develops a recommended strategy of resource acquisition to minimize power system cost and risk. It identifies specific actions the region needs to take during the next five years to realize the goals of the plan.

Regional Policy Issues

Besides determining which resources to develop, the power plan also addresses key regional policy issues that affect the Northwest's power system and fish and wildlife protection and mitigation efforts. The region's electricity system currently consists of a mix of independent power producers, the Bonneville Power Administration, and regulated and consumer-owned utilities. The roles of these entities are not well defined with regard to who is responsible for the planning and development of generation or transmission. This raises concerns about resource adequacy and transmission system reliability. The question of whether Bonneville or its customer utilities will meet growing electricity demands needs to be resolved so Bonneville and utilities can plan appropriately. In spite of a significant presence of independent power production and a history of significant intra- and inter-regional power trading, the region has not been able to agree on how to resolve these issues. If the Council's recommendations in these areas are to be achieved, they must be implemented by many different entities in the region working collaboratively. Failure to resolve these issues places the region at risk of failing to fulfill the goals of the Act for an adequate, efficient, economical, and reliable regional power supply.

Role of the Bonneville Power Administration

On at least two occasions in the last decade, the Bonneville Power Administration has found itself financially and, as a consequence, politically

vulnerable. Bonneville's financial vulnerability arises in part from its dependence on a highly variable hydroelectric base and the effects of a sometimes very volatile wholesale power market. Another source of vulnerability arises from the uncertainty created by the nature of the relationship between Bonneville and many of its customers, and Bonneville's historic choices in implementing its obligations. These vulnerabilities are exacerbated by Bonneville's high fixed costs for debt on the Federal Columbia River Power System and the three nuclear plants that were undertaken, with Bonneville backing, by the Washington Public Power Supply System, now Energy Northwest.¹ At times, these vulnerabilities can cause Bonneville to incur high costs that must be passed on to its customers and ultimately to the region's consumers. If those costs are not passed on to customers, Bonneville risks being unable to make its payments to the U.S. Treasury. Rate increases cause economic hardship in the region; not making a Treasury payment risks a political backlash from outside the region that could cause the Northwest to lose the long-term benefits of power from the federal system.

The Council and others in the region have been working to develop alternative ways in which Bonneville can meet the requirements of the Northwest Power Act with greater financial stability, while reducing the uncertainty surrounding the responsibility for serving load growth and preserving the benefits of the federal system. The Council has recommended that Bonneville implement these changes through new long-term contracts to be offered by 2007. One primary change is that the agency should sell electricity

¹ Of the three plants, only one, Columbia Generating Station, is operating. The other two were terminated before construction was complete. However, Bonneville still has responsibility for paying off the debt incurred during construction.

from the existing Federal Columbia River Power System to eligible customers at cost. Customers that request more power than Bonneville can provide from the existing system would pay the additional cost of providing that service.

Ensuring Power System Adequacy

One of the most important policy issues facing the region is resource adequacy. Resource inadequacy was one of the factors behind the Western electricity crisis of 2000-2001. The Council's analysis suggests there are two kinds of resource adequacy. Physical adequacy means having sufficient resources to prevent the involuntary loss of load. However, economic adequacy is a higher standard that requires sufficient resources to reduce the risk of exposure to unacceptably high power prices. The region needs to address both. If Bonneville's role in meeting the region's load growth is reduced, additional entities that have not had direct responsibility for assuring adequate resources will play an important role. This is not merely a regional issue, because the Northwest is part of an interconnected Western system. This means the region must work with other interests in the West to develop a system that will assure adequacy; recognize the legitimate differences within the West; and ensure that all of the responsible entities bear their share of the responsibility. The region must act soon to address these issues. The Council will establish a Northwest Adequacy Forum to facilitate a discussion of resource adequacy among utility policy makers and other relevant parties in the Northwest to develop adequacy measures and standards for the region. This group will also work closely with the Western

Electricity Coordinating Council (WECC) and the Committee on Regional Electric Power Cooperation to ensure that Northwest considerations are incorporated into any metrics and standards developed in their processes.

Transmission Planning and Operation

A key element of the regional power system is transmission. If the power supplies recommended in this power plan are to be realized, additional requirements will be placed on the transmission system. The region's power system is not currently organized to plan, expand, operate, and manage the regional transmission system as effectively and efficiently as necessary. There has been growing recognition of problems such as:

- Difficulty in managing unscheduled electricity flows over transmission lines leading to increased risks to electric-system reliability
- Lack of clear responsibility and incentives for planning and implementing transmission system expansion, resulting in inadequate transmission capacity
- Inadequate consideration of non-construction alternatives to transmission²
- Inability to monitor effectively the wholesale electricity market, identify market power abuse, or provide mitigation and accountability
- Difficulty in reconciling available physical transmission capacity with capacity available on a contractual basis, resulting in the inefficient use of existing transmission and generation capacity

² Non-construction alternatives include: demand management, conservation, and distributed generation to relieve transmission bottlenecks and defer construction of transmission upgrades.

ity, and limitations on access for new resources to the existing grid

- Transaction- and rate-pancaking, i.e., contracting and paying for the fixed costs of multiple transmission segments on a volumetric basis to complete a power sale, resulting in the inefficient use of generation
- Competitive advantage of control area operators over competing generation owners, resulting in the inefficient use of generation, and a potential proliferation of control areas with greater operational complexity

In response, a regional effort through the Regional Representatives Group (RRG) of Grid West (formerly RTO West) is working to address these problems in a more comprehensive, yet incremental, Northwest grid-wide approach. The Council supports this approach, but is concerned that little agreement has been reached in spite of years of effort, and the time for solving these problems is growing short. If current efforts do not succeed by the end of 2005, the Council will seek alternative means to resolve these transmission issues.

Coordinated Planning and Operation for Fish and Power

The Council's two main responsibilities, regional power planning and fish and wildlife mitigation, are closely linked. The operation of the Columbia River hydropower system affects both the region's energy production and fish and wildlife populations, as well as other activities such as flood control, irrigated agriculture, navigation, recreation, and municipal water supplies. But the operation of the hydrosystem to support salmon and steelhead migration and resident fish populations and the cost of specific projects to implement

the Council's fish and wildlife program also affect the economy of the power system. The Council's power plan and fish and wildlife program are developed to meet the requirements of both the power system and fish and wildlife protection and mitigation as effectively and efficiently as possible.

The analysis for this power plan assumes that all of the fish and wildlife policies pertaining to the operation of the hydroelectric system, as outlined in the NOAA Fisheries' biological opinion, will be followed. Fish and wildlife operations have not been compromised for the sake of power needs. However, the Council realizes that emergencies may occur in which fish and wildlife operations would be interrupted. Ensuring the adequacy of resources for the power system not only minimizes the risk of electrical shortages and high prices, but also minimizes the risk of emergency interruptions to fish operations.



The Northwest Power Act and the Council's Columbia River Basin Fish and Wildlife Program contain language intended to ensure that fish and wildlife actions are cost-effective. The fish and wildlife program is funded by electricity ratepayers through the Bonneville Power Administration, the region's largest power supplier. The Council's decisions on program expenditures are made carefully, to make sure that the projects it recommends are efficient and scientifically credible. To ensure public accountability for these decisions, the Council submits all of the project proposals to thorough reviews by the region's fish and wildlife managers and a panel of independent scientists.

For the region to achieve both an adequate, efficient, economical, and reliable power supply, and healthy populations of fish and wildlife, it is important to coordinate planning and decision making for both power production and fish and wildlife. Outside of the Council, however, no clear process exists for integrated long-term planning. In Chapter 10 of Volume 2, the Council recommends improved coordination among decisionmakers.

Currently, the Northwest region, as a whole has an adequate resource supply. The projected resource surplus is expected to last through the end of this decade, which implies that fish and wildlife operations are not likely to be curtailed. With the recommended improvements in coordination among planning bodies, the region should be assured that both fish and wildlife and power needs will be adequately met.

Planning for an Uncertain Future

The Council's power plans have always contained a description of the current energy situation and changes expected in the future. The plan contains a forecast of demand and a translation of that demand into the need for additional conservation and generation resources. The plan then assesses the resource alternatives available to the region and their costs, inherent risks, and other characteristics that affect how they fit with the existing power system.

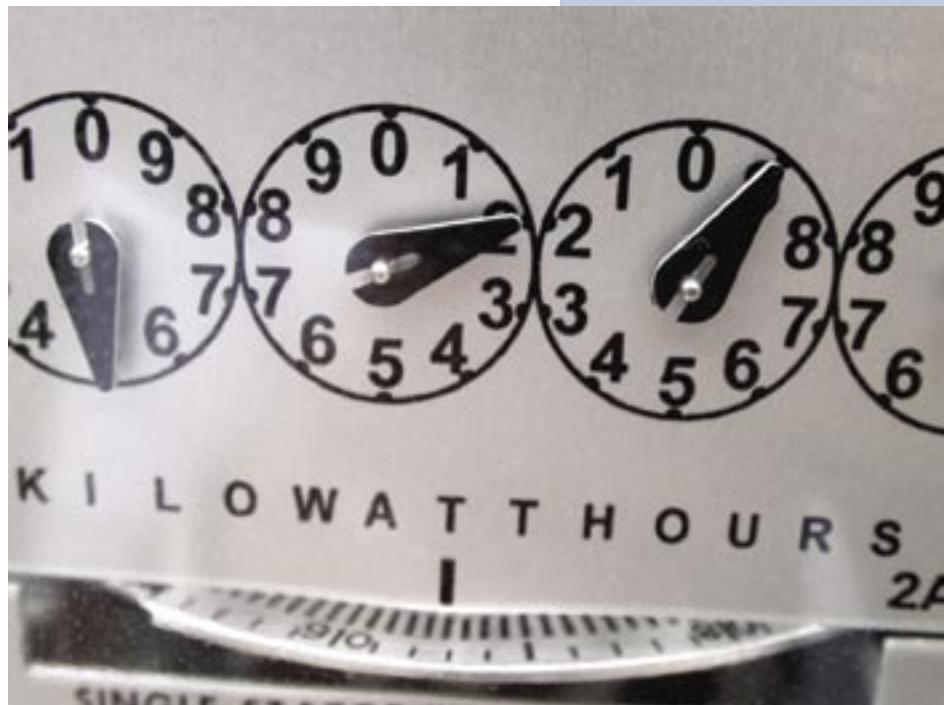
Contributing significantly to the 2000-2001 energy crisis, the region and much of the West had developed a substantial deficit of electricity generating capability. The electricity crisis dramatically increased the costs of many utilities. By 2003 average retail electricity rates in the region had increased by 35 percent. These increased electricity prices had two effects. They reduced consumption by more than 15 percent, sending electricity consumption back to the levels of the late 1980s. Much of the reduced consumption was due to closure of the region's aluminum smelters, but all consumers were affected to some degree by the increased prices.

A second effect of the electricity crisis was the construction of more than 4,000 megawatts of new electricity generating capability in the region. Most of this new capacity was natural gas-fired generation, owned by independent power producers. The combination of decreased demand and increased generating capability created a surplus of about 1,500 average megawatts of electrical capability in the region.

Future conditions are uncertain. To address this uncertainty, Council plans have always dealt with ranges of assumptions about demand growth, fuel prices, hydroelectric conditions, and other factors. This plan is no exception, but it goes beyond previous plans to assess the effects of volatility and seasonal variations in demand and energy prices and treats the wholesale electricity market as a potential resource alternative with its own uncertainties.

Planning for the future requires assessing risk. This involves characterizing the key uncertainties the power system faces. Can planners, through experience, analysis, and informed judgment, develop reasonable characterizations of future uncertainty that will help illuminate resource choices for the region? The Council believes the answer is "yes."

The Council tests possible resource-development plans against 750 "futures," scenarios that



describe the behavior of key sources of uncertainty during the planning period. This assessment is referred to as portfolio analysis. The portfolio analysis helps determine the resource development strategy that will best serve the region. Chapters 6 and 7 describe the portfolio model and its use. Key uncertainties affecting electricity demand and resource costs considered in the portfolio analysis are described below.

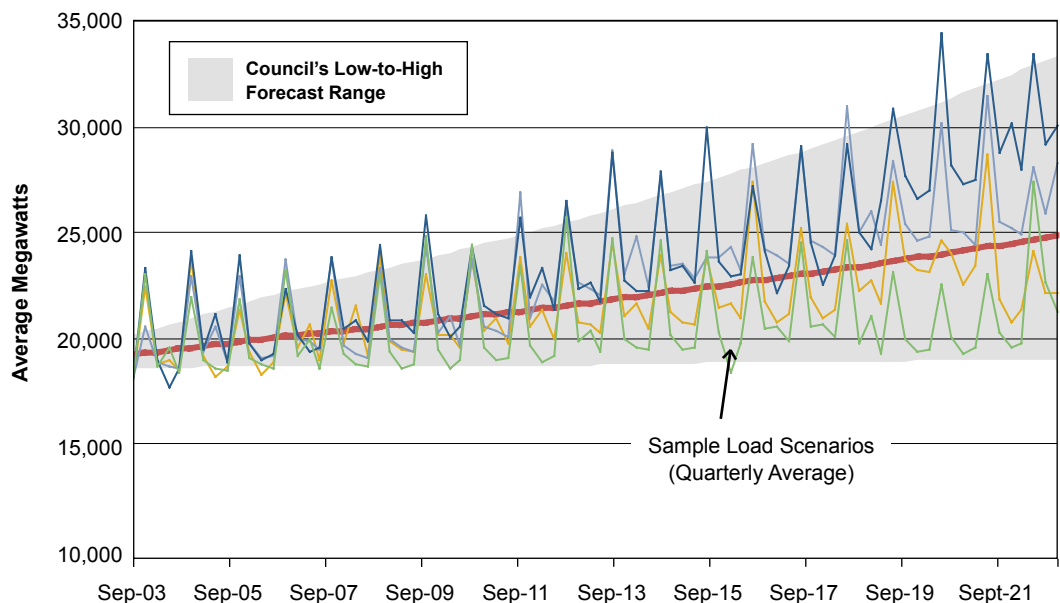
Demand

Demand for electricity is a key uncertainty. Rapid demand growth means additional resources will be required. Conversely, a downturn in load growth means fewer resources and the potential for some resources to go under-used. The Council forecasts potential growth in demand with a range of forecasts. These forecasts are based on analysis of the economic, demographic, and technological factors driving demand for electric-

ity. The medium forecast assumes only modest growth in electricity demand of 1.5 percent per year. From currently depressed levels, this is an average increase of about 330 average megawatts per year. Rates of growth between the medium-high and medium-low forecasts are judged to be equally likely, while rates of growth corresponding to the high and low forecasts have a much lower probability. The low-to-high forecast range recognizes that it is possible, though unlikely, that the future could hold no growth in demand, or growth that is double the medium forecast.

However, overall trends are only part of the story. The region has experienced extended periods of rapid growth and, conversely, periods of load loss and depressed growth. If rapid demand growth outstrips supply, prices can rise and reliability can be at risk. If demand slows or drops, prices may be depressed and expensive resources may be unable to recover all of their costs. In

Figure OV-1: Forecast Range of Annual Non-DSI Loads and Sample Quarterly Loads



addition, there are seasonal variations in demand that are sensitive to temperature conditions and have important implications for resource and transmission requirements to ensure a reliable power system. The portfolio analysis for this plan assesses all of these sources of risk. Figure OV-1 shows a sample of four of the 750 futures for quarterly average loads assessed in the portfolio model compared to the forecast range of annual load trends.

Hydroelectric Generation

The potential variation in the output of the regional hydroelectric system is very large and, therefore, poses an important uncertainty. But more than 50 years of hydrologic data helps planners characterize the year-to-year and month-to-month uncertainty in hydroelectric generation with a high degree of confidence. Figure OV-2 shows the historical distribution of annual hydroelectric generation between 1929 and 1978. In the Council's analysis, the future capability of the hydro system was assumed to decrease by 300 average megawatts by the end of the planning period to

account for potential losses due to relicensing requirements and other competing water uses.

There is further uncertainty resulting from potential shifts in temperatures and precipitation patterns associated with climate change. The Council, in cooperation with scientists at the University of Washington's Climate Impacts Group, has done a preliminary assessment of the possible long-term effects of climate change on the hydroelectric system and on Northwest demand. This work is described in Appendix N. However, the effects of these changes to hydroelectric generation were not included in the portfolio analysis because of the preliminary nature of the work. The Council will continue to work with others to refine the potential effects of climate change and to incorporate these considerations in future revisions of the power plan.

Fuel Price

Similarly, fuel price uncertainty is an important source of risk. The Council forecasts a range of natural gas, oil, and coal prices. Recently, the most important fuel has been natural gas because of the

Figure OV-2: Distribution of Hydroelectric Production, 50-Year Record 1929-1978

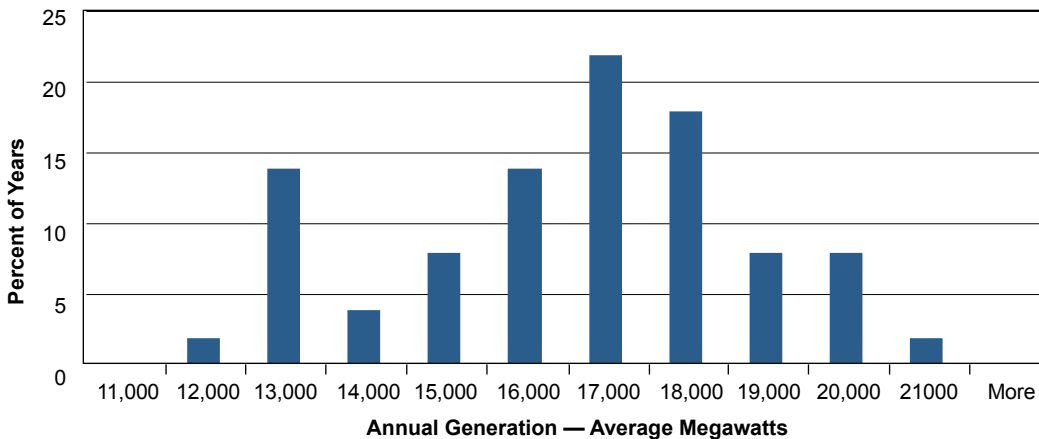


Figure OV-3: Historical and Forecast Natural Gas Prices

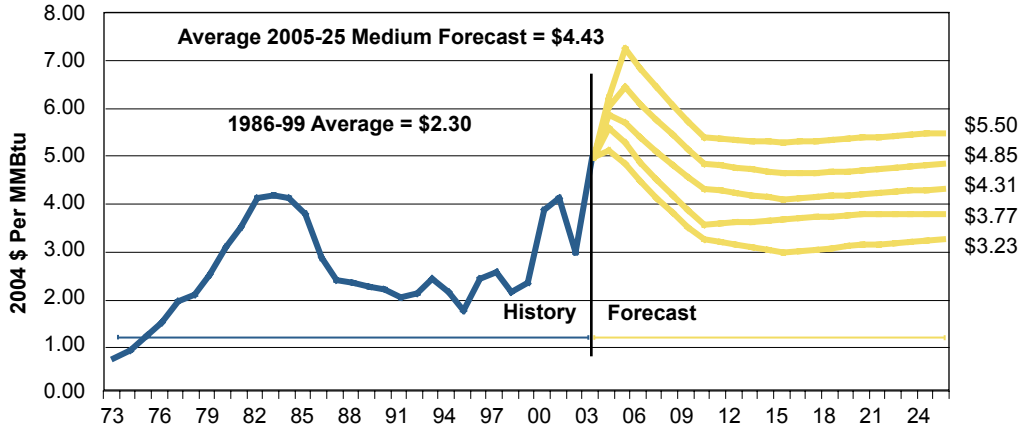
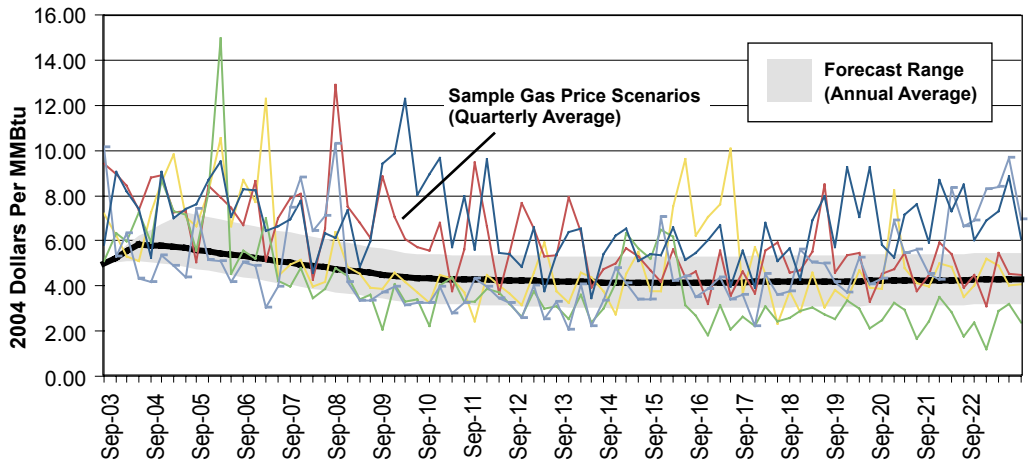


Figure OV-4: Sample Natural Gas Price Scenarios



relative attractiveness of natural gas-fired combined-cycle combustion turbines. Gas-fired generation now constitutes approximately 22 percent of the electricity generation in the region under average water conditions. Periods of high fuel prices can increase operating costs for these resources.

As with demand, the Council prepares a range of gas-price forecasts based on analysis of the outlook for supply and demand. The forecasts of natural gas price for this plan are significantly higher than in the Council's previous power plan. The period through 2008 is espe-

cially vulnerable to high and volatile natural gas prices, but even longer-term natural gas prices are expected to be nearly double the prices experienced during the 1990s.

The price of natural gas exhibits short-term volatility as well as longer-term variation. Periods of oversupply can depress prices for extended periods. Conversely, periods when supplies are tight can result in extended periods of relatively high prices, as the region is experiencing now, until new supplies can be developed. In addition, natural gas prices exhibit seasonal volatility

in response to changes in weather and storage inventories. These periods of price and supply variation can have a significant effect on the costs and risks associated with gas-fired generation. Both the forecast range and a sample of gas price futures used in the portfolio analysis are shown in figures OV-3 and OV-4. The forecast range of long-term fuel price trends is discussed in Chapter 2. The modeling of fuel price variations in the portfolio model is discussed in Chapter 6.

Environmental Regulation

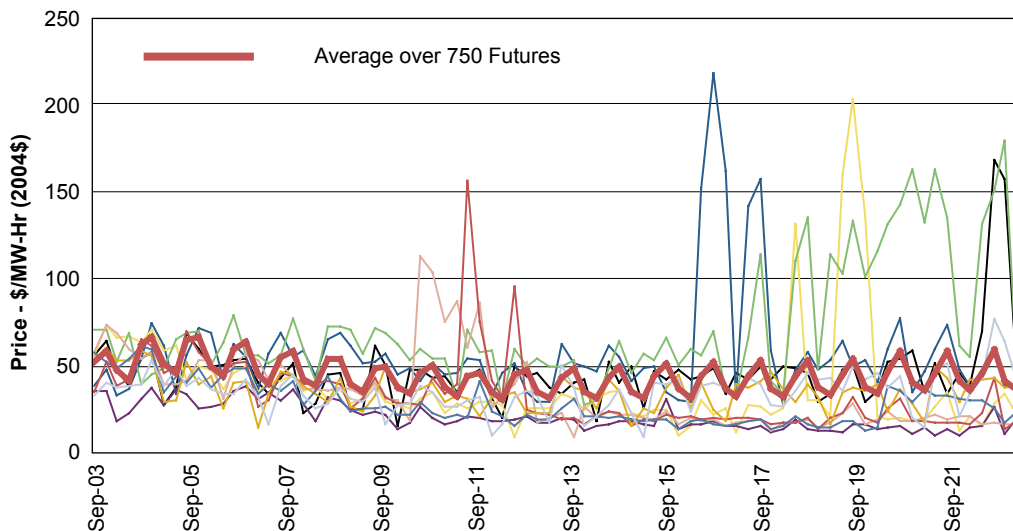
Future environmental regulation, particularly the potential regulation of carbon dioxide emissions, is a significant uncertainty. Without a carbon tax or the equivalent, coal-fired generation could be a more attractive option. With a large carbon penalty in place, coal-fired generation might not be considered, absent a way of reducing carbon dioxide emissions. Currently, future carbon dioxide-control costs are highly uncertain. The small carbon dioxide offsets required of new resources in Oregon and Washington are likely to set a lower limit on carbon-dioxide costs in the

Northwest. Published estimates of the costs of carbon-dioxide offsets required to lower overall carbon-dioxide production to 1990 levels may be at an upper limit for the next decade or two. The Council has treated this issue using probability estimates. The probability of a carbon penalty of some level increases during the planning period, from 0 percent before 2008, increasing to 67 percent by the end of the planning period. Beginning in 2008, the carbon penalty could be between \$0 and \$15 per ton of carbon dioxide and between \$0 and \$30 per ton beginning in 2016.

Electricity Market Price

The market price of electricity is an important uncertainty and source of risk. The market fulfills a balancing function. If a load-serving entity is short of resources to meet its loads, it hopes to be able to buy power from the market at a reasonable price to meet its needs. If a generator has excess power, it hopes to sell into that market at a price sufficient to cover its operating costs and recover a portion of its capital investment.

Figure OV-5: Sample Quarterly Average Electricity Market Prices



The electricity market is not limited to the Northwest, but comprises the entire interconnected Western system up to the limits of transmission capacity. To a large extent, electricity market price is a function of demand, the amount and characteristics of supply, and fuel prices. But as the experience of 2000 and 2001 demonstrated, circumstances can arise that drive prices well beyond the operating costs of the most expensive plants. Such events can be an important source of risk. A sample of peak-period market prices used in the Council's portfolio analysis is shown in Figure OV-5. The forecast of the levelized price of electricity and the Mid-Columbia trading hub for the period 2005 to 2025 is \$38 per megawatt-hour expressed in year 2004 dollars. However, as demonstrated in Figure OV-5, this hides the significant variations that are assessed in the Council's analysis.

Resources for the Future

The performance of a plan depends very much on how resources interact under different possible futures. The Council’s plan is based on detailed analysis of the important characteristics of major-resource alternatives — testing different “portfolios” of resources or plans against a large number of futures. These include both generating resources and “demand-side” resources such as conservation and demand response. Conservation is the more efficient use of electricity and is the highest-priority resource under the Northwest Power Act. Demand response is temporary reductions or shifts in the timing of some uses of electricity. Demand response has not been considered in earlier plans, but it proved to be very beneficial during the 2000-2001 electricity crisis.

The primary resources considered in the portfolio analysis and their relative characteristics are summarized in Table OV-1. Some important considerations are the unit size, capital and operating costs, emissions characteristics, fuel price risk, and construction lead-time. Typically, with smaller unit sizes and shorter lead-times come a greater ability to adapt to changing circumstances. Capital costs are important in that once incurred, they cannot be avoided. Fuel costs and potential changes in emissions policy can significantly affect future costs. For example, a gas-fired, combined-cycle power plant has low capital costs and a short construction lead-time, providing relatively less financial risk, but its costs are subject to substantial risk from uncertain and volatile natural gas prices. A steam-coal plant carries less fuel price risk and relies on a

Table OV-1: Resource Characteristics

Resource	Project Size	Development and Construction Time	Capital Cost	Fuel and Other Operating Costs	Carbon Dioxide ton/GWh	Application
Conservation	Very Small	Short	Moderate to High	None	None	Load Offset
Demand Response	Very Small to Small	Short, once resource confirmed	Low	High with some exceptions	None	Peak Offset
Integrated Gasified Coal-Combined-Cycle	425 MW	36/48 mo	\$1,400/kW Declining	Low Stable	790 (without carbon sequestration)	Baseload
Coal - Steam-electric	400 MW	36/48 mo	\$1,240/kW Stable	Low Stable	1,010	Baseload
Natural Gas - Combined-Cycle Gas Turbine	610 MW	24/24 mo	\$565/kW Declining	Moderate Volatile	430	Baseload, Load-following Peaking
Natural Gas - Oil Sands Cogeneration	2,000 MW Transmission Controlling	48/36 mo Transmission Controlling	\$1,130/kW Uncertain	Low Volatile w/fuel shift potential	370	Baseload
Natural Gas Simple-cycle Gas Turbine	90 MW	18/12 mo	\$600/kW Declining	High, Volatile	580	Load-following Peaking, Grid Support
Wind - Utility Scale Wind Project	100 MW	18/12 mo	\$1,010/kW Declining	Moderate (integration)	None	Intermittent Baseload

plentiful domestic energy source, but it is larger, more capital-intensive, has a longer construction lead-time, and may be vulnerable to changes in carbon-control policies. Integrated gasified-coal combined-cycle technology (IGC) reduces carbon-dioxide emissions and improves efficiency, but it has higher capital costs. It can also be adapted to sequester carbon emissions, depending on location. Recent developments in the industry appear to make IGC a realistic alternative. Conservation and wind have little or no operating costs and little environmental risk, but they are not dispatchable to meet varying loads, and their costs are all up-front capital investment.

Other resources considered in the portfolio analysis include Alberta oil sands cogeneration. This resource would require the development of extensive transmission to bring the power into the region. However, if this can be done at a reasonable cost, it could be a viable alternative.

Other resources were considered, but were not included in the portfolio analysis. Many, such as cogeneration, which is frequently called combined heat and power; power plants using bio-residue fuels, and other “distributed-generation” technologies are very site-specific. Their cost-effectiveness frequently depends on a number of factors such as the ability to offset other fuel use; localized benefits for reliability or power quality; the ability to offset transmission or distribution-system investment or reduce losses; the availability of fuels; and whether construction can be accomplished as part of a larger plant or building renovation. These are frequently potential “lost-opportunity” resources, i.e., their cost-effectiveness may depend on the timing of other actions such as transmis-

sion upgrades, environmental requirements, plant renovation, and so on. These resources are described in Chapter 5. Even though these resources have not been included in the Council’s portfolio analysis, efforts should be made to identify cost-effective projects and develop them when the opportunity arises.

The Council also considered other renewable-energy sources including solar, geothermal, small hydropower, wave energy, and various forms of biomass (Chapter 5). Though very expensive, solar photovoltaics can be cost-effective for small isolated loads. Declining costs should continually expand these opportunities, which should be identified and secured. Attempts to develop Northwest geothermal resources have so far proven unsuccessful. However, the resource remains attractive because of its declining costs, increased siting proposals, and baseload potential. Efforts to confirm geothermal resources should continue. As much as several hundred megawatts of cost-effective, small-hydropower potential may be present in the region, but development efforts have been contentious and time-consuming. Cost-effective projects should be pursued where consistent with the Council’s Protected Areas policy in its fish and wildlife program. A substantial potential for wave energy is present along the Washington and Oregon coast; however, wave-power-conversion technology is not yet commercially available. The Council encourages efforts to assess this potential resource, and to develop the technology to convert wave energy to electricity. The Council will consider this resource in future plans.

While generally expensive and limited in quantity, the use of bio-residues for power gen-

eration will often simultaneously resolve a waste-disposal problem. In addition, it may be possible to utilize waste heat to serve industrial-process heat needs. Such cogeneration can reduce the cost of power generation from bio-residues. Opportunities for cost-effective development of power generation using bio-residues should be identified and secured.

Fuel conversion from electric space-and-water heat to natural gas offers cost-effective electricity alternatives and a more efficient use of total energy in some situations. The appropriate role for the Council in promoting the direct use of natural gas for heating of space and water has long been an issue in the region. The Council's policy on fuel choice has consistently been that fuel conversion, while reducing electricity use, is not conservation under the Northwest Power Act, because it does not constitute a more efficient use of electricity. But the Council also recognizes that in some cases, it is more economically efficient and beneficial to the region and individual consumers to use natural gas directly for space- and water-heating than to use electricity generated by a gas-fired generator. This finding is very case-specific and depends on a number of factors, including the proximity of natural-gas distribution lines, the size and structure of the house, the climate and heating requirements in the area, the desire for air-conditioning, and the suitability for heat-pump applications. One particularly attractive opportunity for conversion to natural gas is in homes that have natural-gas space-heating systems, but electric water-heaters. In most of these cases, it would be cost-effective for consumers to install natural-gas water-heaters.



The Council has not included programs in its power plans to encourage the direct use of natural gas, or to promote conversion of electric heat to natural gas. This policy is consistent with the Council's view of its legal mandate. The Council's policy on fuel choice is a market-based approach. That is, the Council will leave the choice of heating fuels to individual consumers. The Council's analysis indicates that fuel-choice markets have been working well to increase the use of natural gas for space- and water-heating as electricity prices have risen relative to natural-gas prices.

The resources considered potentially cost-effective in the development of this plan are summarized in the "supply curve" shown in Figure OV-6 and Table OV-2. This shows the estimated levelized cost of specific resources in cents per kilowatt-hour and the estimated cumulative supply in average megawatts available during the planning period. Also shown is an estimate of the uncertainty of the estimated costs. For example, gas-fired generation is subject to a range of possible fuel-cost and carbon-emissions penalties

How can resources be compared on an “apples-to-apples” basis?

Not all resources are alike. Some resources, such as conservation, have costs that are entirely, or almost entirely, capital. These costs are incurred when the conservation is installed, but the benefits continue for the life of the measure—30 or more years in many instances. In contrast, other resources, such as a gas turbine, incur capital costs initially, but also have ongoing fuel and operating costs during the life of the project. To compare these resources on the basis of their first-year costs would be very misleading. To compare such resources fairly, we calculate the “levelized cost” of each resource. This involves calculating all of the costs incurred – capital, fuel, and operating – during the planning period, including replacements if required. These future costs are discounted to their present value in fixed-year, inflation-adjusted dollars. Their present-value total costs are converted into a fixed annual payment similar to a mortgage payment. This payment, divided by the annual electricity production or savings, yields the levelized cost per kilowatt-hour.

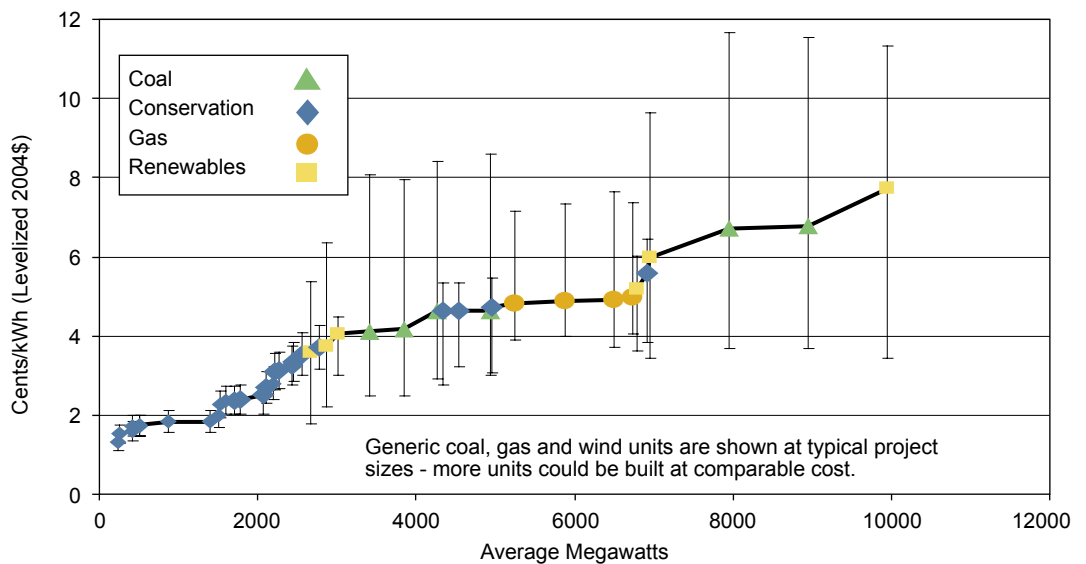
that will affect the cost of the power produced. The cost of power from wind generation is subject to uncertainty regarding cost improvements over time, integration costs, and resource-quality, financing, and transmission costs.

This supply curve should not, however, be interpreted as the order for acquisition. That can only be determined by evaluating resources in the context of the operation of the entire system, including other resource additions and the uncertainties of a large number of possible futures. However, it is indicative of the analytical results that the low-cost end of the supply curve is composed primarily of various conservation measures and some specific types of wind development.

The Role of Independent Power Producers

This is the first time in the Council’s planning history that independent power producers (IPPs) account for a significant amount of the generation in the region. There are approximately 3,000 average megawatts of IPP generation in the region that is not owned by, or under long-term contract to, regional load-serving entities. Most of this generation comes from new, gas-fired combined-cycle combustion turbines, but an existing coal-fired plant produces about 1,100 average megawatts.

Figure OV-6: Resource Supply Curve 2025 (See Data Table OV-2)





This IPP generation does not have firm transmission access to markets outside the region, and it is available to meet regional needs. Extra-regional parties who own firm transmission capacity could contract for some of this power. However, if that power were to be needed in the Northwest, it would most likely be needed in the late fall and winter when Northwest demand peaks. Since demand in most of the rest of the West peaks in the summer, there should be power available outside of the Northwest during the late fall and winter to offset the IPP's export obligation. This would allow the IPP to serve Northwest needs, although possibly at some additional cost to the Northwest. This is called counter-scheduling.

IPP generation poses a different kind of uncertainty for planning. These plants sell their power into the market when prices are high enough to recover their operating costs and help pay their capital costs. While their presence in the region helps to moderate market prices, it

does not eliminate the risk of high market prices for regional consumers.

A number of individual utilities within the region have near-term resource needs. They can satisfy those needs in several ways. Assuming they are not constrained by transmission limitations, they can purchase from the market until the surplus erodes. They can enter into long-term contracts with IPPs or purchase an ownership interest in all or part of an IPP facility. Or they can build additional generation themselves. In the first instance, the utility is exposed to market-price risks. In the latter instances, the utility reduces exposure to market risk (unless they contract at a market-linked price) but incurs increased fixed costs and the risks those entail. It is possible, and even likely, that different decisionmakers will make that tradeoff differently.

The Council's power plan assumes that the uncommitted IPP generation continues to sell in the market when possible. This should not be in-

The Klamath Cogeneration Plant, Klamath Falls, Oregon.

Table OV-2: Resource Supply Curve 2025

	Sector and End-Use	Average Cost (Cents/kWh) (Levelized 2004\$) ¹⁰			Cost- Effective Potential (mWa in 2025)	Cumulative Potential (mWa in 2025)
		Low	Avg.	High		
1	Commercial New & Replacement Lighting ²	1.12	1.32	1.51	245	245
2	Commercial New & Replacement Infrastructure ^{2, 8}	1.3	1.53	1.76	11	256
3	New & Replacement AC/DC Power Converters ²	1.36	1.61	1.85	156	412
4	Residential Dishwashers ²	1.47	1.72	1.98	10	422
5	Agriculture – Irrigation ²	1.47	1.72	1.98	80	502
6	Commercial New & Replacement Shell ²	1.48	1.74	2	13	515
7	Industrial Non-Aluminum ²	1.56	1.83	2.11	350	865
8	Residential Compact Fluorescent Lights ²	1.56	1.83	2.11	535	1400
9	Commercial Retrofit Lighting ²	1.68	1.98	2.27	114	1514
10	Residential Refrigerators ²	1.92	2.26	2.6	5	1519
11	Residential Water Heaters ²	2.02	2.37	2.73	80	1599
12	Commercial Retrofit Infrastructure ^{2, 8}	2.02	2.37	2.73	105	1704
13	Commercial New & Replacement Equipment ^{2, 9}	2.04	2.4	2.76	84	1788
14	Chemical Recovery Boiler Upgrades (incremental cost) ²	2.02	2.52	2.73	280	2068
15	Residential New Space Conditioning-- Shell ²	2.29	2.69	3.1	40	2108
16	Residential Existing Space Conditioning – Shell ²	2.38	2.8	3.22	95	2203
17	Commercial Retrofit Shell ²	2.63	3.09	3.55	9	2212
18	Residential HVAC System Efficiency Upgrades ²	2.66	3.13	3.59	65	2277
19	Commercial New & Replacement HVAC ²	2.77	3.26	3.75	148	2425
20	Residential HVAC System Commissioning ²	2.84	3.34	3.84	20	2445
21	Commercial Retrofit HVAC ²	3.01	3.54	4.08	117	2562
22	Central MT Wind for local load ^{1, 13}	1.77	3.58	5.37	100	2662
23	Commercial Retrofit Equipment ^{2, 9}	3.16	3.72	4.28	109	2771
24	Eastern WA & OR, S. ID Wind ^{1, 13}	2.2	3.74	6.35	100	2871
25	Landfill Gas Energy Recovery ^{12, 13}	3	4.04	4.47	150	3021
26	MT Coal Steam for local load ^{1, 5, 13}	2.48	4.1	8.07	400	3421
27	MT IGCC for local load ^{1, 4, 13}	2.48	4.17	7.96	425	3846
28	Eastern WA/OR IGCC (or MT IGCC @ Mid-C at embedded transmission cost) ^{1, 4, 13}	2.92	4.62	8.42	425	4271
29	Residential HVAC System Conversions to Heat Pumps ²	2.77	4.63	5.33	70	4341
30	Residential Heat Pump Water Heaters ²	3.21	4.63	5.33	195	4536
31	Eastern WA/OR Pulverized Coal (or MT Coal @ Mid-C at embedded transmission cost) ^{1, 5, 11, 13}	3.01	4.63	8.59	400	4936
32	Residential Hot Water Heat Recovery ²	3.08	4.74	5.45	25	4961
33	Mint Farm CCCT ¹³	3.9	4.82	7.14	286	5247
34	Grays Harbor CCCT (Cost to complete) ¹³	3.99	4.87	7.32	640	5887
35	Eastern WA/OR CCCT ^{1, 3, 13}	3.7	4.91	7.63	610	6497
36	Montana First Megawatts (Cost to complete) ¹³	4.05	4.98	7.37	240	6737
37	Animal Manure Energy Recovery ^{12, 13}	3.63	5.2	6.02	50	6787
38	Residential Clothes Washers ²	3.83	5.6	6.44	135	6922
39	Wood Residue Energy Recovery (non-cogen) ^{12, 13}	3.45	5.97	9.64	25	6947
40	MT Coal Steam w/new transmission to Mid-C ¹	3.69	6.71	11.67	1000	7947
41	MT IGCC w/new transmission to Mid-C ^{1, 4, 13}	3.68	6.78	11.55	1000	8947
42	Central MT Wind w/new transmission to Mid-C ^{1, 7, 13}	3.45	7.73	11.34	1000	9947

Footnotes:

- 1) These units do not represent the entire potential of the resource. They are typical size generation installations and could be duplicated.
- 2) The uncertainty interval shown for all of the conservation resources is +/- 15 percent.
- 3) The uncertainty interval for generic combined cycle combustion turbine generators is defined on the low side by medium-low natural gas prices, no carbon dioxide control, a 10 percent "learning factor" for technology and public utility financing costs. The high side of the uncertainty interval is defined by high natural gas prices, carbon dioxide control costs based on the proposed Climate Stewardship Act (CSA), no learning factor, and independent power producer financing costs. The uncertainty intervals for the Grays Harbor and Mint Farm CCTTs used the same assumptions except the generating technology was assumed to be fixed at 2001 levels. All of the gas-fired combined-cycle values are based on full baseload heat rate.
- 4) The uncertainty interval for integrated coal gasification combined-cycle plants (IGCC) is defined on the low side by medium low coal prices, no carbon dioxide control, low construction cost, 36-month construction period, 10 percent learning factor, and all of the public utility financing costs. The high side of the interval is defined by medium coal prices, carbon dioxide control costs based on the CSA, high construction cost, 48-month construction period, no learning factor, and independent power producer financing costs.
- 5) The uncertainty interval for conventional coal-steam generators uses the same assumptions as gasified coal generators, with the exception that the low cost assumption for learning factor is 5 percent instead of 10 percent.
- 6) The uncertainty interval for Eastern WA, OR, and S. ID wind is defined on the low side by 32 percent capacity factor, a 15 percent learning factor, green tag value of \$3.77/MWh, \$4.90/MWh for shaping and firming, all of the public utility financing costs, and the production tax credit for wind continuing indefinitely at \$18.32/MWh. The high side of the interval is defined by a 28 percent capacity factor, a 5 percent learning factor, green tag value of \$3.77/MWh, \$10.51/MWh for shaping and firming, all of the independent power producer financing costs, and no production tax credit after 2005.
- 7) The uncertainty interval for central MT wind uses the same assumptions as Eastern WA, OR, and S. ID except that the assumed capacity factor is 38 percent for the low side, and the capacity factor is 34 percent on the high side.
- 8) Commercial infrastructure includes sewage treatment, municipal water supply, LED traffic lights, and LED exit signs.
- 9) Commercial equipment includes refrigeration equipment and controls, computer and office equipment controls, and laboratory fume hoods.
- 10) Levelized cost estimates in this table are not exactly comparable. Levelized cost estimates for generating resources in this table do not include distribution system costs needed to deliver power to customers. These costs are avoided by conservation, but are very location-specific and are not credited in these figures.
- 11) There may be enough existing transmission capacity to move 400 MW of output from MT to MidC at embedded cost.
- 12) These units do not represent the entire potential of the resource. They are typically sized generation installations and could be duplicated. The size of the total resource is uncertain (e.g., the estimates of potential wood residue projects range from 1,000 to 1,700 MW).
- 13) Except as indicated, the expected case values for generating resources are based on mixed financing (20 percent public utility, 40 percent IOU, and 40 percent IPP), 2010 service, and the medium case fuel price forecast. Capacity factors are 80 percent for coal and cogeneration resources, 65 percent for gas resources, 30 percent for eastern Washington/Oregon wind, and 36 percent for Montana wind. Point-to-point transmission costs representative of delivery to main grid substations are included, except for the "MT delivered to Mid-C" cases. These include the cost of new long distance transmission from Montana to Mid-C. Costs of shaping windpower are included. The costs include the expected cost of carbon dioxide allowances and expected values of renewable energy production tax credit and green tags from the least-risk plan, as applicable. Green tags are not assumed to apply to biomass resources. The production tax credit is assumed to apply to biomass, except for chemical recovery boilers.

terpreted as a prediction or a preference. Clearly, there is significant value in the IPP resources, and they have the advantage of no construction lead-time. Analysis indicated that value, net of fixed operating costs, is approximately \$4 billion, relative to a total average present value cost of \$24 billion.³ But a significant investment will have to be made by regional utilities to secure that value. What happens to the IPP generation has implications for resource development. If the region secures the IPP generation, other resource development could be deferred. Some IPP generation has already been purchased or contracted for long-term use by regional utilities, and more may be acquired. If utilities build additional generation in the near-term, some of the generation identified in this plan could be deferred. However, the analysis cannot capture the financial complexities and risks faced by each individual utility and IPP in the region. The assumption that uncommitted IPP generation will sell into the market provides a reasonable starting place for analyzing the region's energy choices.

the models calculate the cost of operation and expansion of the power system over hundreds of different futures. Two primary measures of a plan's performance are used: the average total system cost over all of the futures, and a measure of risk, the average cost of the worst 10 percent of the outcomes. Other risk measures, such as the standard deviation of the distribution of costs, are also considered, as are measures of the average period-to-period cost variation and maximum cost variation across the study period. These measures give insight into the potential for retail price volatility. In addition, measures of resource adequacy are also evaluated. The objective is to find plans that perform well over a wide range of possible futures. But this is only the start. The plans are "stress-tested" to evaluate sensitivity to different assumptions. This process of testing, changing assumptions, and re-testing continues until the Council is satisfied that a plan makes sense.

Evaluating Plans

In evaluating plans, the Council relies on both analytical models and informed judgment. The Council considers a "plan" to consist of a particular strategy to acquire conservation and demand response and a schedule and amount of resource "options" to put in place. An option, for example, could be a designed and sited power plant ready for construction, if it is needed.

Computer models are used to screen a large number of alternative plans. For each plan,

³ This figure includes the cost of operating the existing system and the costs of building and operating new resources during the next 20 years. It does not include amortization of the debts on existing system resources. These are considered "sunk costs" and do not enter into new resource decisions.

The Resource Plan

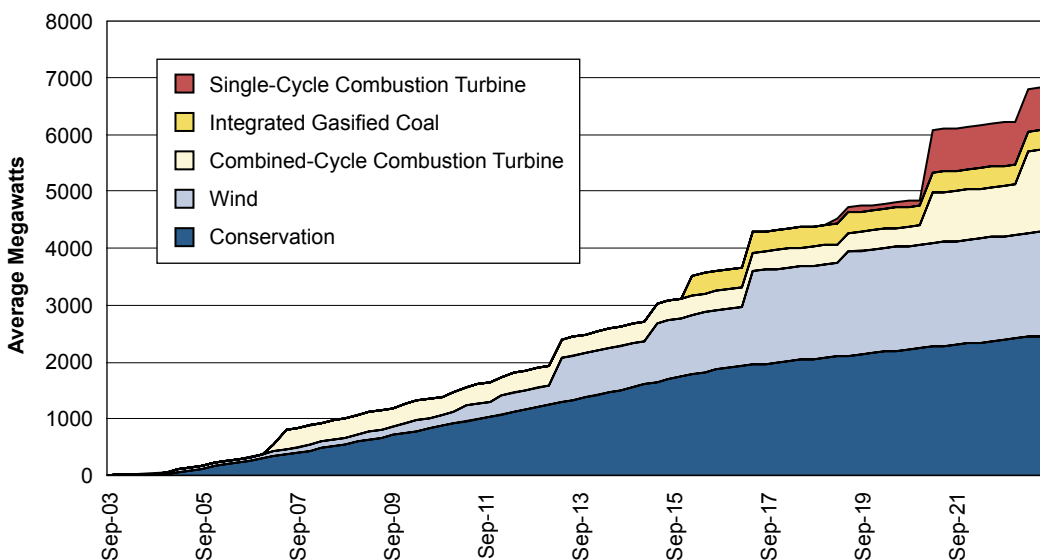
A plan describes the resource actions to be taken during the Action Plan period. The models produce a large number of alternative plans; those with the least expected or average cost for a given level of risk are of greatest interest. The models also identify the plan that is the least cost of all of the plans considered, and also the one that exhibits the least risk. Generally speaking, lower risk means higher average cost. This is due to the cost of adding resources to mitigate potential future market-price spikes, and as a hedge against the risks of fuel price volatility and possible future carbon dioxide control measures. The increase in expected cost can be thought of as an insurance premium paid to reduce the exposure to much higher costs that could occur in some futures.

The Council has chosen a resource plan that entails somewhat more cost on average but considerably less risk than the absolute least-cost plan. This plan reflects concerns about the

adverse effects that very high-cost outcomes can have on the power system; the social and “non-power” economic costs not included in the Council’s risk measures; judgments regarding the value of improved reliability and reductions in price volatility, and the desire for a diverse and orderly development pattern. The analysis is discussed in Chapter 7. A typical development schedule of the resource plan is illustrated in Figure OV-7. However, depending on the characteristics of a particular future, the plan might manifest itself quite differently. Resource development could occur somewhat earlier or later, at higher levels or lower, or not at all, depending on load growth, fuel prices, and carbon penalties, to name a few variables. Several specific scenarios are discussed in Chapter 7.

Absent extremely high growth in demand during the next several years, substantial loss of existing resources, or the failure to develop cost-effective conservation, the resource plan does not call for significant development of new generating resources before the end of the decade, beyond

Figure OV-7: Typical Development Schedule



those resources already committed to development. In the interim, some of the uncertainties influencing this plan may become clearer, helping the region to make better decisions.

However, the Council's portfolio analysis shows that sustained, significant development of cost-effective conservation now, with a goal

of 700 average megawatts during the next five years, is in the region's interests. Accomplishing this and additional conservation during the remainder of the planning period reduces the average system cost by nearly \$2 billion and reduces risk even more, compared to less aggressive implementation. This is in relation to an average system cost of operation and system expansion of approximately \$24.5 billion. In the past, the pace of conservation implementation has varied widely from year to year as utilities responded to market conditions and other factors. The portfolio analysis shows that a sustained and significant pace of investment in cost-effective conservation is beneficial because it reduces the need to build more expensive new resources, and it reduces the region's exposure to periods of high market prices, fuel-price volatility, and possible future carbon penalties.

The power plan calls for increasing conservation acquisition from 130 average megawatts in the first year of the plan to 150 average megawatts in the fifth year. The Bonneville Power Administration and the region's utilities will fund much of the conservation in the first five years, but new codes and standards should contribute some savings as well.

The Council recognizes that this five-year target represents a significant effort. The Council's initial year target of 130 average megawatts is equivalent to the average amount of conservation acquired by Bonneville, the region's utilities, and the Northwest Energy Efficiency Alliance during the Western electricity crisis of 2001 through 2002. It is slightly more than 10 percent higher than the average amount of conservation achieved annually from 1993 through

Why acquire conservation when the region has a surplus of electricity generation?

- Conservation costs less than many of the resources utilities are planning to develop
- Acquiring conservation that costs less than power from existing generating plants reduces the overall cost of the power system because surplus electricity can frequently be sold on the market
- The conservation needs to be in place if it is to provide protection against future price excursions

Haven't we already acquired all of the available conservation?

- Most of the potential conservation identified in this power plan is in new technology and new applications that generally have limited market penetration

Will acquiring more conservation increase electric rates?

- Conservation costs can increase short-term power rates. But the conservation identified in this power plan reduces long-term system costs and risks, which translates into long-term bill savings
- The increased conservation acquisitions will probably require increasing utility conservation expenditures about one-third over that spent in 2002. That is an increase of less than 1 percent of the total electric-system revenue requirements
- Short-term rate impacts could be deferred by financing conservation, although such financing increases conservation costs somewhat

Can the region actually develop this much conservation?

- Conservation has been developed at this rate in the past — the average rate of acquisition from all sources (codes, standards and programs) 1991-2002 was greater than what the plan is recommending
- Several utility integrated resource plans have proportionately similar targets
- Achieving the target means making the region's electricity use efficiency only 10 percent better

1996, a period when utilities increased conservation efforts. On the other hand, it is more than double the average amount of conservation achieved annually from 1997 through 2000 when industry restructuring concerns and low wholesale energy prices dramatically reduced utility conservation investments. The power plan's fifth year conservation target of 150 average megawatts is slightly above the maximum rate of 146 average megawatts for utility system acquisitions. A review of current utility conservation plans indicates that several major utilities already have conservation targets consistent with this plan.

To accomplish the power plan's conservation targets, the Council estimates that regional utility system investments will need to increase. How much will depend on how successful the region is in improving regional coordination and program implementation; the success of market transformation ventures, and the effectiveness of energy codes and standards and the timing of their adoption. Based on the historical cost of regional utility conservation acquisitions, the Council expects that total utility system investments in conservation needed to achieve its five-year target will be approximately in the range of \$1.3 billion to \$1.45 billion. This is slightly less than the \$1.56 billion (year 2004 dollars) in utility investments from 1992 through 1996. The Council understands the difficulty of raising power rates to accomplish this level of investment. Acquiring conservation as inexpensively as possible must be a high priority.

In addition to conservation, the Council recommends developing 500 megawatts of demand response during the next five years, and up to

2,000 megawatts during the 20-year planning period. In the portfolio analysis, demand response was used in 83 percent of all of the years examined. However, in most of those years, demand response was used for only a few hours (fewer than nine hours per year in 85 percent of those years). In 95 percent of all years, 8 percent or less of the available demand response is used. But in futures with very high prices, it was dispatched at higher levels to help moderate prices and maintain reliability. Without demand response, the average cost of the resource plan increased about \$146 million while risk increased by \$235 million. The value of demand response is clearly in mitigating the risks of high market prices. There remains, however, some uncertainty regarding the amount and cost of the demand-response resource.



Wind is expected to play a much-expanded role beginning in approximately 2010. This is the result of a number of factors: possible future policies to reduce the emissions of carbon dioxide, making the use of carbon-intensive fuels more expensive; the forecast of significant wind turbine technology improvement and cost reductions; higher gas prices and price volatility, and relatively low integration costs. It also assumes the ability to extend transmission service to promising wind resource areas at a reasonable cost. The uncertainties regarding these factors have been explored through a sensitivity analysis. Because wind power could play a significant role in the future, these uncertainties need to be resolved before large-scale development is needed. To

accomplish this, the power plan calls for the measured development of commercial-scale wind projects at geographically diverse, promising wind-resource areas during the remainder of the decade. Wind generation incorporated into system benefits charge programs and current utility plans could accomplish this objective. In addition, more analysis of the intermittent nature of wind resources and the requirements for firming the resource is needed. Using the hydroelectric system to firm-up wind may have adverse effects on the ability to produce other ancillary services or reliably meet fish-operations requirements.

The resource plan calls for being fully prepared to begin construction, if needed, of coal resources by the beginning of 2012. Being ready to begin construction means that the siting and licensing of the necessary projects have been accomplished and, if necessary, longer lead-time activities, such as construction of transmission upgrades, have been initiated so that resources can be brought on-line as needed. The Council has analyzed both conventional coal-steam and coal-gasification generation. Recent information indicates that coal-gasification generation has entered the early stage of commercial availability. The analysis indicates that coal-gasification power plants have lower expected costs and, because they are more efficient and produce lower emissions, including carbon dioxide, lower environmental risk compared to the use of conventional coal-fired-generation technology.

However, if commercialization of coal-gasification technology fails to advance as forecast, and other estimates underlying the plan do not change significantly, 400 megawatts of conventional coal-fired capacity could be needed by mid-2013.



This would require preconstruction development to commence by mid-2007 so construction could begin as early as 2010. To provide for this contingency, the Council will issue an assessment of the progress of commercialization of coal-gasification combined-cycle technology and other estimates underlying the plan by 2007. The Council recognizes that individual utilities may find it necessary to acquire additional generation before the schedule set forth in the portfolio analysis. Commitment to coal-gasification technology for near-term acquisitions may be premature.

New gas-fired generation does not figure in this power plan until late in the planning period, largely because of higher gas prices and the expectation of greater volatility in gas prices. Nonetheless, it could figure prominently later in the planning period as the more promising wind sites are developed and carbon-emissions concerns become more significant. While not modeled in the resource plan, gas-fueled, co-generated power from oil sands development in Northern Alberta might be an alternative. Its greater thermal efficiency would improve carbon emissions and reduce fuel costs. Its future depends on the development of transmission from Northern Alberta to bring the power into the region.

The Council recognizes that a plan developed from a regional perspective cannot fully reflect the situation of each individual utility in the region. As described earlier, legitimate reasons exist for individual utility plans to differ in resources or resource timing from this plan. Nevertheless, the plan offers the region real value. It provides an independent source of information on the state of the regional power system and the available alternatives. It also sets a regional goal for

If the region is in surplus, why are some utilities seeking generating projects now?

- While the region has excess generating capacity, in aggregate the region's utilities are energy-short
- Some utilities may need additional peaking capacity or want to reduce their exposure to the market
- Requests for proposals are an effective tool for assessing available options
- Most of the surplus generation is owned by IPPs. This power is available to the region. However, utilities may have reasons not to purchase from the IPPs:
 - 1) They may not want to take on additional gas-price risk. (Most IPP projects are gas-fired)
 - 2) Transmission limitations may preclude access to existing generation on a firm basis
 - 3) Utilities might want to get experience with newer technologies such as wind
 - 4) Utilities may see advantages in building their own:
 - Financial advantages may accrue to utilities that own a physical asset rather than a purchase contract
 - Investor-owned utilities can earn a rate of return on projects they own
 - Publicly-owned utilities can finance projects at lower costs
 - Credit risk issues may increase the cost of long-term purchases from IPPs

conservation acquisition. The goals outlined in past power plans have played a key role in the region's achievement of 2,500 average megawatts of low-cost conservation savings since 1980.

The plan also provides strategic insights that have broad applicability. For example, this plan demonstrates the value of sustained investment in conservation. It also suggests that in many situations during the next few years, some reliance on market purchases of power, much of which could be supplied by in-region independent power producers, can be a lower-cost and lower-risk option. In addition, the method of treating uncertainty and risk in this plan is an approach that can and should be applied in individual utility planning.

Implementing the Plan

To reach the region's goal of an adequate, efficient, economical, and reliable power system, the Council's power plan identifies an implementation strategy for the next five years. The elements of that strategy and some of the key actions were outlined in the Executive Summary. The following section on the Action Plan describes those strategies in detail.

The Council expects to monitor the implementation of the plan and report biennially on the region's progress. The biennial implementation reports will update important information that may affect the plan, including electricity demand, fuel prices, resource development, and significant advancements in technology.

Mountain meadow on the north slope of Mt. Hood, Oregon.



The Action Plan

The Council believes it is critical that the region act now to help secure an adequate, efficient, economical, and reliable power system. The Council is recommending the following actions during the next five years to implement the power plan.

Develop Resources Now That Can Reduce System Cost and Risk

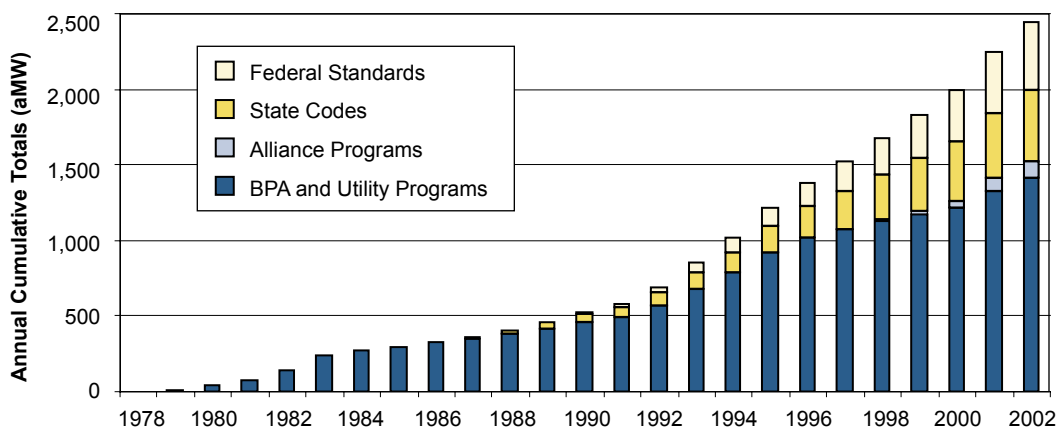
Conservation

Conservation is the highest priority resource under the Northwest Power Act, as shown in Figure AP-1. The region has developed nearly 2,500 average megawatts of conservation since its passage at an average levelized cost of approximately 2.5 cents per kilowatt-hour. Despite the conservation that already has been achieved, there remains a significant amount yet to be developed, largely as a result of new technologies of efficiency.

Conservation has several unique characteristics when compared to other resources. First, the cost of conservation is almost entirely

capital, while operating costs are minimal. This means that unlike a conventional generating unit, there are no operating costs to be avoided when demand is low. Conversely, compared to generating power plants, conservation always produces savings of some value and reduces the risk of increases in fuel prices and the cost of electricity. Second, it has no environmental emissions. This means that conservation reduces the risks associated with future environmental controls. Third, some types of conservation resources are “discretionary,” i.e., they can be developed when they are needed. On the other hand, some conservation resources are not discretionary. For these “lost-opportunity resources,” it is only feasible and/or cost-effective to capture them when, for example, a building is constructed or an appliance is purchased. Fourth, conservation resources come in small increments and have relatively short lead-times for development compared to generation and transmission, assuming the necessary programs and budgets are in place. This means that at least for conservation that can be scheduled, there is some ability to change implementation in response to prevailing conditions.

Figure AP-1: Regional Conservation Savings



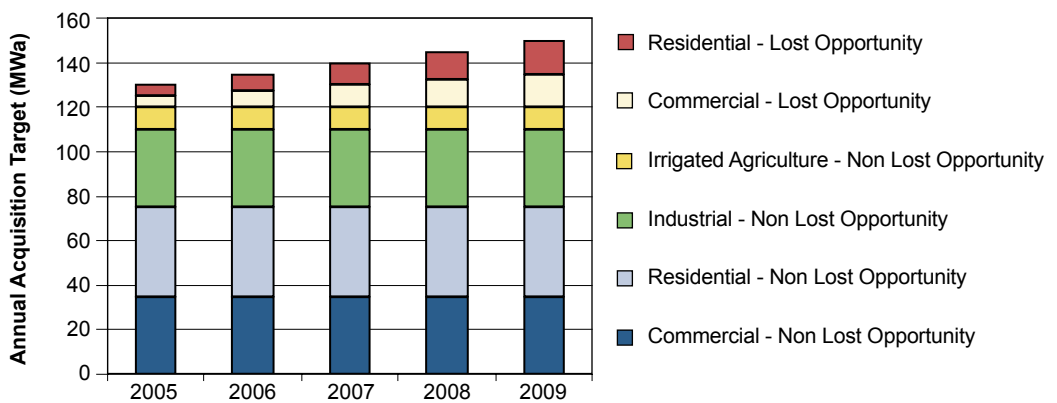
Taking these characteristics into account, the Council’s analysis indicates there is value in aggressively pursuing the development of conservation. In fact, developing some additional conservation beyond that indicated by short-run power prices provides additional value in mitigating fuel costs, market price, and environmental risks. To achieve this, the Council recommends the following actions:

Increase Regional Conservation Acquisition

The Council recommends that the region target 700 average megawatts of cost-effective conservation acquisitions from 2005 through 2009.⁴ The Council recommends that conservation resource development be split between “lost opportunity” and “non-lost opportunity” or “discretionary” conservation, and across all sectors. Figure AP-2 shows the Council’s recommended annual minimum targets by sector and resource type.

The Council’s analysis indicates that regional investment in cost-effective conservation at this level is more likely to lead to a more economical and reliable power system than alternative development policies. The Council’s analysis found the near-term conservation targets set forth in this plan to be consistent across a wide range of future conditions for load growth, electricity market prices and other factors over the five-year Action Plan period. The analysis also demonstrated the value of sustained investment in conservation. Allowing levels of conservation investment to vary with the market price of electricity resulted in higher costs and risk. The Council recognizes that the conservation target represents an increase over recent levels of development. However, the Council’s analysis shows that developing less conservation exposes the region to substantially higher costs and risks. The development of conservation resources provides a “hedge” against future market price volatility. Developing these conservation resources reduces both net present-value system cost and risk.

Figure AP-2: Regional Conservation Targets 2005 -2009



4 The targets set forth in this plan are for cost-effective conservation as defined in the Northwest Power Act. The method for programmatic implementation of cost-effectiveness is set forth in Appendix E, Conservation Cost-Effectiveness Determination Methodology. This methodology takes into consideration that there is no one single cost-effectiveness limit for all conservation measures. Each measure or program has a unique benefit to cost ratio that reflects the value of avoided market purchases based on when the measure’s energy savings occur, and avoided transmission and distribution costs based on when any capacity savings occur. Many other factors are included in the cost-effectiveness methodology. See Appendix E for details.

ACTION CNSV-1⁵

Increase lost-opportunity resource acquisitions

Many of the cost-effective lost-opportunity resources identified in the power plan are relatively new and do not have established programs or approaches for their acquisition. Utilities, with the support of regulatory commissions, the Bonneville Power Administration, system benefits charge administrators (SBC Administrators), the Northwest Energy Efficiency Alliance (Alliance), other program operators, and state and federal standard-setting agencies should increase the annual acquisition of lost-opportunity conservation resources. Existing programs should be expanded, new programs initiated, and codes and standards improved so that within 12 years from the adoption of the plan, the region is capturing at least 85 percent of the cost-effective lost-opportunity potential available annually.^{6, 7} The Council recognizes that near-term lost-opportunity program costs may be relatively high due to start-up costs and initially low market-penetration rates. However, these resources should be pursued so long as program operators can reasonably anticipate that mature program costs and penetration rates will provide cost-effective savings.

ACTION CNSV-2:

Increase non-lost-opportunity resource acquisitions

Utilities, with the support of regulatory commissions, Bonneville, SBC administrators, the Alliance, and other program operators, should increase the annual acquisition of non-lost opportunity (discretionary) conservation resources to capture at least 120 average megawatts of regionally cost-effective savings within one year of the adoption of the power plan. Measures and programs providing greater cost- and risk-reduction should be given priority. This level of annual non-lost-opportunity resource acquisition should be sustained for at least five years.

Strategically Plan Conservation and Provide Adequate Regional Coordination and Administration

Achieving the Council's recommended conservation target will require significant new initiatives, including regional and local acquisition programs, improved energy codes and equipment standards, and market transformation ventures. In addition, the Council believes that acquiring cost-effective conservation in a timely and cost-efficient manner requires the thoughtful development of mechanisms and coordination

5 Each action has been given an identifier, e.g., CNSV-1, for ease in future reference.

6 Lost-opportunity potential varies year-to-year, depending on the number of new buildings constructed, new appliances purchased, and equipment installed. Rates of new installations tend to follow economic cycles, so the Council recommends a maximum penetration rate of 85 percent rather than an energy target. Under medium load growth, an 85 percent penetration rate for lost opportunities would be about 70 average megawatts per year.

7 The Council's estimate of 12 years to reach 85 percent penetration for lost-opportunity measures is based on experience from the last two decades. Several conservation initiatives, including those for residential refrigerators, clothes-washers, and efficient manufactured homes, exhibit a cycle of 10 to 12 years to reach roughly 85 percent penetration of the efficiency levels conceived at program inception. The Council expects that the lost-opportunity measures identified in this plan will take a similar period to develop. However, some measures will be faster and some slower depending on the success of improving codes and standards, market transformation efforts, and technological improvements.

among many local, regional, and national players. The Council recognizes and supports the desire of many public utilities in the region to take greater responsibility for resource development instead of relying on Bonneville. Nonetheless, the Council believes coordinated efforts will be an increasingly necessary ingredient to develop the remaining conservation potential successfully.

The boundaries are blurred among direct acquisition approaches, market transformation, infrastructure support, and codes and standards. In fact, for much of the conservation resource, efforts are needed on all of these fronts to bring emerging efficiency measures into common practice or minimum standard. Of increasing importance is improved coordination among conservation programs operated by local utilities, SBC administrators, the Alliance, Bonneville, and other local, state, and federal conservation entities. Improved coordination is needed to assure that the region can target initiatives where they have the most impact, acquiring the most savings for the lowest cost.

To accomplish the conservation targets set forth in the power plan, the region needs to resolve these key strategic issues: 1) Defining Bonneville's role in conservation implementation; 2) developing a mechanism and funding for conservation that is best acquired and assessed regionally; 3) defining the role, funding, and structure of the Regional Technical Forum; and 4) developing a mechanism and funding for regional conservation research and development.

In addition to resolving these key strategic issues, a strategic plan for conservation should set forth a process and funding to evaluate measure and program performance and to review periodically and revise program focus, if neces-

sary. The Council recognizes that its estimates of costs and savings for measures may need to be revised as the future unfolds. The performance of measures, the degree of certainty of costs and savings, program penetration rates, market-driven adoption rates, changing measure costs, the adoption of revised codes and standards, and other factors should be considered in determining how programmatic efforts should be strategically targeted to make best use of limited conservation budgets. Furthermore, during the next five years, conservation measures and practices not included in the Council's conservation assessment are likely to emerge. If cost-effective, such measures should be pursued.

ACTION CNSV-3

Develop a strategic plan for conservation acquisition

The Council, with Bonneville, utilities, SBC administrators, the Alliance, regulators, state energy offices, the efficiency industry, and other stakeholders will convene a forum to develop a strategic plan to achieve the conservation targets set forth in the power plan, including model conservation standards. This strategic plan will establish the implementation role that Bonneville, utilities, SBC administrators, the Alliance, regulators, state energy offices, and the Regional Technical Forum will play. It will allocate the share of the regional conservation target to be accomplished by each of these major entities and resource development mechanisms. The strategic plan will set forth recommendations for regional coordination, conservation infrastructure development (such as training, education, certification, market research, and evaluation), program evaluation and revision, and administration. The Council

will convene the forum within three months of issuing its Fifth Power Plan. The resulting strategic conservation plan should be presented to the Council within one year.

The Council believes any strategic plan will require specific actions and increased efforts in the categories of local acquisition, market transformation, codes and standards, and regional coordination/acquisition. While the Council cannot prejudge the specifics of the strategic action plan, recommended actions and approximate budget ranges are set forth here for each of these categories.⁸ More detailed discussion of the conservation acquisition approaches by sector and measure is in Appendix D.

ACTION CNSV-4

Increase local acquisition budgets

The Council has estimated that an average annual aggregate utility investment of between \$215 million and \$290 million (2004 dollars), excluding market transformation and regional coordination and acquisition, will be needed to achieve the 700-average-megawatt target during the next five years.⁹ The amount each utility or SBC administrator will need to invest to meet its share of the regional target will depend on its customer mix, growth rate, local economic conditions, program designs, and other factors. The Council estimates that Bonneville and Northwest utilities invested slightly more than

\$215 million (2004 dollars) in conservation in 2002. Therefore, the Council anticipates that local conservation acquisition expenditures will need to increase over current levels to capture fully the benefits of conservation.

ACTION CNSV-5

Expand market transformation initiatives

A portion of the regional conservation target can be acquired most efficiently and effectively through market transformation. The Council's conservation analysis indicates there are additional candidates for new or expanded market transformation ventures. These activities are outlined in Appendix D and include a potential demonstration program for heat-pump water heaters and new or expanded programs for new, efficient, multi-family homes, gravity film heat exchangers, residential compact fluorescent lighting, AC/DC power converters, high-performance commercial lighting, packaged commercial refrigeration equipment, efficient fume hoods, evaporative assist cooling, commercial roof-top HVAC repair and optimization, and others. While the Council anticipates that market transformation acquisition expenditures will need to increase significantly over current levels to capture fully the benefits of conservation, it believes that the level of investment in regional market transformation initiatives should be resolved during the development of the strategic plan for conservation acquisition.

8 The Council sets forth these initial estimates as broad indicators of anticipated utility system expenses. The Council expects the strategic planning process will be used to refine estimates. While the Council expects the sum of conservation budgets of Bonneville, the utilities, the Alliance, SBC administrators, states, and others to be in the ranges identified, it fully acknowledges that budgets needed to acquire the conservation may differ from the Council's expectations. The Council encourages efforts to reduce the utility share of conservation costs to reduce rate impacts, so long as savings targets are met.

9 The derivation of this budget estimate is described in Appendix D.

ACTION CNSV-6

Revise and adopt state and federal energy codes and efficiency standards that capture all of the regionally cost-effective savings

Codes and standards are the most effective method to capture some of the lost opportunity conservation potential identified in the power plan. To achieve savings from new and revised codes and standards, actions must be taken by federal and state government, utilities, SBC administrators, and the Alliance:

- The states should adopt efficiency standards identified in the power plan for appliances and equipment not pre-empted by federal law, including but not limited to commercial refrigerators, freezers, ice-makers, power transformers, and AC/DC power converters

- The U.S. Department of Energy should adopt or revise standards identified in the power plan for residential clothes-washers, dishwashers, refrigerators and freezers, and other appliances and equipment currently covered by federal law
- The U.S. Department of Housing should revise its efficiency standards for new manufactured homes so that these standards satisfy the Council's Model Conservation Standards
- Bonneville, utilities, SBC administrators, and the Alliance should implement the Council's Model Conservation Standards for New Residential and Commercial Buildings Programs within the next five years
- State and local code authorities should revise existing energy codes during the next code-update cycle so they provide savings equivalent to the Council's Model Conservation Standards for New Residential and Commercial Buildings (Appendix F)
- The Alliance, utilities, SBC administrators, and states should provide ongoing annual funding and technical and political support for timely adoption of federal standards to capture cost-effective savings identified in the power plan

The Council will provide assistance to states and their stakeholders to develop and pass improved energy codes and standards, and it will work through the relevant federal processes to advocate for improved codes and standards.

Codes and standards for residential appliances can be improved to capture cost-effective savings.



Develop Mechanisms and Funding for Regional Coordination and Limited Regional Acquisition

The Council believes that a significant share of the savings identified in the power plan can be more effectively and efficiently acquired through regionally administered programs or, at a minimum, will require a regional scope to achieve economy of scale or market impacts. These actions may not qualify as market transformation as currently defined. They include regional coordination and potential acquisition payments for efficient AC/DC power converters, commercial refrigerators and freezers, residential heat-pump water heaters, and Energy Star manufactured homes. These actions could cost \$5 million to \$10 million annually during the next five years. In the past, Bonneville has played a similar role and could do so in the future if the region so decides.¹⁰ The Alliance could also coordinate such activities if its market transformation mission were expanded. The Council intends to use the strategic planning process identified earlier to resolve this question.

ACTION CNSV-7

Within 12 months, the Council, regulators, Bonneville, utilities, SBC administrators, the states, and the Alliance should establish a mechanism and funding to develop regional coordination and acquisition not under the category of market transformation

The options to be considered include using Bonneville, expanding the mission and budget of the Alliance, creating another mechanism to target actions best adminis-

tered regionally, and using some combination of these three options. As with market transformation, care should be taken to ensure that a regional organizational framework of utilities, contractors, and government agencies is in place to carry out the day-to-day acquisition activities.

Track Regional Conservation Accomplishments

Conservation plays a major role in the power plan. It will be essential to track the region's accomplishments.

ACTION CNSV-8

Within six months of adoption of the power plan, the Council, regulators, Bonneville, utilities, SBC administrators, the states, and the Alliance should establish a mechanism and funding to track and report regional conservation investments and accomplishments annually

The Regional Technical Forum or state energy agencies should be considered potential vehicles to accomplish this. State government agencies could add conservation data to the data already collected from utilities. It is essential that sufficient resources, financial and otherwise, be committed to this activity. Estimated costs for tracking and reporting should be developed as part of the strategic plan for conservation acquisition.

¹⁰ For example, Bonneville administered the Manufactured Housing Acquisition Program on behalf of all the region's public and investor-owned utilities.

Address Important Barriers

Utility implementation of conservation has historically faced several barriers. New barriers may emerge if changes like those proposed for the Bonneville Power Administration take effect. Efforts should be made to remove these barriers.

ACTION CNSV-9

Regulators and local boards and commissions should establish criteria and processes for evaluating and reflecting the value of conservation as a hedge against future risks

This should be accomplished in time to be incorporated in subsequent utility integrated least-cost plans. The Council will offer its assistance in these efforts.

ACTION CNSV-10

If revenues lost as a result of conservation remain significant barriers to implementing the cost-effective conservation targeted in the plan, state and local regulators and utilities should consider developing and implementing strategies to mitigate conservation impacts on cost recovery

Utilities should not be penalized financially for reduced retail sales. From a utility perspective, cost-effective energy efficiency investments should be at least as attractive as the avoided investments in generation and grid infrastructure. To eliminate a significant financial disincentive for utilities' energy efficiency initiatives, state and local regulators should consider adopting simple true-up mechanisms that eliminate an unintended link between utilities' retail kilowatt-hour sales and their ability to recover authorized fixed costs. An important step in this direction is a simple system of modest true-ups in

electricity rates, which corrects any annual fluctuations in a utility's retail electricity sales that regulators did not expect when they set the rates initially. Alternatively, rate designs could be modified to reduce the fixed costs recovered in the per-kilowatt-hour charges, combined with carefully designed increasing block rates.

ACTION CNSV-11

Consider financing conservation investments

Because conservation costs are all capital and because they are often expensed, they tend to have short-term rate impacts. The increase in conservation acquisitions identified in the power plan will require an increase of less than one percent of total electric system revenue requirements over that spent in 2002. Nonetheless, cash-flow constraints and competitive pressures on their rates often limit utilities. Financing conservation in the same way that other resources are financed can mitigate these short-term rate impacts, although at some expense of increasing long-run costs. However, the fact that conservation is not a physical asset that the utility owns can be a barrier. This can be reduced, if not overcome, if the states adopt legislation defining conservation investment as a guaranteed regulatory asset. Such an asset would be created by a state guaranteeing the ability of the utility to recover its conservation costs. This instrument could be available to SBC administrators as well as to utilities.

ACTION CNSV-12

Low-Income Housing Weatherization

Cost-effective conservation acquired as a result of low-income housing weatherization

programs has proven to be a useful addition to the region's conservation portfolio. Bonneville and utilities should continue to provide support for this activity where cost-effective savings are achieved. The Council acknowledges that there are non-energy benefits of weatherizing low-income housing that have not been quantified in its analysis. Bonneville and utilities should consider these non-energy benefits when determining whether to support these programs. However, utility system support for low-income housing weatherization that is not cost-effective should not reduce the funding available for acquiring the cost-effective conservation targeted by the power plan.

ACTION CNSV-13

System Benefits Charge

Two Northwest states have established system benefits charge approaches to conservation. In this approach, conservation is funded by a charge on all customers' bills and an administrator, usually other than the utility, disburses funds for conservation acquisition. Other states have adopted similar approaches. But these systems are new and have a limited track record. If utility disincentives seriously impede utility investment in conservation, consideration should be given to a system benefits charge approach to conservation funding and acquisition. The Council will review the performance and effectiveness of Oregon, Montana, and other SBC systems around the country by 2008.

ACTION CNSV-14

As the Bonneville Power Administration's role in power supply is altered, avoid or remedy disincentives to utility conservation

The effort to alter Bonneville's role in power supply is likely to involve an allocation of power from the existing federal system to qualifying customers. Customers are concerned that the allocation could create a disincentive to conservation. Bonneville should design and implement allocation methodologies and net requirements calculations to avoid disincentives to utility conservation acquisition.

Demand Response

Demand response is an appropriate, voluntary change in the level of electricity use when electricity is in short supply. Although technically not a resource under the definition in the Act, it is a practical means of reducing power system costs and reducing the need for investment in more expensive generating resources. Demand response can be accomplished by a variety of approaches, which generally can be grouped into two categories—price mechanisms and demand “buybacks.” While the Council believes there are some benefits to price mechanisms that deserve to be more fully explored, for this power plan the Council’s analysis was limited to voluntary buybacks similar to those employed by several regional utilities during the 2000-2001 electricity crisis.

The region has limited experience with demand response, but the available experience has demonstrated substantial potential benefits in terms of limiting both high price excursions and the ability to exercise market power in tight markets.¹¹ The size and value of this resource, however, are somewhat uncertain. For the portfolio analysis, it was conservatively estimated that 2,000 megawatts of demand response could be developed by 2020. Its “operating” cost is assumed to be \$150 per megawatt-hour, with a fixed cost of \$5,000 per megawatt for the first year and \$1,000 per megawatt-year thereafter (2004 dollars). The portfolio analysis suggests that if the region fails to implement demand response, the potential increase in expected system cost could be about \$150 million (net present value) while system risk would increase by \$235

million (2004 dollars). Demand response provides benefits in the form of greater system reliability—utilities have a better idea about what loads they can easily shed in an emergency—and these reliability benefits can be included in the price that utilities may offer to these customers for the right to reduce load.

The Council’s recommended actions are designed to build on the region’s recent experience, to expand the region’s understanding of the demand response resource, and to guide future policies affecting demand response.

ACTION DR-1

Expand and refine existing programs

Bonneville and utilities, with regulators’ approval, should maintain and begin to expand and refine the demand response programs they have developed in the past few years. This should begin immediately. For example, utilities should maintain their ability to buy back demand when conditions warrant, and should work to expand participation in these programs. Utilities should work to reduce the transaction costs of these programs by streamlining recruitment of participants, notification of buyback opportunities, and verification of and compensation for demand reductions.

ACTION DR-2

Develop cost-effectiveness methodology for demand response

Regional parties, including but not limited to Bonneville, utilities, regulators, and the Council, should develop a clear cost-effective-

¹¹ “Market power” exists when one participant controls a sufficient portion of supply of a commodity to be able to influence or set prices.

ness methodology for demand response no later than 2006. While the general principle of avoided cost is well accepted, there are practical difficulties in calculating avoided cost in the region's power system because of the large hydroelectric component and very substantial transmission links to other regions. A clear and widely accepted methodology would ease the development and adoption of demand response programs. The Council could serve as the convener of such an effort, if necessary.

ACTION DR-3

Incorporate demand response in integrated resource plans

Regulators should require utilities to incorporate demand response fully into utilities' integrated resource plans starting with the next planning cycle. Utilities have made a beginning, but more needs to be done. This work should include refining estimates of the size, cost, and availability of the resource. This is likely to require pilot programs and further analysis.

ACTION DR-4

Evaluate the cost and benefits of improved metering and communication technologies

Utilities, with participation by regulators, should evaluate the costs and benefits of improved metering and communication equipment. The lack of such equipment is an obstacle to securing the participation of many customers in demand response programs. Over time, this equipment has become less expensive and more capable. Evaluations of cost-effectiveness of demand response should use the net cost of the necessary metering

and communication equipment, after the equipment's other benefits have been taken into account.

ACTION DR-5

Monitor cost and availability of emerging demand response technologies

The Council, Bonneville, and utilities should monitor emerging demand response technologies. For example, intelligent appliances that can respond to abnormal system frequency have potential to reduce significantly the cost of maintaining system stability.

ACTION DR-6

Explore ways to make price mechanisms more acceptable

Regional parties, including but not limited to utilities, regulators, and the Council, should explore ways to make price mechanisms more acceptable as a potential means of achieving demand response. In many cases, price mechanisms offer significant advantages compared to buybacks, such as lower transition costs and wider reach. However, concerns regarding fairness and price stability have prevented much adoption of price mechanisms in the region. It is worth a serious effort to see whether these legitimate concerns can be met while achieving some of the advantages of price mechanisms. This should be carried out by 2006. The Council could serve as the convener of such an effort, if necessary.

ACTION DR-7

Transmission grid operators should consider demand response for the provision of ancillary services, on an equal footing with generation

It seems likely this will be facilitated by the development of a formal market for ancillary services, but even if a formal market does not develop, demand response should be able to compete to provide ancillary services.

ACTION DR-8

The Council will host several workshops to identify and coordinate efforts to accomplish the above action items

The Council will enlist the participation of utilities, regulators, environmental groups, and other interested parties. The first workshop will be held in the first quarter of 2005.

Cost-effective Renewable and Cogeneration Generating Resources

Regionwide, major bulk-power generating resources appear unlikely to be needed until early in the next decade. However, opportunities for the development of economic renewable energy and cogeneration (combined heat and power) projects are likely to surface occasionally during this period. They could include industrial or commercial cogeneration projects, landfill, animal waste or wastewater treatment plant energy recovery projects, hydropower renovations, forest residue energy recovery, and remote photovoltaics. The opportunity to economically develop these projects is often transient, created by needs not directly related to electric power production, such as a waste disposal problem, equipment upgrading or replacement, or new commercial and industrial development. Utilities, entities administering resource development incentives, and others able to facilitate resource development should establish procedures to identify, evaluate, and secure these opportunities as they arise. Barriers

to the development of small-scale renewable and cogeneration projects should be removed.

ACTION GEN-1

Utilities, with the support of their boards or commissions, and entities administering resource development incentives, should identify cost-effective renewable and cogeneration projects

Identification of potential projects is a precursor to the acquisition of cost-effective projects. One way to identify such projects is for utilities to conduct inventories when developing integrated resource plans. Other approaches include all-source requests for proposals and open windows for unsolicited proposals. These efforts should be tailored to identify potential lost opportunity projects. This should be accomplished by 2007.

ACTION GEN-2

Utilities, with the support of their boards or commissions, and entities administering resource development incentives, should establish current, accurate, and comprehensive procedures and criteria for evaluating renewable and cogeneration projects

Evaluating renewable and cogeneration projects should be based on an accurate assessment of project costs and benefits. Criteria for evaluating resource cost-effectiveness should be current and accurately reflect all of the significant costs and benefits of acquiring the resource. This includes the energy value, possible value of capacity and other ancillary services, offset transmission and distribution costs and losses, and environmental effects. Cost-effectiveness criteria should account for significant risks and uncertainties. This should be accomplished by 2007.

ACTION GEN-3

Utilities, with the support of their boards or commissions, should remove disincentives to utility acquisition of power from projects owned or operated by others

Investor-owned utilities can earn a return on investments in generation they own. However, they earn no such return on power purchase agreements or investment in generation owned or operated by others. This may create a disincentive to securing these resources. Utilities and commissions should work to reduce or remove these disincentives where present. This should be accomplished by 2007.

ACTION GEN-4

Utilities, with the support of their boards or commissions, should adopt uniform interconnection agreements, technical standards, and accurate and equitable standby tariffs

Uniform interconnection standards and fair and equitable standby tariffs will facilitate development of cost-effective, customer-side generation. Utilities, with the support of their commissions where applicable, should adopt uniform interconnection agreements and technical standards, consistent with Federal Energy Regulatory Commission jurisdiction. Standard agreements should be transparent, free of unnecessary complexity, and expeditiously processed. Standby tariffs should accurately and equitably reflect the costs and benefits of customer-side generation. This should be accomplished by 2007.

ACTION GEN-5

Utilities, with the support of their boards or commissions, and entities administering

resource development incentives, should acquire cost-effective lost opportunity renewable and cogeneration projects

Utilities should acquire cost-effective renewable and cogeneration projects, either by power purchase or investment. This should be in effect by 2006.

ACTION GEN-6

Utilities, with the support of their boards or commissions, should facilitate the sale of excess power from customer-side generation

The economics of cogeneration and other customer-side generation can be improved by the ability to market power in excess of customer needs. Utilities, with the support of their commissions where applicable, should facilitate the sale of excess customer-generated power. Possible means include the expansion of eligibility for net metering agreements and offering accurate and equitably priced distribution system access for sale of excess power. Because the seasonal and daily variation of the value of power is expected to become more significant in the future, net metering should be based on time of day metering. This should be accomplished by 2007.

Prepare to Construct Additional Generating Resources When Needed

The conservation goals of the power plan, in addition to generating plants currently under construction¹² and the expected acquisition of more than 1,100 megawatts of wind or other renewable resources by system benefits charge programs, are expected to defer the need for additional generating resources until after the end of the decade. The plan foresees a possible need for additional wind capacity in-service beginning in 2011, leading to as much as 5,000 megawatts of new wind capacity by the end of the 20-year plan.¹³ Wind incorporated in the plan plays this major role for several reasons: The probability of more aggressive policies to reduce carbon dioxide production; the abundance and quality of the resource; expectations of continued wind plant cost reductions and performance improvements; relatively low integration costs; and the timely availability of electrical transmission service at promising wind resource areas. Wind development in excess of the plan's target is thought to be more expensive than other resource alternatives because of lower resource quality, transmission expansion requirements, and higher integration cost (Chapter 5).

The plan foresees the need for 425 megawatts of coal-gasification power generation capacity to supplement wind power development to be in-service as early as 2016. Coal-gasification combined-cycle technology offers economic power

generation from coal with less environmental impact than conventional coal-fired power generation. The Council has analyzed both conventional coal-steam and coal-gasification generation. The analysis indicates that use of coal-gasification technology would lower expected system cost and risk and has lower emissions of pollutants, including carbon dioxide.

A factor leading to the lower cost and risk associated with use of coal-gasification is that it delays the earliest need for a new coal-gasification resource to 2016.¹⁴ However, the analysis is predicated on continued commercialization of coal-gasification technology. If commercialization of coal-gasification technology fails to advance as forecast and other estimates underlying the plan do not change significantly, 400 megawatts of conventional coal-fired capacity could be needed as early as mid-2013.

The Council recognizes that individual utilities may find it necessary to acquire additional generation before the schedule set forth in the portfolio analysis. Commitment to coal-gasification technology for near-term resource acquisition may be premature.

The increasing probability and magnitude of carbon dioxide penalties lead to the conclusion that natural gas combined-cycle plants may become the thermal resource of choice during the latter portion of the 20-year plan. The lead-time for these resources is such that preparatory actions are not required during the five-year action plan period.

12 The Port Westward project plus several small projects.

13 In addition to an estimated 1,100 megawatts of wind or equivalent renewable or cogeneration resources expected to be acquired under system benefits charge programs.

14 Other factors equal, deferral of resource development will lower cost and risk.

Maintain an Inventory of Ready-to-Construct Projects

Permitting and other preconstruction project development activities are a time consuming, but relatively inexpensive part of the project development process. Construction lead-time and exposure to the risks of shortage and electricity market price volatility can be reduced at low cost by maintaining an inventory of ready-to-develop projects ("options"). The Council recommends developing and maintaining a regional inventory of ready-to-construct projects, sufficient to meet possible needs under the least risk plan and plausible deviations from that plan.

The portfolio analysis, described in Chapter 7, concludes that 100 megawatts of wind capacity may be needed by early 2011, and an additional 1,400 megawatts by early 2013. Completion of 100 megawatts of wind capacity by early 2011 would require construction to start in 2010. Preconstruction activities typically require two years; less, if development efforts are underway, as they are at present. This implies that preconstruction development for the first increment of wind power should commence by early 2008 so project construction could occur, if needed, during 2010.

Completion of 1,400 megawatts of wind capacity by 2013 would require construction to start by early 2012. This is a very large block of capacity for development within a single year, and it is more practical to plan for phasing this capacity during the two-year period following the first increment. Therefore, preconstruction activi-

ties for an increment of 700 megawatts of wind power should commence by early 2009 so project construction could occur, if needed, during 2011 for completion by 2012. Preconstruction activities for another increment of 700 megawatts should commence by early 2010 so project construction could occur, if needed, during 2012 for completion by 2013. This inventory adds to the renewable generating capacity planned to be acquired with system benefits charge funds.

Completion of 425 megawatts of coal gasification combined-cycle capacity by early 2016 would require construction to start during 2012. Because preconstruction development of coal-fired capacity is estimated to require up to three years, preconstruction development should commence by early 2009 so project construction could begin, if needed, during 2012 for completion by 2016.

If commercialization of coal-gasification technology fails to advance as forecast, as mentioned earlier, and other estimates underlying the plan do not change significantly, 400 megawatts of conventional coal-fired capacity could be needed by mid-2013. This would require preconstruction development to commence by 2007 so construction could begin as early as 2010.¹⁵ To provide for this contingency, the Council will issue an assessment of the progress of commercialization of coal-gasification combined-cycle technology and other estimates underlying the plan by 2007.

¹⁵ Preconstruction activities for a conventional coal-fired power plant are estimated to require 36 months. Construction is estimated to require 42 months if immediately following completion of preconstruction activities.

ACTION GEN-7

Project developers, working with permitting agencies and other participants, should develop and maintain an inventory of ready-to-develop projects (options) for possible future needs in accordance with the schedule shown in the table below

The key date of the table is the "Option-in-Place" date.

ACTION GEN-7A

The Council will issue an assessment of the commercial progress of coal-gasification combined-cycle technology by 2007

If commercialization has not progressed as forecast in this plan, and other estimates underlying the plan have not changed significantly, siting and permitting of 400 megawatts of conventional coal-steam generation would need to begin in 2007, in lieu of the 425 megawatts of coal-gasification combined-cycle capacity called for in Action GEN-7. The 400-megawatt option for conventional coal-fired generating capacity should be completed by early 2010.

Resolve Uncertainties Associated with Large-scale Wind Development

The plan foresees the construction of up to 5,000 megawatts of wind capacity in the Northwest during the next 20 years, in addition to expected acquisitions supported by system benefits charges. Uncertainties associated with the assumptions the estimate is based upon must be resolved to confirm the potential role of wind, and to facilitate its future large-scale development when needed.

The intermittent output of wind projects must be shaped to service utility loads. In the Northwest, the most economical shaping resource is the energy storage capability of the hydropower system. Preliminary studies indicate that several thousand megawatts of wind capacity can be economically shaped, largely using the federal and non-federal hydropower system. Though these studies have not suggested that other operations of the hydropower system, including fisheries operations, would be impaired by wind shaping operations, conclusive studies to this effect have not been undertaken. Specific studies of

Schedule for Generating Resource Option Development

	Resource	Capacity (MW)	Initiate Option Development	Option-in-Place	Earliest Operation
1	Wind Power	100	First Quarter 2008	First Quarter 2010	First Quarter 2011
2	Wind Power	700	First Quarter 2009	First Quarter 2011	First Quarter 2012
3A	Coal-Gasification Combined-cycle	425	First Quarter 2009	First Quarter 2012	First Quarter 2016
	Or				
3B	Coal-Steam (contingent alternative to coal-gasification)	400	First Quarter 2007	First Quarter 2010	mid-2013
4	Wind Power	700	First Quarter 2010	First Quarter 2012	First Quarter 2013

the possible effects of shaping large amounts of wind power on other functions of the hydropower system are needed.

ACTION GEN-8

Utilities, developers, Bonneville, and entities administering resource development incentives should confirm cost-effective, large-scale wind power development capability

An effective way to resolve the uncertainties regarding large-scale development of wind generation is to develop commercial-scale pilot wind power projects at promising wind resource areas. While not necessarily cost-effective when developed in advance of need, actual projects appear to be a better approach to resolving these uncertainties than work in the abstract as recommended in earlier plans. Construction of one commercial-scale project per year, on average, during the course of five years with a minimum of 500 megawatts of capacity could, if located at diverse geographic areas, confirm up to five promising resource areas, and provide information needed to help resolve the uncertainties associated with subsequent large-scale development of wind. Projects developed through the efforts of SBC administrators and by utilities planning the near-term acquisition of wind power should be sufficient to achieve this objective. Accomplishing this will require that project selection, development, and operation be designed to support the objectives of this action. Data required to assess the cost of integration and the benefits of geographic diversity must be available to researchers.

When developing the first project at an undeveloped promising wind resource area,

the acquiring entity (utilities, Bonneville, or SBC administrators), working with the project developer, should seek to: 1) assess the development potential of the resource area as a whole, including the wind resource, environmental issues, and transmission and other infrastructure requirements; 2) establish long-term wind monitoring capability where none exists for the site; 3) monitor wind power cost and performance trends; 4) assess the cost of firming and shaping, including the possible benefits of geographic diversity; 5) improve the understanding of the capacity value of wind; 6) secure the permits, to the extent feasible, for developing the ultimate potential of the resource area; and 7) strengthen regional wind development infrastructure.

ACTION GEN-8A

The Council will develop a Wind Confirmation Plan

Regional coordination will be needed to achieve these objectives. The Council, working with Bonneville, utilities, SBC administrators, applicable state agencies, the wind industry, and other stakeholders will convene a forum to develop a strategic plan for accomplishing the objectives of Action GEN-8. The plan will include operational definitions of the objectives, approaches, and schedules for achieving the objectives, roles and responsibilities, funding requirements and possible sources of funding, procedures for information exchange, follow-on coordination and monitoring requirements, and other agreements needed to achieve these objectives in a timely manner. The strategic plan will be completed within one year of adoption of the Fifth Power Plan.

ACTION GEN-9

The Council will assess the effects of shaping wind power on other functions of the hydropower system

A better understanding of the possible effects of shaping large amounts of wind capacity on the hydropower system is essential to correctly valuing shaping services and to establishing possible operational limits on those services in order to avoid adversely affecting other hydropower system operations. The Council will take the lead in devising and conducting an assessment of these effects. Bonneville, the Corps of Engineers, utilities having hydropower resources suitable for shaping wind energy, and other stakeholders are encouraged to participate in this assessment.

ACTION GEN-10

Utilities and Bonneville should develop products for firming and shaping wind

A competitive slate of firming and shaping products will facilitate the timely and

economic development of wind power. The Council encourages Bonneville, utilities, and others that have resources suitable for providing shaping and firming services to aggressively develop and market these products.

Encourage Use of State-of-the-Art Generating Technology When Siting and Permitting Projects

The five-year period of the action plan will see continued advances in generating technologies. Within the past year, for example, construction began in the Northwest on Port Westward, a gas-fired combined-cycle power plant incorporating advanced gas turbine technology. During the same period, industry developments have propelled coal-gasification combined-cycle power plants to the point of commercialization. Advanced technologies will offer improved efficiency, economics, and environmental characteristics likely to provide a reduction in system cost and risk worth the possible cost and uncertainty associated with early adoption.

ACTION GEN-11

Project developers, federal, state and local permitting agencies, utilities with the support of their commissions, architect-engineering firms, and financing entities should seek the use of state-of-the-art generating technology for new power plant construction

Project developers, state and local permitting agencies, utilities, commissions, architect-engineering firms, and financing agencies are encouraged to routinely consider state-of-the-art generating technologies for new power plant construction. The costs and benefits of these technologies should be evaluated using state-of-the-art risk analysis techniques.

Wind turbines at the Stataline Wind Energy Center near Touchet, Washington.



Plan for Needed Transmission

Transmission planning and construction can be the longest lead-time item in power plant development. Efforts should continue to identify the transmission requirements to connect load to areas of likely power plant development, and to undertake preliminary planning. (Additional recommended actions regarding transmission are discussed on page 60.)

ACTION TX-1

The Council will work with Bonneville, other transmission providers, permitting agencies, and project developers to plan for long-distance transmission needs to support the resource development called for in the power plan

The Council will work with the Northwest Transmission Assessment Committee and similar organizations to improve the integration of resource and transmission planning. This effort will incorporate the transmission planning assessments into the Council's power plan. Transmission planning should specifically address the needs of wind and other location-bound resource development.

Improve Utilization of Available Transmission Capacity

Some regional transmission paths are physically underutilized although they have little available contractual transmission capacity. The result is an inefficient use of transmission that can be an impediment to developing needed resources. Bonneville has undertaken some efforts to improve the utilization of transmission capacity within its control area. This effort, while helpful, is limited because it cannot encompass the larger Northwest grid. The existing scheduling rules for



transactions that cross control-area boundaries further complicate the situation. Dealing with this problem across the wider regional grid should be a priority for any regional transmission operator that may be formed.

ACTION TX-2

Bonneville and other transmission providers should work to improve the utilization of available transmission capacity

Dealing with this problem across the wider regional grid should be a priority for any regional transmission entity that may be formed. Should this effort fail, transmission providers and control areas should work cooperatively to improve utilization of transmission capacity across the regional grid. This should be completed by 2007. A useful but limited first step could be broader participation in WestTrans. This Open Access Same-Time Information System (OASIS) site provides a

broader mechanism for facilitating a secondary market in transmission capacity than single provider OASIS sites. WesTTrans could begin to address the discrepancy between physical capacity and contract path limitations by developing a common available transmission capacity calculation. Bonneville and other Northwest transmission owners should participate in this initiative.

Develop Cost-effective Generating Resources When Needed

Construction of new bulk electrical generating resources may be needed on a regionwide basis as early as 2010. Individual situations may require individual utilities to acquire new generation before this time. When new resources are needed, the Council encourages utilities to consider all of the available options, and to consider the effects of risk and uncertainty on the cost-effectiveness of a resource.

ACTION GEN-12

Utilities, with the support of their commissions, should acquire the best available generating resources when needed

Utilities, when seeking additional generation, should ensure that all of the feasible options, including non-generation alternatives, are considered; that alternatives are evaluated using state-of-the-art methods of assessing costs and benefits; and that all of the significant risks and uncertainties are considered during the anticipated life of the project. Other considerations equal, the generating resource priorities of the Northwest Power Act should apply.

Confirm the Availability and Cost of New Resources with Cost and Risk Mitigation Benefits

Coal-Gasification Power Generation with Carbon Sequestration

Coal-gasification power generation offers the opportunity for improving the economic and environmental aspects of generating electricity from coal, an abundant and low-cost energy resource readily available to the region. Recent developments, including announced plans for several commercial coal-gasification, combined-cycle projects and industry actions enabling provision of whole-plant design, construction, and warranties, indicate that coal-gasification power generation technology is entering the early-commercial stage. Though the technology will undoubtedly improve during the coming years, coal-gasification, combined-cycle power generation appears to be available with respect to the power plan, and it is included in the recommended resource portfolio.

Coal-gasification technology also offers the potential for economic separation of carbon for geologic or ocean sequestration. If perfected, this would help resolve the fundamental conflict between reduction of greenhouse gas production and continued reliance on coal as a primary energy resource. Though non-power generating coal-gasification plants with separation, pipeline transportation, and injection of carbon dioxide have successfully operated;¹⁶ long-term reliable operation of coal-gasification power plants with

carbon separation has not been demonstrated. A key issue is the reliable long-term operation of utility-scale gas turbine combined-cycle plants using the high-hydrogen content synthetic fuel produced by a coal-gasification plant with carbon separation. Limited short-term testing has confirmed that F-class gas turbines can operate on 100 percent hydrogen fuel. However, long-term reliable operation of gas turbines on pure hydrogen will require resolution of a number of problems including hydrogen embrittlement, flashback, hot section material degradation, and control of emissions of nitrogen oxides (NOx).

A second issue for the Northwest is confirmation of the carbon sequestration potential of promising geologic formations. The most promising are deep-saline aquifers and unrecoverable coal seams underlying much of eastern Montana.

Tampa Electric's Polk Power Station, an integrated coal-gasification, combined-cycle (IGCC) power plant.



¹⁶ The Great Plains Synfuels Plant in Beulah, North Dakota.

In addition, deep ocean disposal and mineral trapping in the basalt formations that underlie much of eastern Washington and Oregon and southern Idaho have been proposed as possible candidates for carbon dioxide sequestration.

The coal-gasification power plant called for in Action GEN-7 provides the opportunity to further develop coal-gasification power generation technology and the technology of carbon separation and sequestration. The feasibility of augmenting the proposed coal-gasification power plant with technology demonstration features without compromising the underlying power generation mission of the plant should be investigated.

ACTION GEN-13

The Council, states, Bonneville, utilities, and other interested organizations should investigate the feasibility of developing the proposed coal-gasification, combined-cycle power plant of Action GEN-7 with advanced coal-gasification technology demonstration capability, including carbon separation and sequestration

The objectives of the project could include demonstration of the operation of the gasifier during an extended period on the full variety of regional coals and lignites, testing of gas turbine operation on high hydrogen fuels, testing and confirming bulk carbon sequestration in suitable regional geologic formations, and testing equipment and process improvements designed to improve the economics of gasification, carbon separation, transport and injection, co-product production, or other aspects of coal-gasification power plants. Demonstration activities should not compromise the basic power production mission of the plant. The availability of federal or other supplementary funding to help cover the cost of the additional investment associated with the demonstration role of the project, or to justify advancing the timing of Action GEN-7 development should be investigated.

Crown Point, in the Columbia River Gorge



ACTION GEN-14

In coordination with Action GEN-13, the Council, states, and utilities should support and monitor efforts to develop carbon-sequestration technology appropriate for Northwest application

Efforts such as the Northern Rockies and Great Plains Regional Carbon Sequestration Partnership, led by Montana State University, charged with identifying and cataloging promising geologic and terrestrial storage sites and helping define carbon-sequestration strategies, should be monitored and supported.

Oil Sands Cogeneration

The oil sands of Northern Alberta contain the largest petroleum deposits outside the Middle East. The resource is in the form of highly viscous bitumen. Large quantities of steam are required to recover the bitumen, which is then processed into a synthetic crude oil. The steam can be produced using gas-fired boilers. However, it is more efficient to produce the steam with cogeneration of electricity. Though several hundred megawatts of cogeneration capacity is operating in the oil sands region, additional cogeneration development is constrained by the ability to transmit electricity from the oil sands region to electrical load centers. A proposed 2,000-megawatt DC transmission line from the oil sands areas in Alberta to Celilo would open the oil sands region to additional cogeneration development and provide a new generating resource option to the Northwest. Preliminary cost estimates suggest that this resource, which could be available about 2011, is competitive with new natural gas combined-cycle and coal-fired power plants located within the Northwest. Moreover, the high thermal efficiency of cogeneration somewhat



insulates these plants from gas price uncertainties and the possible impacts of climate control policy. Furthermore, it is possible to fuel the cogeneration plants with synthetic gas produced by gasification of byproducts of the bitumen refining process.

Oil sands cogeneration plant, northern Alberta.

ACTION GEN-15

Bonneville and other regional transmission providers should support efforts to refine the design and cost estimates for a transmission intertie from the oil sands region to the Northwest

Efforts are currently under way to refine the design and cost estimates for a transmission intertie from the oil sands region to the Northwest. The intertie would provide a potentially attractive resource opportunity to the Northwest, and possibly strengthen the Northwest transmission grid. Though the initiative is private, the potential benefits of the proposal warrant the cooperation of Bonneville, other Northwest transmission providers, and potential participants in providing constructive review of the proposal.

Energy Storage Technologies

Emerging energy storage technologies such as regenerative fuel cells offer potential to firm and shape solar and wind generation and to support peak period demand.

ACTION GEN-16

Bonneville, the Council, states, and utilities should support and monitor efforts to perfect energy storage technologies with Northwest application potential

Storage systems should be evaluated based on the potential for demand change and energy cost reductions, and for shaping the output of wind and other intermittent resources, as well as distribution system voltage capabilities and transmission voltage applications based on ancillary service tariffs.

Demonstration of Renewable and High Efficiency Generation with Northwest Potential

Routine commercial financing of new technologies and applications requires the successful development, construction, and operation of commercial-scale demonstration projects. Commercial demonstration of promising resources and technologies with potentially cost-effective Northwest application would confirm their viability in the region. These could include various niche biomass energy recovery, forest residue energy recovery, industrial and commercial cogeneration, wave energy conversion, and photovoltaic applications. Successful completion of these demonstration projects will further the engineering, permitting, and financing required for their subsequent development.

ACTION GEN-17

Utilities, with the support of their regulatory commissions, states, SBC administrators, equipment vendors, and project developers should support demonstration of standardized renewable energy and cogeneration applications with extended near-term Northwest potential.

Establish the Policy Framework to Ensure the Ability to Develop Needed Resources

Resource Adequacy

One of the most important policy issues facing the region is resource adequacy. One of the factors behind the Western electricity crisis of 2000-2001 was resource inadequacy. The Council's analysis suggests there are two kinds of resource adequacy. Physical adequacy means having sufficient resources to prevent the involuntary loss of load. However, economic adequacy is a higher standard that requires sufficient resources to reduce the risk of exposure to unacceptably high power prices. The region needs to address both. If Bonneville's role in meeting the region's load growth is reduced, additional entities that have not had direct responsibility for assuring adequate resources will play an important role. This is not merely a regional issue, because the Northwest is part of an interconnected Western system. This means the region must work with other interests in the West to develop a system that will assure adequacy; recognize the legitimate differences within the West; and ensure that all of the responsible entities bear their share of the responsibility. The region should address these issues soon.

ACTION ADQ-1

Establish regional and West-wide reporting standards for the assessment of adequacy

It is essential to have accurate, consistent, and transparent information in order to judge the adequacy of the power supply. The Council will continue to work with the Northwest Power Pool, the Western Electricity Coordinating Council (WECC), and the Committee

on Regional Electric Power Cooperation to establish the necessary measures of resource adequacy and reporting standards.

ACTION ADQ-2

Carry out a process to establish adequacy standards

The Council will establish a Northwest Resource Adequacy Forum. This forum will examine alternative adequacy metrics and standards for the Northwest and their compatibility with West-wide standards being developed by the WECC and others. The forum should consist of utility policy-makers, regulatory commission representatives, and other relevant parties who will help to develop standards and support their implementation. A technical subgroup of this forum will have the function of providing policy-makers viable options for both metrics and standards for the Northwest. The objective would be to reach agreement on appropriate adequacy metrics and standards by the end of 2005. In addition, the Council will continue to work through the WECC and other forums toward West-wide adequacy metrics and standards.

ACTION ADQ-3

Improve consideration of risk in integrated resource planning

Ensuring adequacy will be an easier proposition if load serving entities adequately account for risk in their integrated resource plans. The Council will convene workshops on the treatment of risk in integrated resource planning during 2005. State and local regulatory entities should require an accounting of risk in the integrated resource plans they oversee. States should consider legislation that

would require all of the utilities responsible for developing their own resource portfolios to periodically write integrated resource plans.

Transmission

A key element of the regional power system is transmission. If the power supplies that are recommended in the power plan are to be realized, additional requirements will be placed on the transmission system. The region's power system is not currently organized to plan, expand, operate, and manage the regional transmission system as effectively and efficiently as necessary. There has been growing recognition of problems such as:

- Difficulty in managing unscheduled electricity flows over transmission lines leading to increased risks to electric system reliability
- Lack of clear responsibility and incentives for planning and implementing transmission system expansion, resulting in inadequate transmission capacity
- Inadequate consideration of non-construction alternatives to transmission¹⁷
- Inability to effectively monitor the wholesale electricity market, identify market power abuse, or provide mitigation and accountability
- Difficulty in reconciling available physical transmission capacity with capacity available on a contractual basis, resulting in the inefficient use of existing transmission and generation capacity, and limitations on access for new resources to the existing grid

- Transaction and rate pancaking, i.e., contracting and paying for the fixed costs of multiple transmission segments on a volumetric basis to complete a power sale, resulting in inefficient utilization of generation
- Competitive advantage of control area operators over competing generation owners resulting in the inefficient use of generation, and a potential proliferation of control areas with greater operational complexity

In response, a regional effort through the Regional Representatives Group (RRG) of Grid West (Formerly RTO West) is working to address these problems in a more comprehensive, yet incremental, Northwest grid-wide approach. In addition to the actions already identified regarding better utilization of existing transmission capacity and planning for transmission enhancements, the following actions should be pursued:

ACTION TX-3

It should be a high priority for regional interests to work through the Grid West RRG process to address emerging transmission issues

While success is not assured, the RRG's regional proposal offers a framework for addressing these problems. However, the Council is concerned that the time to address these issues is growing short. The RRG/Grid West process has important decision milestones during the next year. If it appears unlikely that the Grid West process will reach a successful conclusion by the end of 2005, the Council will work with the region to find alternatives to resolve these regional transmission issues.

¹⁷ Non-construction alternatives include: demand management, conservation, and distributed generation to relieve transmission bottlenecks and defer construction of transmission upgrades.

ACTION TX-4

Bonneville and other transmission providers should expand efforts to identify and implement non-construction alternatives to transmission expansion

The Bonneville Power Administration has been carrying out an innovative effort to identify and implement non-construction alternatives to transmission expansion with positive results. This effort should be incorporated as a basic element of transmission planning.

Fish and Power

The Columbia River Basin hydroelectric system is a limited resource that is unable to satisfy the demands of all users under all circumstances. Conflicts often arise that require policy decisions to allocate portions of this resource as equitably as possible. In particular, measures developed to aid fish and wildlife survival often diminish the generating capability of the hydroelectric system. Conversely, “optimizing”¹⁸ the operation of the system to enhance power production can have detrimental effects on fish survival.

Fish and power are inextricably linked in the Northwest. Assuring the adequacy of resources for the power system minimizes not only the risk of electrical shortages and high prices but also minimizes the risk of emergency interruptions to fish operations. Similarly, designing fish and wildlife measures to be as cost-effective as possible can reduce the impact on the power system and the region’s consumers. The Council’s decisions about program expenditures are made carefully

so that the projects to implement the program are efficient and scientifically credible.

For the region to assure both an adequate, efficient, economical, and reliable power supply, and healthy populations of fish and wildlife, it is important to coordinate planning and decision-making for both power production and fish and wildlife. Outside of the Council, however, no clear process exists for integrated long-term planning for both fish and power.

ACTION F&W-1

The Council will work with the federal agencies, states, tribes, and others to broaden the focus of the forums created to address issues surrounding fish and wildlife operations, especially those related to long-term planning

The forums should broaden their focus to include “expertise in both biological and power system issues,” and to directly address longer-term planning concerns, not just weekly and in-season issues. One important objective would be to put in place an emergency operation strategy in the event of extreme dry conditions. Such a strategy would guide decisions on the operation of the hydroelectric system to minimize adverse effects on both the power system and fish mitigation. This action is consistent with actions specified in the Council’s current fish and wildlife program.¹⁹

¹⁸ “Optimizing” here means that energy production is maximized, limited by other than fish and wildlife constraints, such as flood control, irrigation, navigation, etc.

¹⁹ Columbia River Basin Fish and Wildlife Program, Council Document 2000-19, p. 28; and Mainstem Amendments to the Columbia River Basin Fish and Wildlife Program, Council Document 2003-11, pp. 28-29.

Future Role of the Bonneville Power Administration in Power Supply

On at least two occasions during the last decade, the Bonneville Power Administration has found itself financially and, as a consequence, politically vulnerable. Bonneville's financial vulnerability arises in part from its dependence on a highly variable hydroelectric base and the effects of a sometimes very volatile wholesale power market. Another source of vulnerability arises from the uncertainty created by the nature of the relationship between Bonneville and many of its customers, and how Bonneville has historically chosen to implement its obligations. These vulnerabilities are exacerbated by Bonneville's high fixed costs for its debt on the Federal Columbia River Power System and the three nuclear plants that were undertaken, with Bonneville backing, by the Washington Public Power Supply System, now Energy Northwest.²⁰ At times, these vulnerabilities can cause Bonneville to incur high costs that must be passed on to customers, and ultimately to the region's consumers. If those costs are not passed on to customers, Bonneville risks being unable to make its payments to the U.S. Treasury. Rate increases cause economic hardship in the region; not making a Treasury payment risks a political backlash from outside the region that could cause the Northwest to lose the long-term benefits of power from the federal system.

The Council and others in the region have been working to develop alternative ways in which Bonneville can meet the requirements of the Northwest Power Act with greater financial

stability, while reducing the uncertainty surrounding responsibility for serving load growth and preserving the benefits of the federal system. The Council has recommended that Bonneville implement these changes through new long-term contracts to be offered by 2007. The key elements of the Council's recommendations, outlined in the Future Role of the Bonneville Power Administration in Regional Power Supply, Council document 2004-5 are:

ACTION BPA-1

Bonneville should sell electricity from the existing Federal Columbia River Power System to eligible customers at cost. Customers that request more power than Bonneville can provide from the existing federal system would pay the additional cost of providing that service

This would clarify who would exercise responsibility for resource development; it would result in an equitable distribution of the costs of growth; it would provide clear signals of the cost of new resources; and it would prevent the value of the existing federal system from being diluted by the higher costs of new resources. This should be established in Bonneville policy and implemented through new long-term (preferably 20-year) contracts and compatible rate structures. This should be accomplished well in advance of the expiration of the current contracts in 2011.

ACTION BPA-2

Bonneville and the region's utilities should work to resolve the issue of benefits for residential and small-farm customers of investor-owned utilities for a significant period

²⁰ Of the three plants, only one, Columbia Generating Station, is operating. The other two were terminated before construction was complete. However, Bonneville still has responsibility for paying off the debt incurred during construction.

The necessary characteristics of a settlement can be defined. A settlement must be equitable to all of the participants, it must provide certainty, it must be transparent, and it must not be subject to manipulation. This must be accomplished in time to support the offering of new contracts in 2007.

ACTION BPA-3

Bonneville and the region's utilities should continue to acquire the cost-effective conservation and renewable resources identified in the Council's power plans

Bonneville should employ mechanisms similar to the current Conservation and Renewables Discount program and provide essential support activities to encourage and facilitate utility action. Bonneville's role will be substantially reduced to the extent that customers can meet these objectives. But if necessary, Bonneville must be prepared to use the full extent of its authority to ensure that the cost-effective conservation and renewables identified in the Council's power plan are achieved on all of its customers' loads.

ACTION BPA-4

Bonneville should continue to fulfill its obligations for fish and wildlife

Those obligations will be determined in a manner consistent with the requirements of the Northwest Power Act and the Council's Columbia River Basin Fish and Wildlife Program, and are not affected by the recommended changes in Bonneville's role.

ACTION BPA-5

Bonneville should develop a policy to implement long-term contracts and compatible rate structures, and it should include the process

and time schedule for resolving the issues outlined in the Council's recommendations

Bonneville policy must be responsive to concerns among customer utilities that the scope of the policy will include sufficient process detail to guide utility decisions in long-term resource planning; to include provisions by which Bonneville intends to extend assurances of contract durability and enforcement in areas such as Bonneville cost control, dispute resolution, continuation of Bonneville's role in conservation and renewable resource acquisition, allocation of the existing federal power system, and fish and wildlife mitigation.

ACTION BPA-6

Bonneville should consider alternative policy processes, if necessary

Should activities undertaken in response to future Bonneville policy prove inadequate to meet the schedule established for resolution of regional issues leading to the development, offering, and acceptance of new contracts by October 2007, then alternative means of resolving outstanding issues should be considered. Before considering legislation as an alternative, the Council recommends that Bonneville and the Council work jointly to determine if substantive rulemaking under the Federal Administrative Procedure Act can be a vehicle for issue resolution.

Monitor “Key Indicators” That Could Signal Changes in Plans

Load-Resource Situation

The power plan performs well for the majority of the futures examined. However, were the region to sustain high rates of load growth near upper extremes of the forecast growth rates during the first several years of the planning period, or should there be a significant loss of resources, the recommended plan could incur high costs unless adaptations are made to changing conditions. It will be necessary to track loads and resources closely, along with market conditions, to ensure an adequate system and to accelerate development plans, if necessary. The status of independent power producers in the region should be monitored for any indications the availability of IPP generation to the region may be reduced.

ACTION MON-1

The Council will monitor, and periodically report on, the regional load-resource situation and indicate whether there is a need to accelerate or slow resource development activities.

Pace of Conservation Development

The plan includes significant development of conservation at an average rate for 140 average megawatts per year during the next five years. While the region has developed conservation at this rate at some times during the past, the rate of acquisition has frequently been much less – as little as 50 average megawatts. If conservation were to be developed at this rate, the average cost to the region during the planning

period could be almost \$2 billion more, and the risk \$2.5 billion greater (2004 dollars). These cost and risk increases are the result of two factors: the need to accelerate the development of more expensive generation, and the exposure of additional load to periods of higher market prices for electricity.

The region could also fall short of the plan’s conservation goals if the conservation proves to be less available or more expensive than estimated in the plan. In either event, new generating capacity could be needed earlier if conservation goals are not met. Sensitivity analyses of rates of conservation acquisition show that it could be necessary to both increase quantities of thermal generation and advance their in-service dates (Chapter 7).

ACTION MON-2

The Council will monitor regional conservation development

If conservation is not being developed at the recommended levels, efforts should be made to accelerate conservation development. If that cannot be achieved, actions will need to be taken to secure substitute generating resources. The Council will monitor the performance and effectiveness of the conservation measures recommended in the plan and implemented in programs developed throughout the region. The Council will also monitor the emergence of cost-effective measures not identified in this plan. Programmatic conservation activities may need to be modified as a result of this monitoring activity.

Wind Power Cost and Availability

The power plan anticipates development of large amounts of wind capacity. Though current regional wind projects have been successful, uncertainties remain with respect to the ability to develop the much larger amounts of wind the Council recommends. A key recommendation of the plan is the resolution of these uncertainties. If the future cost of wind power is greater, or the availability less than assumed for the plan, other resources may have to be substituted. A sensitivity analysis, in which wind power costs did not decline as assumed, did not change the plan. However, the cost and risk of the plan increased. If wind costs do not decline, resource choices should be re-evaluated with updated information.

ACTION MON-3

The Council will monitor efforts to resolve uncertainties associated with large-scale wind development

If these efforts indicate that wind power is unlikely to be available at the cost and quantities targeted in the plan, resource choices should be re-evaluated using the updated information on the cost and performance of alternatives.

Climate Change Science and Policy

Both coal-fired power plants and gas-fired combustion turbines are present in the power plan. However, in scenarios in which significant penalties on carbon dioxide emissions are implemented relatively early in the planning period, these resources are not developed. If this were to appear likely, the plan should be reconsidered. Conversely, if there were significant reductions in the costs of carbon offsets, or improvements



in the efficiency and emissions characteristics for generation using carbon-based fuels, these technologies could play a larger role.

ACTION MON-4:

The Council will monitor climate change science and policy

If the uncertainty surrounding climate change science and policy is reduced, and with it the likelihood of future carbon emissions control requirements, the role of carbon-fueled generation will be re-examined. Similarly, if there are advances in high-efficiency coal generation technology, carbon sequestration, or the availability and cost of carbon offsets, the role of carbon-based fuel generation should be re-examined.

Demand Response

If demand response is not available, or cannot be developed at the levels and costs estimated, the result will be a somewhat more costly and risky portfolio and could require that additional combined- and/or single-cycle generation be developed.

ACTION MON-5

The Council will monitor the development of the demand response resource.

Implementing the Power Plan: Sections 4(c)(9), 4(i) and 4(j) of the 1980 Northwest Power Act

The resource acquisitions of the Bonneville Power Administration are to be consistent with the Council's power plan. It is the responsibility of the Council to ensure that they are.

ACTION MON-6

The Bonneville Power Administration and other federal agencies, to the extent authorized by other provisions of law, shall furnish the Council all of the information requested by the Council as necessary for the performance of its functions, subject to such requirements of law concerning trade secrets and proprietary data as may be applicable

The Council intends to be vigorous in its review and tracking of Bonneville's actions to ensure they are consistent with the power plan. The Council assumes this responsibility under provisions of the Northwest Power Act, with full recognition of the need for reciprocal cooperation between Bonneville and the Council.

Biennial Monitoring Report

The Council intends the plan to be a flexible and living document. The plan is, among other things, a source of information regarding current and projected loads, resources and resource characteristics, fuel prices and electricity prices. To ensure that this information is timely, it should be reviewed at least biennially, and updated as necessary. If changes in these parameters or other factors are, in the Council's judgment, sufficient to require revisions in the power plan, the Council should initiate a revision.

ACTION MON-7

The Council will prepare a biennial monitoring report, to be published every other December beginning in 2006. The data in the monitoring report will be considered the Council's current official data. The report will include a determination by the Council as to whether the data or other factors merit a revision of the power plan and, if so, a declaration by the Council initiating a revision.

Monitor Progress in Implementing the Changes Recommended for Bonneville's Future Role in Power Supply

Since the mid-1990s, there has been broad recognition of the need to undertake changes in Bonneville's role in power supply to provide greater clarity on the responsibility for acquiring new resources to meet load growth and greater equity in the allocation of the costs of those new resources. While there is now general agreement about the changes required, accomplishing those changes will be difficult.

ACTION MON-8

The Council will monitor progress toward implementation of the recommended changes for Bonneville's future role and will facilitate progress, if necessary.

Review of Bonneville and Council Policy Regarding Section 6(c) of the Northwest Power Act

In 1986, Bonneville and the Council undertook a joint policy-making exercise to develop their respective policies for implementing Section 6(c) of the Northwest Power Act. Section 6(c) calls on Bonneville to review a variety of actions associated with the acquisition of major resources, as defined by the Act, for consistency with the Council's power plan. The same section also gives the Council the option of reviewing such a Bonneville proposal. If either agency finds the proposal inconsistent with the power plan, Bonneville must obtain express authorization from Congress to proceed with the proposed action. In 1993, the two agencies enlarged their respective policies to cover all of the actions related to the acquisition of a major resource set forth in the Act. Bonneville and the Council are also committed to reviewing their respective policies at least every five years. That review has not been undertaken over the years. The Council believes that in light of changes in the utility industry—and in how Bonneville now acquires additional resources, and may be expected to acquire resources in the future — it is time to re-examine the agencies' respective policies.

ACTION MON-9

The Council calls on Bonneville to enter into a joint policy-making exercise to review

the agencies' respective policies for implementing Section 6(c) of the Act.

This should be accomplished in a time frame consistent with Bonneville's offering of new power sales contracts.

Photo Credits

Cover: David Jensen

Inset Cover: Shaun Cammack

Page 1: Shaun Cammack

Page 2: Scott Cressman

Page 6: David Jensen

Page 9: Richard K. Foote

Page 13: Barry Kovish

Page 15: Ken Zirkel

Page 23: Maurice Ciapponi

Page 25: PPM Energy

Page 31: Greg Mullis

Page 32: Peter Bradshaw

Page 34: Norman Ederx

Page 40: Gerald Hash, Extension Housing Associate, University of Kentucky

Page 52: Dick Watson

Page 53: Debi Bishop

Page 55: Technology & Management Services, Inc.

Page 57: Shell Canada

Page 65: Kevin Russ





851 S.W. Sixth Avenue, Suite 1100
Portland, Oregon 97204
1-800-452-5161
www.nwccouncil.org