Northwest Power and Conservation Council

July 6, 2004

MEMORANDUM

TO: Council Members

FROM: Dick Watson

SUBJECT: Power Plan Materials for Agenda Item 5

Attached is a preliminary draft of the Power Plan Summary. It is still incomplete (what's missing will be obvious to you), has had only partial editing by the Public Affairs Division, and has not yet been reviewed by the Power Committee. Nonetheless, I think it will give you a pretty good picture of the power plan. This is supposed to be the "CliffsNotes" version of the plan. You are supposed to be able to read this and have a pretty good idea of what this plan is about without going deep into the details. I'm sure you'll let me know if we succeeded.

Later this week you will also receive the Analysis, Conclusions and Recommendations sections for conservation and demand response.

Fifth Power Plan Summary and Action Plan

Key Conclusions

Unless demand for electricity grows faster than the Council anticipates, or a substantial number of existing power plants are retired or otherwise become unavailable, this plan does not anticipate the need for substantial amounts of new generating capacity before the end of the present decade. At the same time, an aggressive program of conservation acquisition, beginning immediately, will reduce the risk of high prices in the event of another energy crisis like the one the West experienced 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 in place so they could be implemented quickly if needed. The region should be ready to add new generating resources after 2010. An inventory of permitted sites, including projects for which construction has been suspended should be maintained, and needed transmission upgrades should be initiated so that these resources can be constructed and brought on line quickly when needed. Modest levels of wind power development should be undertaken at a geographically diverse set of promising wind resource areas to resolve uncertainties associated with this resource and to prepare for eventual larger-scale development. Finally, efforts to identify and develop cost-effective lost-opportunity generating resources, including combined heat and power (cogeneration) and biomass applications, should be reinforced.

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 an adequate, efficient, economic, and reliable power system. To accomplish this, the plan addresses the uncertain future we face; 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 comes 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 failed 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 were very different. They lay in 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 unscrupulous people who took advantage of the market's vulnerability. The net effect, however, was much the same. 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 these events and their consequences should serve as clear reminders that we cannot know what will happen in the future and that uncertainty breeds risk. It would not have been possible for planners to predict these events with certainty. However, it should have been possible to anticipate that similar events could happen; to test plans against those possibilities; to assess the risks; and to modify plans if the risks were too great.

The Council's plans have always been about assessing risk and planning to manage that risk. The year-to-year uncertainty about hydroelectric generation, uncertainty about future demand for electricity, and uncertainty about fuel prices have always been considered in the Council's plans. Generating resources tended to be large, have long planning and construction lead times, and were very capital-intensive. The risk that investors may not be able to recover their costs if demand was lower than expected was significant.

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; but whether such policies will be implemented, and if so, what the magnitude and timing of any carbon emissions penalties will be, is very uncertain. Some renewable energy technologies, though capital intensive, have short lead times and provide a hedge against fuel price and climate change risk. But it is not known whether their current trends of falling cost will continue, or whether integration of intermittent generation into the power system will prove more costly as the penetration of these technologies 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. Moreover, many of these uncertainties are interdependent. Volatility in gas prices and hydroelectric generation can, for example, translate into volatility in electricity markets.

The region is part of a complex, highly interconnected power system linking the Northwest and the entire West Coast. This 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 this system would be very costly, but inherent in the status quo is significant uncertainty and risk that must be recognized and managed.

Planning for an Uncertain Future

Planning for an uncertain future requires assessing risk. That requires that we characterize the key uncertainties the power system faces. Can we, 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.

To evaluate the performance of possible plans, the different possible paths that the key sources of uncertainty might take over the planning period are combined into "futures." The Council tests its plans against approximately 800 futures. Key uncertainties include:

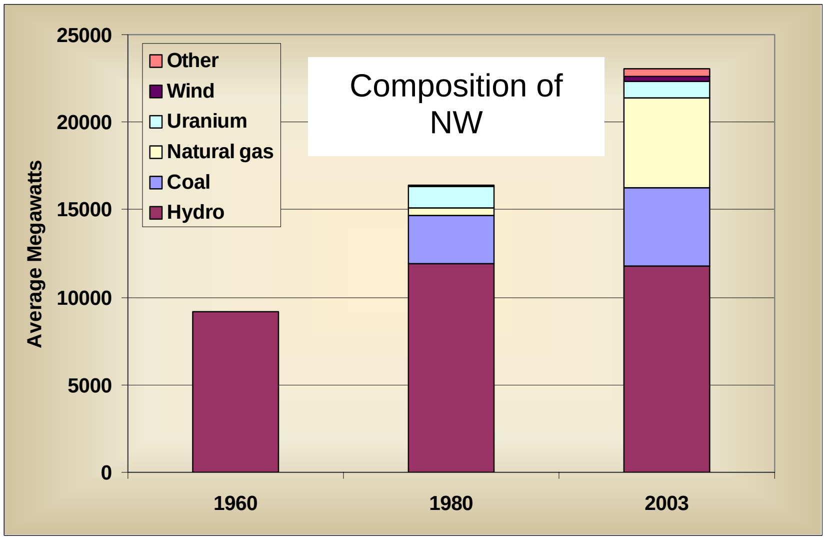
Hydroelectric Generation

The potential variation in the output of the regional hydroelectric system is very large and, therefore, poses an important uncertainty. But we have 50 years of hydrologic data with which we can characterize the year-to-year uncertainty in hydroelectric generation with a high degree of confidence. [chart showing the distribution of hydro electric generation]. There is further uncertainty resulting from potential shifts in temperatures and precipitation patterns associated with climate change. While we have made an assessment of the possible effects, this uncertainty has not been included.

Demand

Demand for electricity is a key uncertainty. Rapid demand growth means additional resources will be required. Conversely, slow load growth means fewer resources. The Council bounds overall rates of growth in demand with a range of forecasts based on analysis of the economic, demographic, and technological factors driving demand for electricity. [chart showing the forecast range and "typical" demand futures] 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 low probability. However, overall trends are only part of the story. We have seen that we can experience extended periods of more rapid growth or, 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 some resources may be unable to fully recover their costs. To assess risk it is necessary to reflect the variation in demand that can occur.

Fuel Price



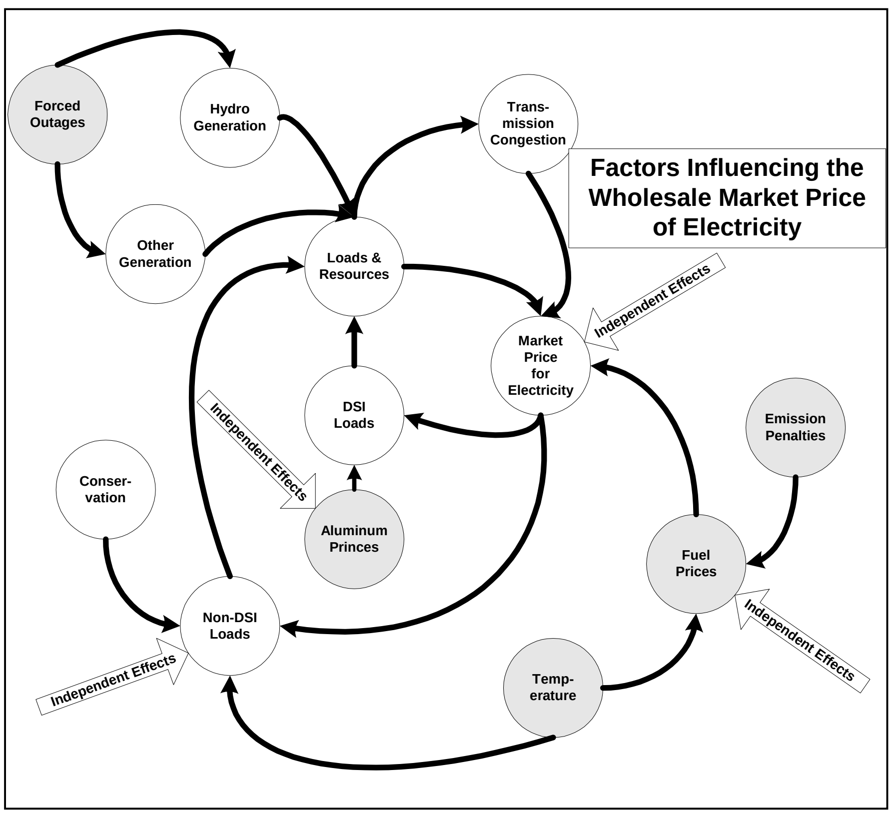
Similarly, fuel price uncertainty is an important source of risk. In particular, periods of high prices can increase operating costs for those resources dependent on that fuel. The Council forecasts a range of natural gas, oil, and coal prices. Currently the most important is natural gas because of the 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 and, under the right conditions, 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. [chart showing range forecast with a sample of futures for natural gas prices]

But we also know that the price of natural gas exhibits short-term volatility and longer term variation. Periods of oversupply can, as we have seen in the recent past, depress prices for extended periods. Conversely, periods when supplies are tight can result in periods of relatively high prices, as we are experiencing now. These periods of price and supply variation can have a significant effect on the costs and risks associated with gas-fired generation.

Environmental Regulation

Future environmental regulation, particularly the potential for regulation of carbon emissions or the imposition of charges on carbon emissions, is an important uncertainty. If we knew with certainty that there would never be a carbon tax or the equivalent, coal-fired generation would be an economically attractive option. Conversely, if we knew with certainty that a significant carbon penalty would be imposed, coal-fired generation would not be considered absent a significant breakthrough in the cost of carbon sequestration. At present, future CO2 control costs are highly uncertain. The small CO2 offsets required of new resources in Oregon and Washington are likely to set a lower bound on CO2 costs in the Northwest. Published estimates of the level of CO2 offset costs required to lower overall CO2 production to 1990 levels may be an upper bound for the next decade or two. We have treated this issue probabilistically with probability of some level of carbon penalty between XX and $30 per ton reaching 80 percent by the end of the planning period.

Electricity Market Price



The market price of electricity is an important uncertainty and source of risk. In a sense, 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 operating costs and make a contribution to recovery of capital. That 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 derived quantity – a function of demand, the amount and characteristics of supply, and fuel prices.

But it can also exhibit variation that is not fully explained by the equilibrium of supply and demand. [chart showing typical electricity price futures]. Those variations can be an important source of risk.

Resources for the Future

The performance of a plan depends very much on how the characteristics of the resources interact with different possible futures. These characteristics include factors such as 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 key resource alternatives for both generating resources and "demand side" resources like conservation (the more efficient use of electricity) and demand response (temporary reductions or shifts in the timing of some uses of electricity). Conservation is the top priority resource under the Northwest Power Act.

The primary resources considered in the portfolio analysis and their relative characteristics are summarized in Table ES-1. Some of the important considerations are the unit size 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.

Table ES-1 – Resource Characteristics

Resource	**Typical Project Size**	**Construc-tion Lead Time**	**Capital Cost**	**Fuel and other operating costs**	**CO2 Production**	**Dispatch-ability**
Conservation	Very small	Short	Moderate to high \	None	None	None
Demand Response[1]	Very small to small	Short	Low	High with some exceptions	None	High
Gas-Fired Combined Cycle Combustion Turbines	250 - 600 MW	2 Years	Moderate, slowly declining	Moderate to high	Moderate	Moderate-high
Gas-Fired Single Cycle Combustion Turbines	100 MW	1 Year	Moderate, slowly declining.	High	Moderate to high	High
Coal-Fired Steam Generation	250 - 500 MW	3 – 4 Years	High, stable	Low	High CO2 production	moderate
Wind Turbines	30- 300 MW	1 year if adequate trans-mission available	High but declining	None	None	None, intermit-tent

There are other resources that have been considered in developing this plan. Many, such as combined heat and power (also known as cogeneration); power plants using bio-residue fuels;

[1] Demand response is the ability to take load off the system or shift it to lower demand periods during periods of very high prices and short supplies.

and other “distributed generation” technologies are very site-specific. Their cost effectiveness frequently depends on a number of factors such as: localized benefits for reliability or power quality; the ability to offset transmission or distribution system investment or reduce losses; the availability of particular fuels; the ability to offset other fuel use; 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. Efforts should be made to identify cost-effective projects and develop them when the opportunity arises.

There are other resources that have not been included in the portfolio risk analysis and resource development recommendations because of significant impediments to their development. Because of this, they are difficult at present to consider “available” as defined by the Northwest Power Act. These include: coal gasification, potentially with carbon sequestration; solar photovoltaics; advanced nuclear power plants; and oil sands cogeneration. Because of the potential attractiveness of these resources under plausible future conditions, it is important to understand their potential role, key impediments to their development, and regional actions that could help resolve these impediments. They may figure prominently when this plan is revised later in this decade.

The resources considered in the development of this plan are summarized in the “supply curve” shown in Figure ES-?. This shows the estimated levelized cost of specific resources in cents per kilowatt hour and estimated cumulative supply in average megawatts. 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 transmission costs.

This 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 subject to the uncertainties of a large number of possible futures.

[Sidebar: Comparing resources on an equal footing, comparing fuel intensive and capital intensive resources, levelized cost]

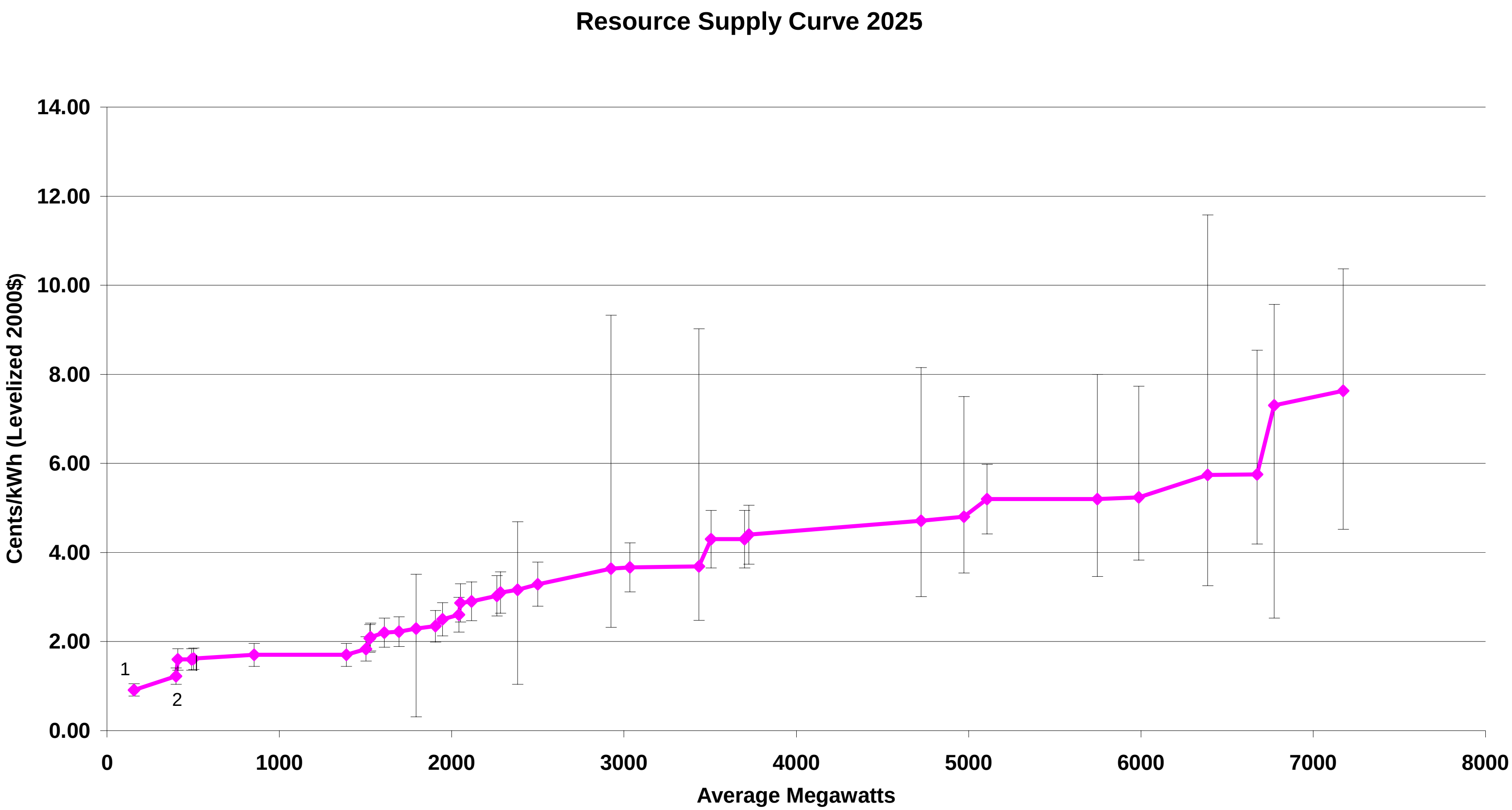

Resource Supply Curve 2025
Cents/kWh (Levelized 2000$)
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0
1000
2000
3000
4000
5000
6000
7000
8000
Average Megawatts
1
2

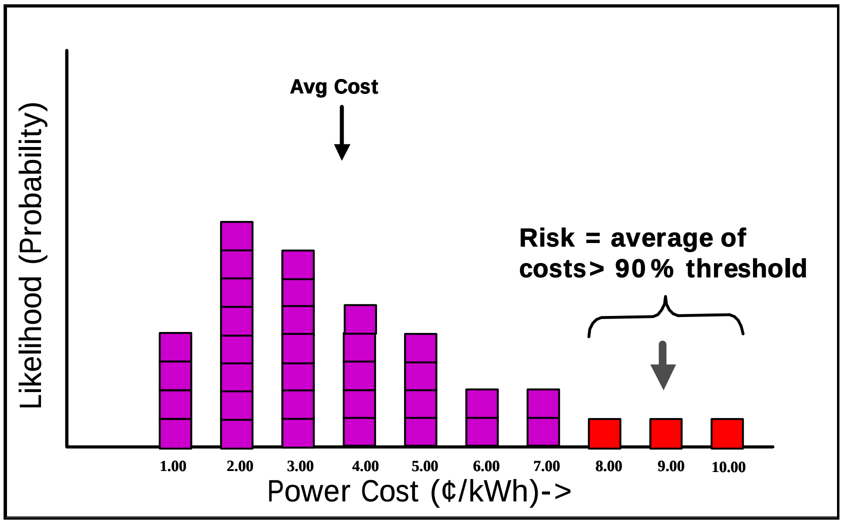
Table XX Resource Supply Curve

		Average Cost (Cents/kWh) (Levelized 2000$)			Cost-Effective Savings Potential	Cumulative Savings
	Sector and End-Use	Low	Avg	High	(MWa in 2025)	(MWa in 2025)
1	New & Replacement AC/DC Power Converters[2]	0.78	0.91	1.05	156	156
2	Commercial New & Replacement Lighting[2]	1.04	1.22	1.41	245	401
3	Residential Dishwashers[2]	1.36	1.60	1.84	10	411
4	Agriculture – Irrigation[2]	1.36	1.60	1.84	80	491
5	Commercial New & Replacement Shell[2]	1.37	1.62	1.86	13	503
6	Industrial Non-Aluminum[2]	1.45	1.70	1.96	350	853
7	Residential Compact Fluorescent Lights[2]	1.45	1.70	1.96	535	1388
8	Commercial Retrofit Lighting[2]	1.56	1.84	2.11	114	1502
9	Commercial New & Replacement Infrastructure[2]	1.76	2.07	2.38	22	1524
10	Residential Refrigerators[2]	1.79	2.10	2.42	5	1529
11	Residential Water Heaters[2]	1.87	2.20	2.53	80	1609
12	Commercial New & Replacement Equipment[2]	1.89	2.22	2.56	84	1693
13	Central MT Wind for local load, firmed and shaped[1]	3.51	0.31	2.29	100	1793
14	Commercial Retrofit Infrastructure[2]	1.99	2.35	2.70	113	1906
15	Residential New Space Conditioning – Shell[2]	2.13	2.50	2.88	40	1946
16	Residential Existing Space Conditioning – Shell[2]	2.21	2.60	2.99	95	2041
17	Commercial Retrofit Shell[2]	2.44	2.87	3.30	9	2050
18	Residential HVAC System Efficiency Upgrades[2]	2.47	2.90	3.34	65	2115
19	Commercial New & Replacement HVAC[2]	2.57	3.03	3.48	148	2263
20	Residential HVAC System Commissioning[2]	2.64	3.10	3.57	20	2283
21	Eastern WA/OR Wind[1]	4.69	1.04	3.16	100	2383
22	Commercial Retrofit HVAC[2]	2.80	3.29	3.78	117	2500
23	Eastern WA/OR IGCC w/o CO2 Separation[1,4]	2.32	3.64	9.33	425	2925
24	Commercial Retrofit Equipment[2]	3.12	3.67	4.22	110	3035
25	Eastern WA/OR Pulverized Coal[1,5]	2.48	3.69	9.02	400	3435
26	Residential HVAC System Conversions[2]	3.66	4.30	4.95	70	3505
27	Residential Heat Pump Water Heaters[2]	3.66	4.30	4.95	195	3700
28	Residential Hot Water Heat Recovery[2]	3.74	4.40	5.06	25	3725
29	Eastern WA/OR CCCT[1,3]	3.01	4.71	8.15	1000	4725
30	Goldendale CCCT[3]	3.54	4.80	7.50	248	4973
31	Residential Clothes Washers[2]	4.42	5.20	5.98	135	5108
32	Grays Harbor CCCT[3]	3.46	5.20	8	640	5748
33	Montana First Megawatts IGCC[2,4]	3.83	5.24	7.73	240	5988
34	MT Coal Steam w/ TX to MidC[1]	3.25	5.74	11.58	400	6388
35	Mint Farm CCCT[3]	4.19	5.75	8.54	286	6674
36	Central MT Wind w/ TX to MidC, firmed and shaped[1]	9.57	2.53	7.3	100	6774
37	MT IGCC w/ TX to MidC and CO2 Separation[1,4]	4.52	7.63	10.37	401	7175

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 conservation resources is +/- 15 percent.
3) The uncertainty interval for generic combined cycle combustion turbine generators is defined on the low side by a 57 percent capacity factor, medium-low natural gas prices, no CO_2 control, a 10 percent "learning factor" for technology and public utility financing costs. The high side of the uncertainty interval is defined by a 48 percent capacity factor, high natural gas prices, CO_2 control costs based on the CSA (define), 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 is defined on the low side by medium low coal prices, no CO_2 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, CO_2 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 wind is defined on the low side by 32 percent capacity factor, a 15 percent learning factor, green tag value of $6/MWh, $4/MWh for shaping and firming, all public utilities' financing costs, and the production tax credit for wind continuing indefinitely at $1.50/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/MWh, $8/MWh for shaping and firming, all independent power producers' 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, except that the assumed capacity factor is 38 percent for the low side, and the capacity factor is 34 percent on the high side.

Evaluating Plans



In evaluating plans the Council relies on both analytical models and informed judgment. 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. Two primary measures of a plan's performance are used: the average total system cost over all the futures; and a measure of risk – the average of the cost of the worst 10 percent of the outcomes. But this is only the start. The plan is "stress tested" to evaluate sensitivity to different assumptions. This process of testing, changing assumptions and re-testing continues until the Council is satisfied that the plan makes sense. Only then does a plan become *The* plan.

The Plan

A plan describes the resource actions to be taken over the planning period. The region currently has a modest surplus of generation. Consequently unless the region experiences extremely high growth in demand over the next several years and/or substantial loss of existing resources, the plan does not call for significant development of new generating resources before the end of the decade. [Sidebar – this is regional plan, individual entities situations may differ??]. However, that does not mean that the region should not develop additional resources. The Council's analysis finds that sustained, aggressive development of conservation now, at the rate of approximately 1XX average megawatts per year, will reduce average cost and risk substantially compared to less aggressive implementation. In the past, the pace of conservation implementation has varied widely from year to year as utilities responded to market conditions. However, our analysis shows a sustained and aggressive pace of investment in conservation to be beneficial in terms of reducing exposure to periods of high market prices, fuel price volatility, and possible future carbon penalties.

In addition, demand response resources in the amount of up to 1,800 megawatts are also developed over the planning period. On average, these resources are dispatched very little (less than zz hours per year). But in futures with very high prices, they can dispatch for longer periods to help moderate prices and maintain reliability. Without any demand response resources, the average cost of the plan increases by $300 million at constant risk levels. There remains, however, some uncertainty regarding the amount and cost of the demand response resource.

Beginning in the early part of the next decade and through 2025, the plan calls for being ready to begin actual construction of both wind (up to XXXX megawatts capacity, approximately 1XX0 average megawatts energy) and combined cycle combustion turbines (YYYY megawatts capacity and up to YYYY average megawatts energy). Being ready to begin construction means that the process of siting and licensing the necessary projects has already 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.

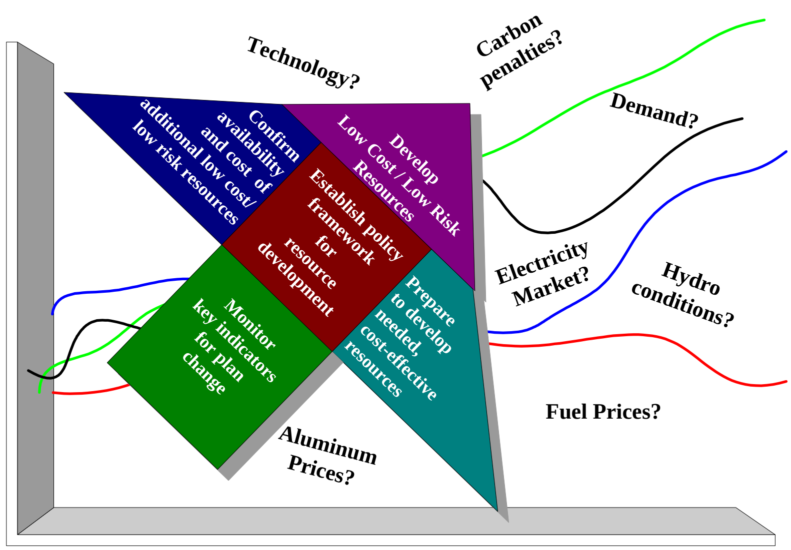
The much expanded role for wind generation in this plan is the result of possible future policies to reduce the emissions of carbon dioxide, making the use of carbon-intensive fuels risky, and also the forecast of significant wind plant cost reductions, wind turbine technology improvement, relatively low integration costs, and the ability to expeditiously extend transmission service to promising wind resource areas. Because of the potentially significant future role of wind power and the need to resolve these uncertainties before large-scale development is needed, the plan calls for measured development of commercial scale pilot wind projects at geographically diverse promising wind resource areas over the remainder of the present decade.

Scenarios

[charts showing resource development for *representative* futures and those for which the plan does and does not perform well.] Discussion of these scenarios

Strategy for an Uncertain Future

The plan does not call for the immediate development of generating resources. This is not, however, an excuse for inaction. This plan is about the actions the region needs to take to manage costs and minimize risk in an unavoidably uncertain future. The time to begin those actions is now.



Develop resources now that can reduce system cost and risk

Even if the region currently has a modest surplus, there are resources that should be developed now. These are resources that reduce long-term system costs and risks and other attractive resources that, if not developed now, would become “lost opportunities.” Lost opportunity resources are typically those that depend on other actions like construction of a building or renovation of a factory in order to be cost-effective. The most important example of this are conservation measures, some of which are lost-opportunity resources and some of which could have more flexibility as to when they are developed. However, the analysis suggests that aggressive implementation of both kinds of conservation should be pursued immediately. There are potentially other examples of lost opportunity resources such as combined heat and power projects that, if cost-effective, should be pursued as they become available.

Confirm the availability and cost of additional resources with cost and risk mitigation benefits

There are other resources that appear to have real benefit to the system in terms of cost and risk mitigation. However, the information on which that assessment is based is incomplete or unconfirmed. Is the potential as great as we think it is? Are the costs as attractive as we estimate? The time to answer these questions is now so that we can implement those resources when they are needed or move to other alternatives.

Prepare to develop additional resources

Time and uncertainty go hand in hand. The longer resource development takes, the greater the uncertainty and risk. This means that the region should be prepared to develop resources when needed, with as short a lead-time as possible, and without making large expenditures until necessary. Practically speaking, for power plants this means getting the important but relatively low cost planning and permitting out of the way in advance of the earliest construction start dates. In some cases, like demand response, it may mean putting in place the necessary software and contractual infrastructure. It also means identifying the very long lead-time actions that may be necessary, such as transmission expansion, so that they are ready when needed.

Establish the policy framework to ensure the ability to develop needed resources

It is likely that for the foreseeable future we will continue to see a mix of vertically integrated utilities, a federal power-marketing agency, local distribution utilities, competitive wholesale suppliers, and a variety of small and large consumers in the regional power system. This system will have elements of federal, state, and local regulation as well as competition. This mix has resulted in uncertainty regarding roles and responsibilities, perpetuated barriers, and diluted incentives. Some of the elements necessary for the system to function effectively are not fully developed. A necessary part of our strategy must be to identify and work to establish the policies that are necessary to clarify roles and responsibilities, remove barriers, and create the incentives to ensure that needed resources will be developed.

Monitor "key indicators" that could signal changes in plans

Managing in an uncertain future requires adapting as the future unfolds. Because the future is uncertain, we develop plans to provide low costs and risks over a wide range of possible futures. But no one plan can be the best for all futures. In reality, only one future is actually realized. This means it is important to identify key indicators that could signal the need to adapt or modify the plan; identify the kind of adaptation required; monitor those indicators; and modify the plan as required. For example, persistent rates of demand growth near the high end of the forecast range would signal a need to accelerate resource development. Clarification of climate change science and policy could alter resource choices. New technologies could offer new choices.

Making it happen – The Action Plan

The Northwest Power Act requires the Council to prepare a 20-year power plan. Resources are usually long-lived. Because uncertainty and the risks it entails become greater with time, it is important to evaluate the performance of a plan for a long period time. But no one expects to slavishly adhere to any plan for the entire 20-year planning period. This plan will be revised several times during that period as new technologies become viable, as current uncertainties become certain, and as new uncertainties arise. However, what is most important for this plan is what we do in the immediate future, the next few years before a new plan is produced. We will not get a chance to revisit those decisions. We will have to live with the consequences for many years to come. The Action Plan identifies those actions that have to occur over the next three to five years to implement the power plan. Those actions have been grouped by the elements of the strategy.

Develop resources now that can reduce system cost and risk

Conservation

Conservation is the highest priority resource under the Northwest Power Act. The region has developed more than 2,700 average megawatts of conservation since its passage at an average levelized cost of approximately 2.5 cents/kilowatt-hour. Despite the conservation that has already been achieved, there remains a significant amount yet to be developed, largely as a result of new efficiency technology.

Conservation has several characteristics that make it unique when compared to other resources. First, its cost 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 it reduces the risk of increases in fuel prices and increases in 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 "schedulable," i.e., they can be developed when they are needed. On the other hand, some conservation resources are not schedulable. For these resources, which are the lost-opportunity resources, it is only feasible and 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, assuming the necessary programs and budgets are in place. This means that at least for schedulable conservation, there is some ability to speed implementation up or down in response to prevailing conditions.

Taking these characteristics into account, even though the Council's analysis indicates that we are likely to have relatively ample power supplies for the next few years, 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, market price, and environmental risks. To achieve this, Council recommends the following actions:

> **Establish a Regional Conservation Target –** The Council recommends that the regional target for conservation development should be 1XX average megawatts annually over the next five years. The Council believes that stabilizing the regional investment in conservation at this level has a much greater probability of producing a more affordable and reliable power system than alternative development policies. The Council recognizes

that the conservation target represents a significant increase over recent levels of development.[2] However, The Council's analysis of the potential regional costs and risks associated with developing lesser amounts of conservation demonstrates that failure to achieve this target exposes the region to substantially higher costs and risks. Figure X-1 shows the Council's recommended targets by sector and resource type

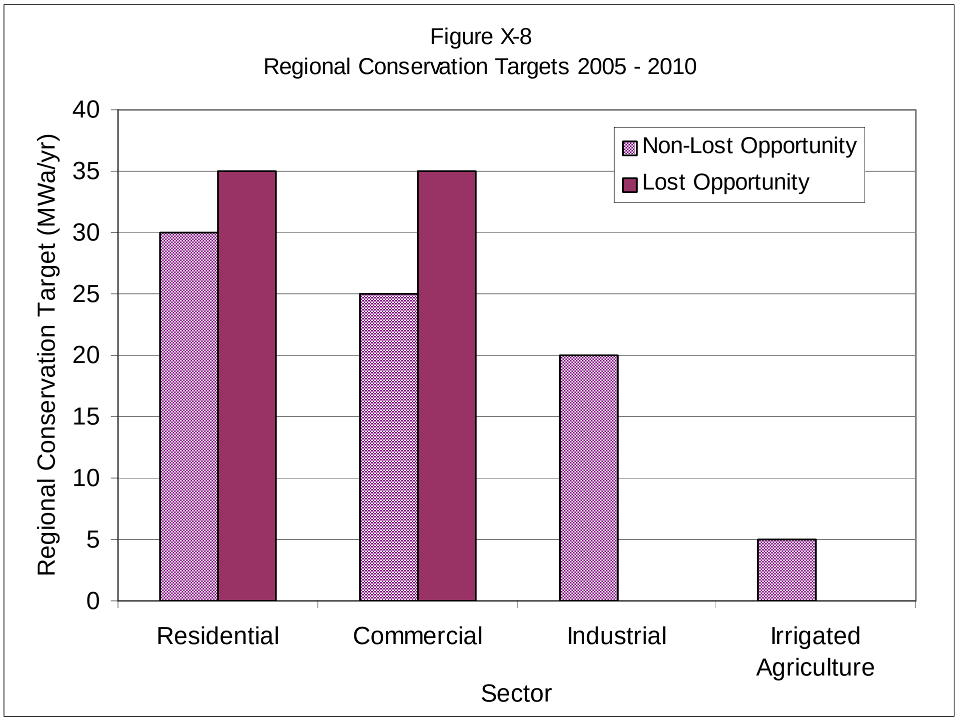


Figure X-1 Regional Conservation Targets 2005 - 2010

Focus on lost opportunity resources – The Council recommends that conservation resource development be split between "lost opportunity" and "non-lost opportunity" resources and across all sectors. The development of substantial lost opportunity resources is a major contributor to the "hedge" that conservation provides against future market price volatility.[3] As described in the discussion of the results of the portfolio analysis (section/chapter xxxx), capturing these lost opportunity conservation resources, in addition to the non-lost opportunity resources, reduces both net present value system cost and risk. If the region does not develop these resources when they are available, this value cannot be secured. These resources represent half of the Council's annual conservation target. Therefore, the region needs to focus on capturing these resources. This will very likely require significant new initiatives, including both local acquisition programs and market transformation ventures.

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[2] The region developed an average of 85 average megawatts annually through utility acquisition and market transformation programs from 1997 through 2002. During this same period the average annual utility system investment was approximately $120 million per year.

[3] A lost opportunity resource is a conservation measure that, due to physical or institutional characteristics, either cannot be developed or cannot be developed cost-effectively unless actions are taken at a particular time, e.g. when a building is being constructed or an appliance is sold.

Employ a mix of resource acquisition development mechanisms – The Council believes a suite of mechanisms should continue to be the foundation used to tap the conservation resource. This power plan cannot identify every action required to meet conservation targets. However, the specific characteristics of the targeted conservation measures and practices, market dynamics, past experience, and other factors suggest that a range of acquisition approaches will be needed to develop cost-effective conservation not captured through market forces. Key among these are: direct acquisition programs run by local electric utilities, system benefits charge administrators[4] or the Bonneville Power Administration; market transformation ventures; infrastructure development; state building codes; national appliance and equipment standards; and state and national tax credits.

Expand market transformation initiatives and increase budgets – A portion of the regional conservation target can be acquired most efficiently and effectively through market transformation. The Council's review of the Northwest Energy Efficiency Alliance's existing market transformation initiatives identified additional resources in this plan that are good candidates for future ventures. Therefore, the Council recommends that the region increase annual investments in market transformation to $40 million. Although this is double the current regional investment in market transformation, the Council does not view it as a disproportionate increase when compared to the overall increase in utility system investments that will be needed to accomplish the 1XX average megawatt target.

Increase local acquisition budgets – Based on historical costs, the Council believes that an aggregate utility system annual investment of between $200 and $225 million, excluding market transformation, will be needed to achieve the 1XX average megawatt target.[5] The amount each utility or system benefits charge 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. Nevertheless, the Council anticipates that local conservation acquisition expenditures will need to increase over current levels in order to capture conservation's benefits.

Provide adequate regional coordination and administration – Acquiring cost-effective conservation in a timely and cost-effective manner requires thoughtful development of mechanisms and coordination 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 successfully develop the remaining conservation potential. The boundaries between direct acquisition approaches, market transformation, infrastructure support, and codes and standards are blurry. In fact, for much of the conservation resource, efforts are needed on all these fronts to bring emerging efficiency measures into common practice or minimum standard. Of increasing importance is improved

[4] Oregon and Montana levy a charge (a percentage of retail sales revenues) to support conservation, renewable resource and low-income weatherization. These are referred to as a system benefits charge.
[5] At the upper bound the Council estimates that the total resource cost (100 percent of measure cost, plus 20 percent administrative cost) of accomplishing the 1XX average megawatt target is $380 million (2000$).

coordination between local utilities, system benefits charge administrators, the Northwest Energy Efficiency Alliance, Bonneville, the states, and others. Improved coordination is needed to assure that the region can take advantage of efforts to target initiatives where they have the most impact on the resource development and to capture synergies of approach.

The Council also believes that a significant share of the savings identified in this 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. In the past, Bonneville has played this role.[6] While the Council expects the agency will play a reduced role in resource acquisition in the future, it may be that it is the only institution that could realistically fulfill this need. The Council intends to work with the Northwest Energy Efficiency Alliance, Bonneville, the region's utilities, and system benefits charge administrators to develop a solution to this problem.

Address important regulatory barriers – to be completed

Other lost-opportunity resources

Some generating opportunities may be potential lost opportunities. For example, some combined heat and power opportunities may arise in the course of industrial plant renovation or upgrades. Similarly, some bio-residue fueled projects may also be potentially lost opportunity resources. They may be developed as part of a solution to a bio-waste problem. Efforts should be made by utilities and other entities to monitor the availability of potential lost opportunity combined heat and power, biomass, hydropower, and other renewable generating resources. Such projects should be acquired if cost-effective.

Confirm the availability and cost of additional resources with cost and risk mitigation benefits

Demand Response

Demand response is an appropriate, voluntary change in the level of electricity use when electricity supply is tight. Demand response can be accomplished by a variety of approaches, which can be generally grouped in 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 now we have limited our analysis to voluntary buybacks similar to those employed by several regional utilities during the 2000-2001 electricity crisis.

This is the first Council power plan in which demand response is treated as a resource. The region has limited experience with demand response, but that experience has demonstrated that it offers substantial potential benefits. The size and value of this resource are uncertain. For the portfolio analysis, we have conservatively estimated that 1,800 MW of demand response could be developed by [use specific year]. We have estimated its "operating" cost would be $1XX per megawatt-hour with a fixed cost of XX per megawatt-year. Our portfolio analysis further

[6] For example, Bonneville administerd the Manufactured Housing Acquisition Program (MAP) on behalf of all of the region's public and investor-owned utilities.

suggests that if we *fail* to implement demand response, the potential increase in expected system cost could be in the $300 million (net present value) range, at constant risk levels or conversely, this demand response could reduce system risk by $600 million at no net cost to the system.

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. Specifically:

> **Expand and refine existing programs –** Utilities, with regulators' approval, should maintain, expand, and refine the demand response programs they have developed in the past few years. For example, utilities should maintain their ability to buyback demand when conditions warrant, and should work to expand participation in these programs. The 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.
>
> **Develop cost-effectiveness methodology for demand response –** Regional parties, including, but not limited to, utilities, regulators, and the Council should work to develop a clear cost-effectiveness methodology for demand response. While the general principle of avoided cost is well accepted, there are practical difficulties in calculating avoided cost in our power system because of its 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.
>
> **Incorporate demand response in integrated resource plans --** Regulators should require utilities to incorporate demand response fully into utilities' integrated resource plans. Utilities have made a beginning, but more needs to be done. This work should include refined estimates of the size of the resource, which is likely to require pilot programs and further analysis.
>
> **Evaluate cost and benefits of improved metering and communication technologies –** Utilities, with participation by regulators, should evaluate all 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 cheaper 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.
>
> **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 such as fairness and price stability have prevented much adoption of price mechanisms in our

region. It is worth a serious effort to see if these legitimate concerns can be met while achieving some of the advantages of price mechanisms.

Transmission grid operators should consider demand response for the provision of ancillary services, on an equal footing with generation – It seems likely that this will be facilitated by the development of a formal market for ancillary services, but even if that formal market does not develop, demand response should be able to compete to provide ancillary services. Utilities, with regulators' approval, should maintain, expand, and refine the demand response programs they have developed in the past few years. For example, utilities should maintain their ability to buy back demand when conditions warrant, and should work to expand the participation in these programs. Utilities should work to reduce program transaction costs by streamlining the recruitment of participants, notification of buyback opportunities, and verification of, and compensation for, demand reductions.

Wind

Wind plays a major mid- to long-term role in the in the power plan for several reasons: the possibility of more aggressive policies to reduce carbon dioxide production, in combination with assumptions of a reasonably abundant quality resource; continued wind plant cost reduction and wind turbine technology improvements; relatively low integration costs; and the ability to expeditiously extend transmission service to promising wind resource areas. Uncertainties associated with these assumptions must be resolved to justify and facilitate future large-scale development of the resource when needed. The Council has concluded that the most effective way to resolve these uncertainties is through learning by doing. This plan therefore recommends limited development of commercial scale pilot wind power projects at promising and geographically diverse wind resource areas through the remainder of this decade. Development of XX megawatts of capacity per year on average through utility acquisitions, state system benefits charges or similar programs should suffice to prepare for large-scale development possibly needed beginning about 2010.

The recommended development of new wind generation in advance of apparent need is intended to meet specific objectives. The pilot projects (which will likely entail above-market costs in the near-term) are intended to confirm currently undeveloped but promising wind resource areas; establish transmission interconnection capability; confirm the costs and availability of wind firming and shaping capability; confirm wind power development cost and performance trends; confirm the degree to which regional wind development provides firm capacity; advance the understanding and benefits of geographical diversity for wind as a resource; and improve regional wind development infrastructure, including environmentally sound and expeditious site evaluation and permitting processes.

Confirm the availability of promising wind resource areas -- The plan foresees development of as much as 5,000 megawatts of new wind capacity beginning about 2010. Transmission constraints limit this development to areas west of the Continental divide. Five thousand megawatts represents a 10-fold increase in the current level of development. Moreover, the availability of 5,000 megawatts of potential capacity is not based on precise estimates of the capability of individual wind resource areas. For the time being, we must rely on rough and preliminary estimates of subregional potential by industry experts. If wind is to play the major role that appears desirable, it is necessary to confirm the ability to develop additional major wind resource areas within the region. This requires wind resource assessment; acquisition of wind rights by developers; assessment of the societal and environmental impacts of development; routing and design of transmission interconnections; wind project engineering; and issuing the necessary permits. In theory, all this could be accomplished, and at considerably lower cost without actual project construction. However, in practice, this has proven difficult to accomplish. For this reason, the Council believes the best way to confirm promising wind resource areas is to proceed with the development of geographically diverse commercial-scale pilot projects. Though potentially more expensive than only undertaking pre-development activities, the pilot project approach has proven effective, as demonstrated by the Stateline wind resource area in eastern Washington and Oregon. Because the objective is to confirm a much larger-scale potential, pre-development activities should, wherever feasible, encompass the entire wind resource area. Data from these projects would permit assessing the value of geographically diverse development.

Establish transmission interconnection capability -- Wind developers maintain that a key impediment to the development of wind power is the provision of transmission interconnection capability. One particularly important issue is the time required by transmission providers to assess grid interconnection requirements. While little can be done to shorten the time required to assess the grid interconnection requirements for the pilot project itself, that assessment should reduce the lead time required for follow-up development.

Monitor and confirm wind generation wind generation cost and performance trends – The estimates of the future cost of wind generation used in the analysis are based on the concept of "learning curves" for new technologies. Wind generators are very much like other new, factory-produced technologies. As experience is gained in the design and manufacture of these technologies, costs will come down. Cumulative volume of production is a measure of experience. The sources of the cost reductions are in both the performance of the technology itself, e.g., learning how to make larger-diameter rotors and stronger gearboxes that increase the power production per turbine, and in economies in manufacturing. Based on the analysis of cost experience and development to date, we have used a learning factor of 0.9. This means that for every doubling of installed wind capacity, there is a 10 percent decrease in cost per megawatt of capacity. Given projections of worldwide deployment of wind generation, this translates into an approximately 35 percent reduction in the bus bar cost of power from wind generators over the planning period. If these cost trends are not realized, it may be necessary to re-evaluate wind's role in the plan.

Monitor and confirm the costs of wind integration

Assess the degree to which regional wind development can provide firm capacity
Improve wind development infrastructure -- Because of the diversity of organizations likely to undertake the wind project development recommended here, the Council is

looking to no one organization to provide the information and achievements sought. Instead, the Council encourages all parties that participate in this development--wind project developers, providers of transmission and integration services, load serving entities taking wind project output, regulatory authorities authorizing utility acquisition, and permitting agencies to support these objectives for wind power development over the next several years. For example, state and local permitting agencies might grant permits for wind development on condition that production data is made available, on a confidential basis, to non-commercial entities like state energy agencies and the Council.

Oil Sands Cogeneration

The oil sands deposits of Northern Alberta contain the largest deposits of oil outside the Middle East. Development of the oil sands requires large quantities of steam to recover bitumen from the oil sands. The bitumen can then be processed into a "synthetic" crude oil. The steam is produced using boilers. However, it is more efficient to produce the steam though cogeneration where electricity is a valuable co-product. Combustion turbines with heat recovery boilers fueled by natural gas can be used. They can also be fueled by gas produced from the bitumen. This would separate this power from volatile gas markets and could produce power at a lower cost, depending on gas prices. The use of cogeneration also helps Canada, a signatory of the Kyoto protocol, toward its carbon emissions reduction targets. Combined production produces fewer emissions than the independent production of steam and electricity. Some cogeneration has already been developed in oil sands fields. However, complete development of the fields through cogeneration will require access to additional markets for the electricity. Discussions have been underway regarding construction of a 2,000 megawatt DC transmission line from the oil sands areas in Alberta to a point in the Northwest.

Monitor the cost and schedule of development of oil sands cogeneration and associated transmission – If the costs that have been quoted are achieved, the cost of the power delivered to the Northwest could be very competitive. The proposed lead-time for development of the transmission could make this power available at about the time that the Northwest would otherwise have to begin developing generating resources. If so, the development of some generation resources with less attractive cost and emissions characteristics could be deferred.

Coal Gasification

Coal gasification could greatly improve the economic and environmental characteristics of electricity production from coal, an abundant and low-cost energy resource. Gasification technology permits the use of efficient gas turbine combined cycle power generation; allows excellent control of air pollutants; and facilitates the separation of carbon dioxide for sequestration at much lower cost than conventional coal technology. Gasification is adaptable to co-production of liquid fuels, chemicals, and hydrogen, offering the opportunity for more flexible and economical plant utilization. Finally, gasification technology can be used with energy resources such as petroleum coke, bitumin, municipal solid waste, and various forms of biomass, providing a means of using the energy of these otherwise difficult fuels.

Circumstances under which coal gasification electricity generation might become especially attractive include sustained high natural gas prices, wind at higher cost and lower availability than forecast, and aggressive greenhouse gas control. The advantage of coal gasification in an aggressive greenhouse gas control situation is the ability to separate CO2 from the pre-combustion synthesis gas at relatively low cost for sequestering in a secure repository. The portfolio analysis would favor some coal development were it not for the risk of carbon penalties. If those risks could be reduced at a low enough cost, coal could figure in subsequent revisions of the power plan.

Support national efforts to develop coal gasification technology and monitor development – The principal impediment to deployment of coal gasification power plants is the commercial status of the technology. While demonstration plants are successfully operating, initial startups have been long and fraught with reliability problems. Overall plant performance warrantees are lacking, precluding financing. Also, experience with Western sub-bituminous coals is limited. Resolution of these issues will require additional demonstration projects. These issues are national in scope. However, the region should be supportive of national efforts to further development and demonstration of coal gasification.

Support and monitor efforts to develop carbon sequestration technology appropriate for Northwest application – Geologic sequestration of CO2 itself is poorly understood, and suitable geologic sites need to be identified and tested. At present it appears that the geologic formations most suitable for CO2 sequestration are found in the eastern portion of the region. The Northern Rockies and Great Plains Regional Carbon Sequestration Partnership is led by Montana State University in Bozeman. This effort will identify and catalogue promising geologic and terrestrial storage sites, and will help to define carbon-sequestration strategies. These efforts should be supported.

Prepare to develop additional resources

Preserve permitted sites – The region has a significant backlog of permitted sites for both thermal and wind generation. Permitting is a time consuming part of the development process. The lead-time for development can be shortened considerably if these already permitted sites can be utilized, reducing the exposure to risk. State and local permitting agencies should make every reasonable effort to preserve permitted sites for power development.

Plan for needed transmission now – Transmission planning and construction can be the longest lead-time item in power plant development. Efforts to identify the transmission requirements to connect areas of likely power plant development to load and to undertake at least preliminary planning should be made. The Council supports the efforts of the Northwest Transmission Assessment Committee (NTAC).

Improve utilization of available transmission capacity – There are contract paths in the region that are under-utilized in a physical sense, but which, contractually, have little, if any, available transmission capacity. The result is an inefficient use of transmission that could be an impediment to development of needed resources. Bonneville has undertaken some efforts to improve utilization of transmission capacity within its control area. This effort, while helpful, is necessarily limited by the fact that it cannot encompass the larger Northwest grid, and by the existing scheduling rules for transactions that cross control area boundaries. Dealing with this problem across the wider regional grid should be a priority for any regional transmission operator that may be formed.

Establish the policy framework to ensure the ability to develop needed resources

Resource Adequacy

One of the factors behind the Western electricity crisis of 2000-2001 was resource inadequacy. The analysis done for this plan suggests that 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 who have not had direct responsibility for assuring adequate resource will play an important role. This is not merely a regional issue because the Northwest is part of an interconnected West Coast 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. Because the Northwest does not face immediate resource needs, the region has some time to address these issues, but we must make sure that time is not wasted. To assure adequacy the region needs to:

Establish regional and West-wide reporting standards for the assessment of adequacy – It is essential that there be accurate, consistent, and transparent information by which the adequacy of power supply can be judged. The Council intends to continue to work with such entities as the Northwest Power Pool (NWPP), the Western Electricity Coordinating Council (WECC), and the Committee on Regional Electric Power Cooperation on this issue.

Carry out a process to establish voluntary adequacy targets – Mandatory adequacy standards could be established if the North American Electric Reliability Council is given the necessary authority. However, it is far from certain that will happen. More immediately, the region and West should work toward voluntary adequacy targets and reporting requirements.

Improve consideration of risk in integrated resource planning – Ensuring adequacy will be an easier proposition if load serving entities are adequately accounting for risk in their integrated resource plans. State and local regulatory entities should require an accounting of risk in the integrated resource plans they oversee.

Transmission

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. It is not clear that we are 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;[7]
- 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.

> **Regional interests should continue 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.
>
> **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 completely 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[8]" [footnote outside the quote] 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. Outside of the Council, however, no clear process exists for integrated long-term planning for both fish and power.

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

[8] "Optimizing" here means that energy production is maximized, limited by other than fish and wildlife constraints, such as flood control, irrigation, navigation, etc.

The region needs 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 by including "expertise in both biological and power system issues," and by directly addressing longer-term planning concerns, not just weekly and in-season issues.

Future Role of the Bonneville Power Administration in Power Supply

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.[9] 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 Treasury payments. 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 of those recommendations are:

Bonneville should sell electricity from the existing Federal Columbia River Power System to eligible customers at its embedded 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 change should be implemented through long-term (preferably 20-year) contracts and compatible rate structures – The contracts and rate structures should be guided by a clear and durable Bonneville policy that sets out a clear aggressive schedule for getting to new contracts.

[9] 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 issue of benefits for the residential and small-farm customers of investor-owned utilities (IOUs) should be resolved for a significant period – The necessary characteristics of a settlement can be defined. A settlement must be equitable to all participants, it must provide certainty, it must be transparent, and it must not be subject to manipulation.

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 (C&RD) 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 provide a backstop mechanism to ensure that these objectives are met.

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.

Other

Monitor "key indicators" that could signal changes in plans

Load-Resource Balance

The recommended 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 projected resources, the recommended plan could incur high costs if strictly adhered to. Obviously it will be necessary to track load growth and resource development closely and to accelerate development plans if necessary.

Removal of price caps

Awaiting completion of sensitivity

Higher than forecast gas prices

Awaiting completion of sensitivity

Climate change science and policy

Neither coal nor single cycle combustion turbines figure in this power plan because of the risk of future carbon costs. We have tested the sensitivity of this conclusion to our assumptions regarding the probability of requirements for future carbon offsets or equivalent costs for carbon emissions. Unless the probability of carbon penalties between X and Y dollars per ton by the end of the planning period is less than Z percent, development of coal-fired generation incurs too great a risk to justify development. However, coal could figure in the plan if there were lower carbon costs. If we were sure that carbon costs would not be assigned to coal-fired generation, coal-fired generation would appear in the plan relatively significantly. This suggests that it will be important to 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 coal-fired generation should be re-examined. Similarly, if there are advances in clean coal technology and/or carbon sequestration, the role of coal should be re-examined.

Conservation not developed at recommended pace

The base plan includes aggressive development of conservation at the rate of 1?? average megawatts per year. While the region has developed conservation at this rate at some times during the past, the rate of acquisition has frequently been less – 40 to 50 average megawatts per year. If conservation were to be developed at this rate, the average cost to the region could be $1.4 billion more and the risk $3.5 billion greater. These cost and risk increases are the result of two factors: the need to develop more expensive generation, including coal-fired generators; and the exposure of additional load to periods of higher market prices for electricity. If conservation is not being developed at the recommended levels, efforts should be made to accelerate conservation development. If that cannot be achieved, the alternative will be to accelerate the development of additional, more expensive, generating projects.

Demand response not available at level estimated

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

New Technologies

In addition to coal gasification, the following technologies described below have the potential to supply a major portion of regional load and in certain circumstances, could be attractive development opportunities late in the planning period. They have not been included in the portfolio risk analysis and resource development recommendations because of significant impediments to their development. They are difficult to consider “available” as defined by the Northwest Power Act. Because of the potential attractiveness of these resources under plausible future conditions, it is important to understand their potential role, key impediments to their development and regional actions that could help resolve these impediments.

> **Solar Photovoltaics --** Conversion of sunlight to electricity using photovoltaic technology is a well-understood and commercially established process, but costs are far too high for economic bulk electricity production. Solar electricity production using photovoltaic (or solar thermal) technology would be particularly attractive with sustained high natural gas prices, wind at higher cost and lower availability than forecast and an aggressive greenhouse gas control policy. An additional factor favoring solar generation would be failure to develop economic means of reducing the CO2 output associated with coal based generation.
>
> Preliminary Council studies suggest that bulk electricity production from solar photovoltaics could be attractive beginning in the 2015-20 period, if costs continued to

declined at rates observed during the 1990s. However, photovoltaic cost reduction has been stagnant in recent years, and technical breakthroughs may be required to achieve the cost levels required for large-scale deployment. Because of the prospects of a continuing high differential between photovoltaic electricity costs and market value, there appears little that the region can afford to do to effect significant cost reductions for this global product beyond seeking out near-economic niche applications and to encourage federal research. The most economic large-scale solar generation sites are far from most regional load. Development will require the ability to develop additional bulk transmission capacity and would also benefit from low-cost/short-term energy storage technologies.

Advanced Nuclear Plants -- Advanced nuclear plants would incorporate passive safety systems and standardized modular components for increased factory fabrication. These features are expected to result in improved safety, reduced cost and greater reliability. Though preliminary engineering of these designs is complete, construction and successful operation of several demonstration projects is required before the technology can be considered to be commercial. Demonstration plant development lead times are such that the technology is unlikely to be available for commercial construction until about 2015, suggesting commercial operation around 2020. In addition, establishment of a fully operational system for spent nuclear fuel disposal is a likely prerequisite to general public acceptance of new nuclear development.

Nuclear plants could be attractive under these conditions, as well as under sustained high natural gas prices, limited wind, and an aggressive greenhouse gas control policy. Additional factors favoring nuclear generation would be the failure to develop the economic means of reducing the CO2 output associated with coal-based generation and the inability to expand long-distance transmission capability. The nature of the actions required to commercialize advanced nuclear technology do not lend themselves to solution by the region, other than through the support of federal activities addressing these issues.

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