Generating Resource Findings, Conclusions & Recommendations

This chapter describes the Council's findings, conclusions and recommendations regarding generating resource development over the period of the plan.

WHEN SHOULD GENERATING RESOURCES BE DEVELOPED?

The highest priority resource for meeting future needs is cost-effective conservation. The Council recommends development of generating resources for bulk power supply when equally cost-effective conservation is insufficient to meet need. There are situations, however, that may call for generating project development in advance of general need for bulk power. One is development of cost-effective lost opportunity projects, such as an industrial cogeneration project keyed to plant renovation. Another is development for special services such as peaking capacity, emergency service or local system support. Finally, targeted generating project development may be used to resolve uncertainties associated with a promising generating resource having potentially widespread future application. The commercial-scale pilot windpower projects recommended in this plan are one such application.

The analysis of resource need and cost-effectiveness used for development of this plan includes enhanced consideration of risk and uncertainty compared the approaches used in earlier plans. The selection and timing of resources are based on the tradeoff of the cost and risk consequences of adding the resources to the Northwest power system. Important uncertainties are explicitly modeled. These include future loads, fuel price uncertainty and volatility, generating project reliability, hydro generation, global climate change policy, resource development incentives and wholesale electricity market prices. Market prices are manifested as the cost of imported power as an alternative to new resource development, the value of exported power as a source of revenue and the cost of purchases from uncontracted independently owned regional resources. Additional uncertainties are examined using sensitivity analysis. These include conservation success, technological development assumptions and success at developing wind power. The result is a greatly improved understanding of the costs and benefits of resource timing and selection. This analysis is further described in Chapter 5.

Because of data requirements and model run time considerations, new resource options considered in the portfolio analysis are limited to those having the potential to become significant players during the 20-year period of the plan. These are the generating resource options forecast to have reasonably competitive costs during the period of the plan, reasonable prospects for successful development and operation and sufficient quantity to measurably impact overall system costs. These include natural gas combined-cycle gas turbines, natural gas simple-cycle gas turbines, wind power plants and coal-fired steam-electric power plants. Variations of these include coal and wind resources located in eastern Montana and requiring additional long-distance transmission and natural gas fired cogeneration plants sited in the Alberta oil sands region, also requiring with new transmission to access regional loads. Coal-fired gasification combined-cycle power plants, while potentially attractive, have not yet reached a state of development where they can be considered to be "available" as defined in the Regional Act. The potential role of this technology was examined using sensitivity analysis.

Other generating resources, though not evaluated in the portfolio risk analysis may become cost effective during the period of the plan. These include industrial and commercial cogeneration, projects using biomass residue fuels, small hydropower and geothermal projects, solar photovoltaics to serve small isolated loads and simple-cycle gas turbines or reciprocating engine-generators for peaking or emergency service.

Generating resources are described more fully in Chapter 3.

UNCERTAINTIES

The assumptions regarding future load, import and export electricity markets, fuel prices and hydro generation are described in Chapter 2. This section describes three additional uncertainties: global climate change policies, renewable energy incentives and the green power market.

Global climate change

The preponderance of scientific opinion, based on both empirical data and large-scale climate modeling holds that the Earth is warming due to atmospheric accumulation of carbon dioxide (CO_2), methane, nitrous oxide and other greenhouse gasses. The increasing atmospheric concentration of these gasses appears to be largely from anthropogenic causes, in particular, the burning of fossil fuels. The effects of warming may include changes in atmospheric temperatures, storm frequency and intensity, ocean temperature and circulation, and the seasonal pattern and amount of precipitation. Possible beneficial aspects to warming, such as improved agricultural productivity in cold climates, on balance appear to be outweighed by adverse effects such as increased frequency of extreme weather events, flooding of low-lying coastal areas, ecosystem stress and displacement, increased frequency and severity of forest fires and northward migration of warm climate disease vectors. While the occurrence of warming and its effects are generally agreed upon, significant uncertainties remain regarding the rates and ultimate magnitude.

The regional effects of climate change are less well understood. Global models seem to agree that Northwest temperatures will be higher, but they disagree regarding levels of precipitation. Current thinking by Northwest scientists leans towards a warmer and wetter climate. The proportion of winter precipitation currently falling as high elevation snow is expected to decline and peak runoff expected to shift from springtime to winter. Summer stream flows would decline as a result of loss of snowpack. Warming would lead to a relative reduction in winter peak electricity demand and an increase in the frequency and intensity of summer peaks.

Nationwide, the power system is a prime contributor to the production of CO_2, producing about 39% of U.S. anthropogenic CO_2 production in 2002[1]. Any meaningful effort to control greenhouse gas production will require substantial reduction in net power system CO_2 production. The most efficient means of achieving this likely to be through a combination of methods: improved end use efficiencies, improved generating plant thermal efficiencies, addition

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[1] U.S. Environmental Protection Agency. Inventory of U.S. Greenhouse Gas Emissions and Sinks1990 - 2002. April 2004.

of generating resources having low or no production of CO_2, and CO_2 sequestration. Because it is unlikely that significant reduction in CO_2 production can be achieved without some increase in cost, future climate control policy can be viewed as a cost risk to the power system of uncertain magnitude and timing.

The other uncertainties related to climate change are loss of snow storage, decline in summertime stream flows and shifting of load peaks from winter to summer. The Climate Impacts Group of the University of Washington is forecasting future Northwest streamflows, seasonal temperatures and hydrologic patterns[2]. These forecasts, while not sufficiently complete for consideration in the draft plan, will help assess the power system impacts of these factors in the future.

Analytical consideration of the effects of climate change requires plausible estimates of the timing and magnitude of possible climate change actions. The approach to capturing the uncertainties of climate change policy used here was to separate the highly uncertain political factors (the probability and extent of actions being undertaken to control greenhouse gasses) from factors more subject to analysis (the cost of offsetting a ton of carbon dioxide).

The current state of climate change policy was summarized for the Council by Dr. Mark Trexler of Trexler Climate + Energy Services in April 2004. He noted that while the United States is not a signatory to the Kyoto Climate Protocol which establishes targets for reduction of greenhouse gas emissions, there is a good deal of climate policy action both in the US and internationally. Canada, for example, has signed the Kyoto protocol, and compliance is a significant factor in Canadian energy policy. Elsewhere, a pilot cap-and-trade system for carbon dioxide is to be implemented in Europe in 2005 with a mandatory system in place by 2008[3].

Here in the United States, half of the states have or are developing climate change mitigation strategies. Oregon, Massachusetts, New Hampshire and Washington require partial offsets of CO_2 produced as a result of power generation.[4] The governors of the West Coast states, through the West Coast Governors' Global Warming Initiative have initiated an effort to develop common regional policy. Nationally, the United States Senate in late 2003 came within a very few votes of passing the McCain-Lieberman Climate Stewardship Act that would have established a cap and trade system for the United States.[5] CO_2 reduction appears to be one of the primary drivers of efforts to reauthorize the federal renewable energy production credits and to expand state renewable portfolio standards and other renewable energy incentives. Finally, corporations increasingly are recognizing the likelihood of global climate change and the need to control greenhouse gas production[6].

Dr. Trexler presented three scenarios for the evolution climate change policy in the United States. One scenario portrayed collapse of efforts to implement climate change policy. He viewed the probability of this to be low. A second scenario looked at the likelihood that a

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[2] http://cses.washington.edu/cig/
[3] Define Cap and Trade
[4] Reference these actions.
[5] S139
[6] "Global Warming: Why Business is Taking it so Seriously" Business Week August 16, 2004.

combination of factors would generate the political will to seriously tackle climate change. He viewed the probability of this as “modest” although perhaps somewhat greater than the probability of total collapse of climate change mitigation efforts. The third scenario was one that postulates that the issue will not go away and that there will be continue to be efforts to enact mitigation policy. He viewed the likelihood of this scenario to be high.

The Council’s estimates of the cost of CO_2 offsets were guided by current state CO_2 offset experience, the conclusions of a Council-sponsored workshop held in May 2003, a June 2003 MIT study of the cost of implementing the McCain-Lieberman proposal[7] and an August 2003 MIT study of the costs of CO2 sequestration[8]. A cap and trade allowance system, as in the McCain-Lieberman proposal and as used for a number of years for control of sulfur emissions, appears to be the most cost-effective approach to CO2 control. However, to simplify modeling, a fuel carbon content tax in $/TonCO2, was used as a proxy for the effects of climate change policy, whatever the means of implementation. The results are believed to be representative of any effort to control CO2 production using carbon-proportional constraints on both existing and new generating resources.

The estimates of CO2 control costs from these sources are very wide. The Oregon and Washington offset requirements for new generating resources include a provision whereby a developer can pay a deemed fee for each ton of CO2 required to be offset. These payments currently amount to about $0.87/tonCO2 for Oregon and $XX/ton CO2 for Washington. It is generally acknowledged that actual offset costs are double to triple these rates. The MIT report on the costs of compliance the Climate Stewardship Act provide a series of time-dependent estimates based on various assumptions regarding implementation. These range from $0 to $39/tonCO2 in 2010, $10 to $70/tonCO2 in 2015 and $13 to $86/tonCO2 in 2020. The Council workgroup estimated offset credits on the international market to range from $5 to 10/tonCO2 in the 2005 - 13 timeframe and $20 to 40/tonCO2 from 2010 - 25. Finally, the MIT study on the costs of CO2 sequestration estimated costs ranging from $2 to $23/tonCO2 for various forms of geologic sequestration. Not included in this latter estimate was the cost of CO2 separation at the power plant or possible offsetting revenues from enhanced petroleum or natural gas recovery.

In base case portfolio analysis the probability that there will be some level of CO_2 control is zero until 2008, 10% in 2008, increasing every four years to 50% in 2024. Through 2015, offset costs for any future having some level of CO_2 control range with equal probability from zero to \$15/tonCO_2. Following 2015, the upper bound increases to $30/tonCO2. Thus, in 2016, for example, 30 percent of futures will have a carbon control requirement, and for those futures possible offset costs will range from $1 to $30/tonCO2 with an average cost of $15/ton. All fossil resources, existing and new, are subject to the offset in those futures where an offset is present. The distribution of outcomes over the study period is illustrated in Figure 9-1. The mean value across all cases is $0.75/tonCO2 in 2008, increasing to $7.50 in 2024. Revenues are assumed to flow out of the power system (e.g., are not used to subsidize low-carbon resources).

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[7] Massachusetts Institute of Technology Joint Program on the Science and Policy of Global change. Emissions Trading to Reduce Greenhouse Gas Emissions in the United states: The McCain-Lieberman Proposal. June 2003.

[8] Massachusetts Institute of Technology Laboratory for Energy and the Environment. The Economics of CO2 Storage. August 2003.

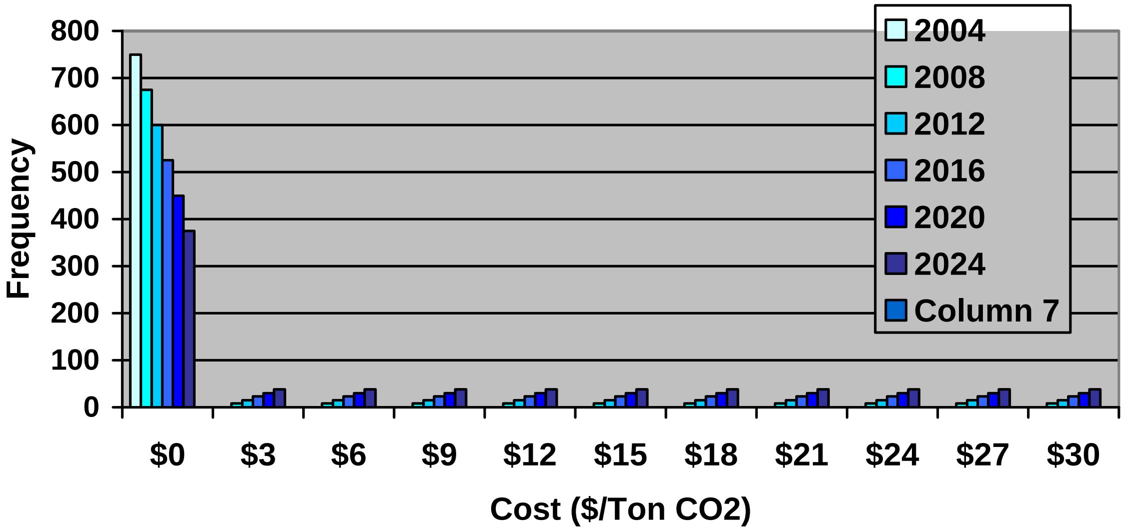

Figure 9-1: Carbon dioxide cost over the 20-year plan

Federal Renewable Energy Production Tax Credit

Resource development incentives influence the effective cost of resources to which they apply. The most important of these incentives is the federal renewable energy production tax credit and the companion renewable energy production incentive for tax-exempt entities. Originally enacted as part of the 1992 Energy Policy Act as a means of commercializing wind and certain biomass technologies, these incentives, amounting to approximately $12/MWh on a levelized basis (year 2000 dollars) have been repeatedly renewed and extended. Recent extensions appear to have been driven as much by climate change and local economic development concerns as by desires to promote technological development. Though the incentives expired in 2003, it appears likely that they will be reauthorized in the near future and possibly expanded to include additional resource types. Their longer-term fate is less certain. It seems likely that pressure to reduce the federal deficit will eventually force reduction or termination of the incentives, as the target technologies become more competitive and especially if federal CO_2 control measures are enacted.

In the base case, the renewable energy production incentive is renewed in **2005** at a levelized value of $**7.80**/MWh. The probability that the credit will continue declines over time (Figure 9-2). The credit is also assumed to terminate if any level of CO2 control is enacted. The mean value across all 750 futures modeled declines from $**XX**/MWh in 2005 to $**YY**/MWH in 2024.

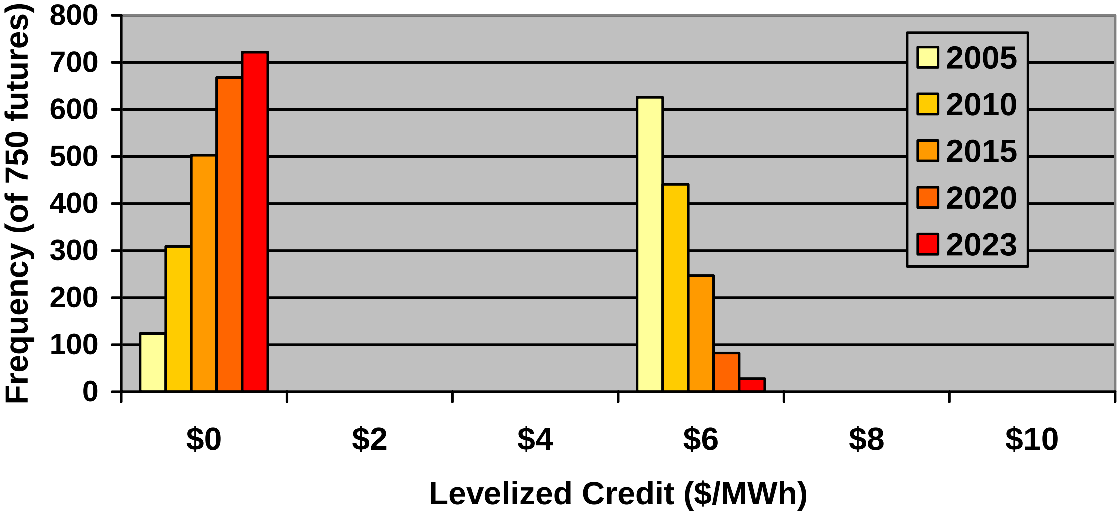

Figure 9-2: Renewable energy production credit over the 20-year plan (Update when extracts from final run are available)

Green power market

Power from renewable energy projects currently commands a market premium. This premium is a reflection of the perceived environmental, sustainability and risk mitigation value of renewable energy resources as compared with conventional power sources. Contributing to the premium are above-market prices paid by utility customers for "green" power products, above-market prices paid by utilities for newer renewable energy components of supply portfolios and above-market prices paid for renewable acquisitions to meet statutory renewable development requirements of renewable portfolio standards and system benefit charges. Global green power values, such as CO2 mitigation can be secured by purchase of tradable "green tag" certificates of renewable energy production. Tag value varies by resource type and is reported to currently range from about $5 to $7 per megawatt-hour for windpower.

In the near-term, green tag revenue is assumed to be available to new wind power at $6/MWh in the majority (about 85%) of futures modeled. The probability that the premium will continue is assumed to decline over time and the range of possible values increases somewhat (Figure 9-3). The premium is assumed to disappear if any level of CO2 control is enacted. The mean value across all 750 futures modeled declines from $6.70 in 2005 to $1.00 in 2024.

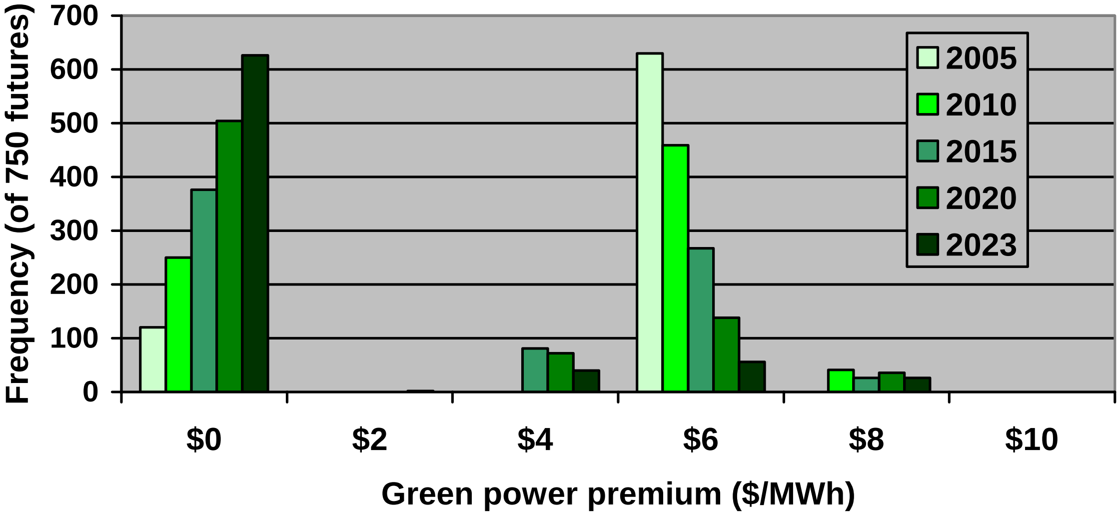

Figure 9-3: Green power market premium over the 20-year plan

FINDINGS & CONCLUSIONS

No apparent need for major generating resource development before 2010

Unless there is an unanticipated significant loss of existing generation[9], there appears to be no need on a regionwide basis for large-scale development of new generating capacity through the remainder of this decade. Two factors drive this conclusion. One is the surplus of generating capacity currently enjoyed by the region. This surplus is to a large extent a result of the power price excursions of 2000 and 2001. High prices lead to a substantial loss of regional load and to construction of over 4200 megawatts of new regional generating capacity. The effects of lost load persist and energy loads have yet to recover to 1999 levels. Much new capacity remains underutilized, especially independently owned gas-fired combined-cycle projects. Even at forecast medium-high rates of load growth, the current resource inventory appears sufficient to maintain a regional load-resource balance of -1500 average megawatts, or less, through 2011, the amount needed to maintain system reliability (Figure 9-4)[10]

The second factor is the amount of cost-effective conservation available for development. Not only is there an abundance of low-cost conservation available, but also conservation is free of natural gas price and carbon dioxide control risks. Aggressive acquisition of conservation provides a lower risk, lower cost regional resource mix than alternatives substituting new generating resources for conservation.

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9 The portfolio risk analysis assumes loss of 1000 megawatts of existing generation capacity between 2004 and 2013. This estimate is based on resource retirements observed in the base case wholesale electricity price forecast (Chapter 2). Though the retirements observed in the price forecast are all thermal plants, it is likely that future retirements will be a mix of aging, less efficient thermal facilities and hydro project deratings and retirements.
10 The Northwest can maintain reliability at a regional deficit of 1500 – 2000 aMW, assuming adequate import capability.

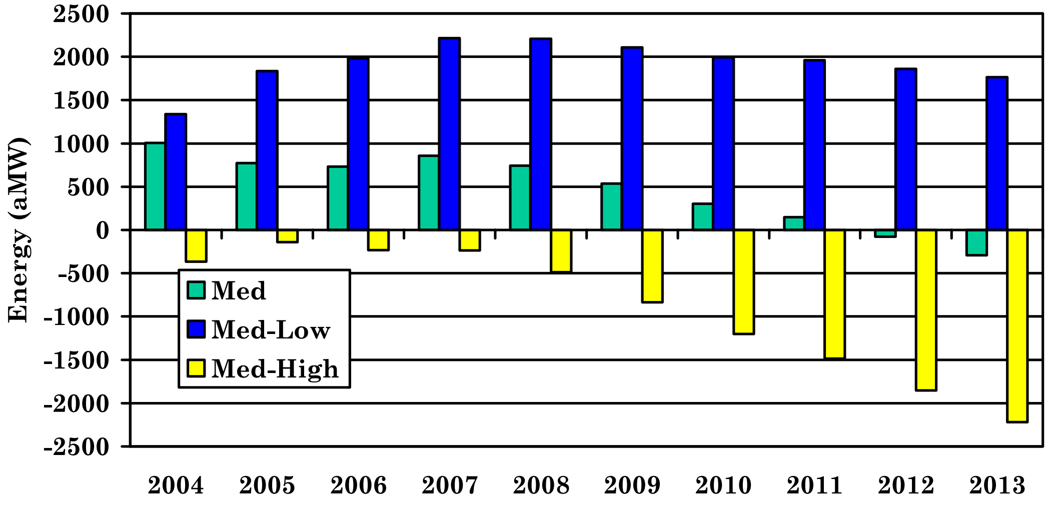

Figure 9-4: Regional load-resource balance

Some individual generating projects may become available and cost-effective prior to 2010

Opportunities for development of cost-effective smaller-scale generating projects are likely to surface prior to 2010. Examples might include industrial or commercial combined heat and power (cogeneration) projects; landfill, animal waste or wastewater treatment plant energy recovery, hydropower renovations, forest residue energy recovery and photovoltaics to serve small isolated loads. The opportunity to economically develop these projects is often created by needs not directly related to electric power production, such as a waste disposal problem, process or equipment upgrading or new commercial and industrial development. These opportunities should be monitored and the projects secured when cost-effective.

Because of their diversity and typically smaller-scale, these types of resources were not included in the portfolio risk analysis. Examples of these projects are described in Chapter 3, where their levelized costs are compared to levelized forecast electricity prices. Though these comparisons suggest that these types of projects are often not cost-effective when evaluated on a purely levelized cost basis, they may be cost-effective when additional attributes are considered. For example, cogeneration projects may provide supplementary revenue streams and avoided transmission and distribution costs. Higher thermal efficiency reduces the exposure of these projects to fuel price and carbon dioxide risk. Likewise biomass, small hydropower, geothermal and other renewable resources offer the fuel and carbon dioxide risk reduction qualities of wind and in addition produce higher-quality (non-intermittent) power. Projects using biomass residues may benefit from avoided waste disposal costs.

Peaking, emergency service, hydrofirming capacity and non-wires generating alternatives to transmission are among the other types of projects that may become cost-effective prior to the end of the decade.

Historically, small-scale renewable and cogeneration projects have faced impediments that have suppressed their development in favor of large central station projects. Many of these impediments are institutional in nature, suggesting that they can be rectified. These impediments include:

- Lack of routine processes for identifying potentially cost-effective customer-side cogeneration and small-scale renewable energy resources.
- Lack of commonly accepted cost-effectiveness criteria that accurately reflect the all costs and benefits including energy and capacity value, and the value of ancillary services, avoided transmission and distribution costs and losses and environmental effects.
- Disincentives to utility acquisition of power from projects owned or operated by others. The inability of investor-owned utilities to receive a return on power purchase agreements or investment in generation owned or operated by others generation creates an economic disincentive for securing these resources.
- Lack of uniform interconnection agreements and technical standards.
- Standby tariffs not accurately and equitably reflecting the costs and benefits of customer-side generation.
- Impediments to the sale of excess customer-generated power through the utility's transmission and distribution system.

Gas combined-cycle and wind are most attractive resources when new bulk power supplies are needed

When new bulk power supplies are needed, the most attractive options will be a mix of wind power and natural gas combined-cycle plants. The attractiveness of natural gas combined-cycle plants in the current environment high gas prices is contrary to some current thinking. However, the Council expects natural gas prices to ease and the thermal efficiencies of these plants to improve. In addition, gas-fuelled plants are less sensitive to climate change policy risk than coal-fired power plants. The relatively short lead construction time of combined-cycle plants (18-24 months) permits more rapid response to price excursions, thereby reducing exposure to high power prices. The preferred plan calls for being prepared to begin construction of up **600** MW of new combined-cycle capacity by 2011, increasing to **2400** MW by 2020 (Figure 9-4).

The attractiveness of wind power is the result forecast continued cost reduction, absence of fuel price risk and immunity to climate change policy risk. The very short construction lead-time of wind projects (12 months, or less) reduces the probability of prolonged exposure to wholesale price excursions. The preferred plan calls for being prepared to begin construction of **900** MW of new wind power capacity by 2011, increasing to **4500** megawatts by 2020 (Figure 9-4).

"Preparation to begin construction" means that all siting, permitting and other project development activities are complete such that new combined cycle capacity could be in service within two years and new windpower plants could be in service within 12 months. For the analysis we assumed that project development had proceeded to the point where engineering, procurement and construction (EPC) contracts had been let and a project was awaiting notice to proceed. In practice, it may not be possible to advance to this stage with the expectation of indefinitely holding construction. Nevertheless, to obtain the full benefits of this plan, it will be necessary to create an inventory of projects for which as many project development activities as possible are completed, thereby resolving uncertainties and shortening lead time for completion. If it is believed that lead time beyond that assumed will be necessary to complete the capacity called for in this plan, or if there is a significant chance of project failure because of unresolved uncertainties, the target schedules will have to be adjusted.

Assuming we have reasonably bounded the possible outcomes for the risk factors, the quantity of resource options recommended here for a given year, other factors equal, will decline as we move into the future and the level of uncertainty declines. Capacity needing to be constructed should be considerably less than the options called for here.

Uncertainties regarding large-scale development of wind power need to be resolved

The portfolio analysis indicates that large-scale windpower development during the next decade will provide significant cost and risk reduction benefits. For wind to provide these benefits requires a large high quality developable resource, continued cost reduction and technology improvements, relatively low shaping and firming costs, the ability to expeditiously extend transmission service to promising wind resource areas and a robust wind development infrastructure. The Council has included large quantities of wind in the plan despite uncertainties associated with these assumptions because of the benefits wind can provide to the regional power system and existing evidence supporting the underlying assumptions. Because large-scale development of new resources is not required before the end of the decade, time is available to resolve remaining uncertainties and to prepare for much larger-scale development than has been seen thus far.

The most effective approach to resolving uncertainties associated with large-scale deployment of wind generation appears to be through new commercial-scale pilot wind power projects at a diverse set of wind resource areas. If developed with this role in mind, these projects can confirm the development potential of additional wind resource areas through wind resource assessment, assessment of environmental issues and planning for transmission and other infrastructure requirements. These projects also can facilitate the monitoring of cost and performance trends and the assessment of the cost of firming and shaping large amounts of energy from wind power plants (including the possible benefits of geographic diversity). These projects can provide data for improving the understanding of the capacity value of wind and serve as vehicles for securing the environmental assessments and permits needed for full development of wind resource areas. Finally, the projects will serve to strengthen regional wind development infrastructure.

Some of these objectives could be achieved by lower cost research and development activities, an approach advocated in the Council's 1991 plan. In practice, resolution of wind power uncertainties through research and development projects has proven difficult because of the highly competitive nature of the windpower sector.

The cost of developing of a series of commercial-scale projects in advance of need was estimated using the portfolio risk model. Development on average of 100 megawatts of wind capacity per year through 2011 increased present value system cost by about $**300** million and increased present value risk by about $**200** million. Though there would be offsetting benefits, these costs are significant enough that the Council recommends that the project size be minimized consistent with the benefits of scale economies and that development be undertaken only if federal production credit or other incentives are available.

The Council believes that there is sufficient interest within the utility community to support the level of wind development needed to resolve uncertainties. It is less clear that utilities and project developers are currently prepared to fully utilize these early projects as laboratories for resolving uncertainties associated with large-scale wind power development.

Promising longer-term bulk power options need to be monitored and supported

Oil Sands Cogeneration

The production of petroleum products from the Alberta oil sands requires substantial amounts of steam. This can be produced using boilers or more efficiently by cogeneration. Though approximately 2000 MW of cogeneration is currently in service in the oil sands region, additional development constrained by the ability to export the electricity to outside markets. A DC intertie from the oil sands region to the Northwest has been proposed as a means of opening up the market for oil sands cogeneration. This power could be available to the Northwest about 2011. Preliminary estimates suggest that power from oil sands cogeneration could be supplied to the Northwest at costs only slightly higher than the forecast cost of power from gas-fired combined-cycle power plants located within the region. However, because of higher thermal efficiencies and the possibility of firing the plants on synthetic gas derived from bitumin, oil sands cogeneration would be less sensitive to natural gas price uncertainty and climate control policy than domestic gas-fired generation. The principal issues are development of the intertie. Recent transmission siting and permitting efforts in the U.S., especially in new corridors, has proven difficult. Financed is proposed to be by subscription. While open season subscription has been effective for financing incremental natural gas pipeline expansions, its use for financing large-scale transmission expansions is untested.

Coal Gasification

Coal gasification could greatly improve the economic and environmental characteristics of electricity production from coal. Gasification 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.

Circumstances under which coal gasification electricity generation might become attractive include sustained high natural gas prices, less wind than estimated and aggressive climate control policy. The cost of power from coal gasification is forecast to be about 10 percent higher than that of gas-fired combined-cycle power plants. However coal gasification would reduce fuel price risk at less carbon dioxide risk than conventional coal because of higher thermal efficiency. Confirmation of the ability to sequester CO2 could provide a further advantage since CO2 can be separated from the synthesis gas at relatively low cost.

Carbon Dioxide Sequestration

Geologic sequestration of carbon dioxide may offer a means of reducing carbon dioxide releases to the atmosphere while preserving the ability to using coal and other fossil resources for power generation. Geologic formations potentially suitable for carbon dioxide sequestration are found in the eastern Montana, but the concept needs further research and development. Efforts to identify and catalog promising geologic and terrestrial storage sites and better defining carbon-sequestration strategies are underway in the Northwest and elsewhere.

Energy Storage

Development of low cost and reliable short-term energy storage technologies could greatly increase the amount of wind power and other intermittent resources available to the Northwest. Short-term energy storage technologies such as regenerative fuel cells and compressed air energy storage located near the point of generation could level the output of intermittent generating projects. This would increase the efficiency of transmission utilization and reduce the cost of transmission, shaping and firming.

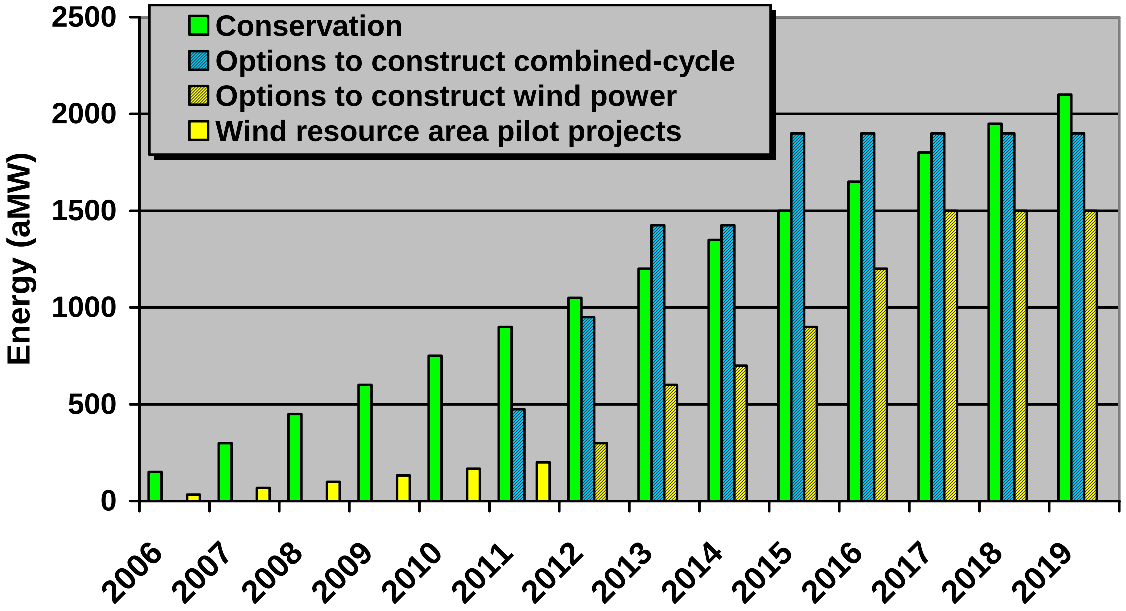

Figure 9-5: Recommended resource development schedule

Individual utility situations may differ

Though no large-scale generating resource development appears to be needed at the regional level, the circumstances of individual utilities may be such that the near-term development or acquisition of new generating resources may be necessary. Some utilities may be in resource deficit, having experienced more rapid load growth than the regional average or having not lost load to the extent of the regional average. The conservation potential available to some utilities may be insufficient to meet near-term loads. A utility may have been purchasing a major portion of supply on short-term contract, and may find it desirable to increase the amount of generation owned or on long-term contract. Some of the recent Request for Proposals for generation may be attempts to secure such supplies at the lowest cost. Finally, some utilities may need generation for peak period capacity, emergency generation needs, hydrofirming capability or system reinforcement. Any of these situations may result in an individual utility needing to acquire generating resources before regionwide needs are present.

Likewise, the preferences cited here for wind power and gas-fired combined-cycle plant are based on the overall regional situation and may not be suitable for all utilities. A utility may already have a large amount of gas-fired capacity, not wish to extend natural gas price risk. Climate change risk, though very important in arriving at the recommendations of this plan, is very uncertain, and a utility may have a different view of the magnitude or timing of climate change risk, leading to different valuation of resource qualities. Finally, because of its geographical, transmission or service territory situation, an individual utility may have different resource choices than considered here, or the cost of resources may differ from the assumptions used here. For any of these reasons, the resource choices of individual utilities may differ from the recommendations of this plan.

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