~~EXECUTIVE SUMMARY~~OVERVIEW

~~KEY CONCLUSIONS~~

~~The 1980 Pacific Northwest Electric Power Planning and Conservation Act requires the Council's power plan to give priority to resources which the Council determines to be cost-effective. Priority shall be given: first to conservation; second to renewable resources; third to generating resources utilizing waste heat or generating resources of high fuel conversion efficiency; and fourth to all other resources.~~

~~With this guidance and the analysis developed in the Fifth Power Plan, the Council recommends that the region should increase its efforts to secure cost-effective conservation, beginning immediately. It is the least expensive, and least harmful to the environment, resource available. Development of conservation will reduce the likelihood of another electricity crisis like the one experienced by the West in 2000 and 2001.~~

~~In addition, demand response resources -- agreements between utilities and customers to reduce demand for power during periods of high prices and short supply -- should be put in place over the next few years so that they can be implemented quickly if needed.~~

~~From a regional standpoint, there is currently a surplus of generating capacity due to reduced demand and the construction of new generating plants over the past three years. Independent power producers (IPPs) own most of the surplus generation. The IPPs do not now have long-term contracts with regional utilities nor do they have firm transmission access to markets outside the region. The plan considers the independent power plants as resources available to serve the regional market, from which the region may purchase at market prices.~~

~~Wind power development at a moderate commercial scale should be undertaken at geographically diverse wind resource areas over the next five years to resolve uncertainties associated with this resource and to prepare for its eventual large-scale development. Wind projects currently being considered by regional utilities and state "system benefits charge" administrators could fulfill this goal.[1] Finally, efforts to identify and develop cost-effective lost-opportunity generating resources, including combined heat and power (cogeneration) and biomass applications, should be reinforced.~~

~~The region should secure sites and permits to be prepared to start construction of new coal generating resources as early as 2010 with additional wind generation shortly thereafter. Later in the 20-year period some additional gas-fired generation could be needed. Needed transmission upgrades should be identified so all these resources can be constructed and brought on line quickly when required. If major transmission upgrades are needed, that work will have to begin before construction of the power plants.~~

~~There are utilities in the region with near-term resource needs that cannot be met with conservation alone. There can be valid reasons why they may choose to develop generating resources in the near-term rather than depend on market purchases or purchase ownership~~

[1] Oregon and Montana have state system benefits charge programs. They are funded by a small percentage charge on retail electricity revenues. The funds are administered by the state, utilities or state-chartered organizations and are used to develop conservation and renewable resources.

~~interests in the existing IPP generating capacity. However, the Council's analysis cannot take into account all the factors that enter into these individual utility decisions. The assumption that the uncommitted IPP generation will sell into the market provides a reasonable starting place for analyzing the region's energy choices. To the extent regional utilities build generating resources in the near term, the regional surplus will be extended and the need for additional generating resources will be deferred.~~

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 (the Act) to assure the region an adequate, efficient, economical, and reliable power system. The power plan is updated every five years. To accomplish the goals of ~~The~~ 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 these 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 were very different. They included the failure to develop adequate resources; the failure to anticipate the price volatility short supplies might spur; the failure to put in place effective market rules and mechanisms; and the actions of some who took advantage of the market's vulnerability. The effect, however, was much the same as the earlier crisis. Retail rates in the region soared and demand plummeted. The impact on the region's economy for the years 2000 though 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 can't 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: the 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 it is more vulnerable to fuel cost risk as gas prices have become more uncertain. 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 like wind, though capital intensive, have short lead-times and provide a hedge against fuel price and climate change risk. But it is uncertain if the current trends of falling cost for this resource will continue, or whether integration of intermittent generation into the power system will prove significantly more costly as the market penetration of these resources increases. And there is electricity market price risk.

It is tempting to think that electricity markets will be orderly and predictable in the future. To assume that, however, could expose the region to significant risk. Volatility in gas prices and hydroelectric generation and 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 is 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 in order to help reduce uncertainty and clarify responsibilities for electricity supply and transmission adequacy and reliability. Second, it provides a detailed analysis of alternative resource strategies for an uncertain and dynamic electricity future, and develops a recommended strategy of resource acquisition to minimize the cost and risk of the power system. It identifies specific actions the region needs to take over the next 5 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, Bonneville, and regulated and consumer-owned utilities. The roles of these entities are not well defined with regard to who is responsible for planning and development of generation or transmission. This raises concerns about resource adequacy and transmission system reliability. The role of Bonneville versus its customer utilities in meeting growing electricity demands needs to be resolved so Bonneville and utilities can plan appropriately. The region, in spite of a significant presence of independent power production and a history of significant intra- and interregional power trading, has not been able to agree on how to resolve these issues. If the Council's recommendations in these areas 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 not fulfilling the Act's goals for an adequate, efficient, economical and reliable regional power supply.

~~attempting to movemoving and a history of significant intra- and interregional power tradinggenerating~~

Role of the Bonneville Power Administration

On at least two occasions over 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.[2] 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. Central to this change in Bonneville's role is that the agency 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 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. It 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 responsible entities bear their share of the responsibility. The region has some time to address these issues, but we must make sure that time is not wasted. The Council will establish a Northwest Adequacy Forum whose function will be to facilitate a discussion of resource adequacy among utility policy makers and other relevant parties in the northwest leading to adequacy metrics and standards for the Northwest. This group will also

[2] 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.

work closely with the WECC and with the Committee on Regional Electric Power Cooperation to ensure that northwest considerations are incorporated into any metrics and standards developed in their processes.~~The Council is committed to working with regional utilities and regulators in the months ahead to develop a standard that will assure an adequate power supply while being fair and equitable to all parties.~~

Transmission Planning and Operation

A key element of the regional power system is transmission. If the power supplies that are 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 presently 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 transmission;[3]
- 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; and
- 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, there has been a "bottoms-up" regional effort through the Regional Representatives Group (RRG) of Grid West (Formerly RTO West) to address these problems in a more comprehensive, yet incremental, Northwest grid-wide approach. The Council supports working through a regional approach but is concerned that little agreement has been reached in spite of years of effort and that the time for reaching agreement on the resolution of these problems is growing short. If current efforts do not succeed in the near future, the Council is committed to seeking alternative means of resolving 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

[3] Non-construction alternatives involve consideration of demand management, conservation, distributed generation, and so on to relieve transmission bottlenecks and defer construction of transmission upgrades.

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 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 minimizes not only 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 intends that its decisions about program expenditures are made carefully and that the projects that implement the program are efficient and scientifically credible. To ensure public accountability for these decisions, the Council submits all 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 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 ~~to long-term~~ in coordination among planning bodies, as described in Chapter 10, 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 situation and how it is expected to change in the future. The plan contains a forecast of demand and how that translates into need for additional conservation and generation resources. The plan then assesses the resource alternatives available to the region; their costs, inherent risks, and other characteristics that affect how they fit with the existing power system.

Leading up to, and contributing significantly to, the 2000-01 energy crisis the region and much of the West had developed a substantial deficit of electricity capability. The electricity crisis increased many utilities' costs dramatically. As these costs found their way into customer's electricity rates, their rates increased by 35 percent. These increased electricity prices had two effects; they reduced consumption by over 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 over 4000 megawatts of new electricity generating capability in the region. Most of this new capacity was natural gas-fired and owned by independent power producers. The combined effect of decreased demand and increased generating capability was to create about a 1000 average megawatt surplus of electrical capability in the region.

Attempts to forecast how conditions will change in the future face a tremendous amount of 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 also goes beyond previous plans in assessing 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 over 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 that have been considered in the portfolio analysis ~~include~~are described below.~~:~~

Demand[this section moved ahead of hydro section]

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 underutilized. 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 electricity. 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 ~~very~~ 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 that in the medium case.

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 fully recover their costs. In 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. ~~To assess risk, it is necessary to reflect the variation in demand that can occur. The forecast range of annual loads and~~ Figure OV-1 shows a sample of the 750 futures for quarterly average loads assessed in the portfolio model compared to the forecast range of annual load trends~~are shown in Figure ES-2~~. ~~.~~

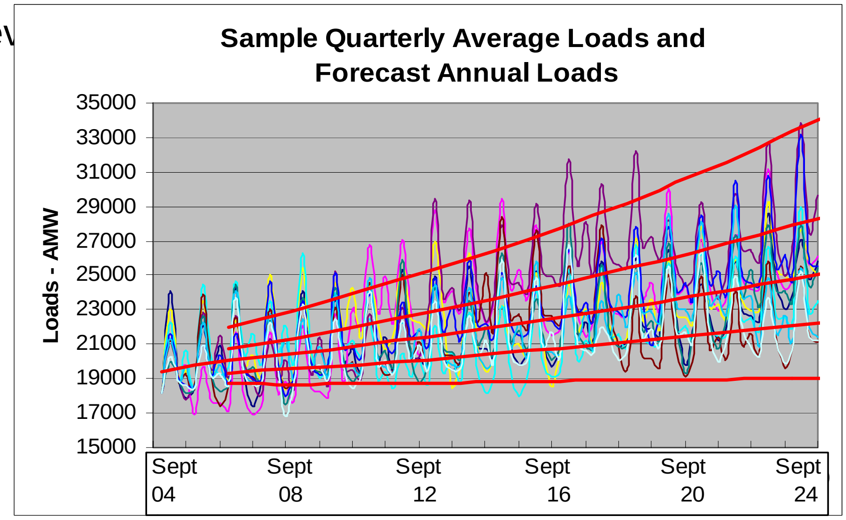


Figure ~~ES~~OV-~~2~~1

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. The future capability of the hydro system has, however, been reduced by 300 average megawatts to account for potential losses due to relicensing requirements.

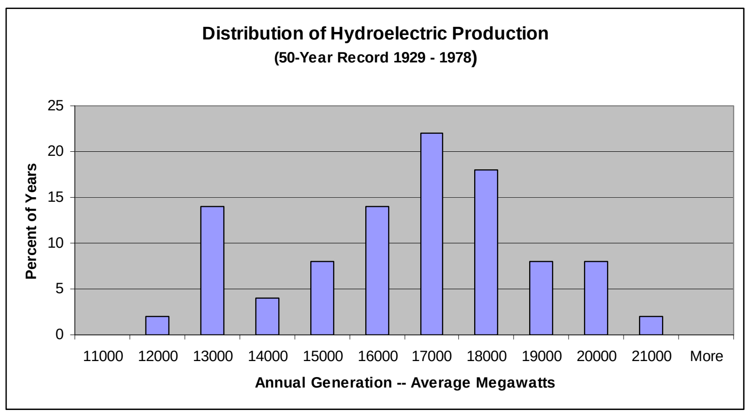


Figure ~~ES~~OV-~~1~~2

There is further uncertainty resulting from potential shifts in temperatures and precipitation patterns associated with climate change. ~~While the Council has assessed the possible long-term effects of climate change on the hydroelectric system, this uncertainty has not been included in the portfolio analysis.~~ 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 demands. 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 better refine potential impacts of climate change and to incorporate these considerations in future revisions of the plan. ~~The capability of the hydro system has, however, been reduced by 300 average megawatts to account for potential losses due to relicensing requirements.~~

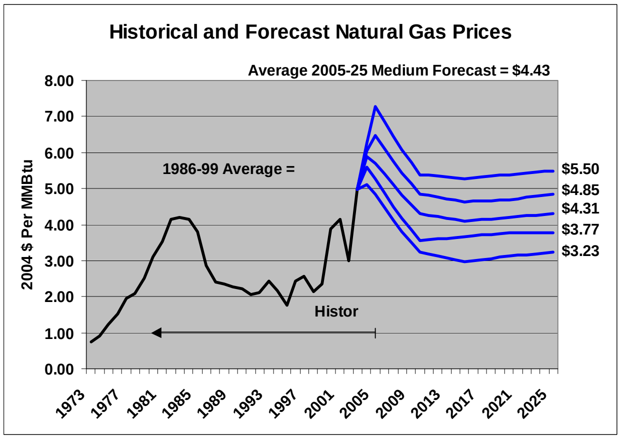
Fuel Price

Similarly, fuel price uncertainty is an important source of risk. ~~Periods of high fuel prices can increase operating costs for those resources dependent on that fuel.~~ The Council forecasts a range of natural gas, oil, and coal prices. Recently, the most important fuel has been natural gas because of the relative attractiveness of natural gas fueled combined cycle combustion turbines. Gas-fired generation now makes up approximately 22 percent of the electricity generation in the region under average water conditions. [Removed Figure ES-3, it appears in Chapter 2] Periods of high fuel prices can increase operating costs for these resources. ~~With low gas prices, it could contribute more.~~

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 especially 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. ~~But~~

~~t~~The price of natural gas exhibits short-term volatility ~~and~~ as well as ~~longer~~ 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 ~~ES-4~~OV-3 and ~~ES-5~~OV-4. The forecast range of long-term fuel price trends are discussed in Chapter 2. The modeling of fuel price variations in the portfolio model is discussed in Chapter 6.



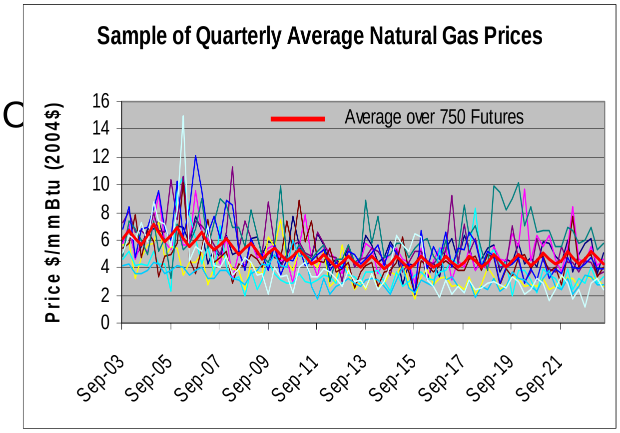


Figure OV-3 Figure OV-4

Environmental Regulation

Future environmental regulation, particularly the potential for regulation of carbon dioxide emissions, is an important uncertainty. If there were certainty that there would never be a carbon tax or the equivalent, coal-fired generation could be a more attractive option. Conversely, if we knew with certainty that a large carbon penalty would be imposed, 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 probabilistically. The probability of a carbon penalty of some level increases over the planning period, from zero percent prior to 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 from the market at a reasonable price to meet its needs. If a generation owner has excess generation, it hopes to sell into that market at a price sufficient to cover its operating costs and recover a portion of its capital investment.

~~That~~ 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, the electricity market price is a function of demand, the amount and characteristics of supply, and fuel prices. [Eliminated Figure ES-6, octopus diagram] 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

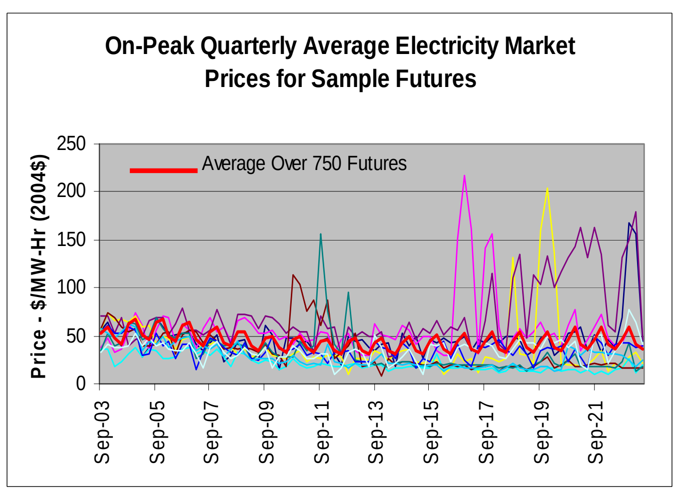


Figure OV-5

source of risk. A sample of peak period market prices used in the Council's portfolio analysis is shown ~~on~~ in Figure ~~ES-6~~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. ~~Resource characteristics include capital cost, efficiency, operating cost, lead-time for construction, fuel type, and so on.~~ 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 like 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 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 ~~ES~~OV-1. Some of the 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 comes 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 plan has low capital costs and short lead times providing relatively less financial risk, but its costs are subject to substantial risk from changing and volatile natural gas prices. A steam coal plant has less fuel price risk and relies on a plentiful domestic energy source, but is larger, more capital intensive, has longer construction lead times and may have a large exposure to changes in carbon control policies. Integrated Gasified Coal combined cycle technology (IGC) reduces carbon dioxide emissions and improves efficiency, but ~~at the cost of~~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.

Table ~~ES~~OV-1: Resource Characteristics

Resource	Project Size	Development & 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
Coal - Integrated Gasification combined-cycle	425 MW	36/48 mo	$1400/kW Declining	Low Stable	790 (w/o Carbon sequestration)	Baseload
Coal - Steam-electric	400 MW	36/42 mo	$1240/kW Stable	Low Stable	1010	Baseload
Natural gas - Combined cycle gas turbine	610 MW	24/24 mo	$565/kW Declining	Moderate Volatile	430	Baseload Ld-following Peaking
Natural gas - Oil sands cogeneration	2000 MW Transmission controlling	48/36 mo Transmission controlling	$1130/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	Ld-following Peaking Grid support
Wind - Utility scale wind project	100 MW	18/12 mo	$1010/kW Declining	Moderate (integration)	None	Intermittent baseload

Other resources considered in the portfolio analysis include ~~integrated coal gasification, potentially with carbon sequestration, and~~ Alberta oil sands cogeneration. This resource will require the development of extensive transmission to bring the power into the region. However, if this can be done at reasonable cost it could be a viable alternative. ~~These resources face impediments to their development. Nonetheless, they could play an important role in future power supplies.~~

Other resources were considered, but were not included in the portfolio analysis. Many, such as cogeneration, which is frequently called combined heat and power (CHP); 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 particular 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 transmission upgrades, environmental requirements, plant renovation, and so on. 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 proven unsuccessful to date. However, the resource remains attractive because of declining costs, increased siting proposals and baseload potential. Efforts to prove up 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 the resource and to develop the technology and will reconsider this resource in future plans.

While generally somewhat expensive and limited in quantity, use of bio-residues for power generation will often simultaneously resolve a waste disposal problem. In addition, it may be possible to utilizing 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.

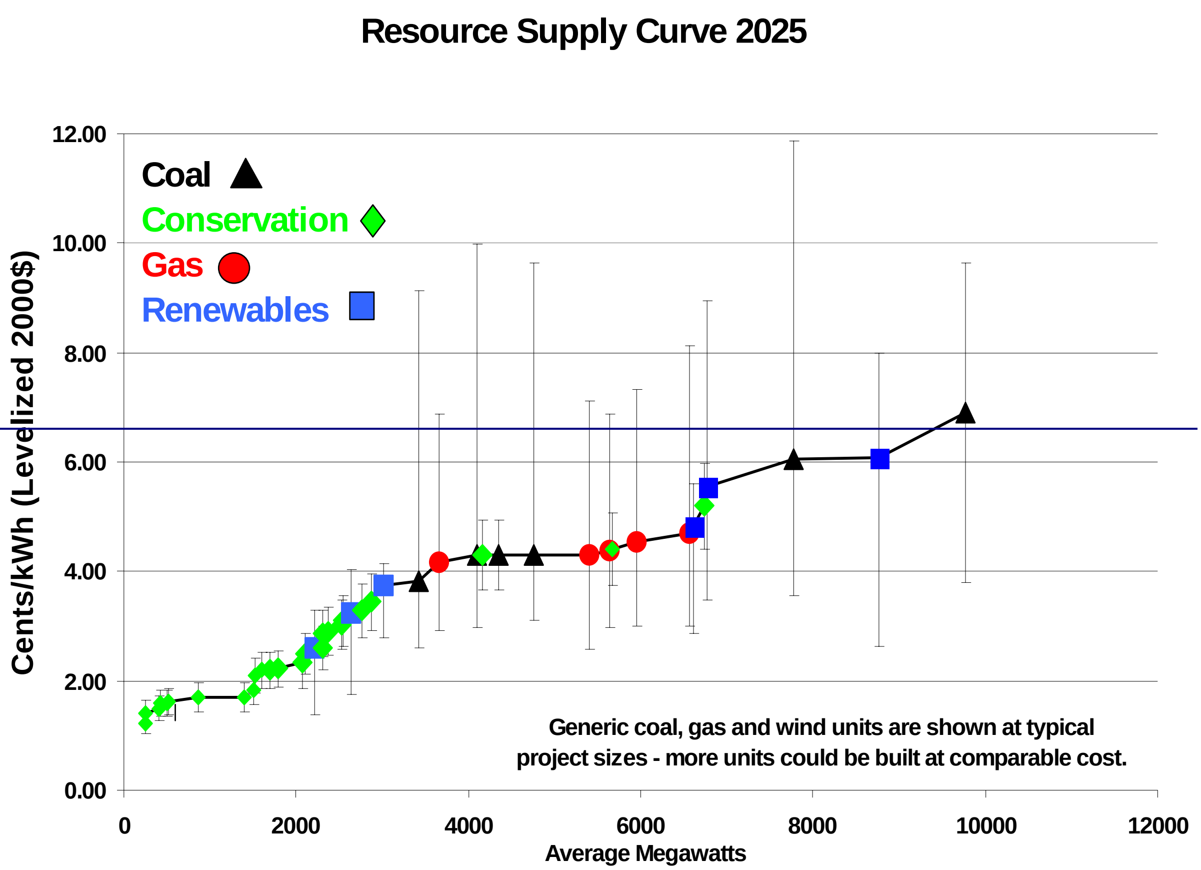
The resources considered potentially cost effective in the development of this plan are summarized in the "supply curve" shown in Figure ~~ES-8~~OV-6 and Table OV-2. This shows the estimated levelized cost of specific resources in cents per kilowatt-hour and the estimated cumulative supply in average megawatts available over the planning period. Also shown is an estimate of the uncertainty band around the estimated costs. For example, gas-fired generation is subject to a range of possible fuel costs and carbon emissions penalties 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, resource quality, financing, and

How can resources be compared on an "apples to apples" basis?

Not all resources are alike. Some resources, like 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, like a gas turbine, incur capital costs initially, but also have ongoing fuel and operating costs over 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 the costs – capital, fuel, and operating – over 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 like a mortgage payment. This payment, divided by the annual electricity production or savings, yields the levelized cost per kilowatt-hour.

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 analysis results that the low-cost end of the supply curve is composed primarily of various conservation measures and some specific types of wind development.



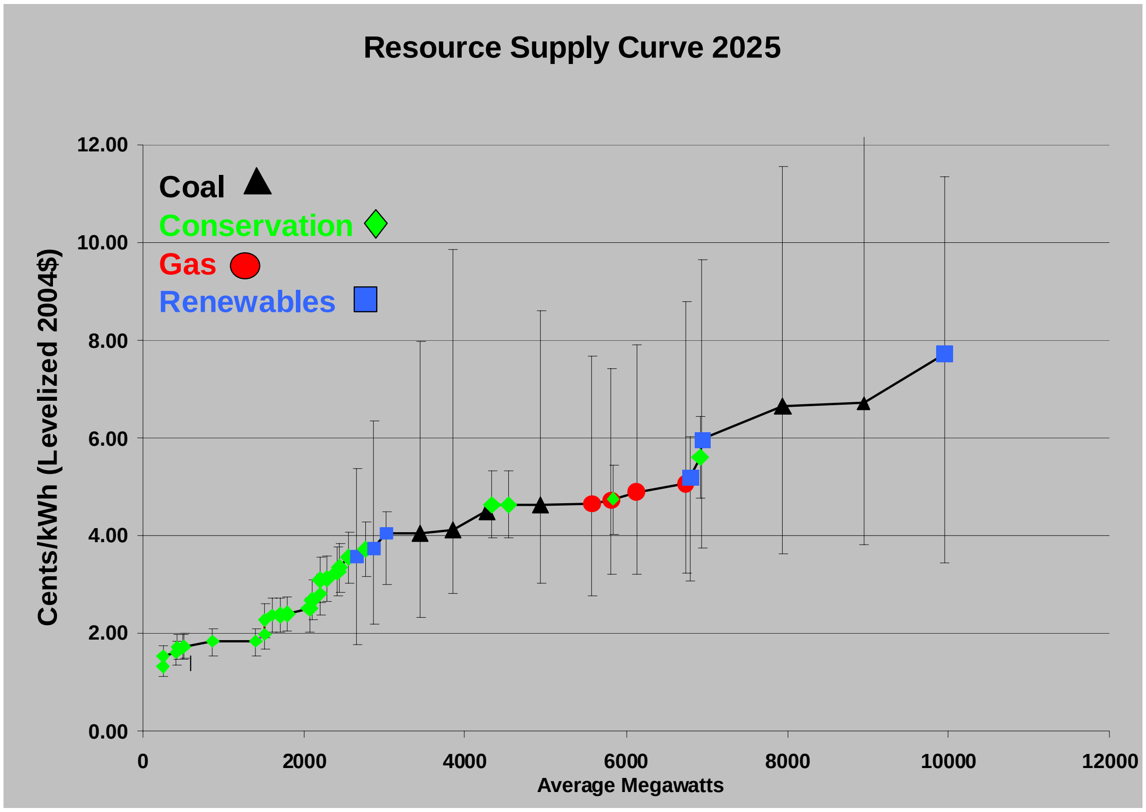


Figure ~~ES-8~~OV-6

Table ~~ES~~OV-2: Resource Supply Curve

		Average Cost (Cents/kWh) (Levelized 2004$)[10]			Cost-Effective Potential	Cumulative Potential
	Sector and End-Use	**Low**	**Avg**	**High**	**(MWa in 2025)**	**(MWa in 2025)**
1	Commercial New & Replacement Lighting[2]	1.12	1.32	1.51	245	245
2	Commercial New & Replacement Infrastructure[2,8]	1.30	1.53	1.76	11	256
3	New & Replacement AC/DC Power Converters[2]	1.36	1.61	1.85	156	412
4	Residential Dishwashers[2]	1.47	1.72	1.98	10	422
5	Agriculture – Irrigation[2]	1.47	1.72	1.98	80	502
6	Commercial New & Replacement Shell[2]	1.48	1.74	2.00	13	514
7	Industrial Non-Aluminum[2]	1.56	1.83	2.11	350	864
8	Residential Compact Fluorescent Lights[2]	1.56	1.83	2.11	535	1399
9	Commercial Retrofit Lighting[2]	1.68	1.98	2.27	114	1513
10	Residential Refrigerators[2]	1.92	2.26	2.60	5	1518
11	Residential Water Heaters[2]	2.02	2.37	2.73	80	1598
		Average Cost (Cents/kWh) (Levelized 2004$)[10]			**Cost-Effective Potential**	**Cumulative Potential**
	Sector and End-Use	**Low**	**Avg**	**High**	**(MWa in 2025)**	**(MWa in 2025)**
12	Commercial Retrofit Infrastructure[2,8]	2.02	2.37	2.73	105	1703
13	Commercial New & Replacement Equipment[2,9]	2.04	2.40	2.76	84	1787
14	Chemical Recovery Boiler Upgrades (incremental cost)	2.02	2.52	2.73	280	2067
15	Residential New Space Conditioning-- Shell[2]	2.29	2.69	3.10	40	2107
16	Residential Existing Space Conditioning – Shell[2]	2.38	2.80	3.22	95	2211
17	Commercial Retrofit Shell[2]	2.63	3.09	3.55	9	2276
18	Residential HVAC System Efficiency Upgrades[2]	2.66	3.13	3.59	65	2424
19	Commercial New & Replacement HVAC[2]	2.77	3.26	3.75	148	2444
20	Residential HVAC System Commissioning[2]	2.84	3.34	3.84	20	2560
21	Commercial Retrofit HVAC[2]	3.01	3.54	4.08	117	2769
22	Central MT Wind for local load[1,13]	1.77	3.58	5.37	100	2202
23	Commercial Retrofit Equipment[2, 9]	3.16	3.72	4.28	109	2869
24	Eastern WA & OR, S. ID Wind[1,13]	2.20	3.74	6.35	100	2660
25	Landfill Gas Energy Recovery[12, 13]	3.00	4.04	4.47	150	3019
26	MT IGCC for local load [1, 4, 13]	2.33	4.05	7.96	425	3444
27	MT Coal Steam for local load [1, 5, 13]	2.80	4.11	9.85	400	3844
~~**26**~~	~~Goldendale CCCT (Cost to complete)[13]~~	2	~~4.17~~		~~248~~	
28	Eastern WA/OR IGCC (or MT IGCC @ Mid-C at embedded transmission cost) [1,4,13]	3.01	4.49	8.42	425	4269
29	Residential HVAC System Conversions to Heat Pumps[2]	2.77	4.63	5.33	70	4339
30	Residential Heat Pump Water Heaters[2]	3.21	4.63	5.33	195	4534
31	Eastern WA/OR Pulverized Coal (or MT Coal @ Mid-C at embedded transmission cost) [1,5,11,13]	4.03	4.63	8.59	400	4934

32	Grays Harbor CCCT (Cost to complete) [13]	3.22	4.64	7.66	640	5574
33	Montana First Megawatts (Cost to complete) [13]	3.24	4.73	7.41	240	5814
34	Residential Hot Water Heat Recovery[2]	3.08	4.74	5.45	25	5839
35	Mint Farm CCCT[13]	4.76	4.90	7.91	286	6125
36	Eastern WA/OR CCCT[1, 3,13]	3.74	5.05	8.78	610	6735
37	Animal Manure Energy Recovery[12, 13]	3.63	5.20	6.02	50	6785
38	Residential Clothes Washers[2]	3.83	5.60	6.44	135	6920
39	Wood Residue Energy Recovery (non-cogen) [12,13]	3.45	5.97	9.64	25	6945
40	MT IGCC w/new transmission to Mid-C [1, 4, 13]	3.01	6.66	11.55	1000	8945
41	MT Coal Steam w/new transmission to Mid-C [1]	2.77	6.71	12.80	1000	7945
42	Central MT Wind w/new transmission to Mid-C [1, 7, 13]	3.21	7.73	11.34	1000	9945
~~**41**~~	~~**MT IGCC w/new trans. to Mid-C and CO2 sequestration 1, 4, 13, 14**~~	~~**3.79**~~	~~**6.90**~~	~~**9.64**~~	~~**1000**~~	~~**9368**~~

[Additional changes to the costs in this table are in process~~needed~~]

Footnotes to Table ES-2:

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 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 ~~Goldendale,~~ Grays Harbor~~,~~ and Mint Farm CCCTs used the same assumptions except the generating technology was assumed fixed at 2001 levels.

4) The uncertainty interval for ~~gasified coal generators~~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 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 ~~all~~ independent power producer financing costs.

5) The uncertainty interval for pulverized coal 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 $~~6~~3.77/MWh, $~~4~~4.90/MWh for shaping and firming, all public utility financing costs, and the production tax credit for wind continuing indefinitely at $18.~~50~~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 $~~6~~3.77/MWh, $~~8~~10.51/MWh for shaping and firming, all 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 typical size 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 1000 to 1700 MW).

13) Except as indicated the expected case values for generating resources are based on mixed financing (20% public utility, 40% IOU and 40% IPP), 2010 service and the medium case fuel price forecast. Capacity factors are 80% for coal and cogeneration resources, 65% for gas resources, 30% for eastern Washington/Oregon wind and 36% 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 PTC is assumed to apply to biomass except for chemical recovery boilers.
14) Elements of this technology are not commercially proven, but are included here for comparative purposes.

The Role of Independent Power Producers [This section moved from policy issues]

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 these plants are new, gas-fired combined cycle combustion turbines, but there are also about 1,100 average megawatts from an existing coal-fired plant. 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, since Northwest's need for that power peaks in the winter compared to summer peaks in most of the rest of the West, the power should be available to the Northwest if needed. This could happen by replacing the power in the purchasing region with local purchases and paying any difference in costs (counter-scheduling).~~, those contracts could very likely be counter- scheduled, making the power available to the Northwest. This generation poses a different kind of uncertainty for planning.~~

~~This~~IPP generation poses a different kind of uncertainty for planning. The power from these plants is currently sold into the market when prices are sufficient to recover their operating costs and contribute to recovering their capital costs. While the presence of these plants in the region helps moderate market prices, it does not eliminate the risk of high market prices for regional consumers.

~~From a utility's perspective, power from these plants is one of the resource alternatives available.~~ (seems superfluous) There are a number of individual utilities within the region that 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 it is able to do so. This should not be interpreted 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. That value is on the order of almost $5 billion (need to re-evaluate th~~ese~~is number~~s~~) relative to an average present value cost of approximately $~~17~~ 24.5 billion for operating the existing system and building and operating new resources over the next 20 years.[4] 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 complexities of the financial and market risk profile of each individual utility and IPP in the region; all the considerations in utilities' "build versus buy" decisions; or the negotiations between utilities and IPPs. The assumption that the uncommitted IPP generation will sell into the market provides a reasonable starting place for analyzing the region's energy choices.

Evaluating Plans

In evaluating plans, the Council relies on both analytical models and informed judgment. The Council considers a "plan" to be 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 ~~gas-fired combined cycle~~ power plant ready for construction if it is needed.

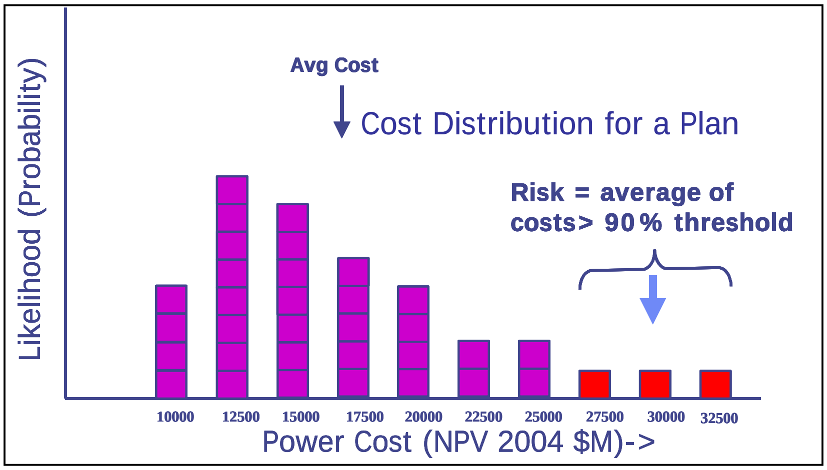


Figure ~~ES-9~~OV-7

Computer models are used to screen a large number of alternative plans. For each plan, the models calculate the cost of operation and expansion of the power system over hundreds of different futures. Figure ~~ES-9~~OV-7 illustrates the distribution of those costs over a number of futures. Two primary measures of a plan's performance are used: the average total system cost over all the futures; and a measure of risk, "$TailVaR_{90}$," the average of the 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 are intended to give insights into the potential for retail price volatility. In addition, measures of resource adequacy are also evaluated. The objective is to find plans that are "robust," that is, 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.

[4] This does not include amortization of the debt on existing system resources. These are considered "sunk costs" and do not enter into new resource decisions.

CHOOSING "THE PLAN"

A plan describes the resource actions to be taken over the planning period. The models produce a number of alternative plans, each of which represents the plan with the least expected or average cost for a given level of risk. The models also identify the plan that is the least cost of all considered and also the one that exhibits the least risk. Generally speaking, as the risk of plans decrease, their expected cost increases. This is the consequence of the costs of additional resources that are added to mitigate the costs associated with 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 the insurance premium that is ~~payed~~paid to reduce the exposure to much higher costs that could occur in some futures.

Of particular interest is what the plans with the least expected cost for given risk levels indicate for the next five years, the maximum time before the Council's power plan is revised. There are several strategic conclusions that can be drawn from the portfolio analysis:

- Significant development of conservation was characteristic of all the plans – whether least cost or least risk. Over the next five years, the Council recommends that the region develop 700 average megawatts of cost-effective conservation. This is an increase of approximately 250 average megawatts over the level of ~~regional~~ utility program conservation development during 1998 - 2002. Moreover, the development of that conservation needs to begin now. Failure to develop that conservation has significant cost and risk penalties. It ~~will~~ would require accelerating the development of generating resources along with their attendant costs and risks.
- Demand response--the temporary reduction, or shift in timing, of some uses of electricity--shows benefits, if available at the power plan's estimated costs. Demand response is used infrequently and while the dollar savings it provides are not huge, they far outweigh the costs. In addition, demand response contributes to improved reliability.
- None of the plans showed significant additions of generating resources during the next five years beyond those ~~that are~~ judged to be already committed to ~~develoment~~development. Those include about 1100 megawatts of wind generation capacity over the next seven years that is part of planned system benefits program and utility acquisitions. There is also a ~~XXX~~399 megawatt gas-fired combined cycle combustion turbine for which ~~construction~~ground was ~~begun~~broken in ~~January~~October of 200~~5~~4. There are several individual utilities that are resource short and will have to acquire additional resources in the next few years. They could fill those needs from existing regional resources, primarily owned by IPPs, if agreements can be negotiated. There are, however, reasons why that may not be possible.

There are other important conclusions that fall beyond the ~~5 year~~5-year period.

- Additional wind plays a very significant role in most of the plans. It provides a hedge against higher, and volatile, gas prices, and carbon dioxide control measures.
- Many of the plans include coal-fueled generation. The role that coal plays is affected by expectations regarding future policies to limit production of carbon dioxide and also by the expectation of high natural gas prices and gas price volatility. The analysis concluded that a coal gasification power plant was the preferable technology because of its higher

efficiency and lower CO2 emissions.[5] ~~Several of the plans included development of coal-fired generation. Improvements in the efficiency of coal generation, e.g., integrated coal gasification, and the development of relatively low cost carbon sequestration methods, would further increase the attractiveness of coal generation.~~

- High near-term natural gas prices delay gas-fired combined cycle and simple cycle generation until late in the planning period of lower risk plans.
- ~~Additional W~~w~~ind played a very significant role in many of the plans. It provided a hedge against higher, and volatile, gas prices, and carbon dioxide control measures.~~

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 choice 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 our risk measures; judgments regarding the value of improved reliability, reductions in price volatility, and the desire for a diverse and orderly development pattern. The analysis is discussed in Chapter 7. The resource plan is illustrated in Figure ~~ES-10~~OV-8 for ~~the most likely~~~~typcial~~typical development schedule. 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, carbon penalties and so on. Several specific scenarios are discussed in Chapter 7.

Absent extremely high growth in demand over the next several years, substantial loss of existing resources, or failure to develop the cost-effective conservation, the resource plan does not call for significant development of new generating resources before the end of the decade beyond those resources already judged to be committed to development. This means that some of the uncertainties affecting this plan may be reduced before major generating resource decisions need to be made. Reduced uncertainty can lead to better decisions.

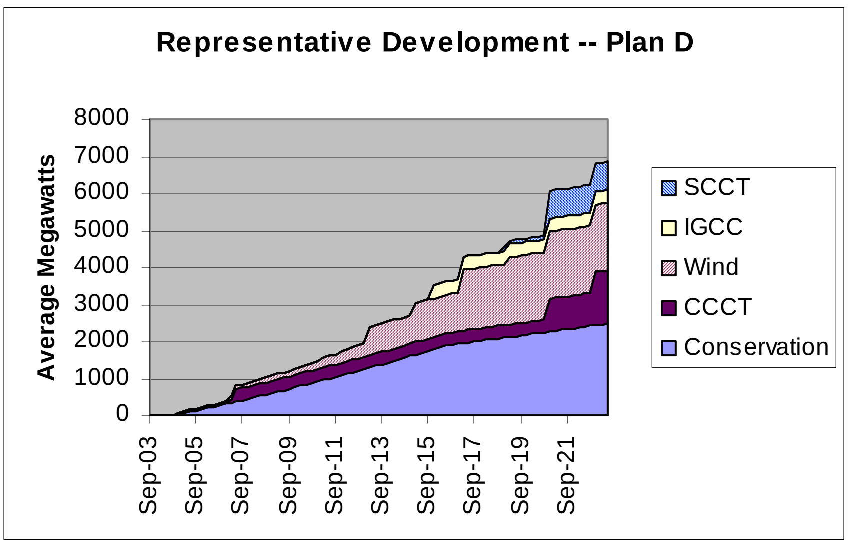


Figure OV-8

[5] The feasibility of the coal-gasification power plant depends partly on timing. This is a technology in the early stages of commercialization. If the technology does not mature as expected, or if a coal plant is needed earlier than what is shown in the Council plan, conventional pulverized coal may be a better option. (See discussion on page OV-21.

However, the Council's portfolio analysis shows that sustained, significant development of cost-effective conservation now, with a goal of 700 average megawatts over the next five years, ~~to be~~is in the region's interests. Accomplishing this and additional conservation over the remainder of the planning period reduces the average system cost by ~~as much as~~nearly $2 ~~to $2.5~~ 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 $~~17~~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 to be beneficial in terms of reduced need for more expensive new resources and reduced 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~~, with modest increases in the following years~~. Bonneville and the region's utilities will fund much of the conservation in the first 5 years, but new codes and standards should contribute some savings as well.

The Council recognizes that this 5-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 the Bonneville Power Administration (Bonneville), the region's utilities, and the Northwest Energy Efficiency Alliance (Alliance) during the Western electricity crisis of 2001 through 2002. It is just over 10 percent higher than the average amount of conservation achieved annually from 1993 through 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. ~~However, more will need to step up.~~

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

- While the region as a whole has excess generating capacity, the region's utilities are, in aggregate, energy short.
- Some may need additional peaking capacity or want to reduce exposure to the market.
- Requests for proposals are an effective tool for assessing available options.
- Most of the surplus generation is owned by independent power producers (IPPs). This power is available to the region. However, utilities may have reasons not to purchase from the IPPs:

-- They may not want to take on additional gas price risk. (Most of IPP projects are gas-fired.)
-- Transmission limitations may prevent accessing existing generation on a firm basis.
-- They may want to get experience with newer technologies like wind.
-- They may see advantages in building their own:

♦ There can be financial advantages in having a physical asset as opposed to 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

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

- **The conservation costs less than many of the resources utilities are planning**
- 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 acquired all available conservation already?

- Most of the conservation potential identified in this power plan is in new technologies and new applications that generally have limited penetration to-date.

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 one 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.~~
- 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 one 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 from all sources (codes, standards and programs) 1991-2002 was greater**
- **Several utility IRPs have proportionately similar targets.**
- **Achieving the target means making the region's electricity use efficiency only 10 percent better**

To accomplish the power plan's conservation targets, the Council estimates that regional utility system investments will need to increase. ~~The increase in utility system investments needed to achieve the targets~~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 timing and effectiveness of energy codes and standards 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 $1.2 to $1.35 billion. This is slightly less than the $1.45 billion (year 2000 dollars) in utility investments from 1992 through 1996. The Council understands the difficulty of raising power rates to accomplish this level of investment. This means that acquiring conservation as cost-efficiently as possible must be a high priority.

In addition to conservation, the Council recommends developing 500 megawatts of demand response over the next five years, and up to 2,000 megawatts over the 20-year planning period. In the portfolio analysis, demand response was used in ~~most years in~~83 percent of all the ~~futures~~

years examined. However, in most of those years it was used for only a few hours (less than ~~87~~ 9 hours per year in 85 percent of those years). In ~~90~~ 95 percent of ~~the~~ all years, ~~10~~ 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 ~~by almost~~about $~~100~~ 146 million while risk increased by $~~500~~ 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 ~~in the long-term~~ 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 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 over the remainder of the decade. Wind generation incorporated in system benefits charge programs and current utility plans ~~and~~ 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 ma~~n~~y 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~~0~~. 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, like construction of transmission upgrades, have been initiated so that resources can be brought on line as needed. The Council has analyzed both conventional pulverized 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 use of coal gasification power plants lowers the expected cost and risk compared to the use of conventional coal generation technology and has lower emissions, including carbon dioxide. However the analysis is predicated on further commercialization of coal gasification technology. The Council will review the progress in commercialization of that technology in early 2007. If it is not occurring as predicted, the Council will instead call for optioning of conventional pulverized coal-steam generation on which construction could begin as early as 2010. ~~Although not modeled as part of the resource plan, further analysis suggests that serious consideration should be given to integrated coal gasification as a way of reducing risks associated with future carbon emissions reduction policies.~~

~~Wind is expected to play a much-expanded role in the long-term. 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 plant and cost reductions; higher gas prices and price volatility; wind turbine technology improvement; and relatively low integration costs. It also assumes the ability to extend transmission service to promising wind resource areas. 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 over the remainder of the decade. Wind generation incorporated in current utility plans and system benefits charge programs 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 many have adverse effects on the ability to produce other ancillary services or reliably meet fish operations requirements.~~

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 in the text box above, there can be legitimate reasons for individual utility plans to differ in resources or resource timing from this plan. Nevertheless, the plan provides 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 conservation acquisition. Historically, the plans' goals have been major factors in the region's achievement of 2500 average megawatts of conservation savings at comparatively low cost 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 over 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. In addition, the treatment of uncertainty and risk used in this plan is an approach that can and should be applied in individual utility planning.

IMPLEMENTING THE PLAN ~~STRATEGIES FOR AN UNCERTAIN FUTURE~~

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 ~~are~~ were outlined ~~below~~in the Executive Summary of the power plan. The actions are described in detail in following chapter on the Action Plan. The Council expects to monitor the implementation of the plan and report annually of the region's progress. The annual implementation reports will update important information that may affect the plan including electricity demand, fuel prices, resource development, and significant technology progress.

~~**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**~~

- ~~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~~
- ~~Improve utilization of available transmission capacity~~

~~**3) Confirm the availability and cost of additional resources that promise cost and risk mitigation benefits**~~

- ~~Oil sands cogeneration~~
- ~~Coal gasification~~
- ~~Carbon sequestration~~
- ~~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 voluntary adequacy targets for the Northwest and the rest of the Western system.~~
- ~~Work through Grid West, RRG process to address emerging transmission issues within the next two years~~
- ~~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.~~

~~ISSUES FOR SPECIAL ATTENTION IN COMMENTS~~

~~The Council invites public comment on all the assumptions and analysis in this draft plan. In particular, there are a number of new or particularly difficult issues in this draft plan. They are called out here to ensure that they get careful thought and attention by the region. Some of these issues are quite broad; others are relatively focused and specific.~~

~~Least cost or least risk~~: ~~In this plan, much more attention is paid to risk – the high costs that could occur under a number of adverse circumstances – than has been the case in previous plans. The analytical methods used are described in Chapter 6. The analysis identifies a number of alternative resource development plans ranging from the one with the least average cost but with relatively high risk, to the one with least risk but with somewhat higher average cost. For the draft plan, the Council has chosen the least risk plan as described in Chapter 7. That choice implies less reliance on the wholesale market and more conservation and potentially more generating resource development in the long term. The least-risk plan is expected to result in less price volatility and less chance of experiencing the kind of high costs the region experienced in 2000 and 2001. However, the average cost is somewhat greater than higher risk plans, though few of the generation development costs would be incurred during the 5-year action plan. Is the choice of the least-risk plan reasonable?~~

~~Treatment of Risk~~: ~~The treatment of risk requires much subjective judgment regarding future uncertainties. The characterizations of future uncertainty were developed with input from regional experts. How could the Council improve its treatment of risk? Are there elements of uncertainty which have been overlooked that would be significant enough to change the conclusions of the plan?~~

~~Conservation~~: ~~The draft plan calls for aggressive and sustained development of conservation (700 average megawatts between 2005 and 2009). This conservation is shown to reduce both cost and risk over the long-term, but may result in small rate increases in the near-term. The conservation resource and the analysis of the rate of development are described in Chapters 3 and 7, respectively. While the region has developed conservation at these rates at times in the past, it has not done so on a sustained basis. The level of near-term development is consistent with the conservation development identified in the resource plans of many, but not all, regional utilities. Is the Council's call for aggressive and sustained conservation appropriate and achievable? Are there changes in policies or implementation practices that would improve the ability to achieve the conservation?~~

~~Demand response~~: ~~The action plan calls for extensive development of demand response programs. Demand response is the ability to temporarily reduce demand during power emergencies or periods of very high wholesale prices (Chapter 4). Demand response has been shown to be effective in helping stabilizing electricity prices and preventing outages. The analysis described in Chapter 7 shows that though it is likely to be used infrequently, demand response reduces both cost and risk compared to developing additional generation. There is, however, some uncertainty about the amounts available and the cost of achieving it. Are the estimated quantities and costs reasonable? Is the development and use of demand response an appropriate role for utilities? Can it be counted on as a firm capacity reserve?~~

~~**Wind generation**: The draft plan includes a significant amount of development of wind generation in the in the next decade. The wind resource is described in Chapter 5. The attractiveness of wind depends on a number of estimates: that wind incentives will continue unless carbon dioxide emissions controls are enacted; that costs will continue to decline significantly over time; that the cost of integrating wind energy into the power system will remain relatively low; that development of large areas of good wind resources west of the Rocky Mountains region will be possible; and that there is some likelihood of increased restrictions on CO_2 emissions in the future. Each of these estimates is uncertain. Over the next few years, the plan calls for gathering more experience and information about wind resources and their performance and cost within the regional power system through limited commercial-scale development. The level of near-term development is consistent with the wind development identified in the resource plans of regional utilities. Are the estimates regarding wind development reasonable? Can the uncertainties regarding these estimates be resolved with limited commercial scale development in the near term?~~

~~**Global climate change policy**: Assumptions regarding the likelihood and magnitude of future policies to reduce carbon dioxide emissions influence the resource choices in this plan. The treatment of possible carbon dioxide emissions policies is described in Chapters 6. Are the assumptions used reasonable for exploring the effects of possible future policies?~~

~~**Current regional issues**: The region is working through difficult issues in various forums. These include transmission operation and planning issues, the establishment of resource adequacy standards and the future role of the Bonneville Power Administration in power supply. The Council has provided some specific recommendations with respect to Bonneville's role. On other issues, the plan provides some background and principles but has generally supported the ongoing collaborative processes in the region, rather than proposing specific solutions. Is this an appropriate position for the Council's plan?~~

~~**Independent power producers**: In the mixed wholesale power market that exists in the region, there is now a significant presence of independent power generation. Most of this power is not committed long-term to load serving entities inside or outside of the region and does not have firm transmission access to markets outside the region. In a physical sense, the presence of these plants in the region contribute to the current regional power supply surplus even though regional utilities in aggregate have a power supply deficit under critical water conditions. The plan considers the independent power plants as resources available to serve the regional market, from which the region may purchase at market prices, absent any actions by regional utilities to acquire that output under other conditions. Is this an appropriate treatment of this issue?~~

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