



Sixth Northwest Conservation and Electric Power Plan



Sixth Northwest Conservation and Electric Power Plan

Executive Summary

Action Plan

Chapter 1: Introduction

Chapter 2: Key Assumptions

Chapter 3: Electricity Demand Forecast

Chapter 4: Conservation Supply Assumptions

Chapter 5: Demand Response

Chapter 6: Generating Resources and Energy Storage Technologies

Chapter 7: Transmission

Chapter 8: Direct Use of Natural Gas

Chapter 9: Developing a Resource Strategy

Chapter 10: Resource Strategy

Chapter 11: Climate Change Issues

Chapter 12: Capacity and Flexibility Resources

Chapter 13: Bonneville's Obligations

Chapter 14: Regional Adequacy Standards

Appendices

A. Fuel Price Forecast

B. Economic Forecast

C. Demand Forecast

D. Wholesale Electricity Price Forecast

E. Conservation Supply Curve Development

F. Model Conservation Standards

G. MCS Cost-Effectiveness for Residences

H. Demand Response

I. Generating Resources

J. Regional Portfolio Model

K. Smart Grid

L. Climate Change and Power Planning

M. Integrating Fish & Wildlife and Power Planning

N. Financial Assumptions and Discount Rate

O. Calculation of Revenue Requirements and Customer Bills

P. Methodology for Determining Quantifiable Environmental Costs and Benefits

Sixth Power Plan Overview

Summary 1
Future Regional Electricity Needs 2
Resource strategy 3
 Efficiency 4
 Generation Alternatives 5
Climate Change Policy 6
Capacity, Flexibility, and Wind Integration 7
Fish and Wildlife Program and the Power Plan..... 8

SUMMARY

The Pacific Northwest power system is faced with significant uncertainties about the direction and form of climate change policy, future fuel prices, salmon recovery actions, economic growth, and integrating rapidly growing amounts of variable wind generation. And yet the focus of the Council’s power plan is clear, especially with regard to the important near-term actions.

The Council’s power plan addresses the risks these uncertainties pose for the region’s electricity future and seeks an electrical resource strategy that minimizes the expected cost of, and risks to, the regional power system over the next 20 years. Across multiple scenarios considered in the development of the plan, one conclusion was constant: the most cost-effective and least risky resource for the region is improved efficiency of electricity use.

In each of its power plans, the Council has found substantial amounts of conservation to be cheaper and more sustainable than most other types of generation. In this Sixth Power Plan, because of the higher costs of alternative generation sources, rapidly developing technology, and heightened concerns about global climate change, conservation holds an even larger potential for the region.

The plan finds enough conservation to be available and cost-effective to meet 85 percent of the region’s load growth for the next 20 years. If developed aggressively, this conservation, combined with the region’s past successful development of energy efficiency could constitute a resource comparable in size to the Northwest federal hydroelectric system. This efficiency resource will complement and protect the Northwest’s heritage of clean and affordable power.

Aggressive pursuit of this conservation is the primary focus of the power plan’s actions for the next five years. Combined with investments in renewable generation as required by state renewable portfolio standards, improved efficiency will help delay investments in more expensive and less clean forms of electricity until the direction and form of future climate change legislation becomes clearer, and alternative low-carbon energy technologies become cost-effective.

At the same time, the region cannot stand still in maintaining and improving the reliability of its power system. Investments to add transmission capability and improve operational agreements are important for the region, both to access growing site-based renewable energy and to better integrate it into the power system. The Council also expects that there are small-scale resources

available at the local level in the form of cogeneration or renewable energy opportunities. The plan encourages investment in these resources when cost-effective.

The power plan recognizes that meeting capacity needs and providing the flexibility reserves necessary to successfully integrate growing variable generation sources may require near-term investments in generation resources to provide reliable electricity supplies in specific utility balancing areas. In addition, individual utilities have varying degrees of access to electricity markets and varying resource needs. The Council's regional power plan is not necessarily a plan for every individual utility in the region, but is intended to provide guidance to the region on the types of resources that should be considered and their priority of development.

The near-term actions recommended in the Council's Sixth Power Plan are important, but the region cannot neglect longer-term needs. The plan encourages research in advanced technologies for the long-term development of the power system. For example, emerging smart-grid technologies could make it possible for consumers to help balance supply and demand. By providing information and tools to consumers to adjust electricity use in response to available supplies and costs, the capacity and flexibility of the power system would be enhanced. Smart-grid development also may facilitate the deployment of plug-in hybrid electric vehicles that work in concert with the power system to improve the use of available generating capacity and help reduce carbon emissions in the transportation sector. In general, these technologies offer the potential to fundamentally change the power system while improving its efficiency and reliability. Developing these technologies is a long-term process that will require many years to reach full potential, but the region can facilitate progress through research, development, and demonstration of the technologies.

Along with the smart grid, other technologies may be able to provide power when it is needed with low cost, low risk, and low emissions. In the future, the region may find greater value in power generated by geothermal resources, ocean waves, tides, gasified coal with carbon sequestration, advanced nuclear, or currently unknown technologies. New methods to store electric power, such as pumped storage or advanced battery technologies may enhance the value of existing variable generation like wind. Given the uncertainties of the future, the region should not concentrate on any one potential future solution to its power supply, but should explore a diversity of potential sources of future energy generation and conservation.

FUTURE REGIONAL ELECTRICITY NEEDS

The Pacific Northwest is expected to develop and expand over the next 20 years. Regional population is likely to increase from 12.7 million in 2007 to 16.7 million by 2030. This four million increase compares to a 3.8 million increase between 1985 and 2007. The population growth will be focused on older age categories as the baby boom generation reaches retirement age. While the total regional population is projected to increase by over 28 percent, the population over age 65 is expected to nearly double. Such a large shift in the age distribution of the population will change consumption patterns and electricity uses. Some possible effects could include increased health care, more retirement and elder care facilities, more leisure activities and travel, and smaller-sized homes.

The cost of energy (natural gas, oil, electricity) is expected to be significantly higher than during the 1980s and 1990s. Although these prices have decreased significantly since the summer of

2008, a significant portion of the reductions are likely due to the effects of the current economic recession. Natural gas prices have also been affected by the recent growth of production from nonconventional natural gas supplies. The technology to retrieve these supplies cost-effectively has only developed recently and has improved expectations of adequate future supplies. Nevertheless, the cost of finding and producing these supplies is higher than for conventional supplies, which increases the estimated future price trend for natural gas.

If carbon emissions taxes or cap-and-trade policies are implemented, energy costs are likely to increase. Some of the planning scenarios used to develop this plan include a wide range of possible carbon mitigation costs from zero to \$100 per ton. The expected average prices in this range start at zero and increase over time to \$47 per ton of CO₂ emissions by 2030. Carbon costs can have a significant impact on electricity costs and prices to consumers. While higher prices reduce demand, they also stimulate new sources of supply and efficiency and make more efficiency measures cost-effective.

Electricity load (before accounting for new conservation) is expected to grow by about 7,000 average megawatts between 2009 and 2030, growing at about 335 average megawatts, or 1.4 percent, per year. Residential and commercial sector electricity use account for much of the growth in demand. Contributing to the growth in the residential sector is an anticipated increase in air conditioning and consumer electronics. Also, summer peak electricity use is expected to grow more rapidly than annual energy. All of this growth in energy demand must be met by a combination of existing resources, more efficient use of electricity, and new generation. An important change for the Sixth Power Plan is that electricity needs in the future can no longer be adequately addressed by evaluating only average annual energy requirements. In the future, resource needs must also consider capacity to meet peak load and the flexibility to provide within-hour, load-following, and regulation services. The requirements for within-hour flexibility reserves have increased because of the growing amount of variable wind generation located in the region.

RESOURCE STRATEGY

The Council's resource strategy for the Sixth Power Plan provides guidance for the Bonneville Power Administration and the region's utilities on choices that will help meet the region's growing electricity needs while also reducing the risk associated with uncertain future conditions. The strategy minimizes the cost of, and risks to, the future power system. The timing of specific resource acquisitions is not the essence of the strategy because the timing of resource needs will vary for every utility. Rather, the important message of the resource strategy lies in the nature of the resources and their priorities.

The resource strategy can be summarized in five specific recommendations:

1. Improved efficiency of electricity use is by far the lowest-cost and lowest-risk resource available to the region. Cost-effective efficiency should be developed aggressively and on a consistent basis for the foreseeable future. The Council's plan demonstrates that cost-effective efficiency improvements could on average meet 85 percent of the region's growth in energy needs over the next 20 years.

2. Renewable resource development is required by resource portfolio standards in three of the four Northwest states. The most readily available and cost-effective renewable resource is wind power and it is being developed rapidly. Wind requires additional strategies to integrate its variable output into the power system and, in addition, it provides little capacity value for the region. The region needs to devote significant effort to expanding the supply of cost-effective renewable resources, many of which may be small scale and local in nature.
3. Remaining needs for new energy and capacity should be based on natural gas-fired generation until more attractive technologies become available. The resource strategy does not include any additional coal-fired generation to serve the region's needs. Further, the Council's plan demonstrates that meeting the Northwest power system's share of carbon reductions called for in some state, regional, and federal carbon-reduction goals will require reduced reliance on the region's existing coal plants.
4. The challenges of wind integration and the need for additional within-hour reserves initially should be addressed through improvements in system operating procedures and business practices. Changes in wind forecasting, reserve sharing among control areas, scheduling the system on a shorter time scale, and advancing dynamic scheduling can all help address wind integration and contribute to a more efficient use of existing system flexibility. The region is already making significant progress in these areas.
5. Finally, the Council's resource strategy calls for efforts to expand long-term resource alternatives. The region should demonstrate the potential of smart-grid applications to improve the operation and reliability of the regional power system and to access the potential of consumers to provide demand response for the capacity and flexibility of the power system. The region should continue to assess new efficiency opportunities, expand the availability of cost-effective renewable energy technologies, and monitor development of carbon capture and sequestration, advanced nuclear technologies, and other low-carbon or no-carbon resources.

Efficiency

The Council's power plan includes a detailed analysis of efficiency potential in hundreds of applications. The achievable technical potential of efficiency improvements increased from the Fifth Power Plan levels due to advancing technology, reduced cost, and estimates in new areas such as efficiency in electricity distribution systems, consumer electronics, and street, parking, and exterior building lighting. In addition, the cost-effectiveness of these technologies has increased significantly because avoided costs have doubled and carbon-cost risk is several times higher than in the Fifth Power Plan. The estimated achievable potential conservation is nearly 6,000 average megawatts for measures costing under \$100 per megawatt-hour. Over 4,000 average megawatts are available at a cost of less than \$40 per megawatt-hour. These increased opportunities exclude future savings from efficiencies that have already been secured through building codes and appliance efficiency standards.

The plan shows that a substantial amount of the growth in electricity demand could be met by conservation. Portfolio model analysis shows that over 5,900 average megawatts of conservation are cost-effective, double the amount in the Council's Fifth Power Plan. The amount that can be

achieved is constrained by the commercial availability of technologies, limits on the annual development rate, and an ultimate penetration rate limit of 85 percent. The amount of conservation found to be cost-effective changed very little in response to changing assumptions about carbon costs and policies. Conservation in the plan is projected to be responsible for reducing carbon emissions by 17 million tons per year by 2030, a 30 percent reduction in 2030 emissions. Failure to achieve the conservation included in the plan will increase both the cost of, and risks to, the power system and likely prevent Washington and Oregon from meeting legislated carbon-reduction goals.

Generation Alternatives

The Council analyzed a large number of alternative generating technologies. Each of these technologies is compared in terms of risk characteristics and cost with other generating technologies, efficiency improvements, and demand response. In addition, resource contributions need to be considered in terms of their energy, capacity, and flexibility characteristics.

Generating technologies that are technologically mature, meet restrictions on new plant emissions, and are cost-effective are limited in the short to intermediate term. Wind remains the primary large-scale, cost-effective renewable generation source in the near term. However, the Council believes there likely are small-scale dispersed renewable generation alternatives that are local and site-specific. Cost-effective development of these is encouraged, even though the Council currently lacks enough information to include them explicitly in the plan. Natural gas-fired generation is also feasible and cost-effective. New coal-fired generation is difficult to site and permit, and prohibited in many states by new plant emissions standards. During the next 20 years, alternatives may develop such as carbon separation and sequestration, maturing renewable technologies, advanced nuclear generation, demand response, smart-grid technologies, and storage strategies to help provide flexibility reserves. When CO₂ costs are added to the direct cost of generating alternatives, the cost of most generating resource alternatives range between \$70 and \$105 per megawatt-hour or higher (levelized 2006\$).

New renewable generation (primarily wind) is required to meet renewable portfolio standards in Washington, Oregon, and Montana. Analysis shows that meeting RPS requirements uses most of the 5,300 megawatts of readily accessible wind potential in the region. In addition to the wind, some geothermal resources were found to be attractive. However, the amount of geothermal potential is considered quite limited. Given the risk that a carbon-pricing policy might be enacted in the future, some renewable generation is cost-effective even without renewable portfolio standards.

Natural gas-fired generation is anticipated toward the middle of the planning period. Natural gas is attractive for energy and capacity needs and provides an ability to displace coal plants in the event of high carbon costs or coal plant closures. Both combined-cycle turbines and simple-cycle turbines are included in most scenarios. Although these natural gas plants are sited and licensed in the plan, this does not occur until after the five-year action plan period. Preparing to add natural gas-fired generation helps protect against the risk of uncertain future conditions, but the generating plants are not actually completed in many of the simulated futures during the 20-year planning period. The Council recognizes that individual utilities' needs and access to market resources vary. Some utilities will need additional resources in the near-term even if they

meet their renewable portfolio standards and acquire all conservation available to their service territories.

During the last 10 years of the power plan the generating resource priorities become less clear. Given current climate change policies and concerns, new coal without carbon sequestration is unlikely. Further, any significant reduction in carbon will require reduced operations of existing coal plants. Alternatives beyond greater reliance on natural gas are typically unproven commercial technologies or alternatives that require significant new transmission investments. Long-term generating resources considered include wind developed outside the region and imported on new transmission lines, advanced nuclear, gasified coal with carbon sequestration, and development of relatively unproven renewable resources, or ones that are currently too expensive. Natural gas is used in the plan to meet long-term needs, but the Council recognizes that other alternatives are likely to become available over time. In particular, the evolution of smart-grid technologies could significantly change the nature of future power system needs and the kinds of resource alternatives required and available.

CLIMATE CHANGE POLICY

Addressing the topic of uncertain climate policies was identified as one of the most important issues for the Sixth Power Plan. The focus of climate policy, especially for the power generation sector, will be on carbon dioxide emissions. Nationwide, carbon dioxide accounts for 85 percent of greenhouse gas emissions. Nationally, about 38 percent of carbon dioxide emissions are emitted from electricity generation, but for the Pacific Northwest the power generation share is only 23 percent because of the hydroelectric system. Analysis by others has shown that substantial and inexpensive reductions in carbon emissions can come from more efficient buildings and vehicles. More expensive reductions can come from substituting non- or reduced-carbon electricity generation such as renewable resources, natural gas, and nuclear generation, or from sequestering carbon.

Reductions in carbon emissions can be encouraged through various policy approaches, including regulatory mandates (RPS or emission standards), emissions cap-and-trade systems, emissions taxation, and efficiency improvement programs. State policy responses within the region to climate change concerns have focused on renewable energy standards and new generation emission limits. In addition, Oregon and Washington have carbon reduction targets adopted by statute. National and regional proposals have focused on cap-and-trade systems intended to reduce carbon and other greenhouse gases, although none have been implemented successfully in the region. Although carbon taxes are easier to implement than cap-and-trade systems, policy discussions have focused mainly on cap-and-trade systems.

The question for the power plan is what strategies are prudent given a future where carbon pricing policies are unclear. The Council does not take a position on any particular regional carbon reduction goal or carbon price in this power plan. The plan does recognize the uncertainty about future carbon prices and that possible carbon emission reductions are important risk issues for the regional power system. Multiple carbon reduction scenarios, including a carbon risk scenario that considers a range of future carbon prices between zero and \$100 per ton provide relevant information for policy makers in the region. In general, the resource strategy in the plan will allow Washington and Oregon to meet their carbon reduction targets and constructively address the risk of uncertain future carbon policy. According to Council analysis,

states and/or the federal government will need to take additional actions in order to achieve these targets. Potential carbon pricing plays an important role in the Council's resource strategy, with the exception of the conservation resource, which remains a key component regardless of climate change policy assumptions.

The key findings from the Council's analysis of climate change policies include the following:

- Without any carbon control policies, including existing ones, carbon emissions from the Northwest power system would continue to grow to 6 percent over 2005 levels by 2030. However, without the significant amount of conservation (which is cost-effective even without carbon policies) the growth in emissions would be far greater.
- Without additional carbon pricing policies, current policies would stabilize carbon emissions from the Northwest power system at 2005 levels, but not meet current carbon reduction goals.
- Assuming a risk of higher carbon prices, the Sixth Power Plan resource strategy has the potential to reduce average regional power system carbon emissions to 9 percent below 1990 levels, or 30 percent below 2005 levels, adjusted for normal hydro conditions.
- Significant reductions of carbon emissions from the Northwest's power system require reduced reliance on coal, which currently emits more than 85 percent of the carbon dioxide from the regional power system. A carefully coordinated retirement and replacement of half the existing coal-fired generation serving the region with conservation, renewable generation, and lower carbon-emission resources could reduce average carbon emissions to 18 percent below 1990 levels.
- To the extent that public policy raises the cost of carbon, we can expect an increase in a typical consumer's electric bill and a decrease in carbon emissions, especially when the carbon price begins to exceed \$40 per ton. A fixed carbon price of \$45 dollars per ton has a similar effect on carbon emissions as retiring half of the existing coal-fired generation. Both would meet current carbon reduction targets for 2020 on average, but coal retirement would provide more certainty in meeting the targets.
- Preserving the capability of existing regional hydroelectric generation will help keep power system costs and carbon emissions down. In scenarios where the capability of existing resources are reduced, whether hydroelectric or coal, the energy and capacity are largely replaced with gas-fired generation to maintain the adequacy and reliability of the power system.

CAPACITY, FLEXIBILITY, AND WIND INTEGRATION

Reliable operation of a power system requires minute-to-minute matching of electricity generation to varying electricity demand. In the Pacific Northwest, resource planners have been able to focus mostly on annual average energy requirements, leaving the minute-to-minute balancing problem to system operators. This was because, historically, the hydroelectric system had sufficient peaking capacity and flexibility to provide the needed operations as long as there was sufficient energy capability. This is changing for several reasons: growing regional

electricity needs are reducing the share of hydroelectricity in total demand, peak load has grown faster than annual energy, the capacity and flexibility of the hydro system has been reduced over time for fish operations, and growing amounts of variable wind generation have added to the balancing requirements of the system.

As a result, planners must now consider potential resources in terms of their energy, capacity, and flexibility contributions. The rapid growth of wind generation (which has little capacity value and increases the need for flexibility reserves) means that meeting growing peak load and flexibility reserves will require adding these capabilities to the power system. Changes can be made to the operation of the power and transmission system that will reduce flexibility reserve needs. These operational changes are expected to cost less than adding peaking generation, demand response, or flexibility storage, and they can be implemented more quickly.

FISH AND WILDLIFE PROGRAM AND THE POWER PLAN

The Columbia River Basin Fish and Wildlife Program is by statute incorporated into the Council's power plan. The fish and wildlife program guides Bonneville's efforts to mitigate the adverse effects of the Columbia River hydroelectric system on fish and wildlife. One of the roles of the power plan is to help assure reliable implementation of fish and wildlife hydrosystem operations. The Columbia River power system operators have reliably provided hydrosystem actions specified to benefit fish and wildlife (and Bonneville ratepayers have absorbed the cost of those actions) while maintaining an adequate, efficient, economic, and reliable energy supply. This is so even though the hydroelectric operations for fish and wildlife have a sizeable impact on power generation. On average, hydroelectric generation is reduced by about 1,200 average megawatts, relative to operation without any constraints for fish and wildlife. Since 1980, the power plan and the Bonneville Power Administration have addressed this impact through changes in secondary power sales and purchases, by acquiring conservation and some generating resources, by developing resource adequacy standards, and by implementing other strategies to minimize power system emergencies and events that might compromise fish operations.

In addition to operational changes, most of the direct cost and capital costs of fish and wildlife programs have been recovered through Bonneville revenues and Bonneville has absorbed the financial effects of lost generation, resulting in higher electricity prices. Bonneville estimates that the total financial effect of replacing lost hydropower capability and funding direct fish and wildlife program expenditures totals from \$750 million to \$900 million per year (a range affected by, among other things, water conditions and electric prices). The power system is less economical as a result of fish and wildlife program costs, but still economical in a broad affordability sense when compared to the costs of other reliable and available power supplies.

The future presents a host of uncertain changes that are sure to pose challenges for the successful integration of power system and fish and wildlife needs. These include possible new fish and wildlife requirements, increasing wind generation and other variable renewable integration needs that could require more flexibility in power system operations, conflicts between climate change policies and fish and wildlife operations, possible changes to the water supply from climate change that might make it more difficult to deliver flows for fish and meet power needs, and possible revisions to Columbia River Treaty operations to match 21st century power, flood control, and fish needs.

To address current operations and prepare for these additional challenges, the Council has adopted a regional adequacy standard to help ensure that events like the 2000-01 energy crisis, in which fish operations and power costs were affected, do not happen again. In addition, the Wind Integration Forum is addressing issues with integration of wind into the power system. Large swings in wind output have sometimes adversely affected hydropower and fish operations. Addressing adequacy and flexibility issues in the Sixth Power Plan will improve electricity reliability and help ensure reliable fish operations.

Sixth Power Plan Action Plan

Introduction.....	1
Conservation	1
Deployment.....	2
Adaptive Management	5
Development and Confirmation.....	8
Generating Resources	9
Generating Resource Acquisition	10
Adequacy of System Integration Services	11
Information to Support Sound Planning and Decisionmaking	15
Future Role of Bonneville.....	15
Ensuring Adequacy	18
Demand Response.....	19
Smart Grid.....	20
Transmission	21
Fish and Power.....	22
Monitoring Plan Implementation.....	23
Maintaining and Enhancing Council’s Analytical Capability	23

INTRODUCTION

The action plan describes things that need to happen in order to implement the Council’s Sixth Power Plan. It focuses on the next five years and the priorities in the plan. Actions are organized by resource areas, Bonneville Power Administration, and Council monitoring activities. In many cases, the action plan suggests the entities that have primary responsibility for implementation activities.

CONSERVATION

Energy efficiency is the first priority resource in the Northwest Power Act. The Council’s analysis for the Sixth Power Plan strongly affirmed that energy efficiency improvements provide the most cost-effective and least risky response to the region’s growing electricity needs. Further, accelerated acquisition of cost-effective efficiency reduces the contribution of the power system to greenhouse gas emissions. With greenhouse gas reduction policies in flux, and many new sources of carbon-free electricity expensive or lacking capacity contributions to go with their energy, accelerated acquisition of cost-effective efficiency can buy time to develop policies and identify alternative sources of carbon-free generation.

The region is increasing its efforts to accomplish conservation through integrated resource planning requirements, state and utility programs, and the Northwest Energy Efficiency Taskforce. Nevertheless, achieving the level of conservation identified in the Sixth Power Plan is a task that will require aggressive actions by the region. The action plan of the Sixth Power Plan contains a list of recommendations that will help the region to meet the efficiency challenge.

Key areas for enhanced implementation activity include: (1) enhancing the region's ability to acquire the identified efficiency potential; (2) increasing efforts to identify and verify new cost-effective and feasible technologies; and (3) developing regional mechanisms to keep efficiency policies up to date with changing information, track and verify achievements, and adaptively manage regional efficiency acquisition strategies.

Deployment

CONS-1. Achieve the level of conservation resource acquisition identified in the Sixth Power Plan's conservation target and accomplish the other actions necessary to accelerate conservation deployment. [Utilities, Energy Trust of Oregon, Utility Regulators, Bonneville Power Administration, Northwest Energy Efficiency Alliance (NEEA), and States]¹ The Council target for regional acquisition of conservation over the first five years of the plan is 1,200 average megawatts. Consequently, activities, resources and budgets should be geared to acquire 1,200 average megawatts of savings from 2010-2014 from utility program implementation, market transformation efforts, and codes and standards not included in the regional load forecast. However, the Council recognizes that there is a level of uncertainty inherent in its assessment of regional conservation potential, the pace of anticipated economic recovery, power market conditions, carbon control requirements, technology evolution, the success or failure of acquisition mechanisms and strategies, progress on research and development, and the adoption of codes and standards. This means that the total amount of targeted conservation available in the first five years is uncertain. For this reason, the Council developed a range of likely conservation savings over the first years of 1,100 to 1,400 average megawatts. The Council will monitor the actual conservation savings acquired by the region by conducting reviews of the region's progress each year during the initial five-year planning horizon of the Sixth Power Plan. More specifically, CONS-16, calls for a mid-term review of regional progress toward the regional conservation target. This will permit the Council to consider adjustments to its regional conservation target for the remainder of the period covered by the action plan. In addition, the mid-term review will assess the impact of the region's progress on the acquisition of other resource development actions.

CONS-2. Develop and implement an action plan for measures that are commercially viable but relatively new to programs or markets. [Bonneville, Utilities, Energy Trust of Oregon, and NEEA] The Sixth Power Plan identifies new or technologically improved efficiency measures that are cost-effective to pursue. The plan identified nearly 6,000 average megawatts of cost-effective conservation realistically achievable over 20 years. Of that, approximately 2,500 average megawatts will require new initiatives, programs, market transformation efforts or progress toward adoption in codes and standards. While in the near term these measures make up about one-quarter of the conservation targets, activities to develop these measures need to start now so the region is positioned to place increased reliance on them in the future. The Council believes that regional collaboration on initiatives to develop and deploy these measures would greatly enhance their chance of success. This activity will require concurrent market research to determine the most effective ways to develop and deploy these new measures. Each of these measures is at a

¹ Format note: The text in brackets following the bolded actions identifies the implementing entities.

different stage of development and requires a different implementation strategy. All require efforts beyond what is now being done. An initial list of these measures includes distribution system efficiency, commercial outdoor lighting, residential heat-pump water heaters, residential ductless heat pumps, TV, set-top boxes, desktop PCs, PC monitors and industrial system optimization.

CONS-3. Provide continued funding, in adequate amounts, for the Northwest Energy Efficiency Alliance's (NEEA) to support its market transformation efforts.

[Bonneville, Utilities, and Energy Trust of Oregon] NEEA's regional market transformation activities have proved to be a great value. Market transformation has been a key part of the development of many existing efficiency initiatives, and will need to be so for many of the new initiatives that the region must take up.

NEEA's newly adopted strategic plan should be funded by regional utilities. In addition, the region should institute an ongoing process to identify needed market transformation efforts that are not in the current NEEA business plan but which may be necessary to reach regional conservation targets. The process should include a mechanism, such as subscription-based initiatives, to adjust funding allocations between regional and local programs as market dynamics change and new opportunities arise.

CONS-4. Develop long-term partnerships with energy efficiency businesses, trade allies and other parties in product and service supply chains. [Bonneville, Utilities, Energy Trust of Oregon, NEEA, Governors, and States] Decisions to adopt efficiency measures and practices are made by consumers. Consumer's decisions are influenced by many factors, including relationships with the energy efficiency industry and trade allies such as building designers, equipment vendors, contractors, engineering firms, lighting designers, and the product and service options available to them. Accelerating consumer adoption of energy-efficient technologies and practices can be facilitated by creating cooperative working relationships between NEEA and utility programs, product manufacturers, distributors, retailers, and the energy efficiency industry and trade allies to leverage their market relationships.

CONS-5. Support the adoption of cost-effective codes and standards and work to help ensure compliance. [Council, Utilities, Energy Trust of Oregon, NEEA, Bonneville, Governors and States] The Council will encourage the adoption of new codes in the region by working closely with the governors' offices and with the responsible energy code adoption and enforcement agencies and other regional entities. This includes, but is not limited to the following activities:

- Advocating for the development and adoption of cost-effective energy codes and equipment and appliance standards at the state and national level in a manner that is consistent with the entities' roles in the acquisition of efficiency resources and legal limitations on political activities.
- Providing technical and political leadership in both legislative and rulemaking processes.
- Enhancing code compliance by working with local government officials to create a supportive environment and adequate funding for comprehensive energy code implementation.

- Providing technical and educational support to code-enforcement staff.
- Developing and implementing a coordinated, high-level, adequately funded Pacific Northwest presence in federal efficiency standard rulemaking processes, to ensure that efficiency standards for federally regulated appliances and equipment achieve cost-effective energy savings.

CONS-6. Implement the Sixth Plan's Model Conservation Standards (MCS). [utilities, Energy Trust of Oregon, NEEA, Bonneville, governors and states] This includes supporting the adoption of the MCS in state codes and standards and working with local jurisdictions to increase compliance rates. It also includes implementing programs to achieve savings from measures in the MCS not adopted into code and operating programs consistent with the MCS for conservation programs not covered by other MCS.

CONS-7. Adopt policies that encourage utilities to actively participate in the processes to establish and improve the implementation of state efficiency codes and federal efficiency standards in a manner that is consistent with their responsibility to acquire cost-effective efficiency resources. [utility regulatory commissions] For example, state regulators could clarify conditions under which utilities could qualify for cost recovery for efforts to establish new codes and standards.

CONS-8. Support the ongoing operation of the Regional Technical Forum (RTF) and assure that the RTF has sufficient resources to review the new efficiency measures identified in the power plan. [Bonneville, utilities, Energy Trust of Oregon, and states] The financial resources provided to the RTF's to support its review of energy savings estimates, development of measurement and verification protocols, and establishment of measure specifications needs to be enhanced to cover the expanding suite of conservation activities. In order to avoid delaying the acceleration of regional conservation acquisition efforts the RTF will require increased funding to carry out its reviews in a timely and thorough manner. The region should provisionally increase its support of the RTF in 2010 at a level commensurate with estimated cost of identified research, analysis, tracking and evaluation while the Northwest Energy Efficiency Taskforce (NEET) conducts a review of the RTF's function, role, funding, and governance. Upon completion of the independent review, NEET should submit its recommendations regarding these issues to the Council for consideration.

CONS-9. Develop energy savings verification protocols for conservation measures, practices, and programs when current verification methods appear problematic or expensive or verification methods do not exist. [Regional Technical Forum] Streamlined measurement and verification protocols will allow the region to monitor the reality and persistence of savings as well as help Bonneville, the utilities, and regulators identify savings against targets and goals. The RTF should work with utilities for consistent guidance on tracking and verification of savings. Pursuant to CONS-17, the RTF should develop measurement and verification protocols and/or recommend mechanisms for savings evaluation and verification that recognize the limited capabilities, customer and service territory characteristics and experience of the region's small and/or rural utilities. The RTF should prioritize its work to allow the region to move forward quickly to capture and verify savings. The RTF should also recommend

improvements to the regional conservation measurement and evaluation procedures based on recommendations from the NEET workgroup as a starting point.

CONS-10. Develop a comprehensive library of estimates of savings from conservation measures and savings evaluation and measurement protocols. [Regional Technical Forum] Review and compare utility and Energy Trust of Oregon savings estimates for measures not addressed by current RTF recommendations. Expand and update the library of energy savings estimates, over time resolve any inconsistencies, and make the library available for use across the region. Pursuant to CONS-17, in consultation with Bonneville and the region's small and/or rural utilities identify conservation measures that recognize the limited capabilities, customer and service territory characteristics and experience of the region's small and/or rural utilities.

CONS-11. In recognition of the higher goal for industry-sector conservation, develop and implement a comprehensive strategy to improve the energy efficiency and economic competitiveness of industries in the region. [industry and trade allies, Bonneville, utilities, Energy Trust of Oregon, NEEA, and states]

CONS-12. Consistent with standard practices for integrated resource plans, establish policies for incorporating a risk-mitigation premium for conservation in the determination of the avoided cost used to establish the cost-effectiveness of conservation measures. [state utility regulatory commissions and utilities] The Council's resource portfolio modeling identified valuable risk-mitigation benefits for the region from developing conservation. A risk-mitigation value should be incorporated into conservation cost-effectiveness methodologies used by utilities and their regulators and system benefits administrators. The Council recognizes that each utility and system benefits administrator is in a different position with regard to the risks it faces. Regulators and utilities should establish policies on how to incorporate the estimated cost of addressing greenhouse gas emissions from thermal resources in conservation avoided-cost methodologies and integrated resource plans.

CONS-13. Identify regulatory barriers and disincentives to the deployment of conservation, and consider policies to address these barriers. [state utility regulatory commissions, investor-owned and publicly-owned utilities, states, BPA and others] Responsible organizations should identify barriers to achieving efficiency improvements. Some policies to reduce barriers will be addressed through the Northwest Energy Efficiency Taskforce. Others may be addressed by individual utilities. The Council will work with regional interests to evaluate the use of prices and incentives to encourage the achievement of conservation targets. If some utilities are having difficulty achieving the efficiency targets in the plan, they should consider pricing structures, including the use of inverted block rates, to provide better incentives to their customers to improve the efficiency of their homes and businesses.

Adaptive Management

The Council is well positioned to conduct periodic reviews of the remaining conservation potential, and of existing and planned conservation initiatives as well as conservation research and evaluation efforts. However, Bonneville, the utilities, the Energy Trust of Oregon, and

NEEA, along with the states are best positioned to develop and adaptively manage the actual acquisition of conservation resources. These entities have a long and successful history of developing strategies and funding programs to acquire conservation, transform markets, and upgrade codes and standards.

CONS-14. Prepare a strategic and tactical plan to achieve the Sixth Power Plan's regional conservation target and accomplish the other actions that are necessary to build the capability to accelerate conservation deployment for the remainder of the planning period in a cost-efficient manner. [Bonneville, utilities, Energy Trust of Oregon, and NEEA] A regional conservation implementation plan is needed to assure resources are being effectively deployed to reach the Sixth Power Plan's conservation target. The Council recognizes that Bonneville, utilities, Energy Trust of Oregon, and NEEA are best positioned to prepare and adaptively manage the implementation of such a plan. However, the development and implementation of this plan will require the active collaboration of these entities with other market actors, including energy-efficiency business and their trade allies, state and local governments, as well as associations and organizations that represent key customer groups. The Council believes that the plan should include specific actions focused on developing energy-efficiency technologies and practices. The plan should describe how these technologies and practices will be brought to market from conception to full deployment using local utility programs, coordinated regional programs, market transformation, codes and standards adoption and enforcement and any other mechanism deemed appropriate and all parties should collaborate on the disaggregation of these savings into these delivery categories. In particular, the plan should address the need to transition from reliance on compact fluorescent light bulbs (CFLs) to a more diversified portfolio of measures. Savings achieved through all of these mechanisms, including savings for utility-acquired CFLs until federal standards take effect in 2012, will count toward achievement of the Council's conservation target. The plan should also set forth the level of funding for staffing and infrastructure needed for its successful implementation. Finally, the plan should develop quantifiable milestones to measure progress toward these targets and actions that can be evaluated at strategic points over the five-year action plan. Progress toward these milestones should be reviewed in the mid-term report on progress toward meeting plan objectives (CONS-16).

CONS-15. Develop an ongoing mechanism to identify high-priority actions that will enhance the deployment of cost-effective energy efficiency across the region. [Bonneville, Utilities, Energy Trust of Oregon, NEEA, State Regulatory Commissions, along with the States and the Council] Adaptive management of the implementation of the regional conservation action plan called for in CONS-14 will require timely decisions regarding the allocation of resources between local, regional programs and market transformation initiatives; the continuation and expansion of successful existing programs and efforts; the modification or termination of poorly performing programs, and the development of new initiatives for new efficiency measures and practices identified in the Sixth Power Plan. In order to accomplish this, the Council believes that a high-level forum for ongoing policy-level guidance on these issues should be formed. The Council views this as a continuance of the NEET efforts to address the dynamic nature of conservation acquisition and, like NEET, this forum must include senior-level management and decisionmakers to assure common understanding, commitments, and follow-through. While pursuant to the NEET recommendations NEEA has agreed to host

and facilitate regional efforts to better coordinate programs that do not adequately address this need.

CONS-16. Report on progress toward meeting plan objectives. [Bonneville, utilities, Energy Trust of Oregon, and NEEA] As part of the Council’s biennial review of the Sixth Power Plan, Bonneville, Utilities, Energy Trust of Oregon, and NEEA should report on progress toward meeting the plan’s conservation targets and objectives. The report should include an assessment of progress toward mid-term milestones established in the strategic plan developed in CONS-14. The Council recognizes that the plan’s conservation targets are based on an “expected value” across a wide range of potential futures. The actual future the region experiences will differ in some regard from the plan’s assumptions. Therefore, this report should identify whether the regional conservation acquisition plan (CONS-14), the implementation of that plan (CONS-15) and/or the Council’s target (CONS-1), need to be modified to account for conditions or circumstances different than expected. These include slower- or faster-than-anticipated economic recovery, substantially different power market conditions, carbon control requirements, technology evolution, the success or failure of acquisition mechanisms and strategies, progress on research and development and the adoption of codes and standards.

CONS-17. Take into account the unique circumstances and special barriers faced by small and/or rural utilities in achieving conservation and the development and implementation of conservation programs. [Bonneville] Work with and give assistance to these customers to ensure that their capabilities, customer and service territory characteristics, and experiences are addressed in the identification of conservation measures applicable in their service territories and in the implementation of these conservation measures. Work with the RTF to see that these measures are expeditiously evaluated so that they are available to meet the conservation goals of small and/or rural utilities. Assist these utilities as needed in their efforts to implement these conservation measures and help Bonneville meet its share of the regional conservation target, working with these utilities either individually or pooled, as appropriate in each circumstance. Finally, a panel consisting of Bonneville and small and/or rural utilities should report its findings back to the Council during the mid-term check-in of the Sixth Power Plan.

CONS-18. In consultation with Bonneville, utilities, Energy Trust of Oregon, and NEEA develop recommendations on measure bundling, the use of cost-effectiveness tests, research and development investments, and other issues. [Council] Guidance is needed to ensure that the Sixth Power Plan’s conservation resource assessment is translated into acquisition programs and research and development activities. The NEET process identified the Council as the lead for the development of a cost-effectiveness reference document and the need for an ongoing process to assist utilities and others in their efforts to design, implement, and administer an effective and efficient conservation program using the data from the Council’s plan.

CONS-19. Develop and implement improvements to the regional conservation planning, tracking and reporting (PTR) systems so that energy efficiency savings and expenditures are more consistently and comprehensively reported. [Regional Technical Forum, utilities, Energy Trust of Oregon, Bonneville, NEEA, and states]

Also identify a governance structure to guide improvement of the systems and funding agreements to share the responsibility for its ongoing operation and maintenance equitably. The tracking system should evolve over time so that conservation from all mechanisms and funding sources, including utility, state and local conservation programs, codes and standards, state and federal tax credits, market transformation, and non-programmatic changes in markets can be reported. Savings from market changes outside of programs may need to be tracked outside of the PTR system.

Development and Confirmation

The Sixth Power Plan's assessment of technically achievable energy efficiency resources relies on research and demonstration program results initiated as long ago as the early 1980's. In order to expand the conservation options available in the future, and to confirm the resource cost, savings, and consumer acceptance of some measures identified in the plan, the region should fund conservation research and demonstration activities. The responsibility for carrying out these activities varies with their purpose and scope. However, given the "community property" nature of the results of these projects, Bonneville, the utilities, NEEA and the Energy Trust of Oregon should, to the extent practicable, collaborate on funding and coordinate on implementation. At the same time, regulatory commissions should establish guidelines to allow cost recovery for such research and demonstration activities.

CONS-20. In order to ensure the long-term supply of conservation resources, develop and fund a regional research plan that directs development, demonstration, and pilot program activity. [utilities, Bonneville, Energy Trust of Oregon, NEEA and other program operators] The plan should focus on both the new measures and practices identified in the Sixth Power Plan conservation assessment and promising measures that emerge over the next five years that require additional technical, market, or other research. An initial list of measures that should be incorporated into the research plan is in an attachment to Appendix E. Assess feasibility, collect and evaluate data on costs and savings (including load-shape impacts), and identify programmatic approaches, delivery mechanisms, implementation strategies, and infrastructure needs. The research plan should :

- a. Prioritize research needs based on the magnitude of potential savings and level of uncertainty of measure performance.
- b. Identify research objectives that define specific milestones or the knowledge sought in order to increase certainty and solidify resource components of the long-term conservation supply.
- c. Identify funding requirements and commitments to accomplish research objectives.
- d. Assign the roles and responsibilities of the various regional entities, including but not limited to the Regional Technical Forum, Bonneville, NEEA, utilities, Energy Trust of Oregon, and the states.
- e. Identify milestones for reviewing research progress, determining additional research needs, and determining how regional conservation potential and associated targets should be adjusted based on the findings. Periodic review of the research plan and findings could be done as part of a biennium review of the power plan, or as needed.

CONS-21. Develop a regional approach to support data needs for energy efficiency.

[Bonneville, NEEA, utilities, Council and Regional Technical Forum] The region should develop a multi-year data collection and research plan that prioritizes the initiatives needed to facilitate the implementation of conservation resources and determine their impact on the power system. The plan should set forth a process to improve data coordination, distillation, and dissemination and outline the most appropriate and cost-efficient way to acquire needed data. The development of this plan should be carried out in a manner consistent with the NEET recommendations. Elements of this data collection work can assigned to the Regional Technical Forum, NEEA, Bonneville, and the utilities. High priority data needs include:

- a. Residential and commercial building characteristics
- b. Customer end-use surveys
- c. Measured end use & savings load shapes
- d. Efficiency measure saturations
- e. Capacity impact of efficiency measures
- f. Appliance and equipment saturations
- g. Market/Supply Chain structure
- h. Tracking of non-programmatic conservation savings

CONS-22. Establish guidelines to consider balancing utility and consumer interests, cost recovery for conservation research, demonstration, confirmation, and coordination activities. [state utility regulatory commissions, public utility boards and commissions, and utilities]

GENERATING RESOURCES

From a regional perspective, actions to develop new generating capacity in excess of that needed to meet state renewable portfolio standards is unlikely to be needed within the next five years for purposes of energy adequacy, risk reduction or cost reduction. Individual utilities, however, may need to acquire energy generation capacity because of transmission or other limitations that constrain access to energy markets and surplus generation, or because of a need to reduce market price, fuel price or carbon exposure. The action plan includes guidelines for energy acquisitions in these circumstances.

Though the summertime surplus of firm capacity is declining, actions to develop additional firm capacity are not needed on a regional basis over the next five years to maintain adequate winter or summer peaking reserves. As with energy, individual utilities may require additional firm capacity to maintain adequate reliability reserves.

Continued development of wind power to meet regional renewable portfolio standards and for export² will continue to increase the demand for flexibility reserves.³ This action plan includes actions to reduce the demand for system flexibility and to more fully access the latent flexibility

² Bonneville and other balancing authorities are obligated to provide interconnection and integration services for generators irrespective of local need.

³ Flexibility reserves (also called balancing reserves, rapid-response reserves, or regulation and load-following capability) provide the ability to balance generation and load on a sub-hourly basis. Balancing within intervals of seconds to minutes is referred to as regulation. Balancing within the hour is referred to as load following.

of the existing system. These actions are high priority and are consistent with the recommendations of the Northwest Wind Integration Forum.

Even with implementing measures to enhance existing system flexibility, growing wind and other variable-output resources may require augmenting flexibility reserves. Though the timing of this need on a regional basis is not well understood, Bonneville has asserted this may happen within several years because of the geographic concentration of wind development within its balancing area. The action plan includes actions to develop and implement a system to monitor the regional flexibility adequacy and guidelines for acquisition of balancing reserves.

Utilities that need to acquire new low-carbon emitting resources should consider the economic and environmental costs of the balancing reserves to firm and shape this variable-output generation, as well as the economic and environmental costs of the transmission facilities to integrate such resources.

The action plan includes actions to improve the cost-effectiveness and commercial availability of emerging low-carbon generating resources and storage alternatives with a focus on options of special relevance to the Northwest. Prospects include enhanced geothermal, wave energy, offshore wind, advanced and modular nuclear plants, solar photovoltaics, imported wind, concentrating solar power, tidal current energy, and technologies to capture, store or recycle carbon from existing and new fossil-fueled power plants. Technologies such as pumped storage, compressed air storage, batteries, and “smart grid” technologies offer low-carbon approaches to augment system flexibility.

Sound power system planning requires capable analysis tools and reliable supporting data. In particular, techniques and data to assess the most cost-effective approaches to develop and integrate variable-output resources long term are inadequate or lacking. This action plan contains actions to support improved planning and decisionmaking.

Generating Resource Acquisition

GEN-1. Acquisitions to meet energy, capacity, and ancillary service needs.

Bonneville, other balancing authorities, and utilities needing to acquire resources to provide energy, capacity or ancillary services should seek to acquire the most cost-effective, suitably reliable resources available to provide the needed service. All potentially cost-effective alternatives capable of providing the needed services should be considered including, but not limited to, conservation, demand management, storage, transmission, generating resources, operational and institutional solutions, and other emerging technologies (for example smart grid technologies). Resource acquisition decisions should recognize the full value of services (e.g. energy, capacity, ancillary services, avoided transmission and distribution costs, cogeneration load) provided by the available alternatives (e.g., and the full cost of services needed to support the available alternatives (e.g., costs of transmission, balancing services, and supplemental firm capacity). Significant investment, performance, environmental, and other risks should be quantified where feasible.

GEN-2. Facilitate development of smaller-scale, cost-effective, low-carbon resources.

Generating resource development in recent years has been dominated by wind power and

natural gas combined-cycle plants. However, smaller-scale renewable and high-efficiency projects can be equally, if not more, cost-effective than these more prevalent resources. Smaller-scale resource development opportunities include waste heat energy recovery, bioresidue energy recovery, cogeneration, geothermal, hydropower upgrades and new hydropower projects. These opportunities are available in limited quantity and can be challenging to develop because of the complexity of business and fuel supply arrangements; costly or unique engineering, interconnection and other infrastructure requirements; and proportionally high transaction costs and long lead times. Design and engineering is often highly site-specific, as are costs and business arrangements. If successful, however, these projects can provide firm capacity, base load energy, avoided transmission and distribution costs, residue disposal solutions, local economic benefits, low-carbon energy production, and revenues to host facilities.

The Council encourages Bonneville and the utilities to facilitate development of these resources where cost-effective by activities such as the following:

- Surveying resource development potential
- Structuring requests for proposals to accommodate small and diverse projects
- Establishing “open windows” for unsolicited proposals
- Establishing standard power purchase offers for qualifying projects
- Establishing standard interconnection provisions
- Considering all project attributes in proposal evaluations
- Providing financial, engineering and other development assistance
- Supporting demonstration and pilot projects for developing, testing and demonstrating technologies and business practices with potentially widespread application

Adequacy of System Integration Services

GEN-3. **Reduce demand for system flexibility.** The demand for balancing reserves for integrating variable-output resources can be reduced by improved wind forecasting, sub-hourly scheduling, liquid intra-hour wholesale power markets, curtailment of wind plant output during severe ramp-up events, curtailment of wind export schedules during severe ramp-down events, and ACE⁴ diversity sharing among balancing areas. Bonneville and other balancing authorities and grid entities should assess the feasibility, cost and benefits of these and other measures to reduce the demand for balancing reserves and implement promising measures.

GEN-4. **Expand access to existing system flexibility.** The balancing capability of the existing power system is not fully available because of business practices, operating protocols, transmission and communication limitations, absence of equipment allowing plants to be operated for balancing purposes, and environmental constraints. This latent balancing capability can be more fully tapped by expanded dynamic scheduling capability within the region and between interconnected regions, and by retrofit of existing plants where feasible and if necessary to provide balancing capability. Bonneville, other balancing authorities, grid entities, and plant owners should assess the

⁴ Area Control Error - A measure of the instantaneous difference in scheduled and actual system frequency and a balancing authority's scheduled and actual interchanges with other balancing areas.

feasibility, cost, and benefits of expanded dynamic scheduling within region and across the Northern and Southern interties. Attractive opportunities for expansion should be developed.

GEN-5. Assess adequacy of system flexibility. Periodic assessments of the adequacy of available balancing capability for following load and for variable-output generating resource integration are needed to complement to existing assessments of energy and capacity adequacy. The Wind Integration Forum, working with the Resource Adequacy Forum should develop a metric and methodology for evaluating the balancing reserve adequacy. Regular assessments of the adequacy of balancing capability should be implemented once the metric and methodology have been developed and tested.

GEN-6. Evaluate flexibility augmentation options. This plan recommends developing wind and other renewable resources to offset carbon and natural gas price risks. Adding wind and other variable-output resources will continue to expand the need for balancing capability. In response, priority should be given to measures to reduce the demand for balancing reserves and measures to expand access to the latent flexibility of the existing system, as called for in GEN-3 and GEN-4. However, Bonneville and other balancing authorities may eventually need to augment the supply of balancing capability to serve the expanding inventory of variable-output resources. The Council, working with the Wind Integration Forum and others, will assess the availability, reliability, and cost-effectiveness of resources for augmenting the existing balancing capability of the power system. Priority in this effort will be given to resources or combinations of resources that can jointly satisfy peak-load and system-flexibility requirements. This effort will consider, but not be limited to, combined-cycle plants, gas turbine generators and reciprocating engines, compressed-air energy storage, pumped-storage hydro, battery storage, smart grid technologies, and demand-side options. Metrics should be developed to measure and compare the various options. The completed assessment should identify research, development, and demonstration activities to ensure that the most promising options are available when required.

GEN-7. Commercialize and confirm low-carbon resources with special Northwest promise. Wave energy, deep-water wind power, enhanced geothermal power generation and salinity gradient energy systems have promise for future development in the Northwest as potentially abundant, low-carbon resources. Yet these resources, together with tidal current generation, are technically immature and the benefits, costs, and consequences of commercial-scale development insufficiently understood. Bonneville, regional utilities, industry groups, and the states, working with the federal government, should initiate and support efforts to develop and demonstrate the relevant technologies. They should also work to establish the body of knowledge and legal framework to support commercial development of the resources when available and needed. These efforts should include: 1) measuring the resource using a sufficient geographic scope, frequency, and duration to assess the economics of the resource, identifying promising resource areas and assessing resource integration needs; 2) technology assessment; 3) identifying and resolving potential environmental, economic, and other development conflicts; 4) demonstration projects to test and evaluate technology; 5) assessing system integration needs; and, 6) pilot projects to serve as the basis for commercial development.

The Oregon Wave Energy Trust initiative is a comprehensive model resource-confirmation effort.

GEN-8. Carbon separation and sequestration technologies. Though not yet fully commercial, carbon separation, sequestration, and recycling may prove to be an economic approach to reducing carbon dioxide releases in the long term. The Council encourages states and utilities to support efforts to develop commercial technologies for separation, sequestration, and recycling of carbon dioxide with emphasis on technologies unique to Northwest situations such as flood basalt sequestration. The Council also encourages the states to establish the legal framework for permitting and operating carbon dioxide transportation and sequestration facilities.

GEN-9. Monitoring development of other promising resources and technologies. Commercial development of other promising technologies is likely to be promoted primarily by policies, incentives, and other drivers at the federal level, or within other countries or regions where the technology might play a particularly vital role. These technologies include post-combustion carbon dioxide capture from conventional fossil-fuel power plants, algae-derived biofuel production and other carbon dioxide “recycling” technologies, integrated coal gasification combined-cycle technology, advanced nuclear technology, carbon dioxide sequestration in saline reservoirs and depleted gas and oil fields, and concentrating solar thermal and photovoltaic technologies. While active participation of the Northwest utility industry in developing these technologies may not be needed, their development should be closely monitored, and joint participation in demonstration projects and other resource development efforts should be considered. In addition, the Council expects that the strong energy research and development organizations present in the Northwest will participate in developing these technologies.

GEN-10. Resource development mandates and incentives. A diverse collection of federal and state resource development mandates and incentives has developed over time. Their underlying public goals include commercializing immature, but promising, technologies, developing the power system and social infrastructure to support commercial-scale development of promising resources, economic development, and promoting development of low-carbon resources. While these mandates and incentives are effectively promoting development of specific resources, their focus on resource types rather than ends (e.g., GHG reduction, cost and risk minimization) may constrain development of equally attractive resources and affect efficient system operation. The Council, working with other interested entities will review the impact and effectiveness of mandates and incentives, including consideration of the following:

- a. **Impact on optimal resource dispatch.** The federal production tax credit and renewable energy credits lower the effective variable cost of generation, under some conditions to negative levels. Concerns have been voiced that this can result in inefficient resource dispatch, and in some cases, increased environmental impact.
- b. **Effects of an unbundled REC market.** Renewable energy credits (RECs) represent the environmental and renewable attributes of renewable energy production as a separate commodity from the associated energy. RECs can be

transacted as “fully bundled” (delivered with the associated energy), “partly bundled” (the associated energy can be delivered within a specified time), or “fully unbundled” (marketed separately from the associated energy). As states, particularly California, move toward more aggressive and challenging renewable portfolio standards, interest in meeting RPS requirements with partially or fully unbundled RECs has increased. Unbundling can expand the pool of qualifying resources available to utilities, and expand the customer base for developers of qualifying resources. Market flexibility and liquidity, less constrained by transmission considerations, should increase. Because the value of CO₂ reduction is not location-specific, greenhouse gas reduction benefits are preserved. Partly unbundled transactions will improve transmission load factors and the need for new long-distance transmission lines will be reduced. Local economic benefits will shift to areas rich in lower-cost qualifying resources. Unbundling, however, raises issues of concern to resource-rich areas such as the Northwest. The demand for, and cost of, balancing reserves in the supply region will increase. The need for equitable allocation and recovery of the cost of balancing services will become more acute. The residual (“null”) energy must be marketed within the supply region and may depress power prices and introduce additional volatility to the wholesale power market. Dispatch conflicts with minimum hydropower operating limits and must-run resources may increase. Finally, the cost of acquiring RPS-qualifying and other low-carbon resources may rise for Northwest utilities because of increased competition. The potential extent of the future unbundled REC market should be assessed, the resulting benefits and costs characterized and actions needed to remedy significant impacts identified.

- c. **Geothermal development risk reduction.** Geothermal is an attractive, competitive low-carbon resource. Geothermal development, however, is hampered by a financially risky resource exploration and confirmation phase. Current federal incentives that reward successful production may be insufficient to offset the investment risk of resource development. Earlier federal incentives intended to offset resource exploration and development risk resulted in substantial geothermal power development and production. The cost and effectiveness of a range of incentives should be assessed to determine what set of incentives appear to be the most cost-effective in stimulating productive geothermal development.
- d. **Promote CO₂ reduction parity of resource mandates and incentives.** The principal underlying public purpose of many resource mandates and incentives is to reduce greenhouse gases, yet CO₂ reduction potential is not always reflected in the structure and level of mandates and incentives. An example is the prevalent failure to equate the carbon dioxide reduction potential of energy efficiency with that of renewable generating resources in state renewable portfolio standards. This may result in overly costly carbon dioxide reduction and a greater environmental impact by diverting expenditures from conservation to renewable resource development. States should attempt to establish a reasonable parity in the treatment of resources, including energy efficiency, in the design of renewable portfolio standards and other low-carbon resource incentives.

Information to Support Sound Planning and Decisionmaking

GEN-11. **Resource Assessment.** Bonneville, working with the Council, should re-establish a program of periodically assessing the availability, cost, and performance of generating resources and associated technologies to support the Council's power plan and Bonneville's resource program. These assessments should focus on resources identified in this plan with near- or longer-term promise to the Northwest, including waste-heat energy recovery, bioresidue energy recovery, cogeneration, conventional and enhanced geothermal, hydropower upgrades, new hydropower projects, natural gas technologies for energy, firm capacity and flexibility, wave, and offshore wind power. This work should be coordinated with the inventories of small-scale renewable energy and cogeneration resources called for in GEN-2.

GEN-12. **Planning for optimal development of the power system.** The Council will work with the Wind Integration Forum and other interested entities to identify the optimal development of a future power system containing a high penetration of wind and other new low-carbon resources. This effort should assess the cost and environmental tradeoffs associated with various combinations of transmission facilities, balancing capacity, and storage capacity needed to secure remote or local low-carbon resources. The work will consider the diversity value, and possibly greater productivity, of wind developed on a broader geographic basis, and the tradeoff between conditional firm transmission service and the value of delivered wind energy. Solar, wave, tidal current, and offshore wind sources of low-carbon power should also be evaluated. This work will draw on the results of the flexibility augmentation assessment to estimate the availability, cost, and performance of new sources of system flexibility, including various generating, demand-side, and storage options.

GEN-13. **Long-term synthetic, hourly wind data series.** The Resource Adequacy Forum should complete a long-term synthetic, hourly wind data series. This work is needed to further refine estimates of the sustained peaking value of wind, and to implement analytic capability to evaluate the tradeoffs between hydropower operational constraints and providing flexibility from the hydropower system.

FUTURE ROLE OF BONNEVILLE

The Bonneville section of the action plan encourages Bonneville and its customers to successfully complete and implement the regional dialogue policy and contracts. It recognizes that there remains litigation on some of the elements of the policy, and encourages Bonneville and its customers to resolve the issues, or if necessary, to seek a legislative solution to the contested areas. The action plan says Bonneville should follow the Council's regional resource strategy in its own acquisitions, and meet its share of the conservation targets as it has agreed to do. Bonneville should actively fund and support regional conservation activities and provide incentives and support for utility conservation acquisitions. It specifies that Bonneville continue to meet its fish and wildlife mitigation responsibilities.

BPA-1. **Implement the Council's Plan.** Pursuant to the overall directives of the Act, Bonneville's resource acquisition activities should be consistent with the Council's power

plan, including the resource strategies relevant to Bonneville identified in other sections of the action plan and further described in Chapter 12.

BPA-2. Conservation goals. Bonneville should meet its conservation goals. The Council believes Bonneville should observe certain principles in designing its post-2011 energy efficiency efforts. These principles include:

- a. **Conservation targets.** Bonneville should continue to commit that it will work with its public utility customers and meet Bonneville's share of the Council's conservation targets. Bonneville should ensure that public utilities have the incentives, support, and flexibility to pursue sustained conservation acquisitions appropriate to their service areas in a cooperative manner, as set forth in detail in the conservation action plan items, especially in the introduction and in CONS-1, CONS-14 and CONS-17. The Council supports Bonneville's regional dialogue policy to fund conservation primarily as a tier 1 obligation of the federal base system (FBS).
- b. **Utility reporting.** Bonneville should enforce provisions in its power sales contracts that require utility reporting and verification of conservation savings so that Bonneville and the Council can track whether conservation targets are being achieved.
- c. **Implementation mechanism.** Bonneville should offer flexible and workable programs to assist utilities in meeting the conservation goals, including a backstop role for Bonneville should utility programs fail to achieve these goals.
- d. **Regional conservation support.** Bonneville should continue to be active in funding and implementing conservation programs and activities that are inherently regional in scope, such as the Northwest Energy Efficiency Alliance, the Regional Technical Forum, and other regional efforts proposed as a result of the Northwest Energy Efficiency Taskforce process.

BPA-3. Additional resources, including capacity and flexibility priorities. Bonneville may have a need for additional resources for a number of reasons, including possible resource acquisitions to address capacity and flexibility needs, after taking account of its conservation acquisition. Bonneville should make these resource acquisition decisions consistent with the following:

- a. **Institutional changes to meet flexibility needs.** Bonneville should aggressively pursue the various institutional and business practice changes that are currently being discussed to reduce the demand for flexibility, and more fully to use existing resources (federal and non-federal) for its balancing needs, before acquiring additional generating resources for this purpose. These institutional measures, including better forecasting, short-term wind curtailment, sub-hourly scheduling, markets for the exchange of balancing services among balancing authorities, generation owners and operators, and demand response providers, have the potential to be more cost-effective and faster to develop than building new generation.

- b. **Generation for capacity and flexibility.** Institutional changes described above may require complex multilateral agreements and similarly complex changes in operating systems. And even if accomplished, these changes may not completely solve Bonneville's flexibility needs. Given these factors, BPA may need to acquire flexibility or capacity resources that could include investments in a smart grid and storage. Bonneville should take a broad look at the cost-effectiveness and reliability of the possible sources of additional capacity and flexibility if it turns out they are needed to meet its obligations. The possible synergies in simultaneously meeting both capacity and flexibility requirements need to be taken into account, and the possibility of newly developed technologies should also be considered.
- c. **Possible additional resources to meet other needs.** Besides the flexibility and capacity needs described above, Bonneville may need additional resources for a number of reasons. These include Bonneville's proposal to acquire resources to augment the existing system to serve the "high water mark" load of its preference customers at tier 1 rates; additional energy resources, if needed, because customers call on Bonneville to meet their load growth; at tier 2 rates reflecting the costs of the additional resources; additional resources to serve DSI loads, if Bonneville decides to offer such service; additional resources necessary for system reserves, system reliability, and transmission support; and additional resources to assist the Administrator in meeting Bonneville's fish and wildlife obligations under Section 4(h) of the Northwest Power Act. Conservation resources will help reduce the need for additional resources, but may not address all of these needs. The Council is not undertaking at this time a detailed, quantitative assessment of Bonneville's need for additional resources for any of these reasons, but will work with Bonneville to identify if these needs exist and whether and when additional resources should be acquired. In making decisions about additional resources for these reasons, Bonneville should act consistent with the principles set forth in Chapter 12 and with the details in the relevant resource chapters of the plan.
- BPA-4. **Proper financial incentives for customers.** Bonneville should meet the loads placed on the agency by its customers and ensure system reliability with the existing federal base system, acquire conservation resources and, if necessary, acquire additional generating resources consistent with the power plan and with Bonneville's regional dialogue policy and tiered rates methodology. Bonneville resource acquisitions to meet customers' loads above their "high water marks" should be structured so that these customers bear the financial risk associated with such acquisitions.
- BPA-5. **Focus on preserving the FBS.** Bonneville should conduct its business in a way that will preserve the benefits of the FBS for the region.
- BPA-6. **Fish and wildlife.** Bonneville should meet its fish and wildlife obligations.
- BPA-7. **Implement the regional dialogue policy.** Bonneville should implement the policy choices it has made in adopting tiered rates, signing long-term contracts, and

revising its residential exchange program in ways that will allow the agency to achieve the goals identified in the various regional processes that established Bonneville's future role.

BPA-8. Solve legal challenges to regional dialogue implementation. Bonneville should be prepared to take all necessary steps to revise those policy choices, as necessary, if the Ninth Circuit rules that the choices or some aspects of the choices must be overturned. Bonneville should be prepared to engage the region in any such revisions. If Bonneville's policies for tiered rates, the residential exchange program (including the average system cost methodology), long-term contracts and related matters are struck down by the Ninth Circuit, Bonneville should initiate regional efforts to bring those policies into line with the court's decision(s) or, if necessary, after exhausting legal remedies, seek a legislative solution to enable the agency to achieve the goals those policies were intended to reach.

BPA-9. Conditions if considering service to the DSIs. If the Administrator decides to offer service to the DSIs, consistent with any court rulings, such service should include the reserves required under the Northwest Power Act and provide, so far as possible, additional ancillary services.

ENSURING ADEQUACY

Developing and adopting regional adequacy standards was an important accomplishment of one of the key action items in the Council's Fifth Power Plan. It not only protects against future energy or capacity shortages by providing an early warning system, it also helps ensure that fish and wildlife operations are reliably implemented. The action plan is intended to ensure that the Council, working with others in the region, completes an annual assessment using the standards, but also that the Resource Adequacy Forum continues to refine and update the standards to reflect new information and adjust to changing conditions. In addition, an action item is included to enhance the region's ability to assess the adequacy of flexibility resources for within hour wind integration and system balancing.

ADQ-1. Adequacy Assessment. The Council, in collaboration with the Northwest Resource Adequacy Forum and others, will annually assess the adequacy of the regional power supply.

ADQ-2. Data Review. The Council, in collaboration with the forum and others, will annually review demand and resource data used for the adequacy assessment, compare its results with other regional reports and work to standardize data reporting.

ADQ-3. Methodology Review. The Council, in collaboration with the forum and others, will periodically review the Pacific Northwest's adequacy standard and the methodology used to define the standard. If warranted, the Council will amend the standard.

ADQ-4. Working with other regions. The Council will monitor adequacy assessment methodologies in other regions and work with the Western Electricity Coordinating

Council to incorporate Pacific Northwest adequacy metrics and assessments into West-wide adequacy reports.

DEMAND RESPONSE

Power systems are required to maintain resources to meet extreme peak-load events. Some of these resources are seldom used and therefore are very expensive on a per kilowatt-hour basis if significant capital costs are involved in building the capability. A growing alternative is demand response, which allows voluntary reductions in load during extreme load events or interruptions of generation or transmission. The action plan for demand response includes increasing our understanding of demand response potential and cost-effectiveness. This involves monitoring implementation of demand response in the Pacific Northwest and other areas where more demand response programs have been tested, supporting pilot programs to test demand response approaches, and exploring the potential of demand response as a source of system flexibility for within-hour balancing reserves.

- DR-1. **Inventory demand response programs.** The Council should compile and maintain an inventory of demand response acquisition programs and pilot programs that are active or in the planning stages in the region. The objective is to encourage communication among planners and administrators of these efforts at early stages in the work so that experience is shared and unnecessary duplication is avoided as much as possible.
- DR-2. **Evaluate and demonstrate demand response programs.** Utilities and regulators should consider not only pilots that test implementation strategies and demonstrate effectiveness of programs that have been successful elsewhere (e.g. direct load control of space heating or air conditioning), but also pilots that explore innovative programs that have little or no history, but have promise (e.g. use of demand response from dispatchable electric water heaters to provide load following and/or wind integration).
- DR-3. **Evaluate potential for providing ancillary services.** The Council, the region's utilities, and regulators should examine demand response as a source of ancillary services, including estimation of potential megawatts available, its cost and cost-effectiveness.
- DR-4. **Monitor new programs.** The Council, the region's utilities, and regulators should monitor new programs to obtain demand response, including Bonneville's pilot programs and the aggregator contracts of PacifiCorp, Portland General Electric, and Idaho Power.
- DR-5. **Monitor experience in other regions.** The Council, the region's utilities and regulators should monitor progress outside the Pacific Northwest on demand response.
- DR-6. **Evaluate direct service industry as a source of demand response.** If Bonneville serves direct service industry load, it should analyze all possibilities for using this load to provide reserves as required in the Power Act. In particular, the potential for this load to provide ancillary services should be examined for its cost-effectiveness.

- DR-7. **Complete the work of the PNDRP.** Council should continue coordinating with the Regulatory Assistance Project, of the Pacific Northwest Demand Response Project (PNDRP). In particular, PNDRP should complete examination of pricing strategies to stimulate demand response.
- DR-8. **Include appliance response controls in standards.** The region should advocate appliance standards that include Smart Grid controls to interrupt load (at least for under frequency events and utility calls). This action item could be included in energy-efficiency action items. Appliances could include:
- a. Water heaters (mixing valve as well as smart thermostat switch)
 - b. Clothes dryers
 - c. Refrigerators
 - d. Freezers
 - e. Air conditioners
- DR-9. **Implement demand response recommendations of NEET.** The final recommendations of the Northwest Energy Efficiency Taskforce are likely to provide suggestions on how to develop demand response in the region. These recommendations should be pursued by the region.
- DR-10. **Improve Council modeling of demand response.** The Council should examine the treatment of demand response in its regional portfolio model to ensure that the model properly captures the benefits and costs of demand response. To the extent that demand response has benefits that are difficult or impossible to simulate with the portfolio model, such as the benefits of demand response providing ancillary services, the Council should work with other parties to identify alternative analytical approaches to estimate these benefits.

SMART GRID

Smart-grid technologies have the potential to transform the operation of the power system in ways that are difficult to predict, but that hold great potential for improved operations and reliability, and for making electricity consumers partners in maintaining the efficiency and reliability of the power system. These technologies are in their infancy and will take time to develop to full potential. To better understand smart-grid potential, the action plan supports regional pilot programs to gain experience with smart-grid technologies and the role they might play in the power system.

- SG-1. **Monitoring smart grid technology.** Monitor development and adoption of smart grid technology for its benefits and cost-effectiveness.
- SG-2. **Smart grid demonstration.** Evaluate smart grid demonstration projects and develop additional demonstration projects when appropriate.
- SG-3. **Develop evaluation methods.** Develop methodology for evaluating demand response used for ancillary services.

TRANSMISSION

When the Council developed the Fifth Power Plan, there was reason to be concerned about the transmission system. There had been no progress on improving the operation of the transmission system and little activity in planning for transmission system expansion. To a large extent, this is no longer the case either in the region or in the broader Western interconnection. The Council will continue to participate in WECC activities relating to wind integration, transmission planning, and adequacy assessment. Bonneville is moving ahead with critical transmission expansions within its balancing area, and there are several large transmission projects in various stages of planning by other utilities or merchant transmission providers that would affect the Northwest. The action plan encourages continued regional efforts to improve wind integration capability through improved operational procedures such as reserve sharing, dynamic scheduling, improved wind forecasting, and the ability to curtail wind ramps under extreme conditions.

- TX-1. **Participate in and track WECC activities.** Many of the actions that the Council is interested in, e.g., integration of large amounts of intermittent renewable generation, expansion of the transmission system to accommodate this generation, and development of resource adequacy assessments and guidelines, are affected by WECC actions.
- a. **Wind: Variable Generation Subcommittee (VGS).** The VGS was formed in early 2009 to coordinate WECC actions and information sharing (both internally and with the actions of WECC members) regarding intermittent generation, especially wind and solar. Many of the actions needed to integrate large amounts of intermittent generation into the system need to take place, or are more effective if they take place, on a wider scale than just in the Northwest. Examples include: changes in business practices like scheduling (e.g., to greater frequency than every hour), standardizing protocols for dynamic scheduling, and developing detailed operating dynamics models of wind generation.
 - b. **Resource Adequacy: Loads and Resources Subcommittee (LRS).** LRS develops WECC resource adequacy guidelines and assessments and acts as the interface with NERC in these areas and on NERC's development of standards in the resource adequacy area. The WECC and NERC activities provide the background within which the Council analyzes adequacy issues and approaches and develops assessments.
 - c. **Transmission: Transmission Expansion Planning Policy Committee (TEPPC).** Coordinated transmission planning for larger scale projects needed to move distant, typically renewable, generation to load centers takes place primarily in two forums: subregional planning groups (SPGs) like Northern Tier Transmission Group and ColumbiaGrid and interconnection-wide, through TEPPC. TEPPC provides data and overall scoping studies for the SPGs and other entities like the Committee on Regional Electric Power Cooperation (CREPC) and the Western Governors' Association (WGA). TEPPC is expected to receive substantial funding from DOE under the American Recovery and Reinvestment Act of 2009 (ARRA) to develop an interconnection-wide transmission plan, which will substantially expand the scope of its current activities.

TX-2. Track transmission expansion proposals and evaluate impact on the region.

This effort focuses on monitoring the status of transmission proposals that would have significant effects on the ability of regional utilities to develop resources, particularly to import renewables, and to access regional and other markets.

TX-3. Continue to assess needs and costs of transmission for wind development.**FISH AND POWER**

The Council's Columbia River Basin Fish and Wildlife Program and Electric Power and Conservation Plan must provide measures to "protect, mitigate, and enhance fish and wildlife affected by the development, operation, and management of [hydropower] facilities while assuring the Pacific Northwest an adequate, efficient, economical, and reliable power supply." In other words, the mutual impacts of fish and power measures are intended to be examined together. By statute, hydroelectric operations to improve fish survival that are specified in the fish and wildlife program become a part of the power plan and the plan must be designed to accommodate these operations and their cost. Guided by the Council's power plan, Bonneville is to acquire resources to assist in meeting the requirements of the fish and wildlife program.

The action items listed below are designed to improve the way in which we plan for the long-term needs of both power and fish and wildlife. The key action is for power planners to work more extensively with fish and wildlife managers to explore ways to better identify and analyze long-term uncertainties that affect all elements of fish and power operations. These uncertainties include climate change, electricity demand, fuel prices, policies involving resource operation, and treaties affecting the hydroelectric system. Discussions should provide an opportunity to identify synergies that may exist between power and fish operations and to explore ways of taking advantage of those situations. Another critical topic for discussion is the integration of variable generation resources, its affect on the operation of the hydroelectric system and possible consequences for fish and wildlife.

F&W-1. Long-term planning coordination. The Council will work with federal, state, tribal, and other entities through existing forums to expand the discussion of long-term fish and wildlife and power planning integration.

F&W-2. Contingency plans. The Council will continue to work with fish and wildlife managers and regional power planners to: 1) review curtailment plans for fish and wildlife operations in the event of a power emergency; 2) review contingency power operations in the event of a fish and wildlife emergency; and 3) aid in developing a plan to improve our ability to forecast and operate the hydroelectric system to reduce the likelihood of emergencies.

F&W-3. Analytical capability. The Council will work with Bonneville and other federal action agencies, federal and state fish-and-wildlife agencies and tribes, and other regional entities (in particular the Independent Economic Analysis Board, the Independent Scientific Advisory Board, and the Independent Scientific Review Panel) to analyze the physical, economic, and biological impacts of alternative operations for fish and wildlife and to develop ways of improving the cost-effectiveness of fish and wildlife programs.

F&W-4. Columbia River Treaty. The Council will work with Bonneville and others to examine the impacts of possible changes to the Columbia River Treaty between the United States and Canada. The system flood control elements of the treaty expire during this plan's study horizon, and possible modifications to both the flood control and power supply aspects of the treaty could likely affect both the region's power system and operations to benefit fish and wildlife. The Council should be proactive in addressing this issue.

F&W-5. Climate change. The Council will work with federal agencies, the University of Washington's Climate Impacts Group, and others to examine the physical impacts of climate change to electricity demand, river flows, reservoir elevations, power production, and cost. The Council will examine ways to mitigate these impacts and encourage others to improve runoff volume forecasting methods, especially for the fall. The Council will also work to develop methods that include the potential physical impacts of climate change into its resource planning methodology.

MONITORING PLAN IMPLEMENTATION

The Council will monitor conditions in the region for significant changes that would affect the power plan. The region's progress in implementing the resource strategy in the plan will be assessed and a biennial monitoring report will be prepared describing any significant changes in the assumptions underlying the plan. The monitoring report also will assess resource development in the region including efficiency acquisition compared to the Power Plan's recommendations.

MON-1 Biennial monitoring report. Council will monitor implementation of the recommendations in the Sixth Power Plan and report on progress biennially.

MON-2 Assess changing conditions affecting the plan. Council will monitor how developing electricity load, fuel price, electricity prices, conservation technologies, resource costs, and other planning forecasts and assumptions compare to assumptions included in the Sixth Power Plan.

MON-3 Analyze changes for significance. The Council will conduct analysis of specific changes or issues to determine their effects on the regional power system and the Power Plan.

MON-4 Monitor climate change policies and analysis. Continue to monitor progress in climate change models and their assessments of impacts on temperature, precipitation and stream flows. As the need arises, analyze specific climate change scenarios and assess potential effects on the plan's resource strategy.

MAINTAINING AND ENHANCING COUNCIL'S ANALYTICAL CAPABILITY

The Council's power plan is extremely data and model intensive. Maintaining data on electricity demand, resource development, energy prices, and generating and efficiency resources is a significant effort. It is one that the Council's staff cannot do alone. As recognized in the NEET

recommendations, data collection for the regional power system and alternative resources available to meet demand is something best accomplished through regional cooperation. The action plan contains recommendations to maintain and improve planning data for the region.

ANLYS-1. Review analytical methods. As is customary between power plans, the Council will undertake a comprehensive review of the analytic methods and models that are used to support the Council's decisions in the power plan. The goal of this review is to improve the Council's ability to analyze major changes in regional and Bonneville Power systems and make recommendations on how the BPA Administrator can best meet its obligations and ensure a low-cost, low-risk power system for the region. This review will focus on changing regional power system conditions such as capacity constraints, integrating intermittent resources, and transmission limitations because these currently pressing issues will need to be more formally addressed in future power plans. The Council will work with Bonneville and other utilities to evaluate available data and models that can be used to support the Council's planning. This action item will require the Council to clearly define the planning problems facing BPA and the region and identify or develop new analytic tools that can help the Council to identify the best possible approaches to meet the region's and BPA's future power needs.

ANLYS-2. Improve hourly load data. Work with utilities and NWPP to standardize collection of regional hourly loads data. Currently there is a substantial lag in getting regional hourly loads from NWPP. In fact, the last year of hourly data from NWPP is for 2002. This situation creates problems for updating the short-term forecasting model which is used for resource adequacy work.

ANLYS-3. Improve irrigation sales reporting. Work with utilities to receive irrigation sales data annually. Currently, there is a substantial problem with getting accurate data on irrigation sales in the region. This problem is more pronounced when it comes to public utilities. This problem has been solved in the past by Council staff devoting a substantial amount of work to contact individual utilities and obtain the data.

ANLYS-4. Improve industrial sales data. Work with utilities to improve industrial sector sales data. Currently, industrial sales are reported by utilities to FERC and EIA in an aggregate fashion. Reporting sales data at a more disaggregated industrial level would improve the ability to forecast loads. Confidentiality concerns should be addressed and solved.

ANLYS-5. Follow up on NEET data recommendations. There are other "data holes" where updating information would substantially benefit the region. Some of these data needs were identified in the NEET recommendation from workgroup 1. An action item would be to track and implement NEET recommendations. Examples of data holes are:

- a. End-use hourly load shapes
- b. Energy use for end-uses (ICE)
- c. Establishing panel data for residential and small commercial, especially elder care facilities.
- d. Improve the baseline consumption and conservation potential for data centers

ANLYS-6. Improve electricity end-use data. Work with NEEA, RTF and utilities to:

- a. Develop a common survey and data gathering instrument
 - b. Develop the requirements for a data clearinghouse
 - c. Develop the data gathering cycles for each sector/measure
 - d. Coordinate the data gathering implementation plan for 2010-2015
- ANLYS-7. **Improve peak-load forecasting.** Facilitate a discussion among regional forecasters and others on peak-load forecasting methodologies used in the region.
- ANLYS-8. **Improve natural gas demand forecasting.** Work with regional gas utility demand forecasters to fine-tune gas forecasting capabilities of the load forecasting model
- ANLYS-9. **Develop the supply side of the demand forecasting system.** Work with BPA to integrate the electric supply module of long-term forecasting model with the current demand forecasting model. This integration should enhance the Council's ability to see the impact of various policies in a more cohesive manner.
- ANLYS-10. **Improve transportation electricity use forecasting.** Enhance the electric transportation segment of the long-term model for better representation of potential demand and impact on electric supply from the plug-in hybrid electric vehicles.
- ANLYS-11. **Demand response modeling methods.** Work with BPA and others to incorporate the framework for modeling DR in the long-term forecasting model.
- ANLYS-12. **Evaluating sustained-peaking capability of the hydroelectric system.** Work with others in the region, in particular the Resource Adequacy Forum, to develop a better methodology to assess the sustained-peaking capability of the regional hydroelectric system.
- ANLYS-13. **Improved demand response modeling.** The Council should examine the regional portfolio model's treatment of demand response in case there are opportunities for improvement (see Action Item DR-9).
- ANLYS-14. **Planning coordination and information outreach.** The Council will continue to participate in the development of Bonneville's Resource Program and in utility integrated resource planning efforts. In addition, the Council will periodically convene its planning advisory committees including the Natural Gas Advisory Committee, Conservation Resources Advisory Committee and Generating Resources Advisory Committee for purposes of sharing information, tools, and approaches to resource planning.
- ANLYS-15. **Improve Regional Conservation Resource Potential Assessment Input Assumptions and Methodology.** The Council will convene Conservation Resources Advisory Committee to identify data and methodological requirements that are required to support regionally consistent utility or sub-regional assessments of the conservation resource potential. The Council, in cooperation with NEEA, BPA, regional utilities, and administrators of system benefit charge programs will seek to prioritize that market research and data development necessary to implement improvements in both the Council and utility conservation potentials assessments.

ANLYS-16. Review of Council Policy on Direct Use of Natural Gas. The Council was unable to complete the analysis of the economics and emissions impacts of the direct use of natural gas prior to the release of the draft Sixth Power Plan. Due to the significant regional interest in this analysis, the Council believes it should provide adequate opportunity for review and comment on the input assumptions and results of this work before considering changes to its current policy. Therefore, the Council will complete this analysis during the first six months of 2010 during which time it will conduct a public review process to consider any policy changes and action items related to its findings.

ANLYS-17. Incorporate conservation acquisition risk. Council staff began the modification of the resource portfolio model to reflect uncertainty about conservation achievement rates. The revisions will be completed as an action over the next year, so that conservation uncertainties can be treated similarly to other resource risks in the Council's analysis. For the Sixth Power Plan, the Council has treated this uncertainty through scenario analysis.

Chapter 1: Introduction

Purpose of the Power Plan 1
 Major Issues 3
 Climate Change..... 3
 Providing Capacity and Ancillary Services 4
 Bonneville’s Role..... 5
 Changing Technologies 6
 Growing Cost of Energy 7
 Historical context 7
 Electricity Demand 8
 Electricity Generation 10
 Energy Cost Trends..... 12
 A Vision for the Sixth Power Plan..... 14

PURPOSE OF THE POWER PLAN

The Northwest Power and Conservation Council (Council) was formed by the Northwest states in 1981 in accordance with the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Act). Each state’s governor appoints two members to the Council making eight members in total representing Washington, Oregon, Idaho, and Montana. The Council was formed to give the Pacific Northwest states and the region’s citizens a say in how growing electricity needs of the region would be provided. The Act charges the Council with creating a power plan for the region. The purpose of the Council’s power plan is to ensure an adequate, efficient, economical, and reliable power supply for the Pacific Northwest¹.

The Act also recognized that development of the region’s hydropower dams had detrimental effects on migratory fish and wildlife and required the Council to develop a program to mitigate those effects. The fish and wildlife program is an integral part of the Council’s power plans.

The Council’s power plan and the fish and wildlife program are developed through an open, public process to involve the region’s citizens and businesses in decisions about the future of these two interdependent aspects of the Pacific Northwest environment and economy. The Act grants different approaches for these two Council responsibilities. The fish and wildlife program is based on, and defers to, recommendations from fish and wildlife agencies and tribes. However, the power plan is developed through Council analysis, helped by scientific and statistical advisory committees.

The power plan develops a strategy for the region to meet its future electricity needs. The Act recognizes that the demand for electricity is derived from the need for services electricity can provide, such as heat for homes, lights for commercial buildings, or motors for industrial processes. These services are the focus of the power plan. Technologies that allow production of these services more efficiently are the equivalent of generating additional electricity. In fact, the Act designates efficiency improvements as the highest-priority resource for meeting electricity demands and gives it a 10 percent cost advantage. Second priority is renewable

¹ Public Law 96-501, Sec. 2(2).

resources followed by high-efficiency generating technologies and then other generating technologies.² Except for efficiency improvements, the priorities of the Act are only tie breakers when alternative resources have equal cost.

The power plan includes a resource strategy to ensure demand for electricity is met by a combination of improved efficiency and generating resources that minimizes the cost of the energy system, including quantifiable environmental costs. Because there are many unknowns in the future, the power plan considers how costs might vary with changing conditions and identifies strategies to reduce the risk of high-cost futures. The action plan identifies specific actions needed in the next five years for the region to achieve the long-term strategy. These actions are the heart of the power plan because they set an agenda for the next several years.

The Act requires that the Council's power plan be reviewed at least every five years. This power plan is the sixth produced by the Council since the Act was passed. In each plan, costs and technologies have changed resulting in subtle changes in the plans. Generating technology cost-effectiveness has shifted away from large coal and nuclear facilities toward shorter-lead-time, more flexible, gas-fired generation. Recently, climate concerns and related state regulations have made renewable generation technologies more attractive.

However, consistently in all of the Council's power plans, efficiency improvement has been the lowest-cost resource. As the Council's ability to assess risk has grown more sophisticated, efficiency also has proven to be the least-risky resource alternative. As a result, in each of the Council's plans energy efficiency has been identified as an important resource for the region. In the Council's first plan, conservation was expected to meet half of the region's 20-year, medium-high load growth to 2002. In successive plans, the amount and share of conservation varied as utility programs or codes and standards captured some of the potential, new technologies became available, and cost-effectiveness levels changed. But the share of expected new energy resources to be provided by efficiency improvements never fell below 25 percent, and has typically been between 30 percent and 40 percent.

Over the years since the Council was formed, conservation has met nearly half of the region's growth in energy-service demand. If the region's energy savings were added back to the regional energy loads, load would have increased by 8,150 average megawatts between 1980 and 2008. During that time the region acquired 3,900 average megawatts of conservation, so that actual loads to be met by electricity generation only increased by 4,250 average megawatts.

In addition to the resource strategy, the Council's power plan addresses significant issues facing the Northwest power system and provides guidance to the region on addressing those issues. The focusing issues have changed with each power plan. The region's power system has gone through many changes over the 28 years of the Council's existence, including changes to the operation of the power system to aid fish and wildlife; electricity industry restructuring; a changing role for the Bonneville Power Administration, the federal power-marketing agency that implements the Council's power plan; and evolving environmental concerns. The Council's power plans have reflected those changing conditions.

A constant focus through all of the Council's power plans has been the significant uncertainty facing the regional power system. In early plans, long resource lead times for coal and nuclear

² Public Law 96-501, Sec. 4(e)(1).

plants created risk in the face of highly uncertain load growth. Over time, other risks became a larger part of the problem including fuel prices and availability, industry restructuring, and environmental risks. Although the regional power system has changed in many ways from what was envisioned in the Act, the basic planning guidelines have proven resilient and continue to provide guidance to the region.

MAJOR ISSUES

The regional power system is facing significant changes. The Sixth Power Plan addresses these changes through its resource recommendations and action plan. Some of the most important changes include:

- Growing concern about, and evolving policies to address, climate change
- Increased importance of assessing the capacity of the power system to meet periods of sustained peak electricity needs and provide ancillary services to meet system operation and wind integration requirements
- The changing role of the Bonneville Power Administration in providing resources to meet the growing needs of public utilities
- Emerging technologies and incentives with the potential to change significantly the relationships among electricity producers, utilities, and consumers
- Significant increases in the price of natural gas, oil, and coal supplies

Climate Change

Concerns about climate change have changed the power planning landscape dramatically. Regardless of one's beliefs about the causes of climate change there is a wide consensus among scientists and policy-makers that human-caused greenhouse gas emissions are contributors. These concerns have resulted in a wide variety of policies throughout the world, the nation, and the Pacific Northwest and western states. These policies are affecting the resource choices available for electricity generation both directly through restrictions on certain types of resources, and indirectly through incentive programs to encourage certain types of resources.³

An example of these policies is restrictions on new coal-fired power plants. In some cases these restrictions are direct prohibitions against new power plants emitting more than a determined amount of carbon. In others, it is regulatory or public resistance. But in any case, new conventional coal-fired power plants appear unlikely to be an alternative in the Northwest's future.

Renewable portfolio standards in Montana, Oregon, and Washington will require that a substantial portion of utilities' added electricity generation will be from renewable resources. By 2030, the shares of loads that must be met from renewable technologies are: 15 percent in

³ See Chapter 11 for a discussion of these policies.

Montana, 25 percent in Oregon, and 15 percent (by 2020) in Washington. The timing to reach these levels varies by state. Many other states in the West have similar renewable requirements.

Some policies already are in place. However, that does not mean they will remain unchanged. Policies can be reassessed and refined. Further, the Western Climate Initiative (WCI), an effort of 11 U.S. states and Canadian provinces to address climate issues, has set greenhouse-gas emissions goals and designed a market-oriented cap-and-trade process to facilitate meeting their goals. Participants in the WCI may have individual goals to reduce greenhouse gas emissions. Such initiatives are often accompanied by a host of state policies to help reach the goals. The U.S. has yet to act at the national level on greenhouse gas policies although legislation is being actively considered. The carbon-reduction goals of these policies vary but typically would imply about a 40- percent reduction from 2005 levels of emission by 2030, and an 80 percent reduction from 2005 levels by 2050. The result of all these factors is simply that many future policies that could profoundly affect resource choices remain unknown, creating risks for resource decisions that have to be made now.

Uncertainty about climate policies raises several questions for the Sixth Power Plan. These include:

- What are likely costs of carbon-control policies, and will those costs be known (carbon tax) or unknown (cap-and-trade system)?
- What is the lowest-cost approach to meeting carbon emissions reduction targets, and what are those targets most likely to be?
- What are the costs of renewable resources, and what will be the costs to consumers of meeting renewable portfolio standards?
- How will development of renewable generation affect the operation of the power system and the need for new transmission investments?
- Are there carbon-control policies in other sectors, such as transportation or building construction and maintenance, that will affect the need for electricity?
- Will uncertainty about future carbon policies and their effects on energy costs lead to inadequate investment in electricity supplies?

Providing Capacity and Ancillary Services

Until recently, the Pacific Northwest was able to plan its power system based on average annual energy needs and supplies. The hydroelectric system provided a large share of the regional electricity supply and had the flexibility to provide most of the peaking and shaping (ancillary services) required to match reliably electricity generation to consumption on an annual, seasonal, hourly and sub-hourly time scale.

The hydroelectric system, however, can no longer be assumed to provide all of these services. There are several reasons for this change:

- First, the seasonal patterns of electricity demand in the region are changing as air conditioning use has grown.
- Second, flexibility of the hydroelectric system has been constrained by actions taken to help mitigate for its impacts on fish and wildlife.
- Third, the share of non-hydroelectric generating resources has been growing over the last 40 years and those resources typically do not have the same degree of flexibility as the hydroelectric system.
- Finally, the region has added significant amounts of wind generation, which is a variable resource and adds to the shaping and flexibility requirements of the power system.

Assuring an adequate and reliable power system increasingly requires addressing the peaking and shaping capability of the power system. This power plan, for the first time, addresses these issues.

- What is the capacity of the hydroelectric system to meet peak loads and provide flexibility resources?
- Are there actions that can reduce the need for additional capacity and flexibility?
- What other resources can provide such services and what are their costs?
- What mix of generating resources, energy storage, and demand-side response is most cost-effective for providing needed flexibility?

Bonneville's Role

More than 10 years ago, the Comprehensive Review of the Northwest Energy System recommended that Bonneville should focus on marketing the existing resources of the federal base system to protect its low cost and ensure regional commitment to repaying debt to the U.S. Treasury.⁴ One of the review's basic tenets was that utilities would pay the cost of new electricity supplies for growth in their customers' demand beyond that provided through the existing federal base system.

Bonneville adopted its Regional Dialogue Policy in July 2007. Subsequently, Bonneville and its customer utilities signed long-term contracts in 2008 to implement the policy with the intention of protecting the cost-based federal system while providing better incentives for utility resource decisions.

This change will empower many customer-owned utilities to make their own resource decisions. In addition, many of these utilities are now subject to planning requirements and renewable portfolio standards imposed by states in the region.

⁴ Comprehensive Review of the Northwest Energy System: Final Report. December 12, 1996.

As a result of these changes, implementation of the Council's plan will become even more diverse. Bonneville's role in developing future power resources for the region likely will be reduced. These changes prompt several questions:

- How will the region implement the Council's power plan?
- Who will be responsible for meeting efficiency goals, and how will achievements be tracked?
- How will small customer-owned utilities develop resources to meet their load growth?

Changing Technologies

The digital revolution has created technologies that could substantially change the way the power system is planned and operated. These technologies offer the possibility for improved control, reliability, and efficiency of power system operations, an enhanced market for energy and ancillary services, and a greater opportunity for consumers and distributed generation to participate in the operation of the power system.

This general area of technology is frequently referred to as the "smart grid." Components of this technology include electric meters at homes and businesses that can be remotely monitored, saving utilities meter-reading costs, but also other sensor technology that can communicate back to the power system on the status of electricity use, the exact location of outages, and the status of the distribution system at all points in a utility's system. This technology provides a foundation for automated demand response when coupled with appropriate price signals, consumer agreements, and end-use equipment controls.

The advancement and deployment of these technologies is likely to significantly change the way in which improved efficiency is acquired. With data on each customer's use at intervals of one hour or less, energy-savings estimates and evaluations of conservation-acquisition alternatives can be more confident. As better information about the value of electricity savings in particular locations and at particular times is made available to consumers, efficiency improvements increasingly will be pursued as a business strategy. Energy service and management companies will be able to offer a business case to consumers that improves the quality and reduces the cost of electricity. This continues a trend of increasing roles for non-utility entities in the acquisition of energy efficiency. This trend has included the creation of the Northwest Energy Efficiency Alliance, the Energy Trust of Oregon, and numerous energy-service companies. Pursuit of efficiency as a profitable business case may be the next stage of energy efficiency acquisition strategies. Technology advancements pose questions for power planners, including:

- How will advancement of smart-grid technologies change the role of utilities and customers?
- What actions are needed to facilitate development of these technologies?
- Are there barriers to expansion of these technologies?

- Will smart-grid technologies and practices improve the reliability and efficiency of the electrical grid, or will diffusion of control create problems for management of the system?
- How will smart-grid technologies facilitate other objectives of energy or climate policy? For example, is it needed to integrate plug-in electric vehicles into the power system?

Growing Cost of Energy

Since the Council was formed in 1981 there have been two major incidents of electricity price increases. The first was just about completed as the Council was created and it was due to large overinvestment in nuclear facilities that turned out to be unneeded. The second large increase occurred in 2000-2001 and was due to underinvestment in electricity generation.

Current expectations are that the region faces a third increase in electricity costs, although perhaps it may occur over a more extended time period. In this case, the increase will be due to increased cost of basic energy supplies, such as oil, natural gas, and coal, increased carbon-emissions controls, and requirements to develop more expensive renewable sources of electricity.

Each historical increase in electricity prices changed the Northwest economy and electricity use. The 1979-1981 increase pushed electricity-intensive industries of the region to marginal producers in world markets. The 2000-2001 increase resulted in the permanent closure of many of these regional industries. From the 10 aluminum plants that were operating in the region when the Act was passed, only three remain in partial operation. In addition, many other energy-intensive industries have closed permanently in the last 10 years. The potential for higher future energy costs raises these questions:

- What additional effects will increasing electricity prices have on the economic structure of the region?
- Are there strategies to reduce the effects of higher prices on the region's consumers of electricity?
- Are there approaches to carbon-emissions reduction that moderate the price increases?

HISTORICAL CONTEXT

The Council's power plan looks 20 years into the region's electricity future. Decisions regarding this future are long-lasting and have important effects on the adequacy, efficiency, reliability, cost, and environmental footprint of the power system. To plan for a future that ensures the region a resilient supply of electricity consistent with long-term growth and environmental sustainability, it is important to understand how the regional electricity market has evolved. Anticipating changes that could take place during a period of 20 years requires investing in a power system that is as adaptable as possible.

This section provides background on trends in electricity demand and supply since the time the Council was created. It looks at changes that have occurred during the past 25 years to provide

important insights into the region's energy future. This section seeks to answer questions: How has the use of electricity grown and changed? What role has improved efficiency played in these trends? How have the sources of electricity generation changed over the years, and how have the institutions and regulations changed?

Electricity Demand

The year 1980, the year the Northwest Power Act was passed, was a watershed for the region. In preceding decades, the region had experienced rapid growth in electricity demand. There was an expectation that this rate of demand growth would continue. During this time, there was little hydroelectric expansion and many planned investments in large-scale coal and nuclear generating plants. The cost of these new generating sources was much higher than existing hydroelectricity. Their development created a huge increase in electricity costs.

Instead of the ever-growing electricity demand experienced before 1980, the region found that demand was indeed responsive to price changes. The region's aluminum plants, which accounted for nearly 20 percent of all regional electricity use, became far less competitive in world markets. But other users of electricity also responded by altering their consumption. Between 1960 and 1980 regional electricity loads grew at 5 percent per year, but in the subsequent 20 years from 1980 to 2000, load growth was only slightly over 1 percent per year. Slowed growth in demand and escalated costs of new power plants combined and forced many of the regional investments in new nuclear facilities to be abandoned. Unfortunately, many of their costs already were incurred and still affect electricity prices today.

In 2000 and 2001, the region experienced a second large electricity price increase. Unlike the 1980 price increase, this one was a result of too little investment in electricity generation, combined with a poor water year and a flawed power-market design in California. This price increase confirmed the demise of most of the region's aluminum smelters and resulted in closure or cutbacks in other energy-intensive industries as well. Regional loads dropped by 16 percent between 1999 and 2001, falling back to levels of the mid-1980s.

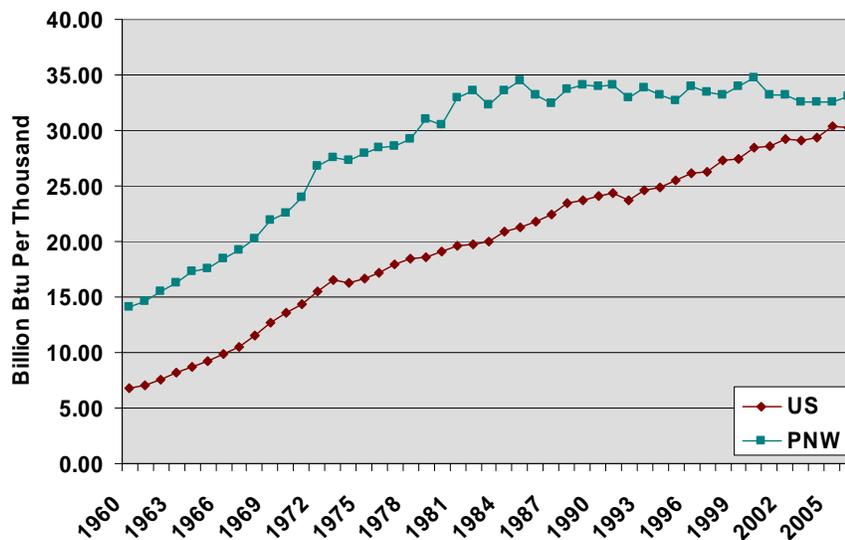
Electricity prices and consumption are often compared to national statistics. Such comparisons help us understand regional long-term trends. The Pacific Northwest economy historically has been both more energy-intensive than the rest of the nation, and more electricity-intensive. However, the regional trends in total energy use per capita, and per dollar of economic production (Gross Domestic Product (GDP) or Gross State Product (GSP)), have been different from the national trends in recent decades. National total energy use per capita flattened following the early 1970s whereas the regional use of energy per capita declined. By 2006, the region's energy use per capita and the nation's were the same. National total energy use per real dollar of GDP has declined since 1977 when the data first were available. However, the Pacific Northwest's energy use per real dollar of GSP declined faster, and has equaled the nation's since 2001.

The Pacific Northwest remains more electricity intensive than the nation. That is, the share of electricity used to meet all energy needs is higher in the Northwest than it is in the rest of the nation. But that gap has narrowed significantly since 1980. Until 1980 the regional share of end-use energy needs met by electricity, compared to other sources such as oil or natural gas, was nearly double the national share. Both the national and regional shares grew between 1960

and 1980. However after 1980, the national electricity share continued to grow, but the regional share remained stable. By 2006, the regional electricity share in total energy consumption by households and business was 20 percent compared to a national share of 17 percent.

The greater electricity intensity of the Pacific Northwest historically was due in large part to the region's electricity-intensive industries drawn here because of low-cost electricity supplies. The loss of some of these industries has significantly reduced the region's electricity demand. Not only has the region's industrial use been electricity-intensive, the region's residential and commercial energy use also historically has been more electricity-intensive than the rest of the nation. The national electrical intensity of these sectors has grown over the last 45 years, but the region's intensity has remained flat since 1980. Figure 1-1 shows that the region's per capita residential and commercial electricity demand has been higher but its rate stable, whereas the nation's demand has been lower but is growing at a steady rate.

Figure 1-1: Residential and Commercial Electricity Use Per Capita: U.S. versus Region

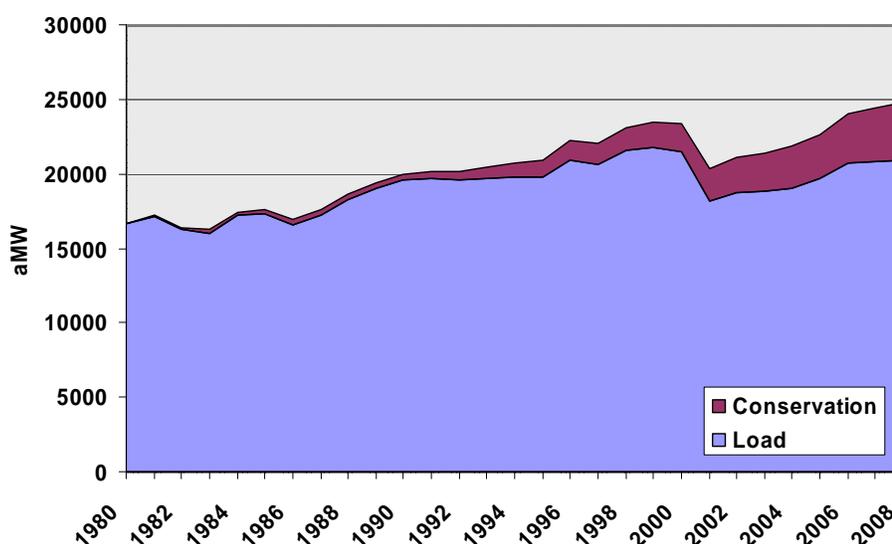


Both regional and national electricity prices have increased over the last 35 years. National prices increased following the oil embargo in 1973, but the region's prices, which were less influenced by changes in oil and natural gas prices, did not escalate rapidly until 1980. During the 1980s and 1990s regional electricity prices remained roughly half of national prices. With the price increases following the Western electricity crisis in 2000-2001, the gap closed some, but as shown in Figure 1-6, the region continues to have significantly lower prices than the nation as a whole.

Although the nation and the region had similar electricity price growth, regional demand per capita stopped growing after 1980 while the nation's continued to grow. What accounts for this difference in response? Part of the explanation is the loss of electricity-intensive industrial sectors. However, the pattern is also evident in the residential and commercial sectors. Part of the pattern can be traced to conversions of space and water heat from electricity to natural gas. Other parts of the country already used natural gas for these services.

Another important factor limiting the region's growth of electricity demand has been its efforts to improve the efficiency of electricity use. Since the Northwest Power Act in 1980, the Pacific Northwest has pursued programs to improve the efficiency of electricity use. By 2008, the region had saved 3,900 average megawatts of electricity as a result of the accumulated effects of Bonneville and utility conservation programs, improved energy codes and appliance-efficiency standards, and market-transformation initiatives. Figure 1-2 shows the effects of these savings over time. These efficiency improvements have met 48 percent of the region's load growth since 1980, and the savings now amount to more than the total electricity use of Idaho and Western Montana combined. Without improved efficiency, the growth of regional electricity use would have been 1.5 percent per year from 1980 to 2008 instead of the 0.8-percent the region experienced during that time.

Figure 1-2: Effects of Conservation on Growth of Demand



The region's historical electricity use has implications for electricity demand forecasts. Because fuel conversions and fewer electricity-intensive industries played an important role in the past stabilization of the electricity intensity of the Pacific Northwest, it may be more difficult to offset growth in the future. Without aggressive conservation efforts, electricity demand may return to growing at the same rate as population and economic activity.

Electricity Generation

A long-term view of electricity generation in the Pacific Northwest reveals a trend of growing diversity of energy sources. In 1960, nearly all electricity was supplied from hydroelectric dams. As Figure 1-3 shows, growth in electric generation needs has been met by other sources, such as coal, nuclear, natural gas, biofuels, and most recently wind power.⁵ These resources weren't developed with diversity in mind; they were developed in phases based what was apparently most attractive at the time. Early diversification from hydroelectricity focused on coal and

⁵ Figure 1-3 shows average annual energy capability. The hydropower numbers are critical-water, and wind assumes a 30-percent capacity factor.

nuclear generation. In the late 1990s and early 2000s natural gas was favored, and most recently wind has been encouraged by economic incentives and state renewable portfolio standards.

But not all growth in electricity consumption has been met by increased generation capability. Figure 1-3 shows conservation as part of the current mix of electricity generating resources. Conservation is the fourth-largest resource meeting the Northwest's electric energy needs, exceeded only by hydropower, coal, and natural gas.

Figure 1-3: Growing Electricity Resource Diversification in the Pacific Northwest

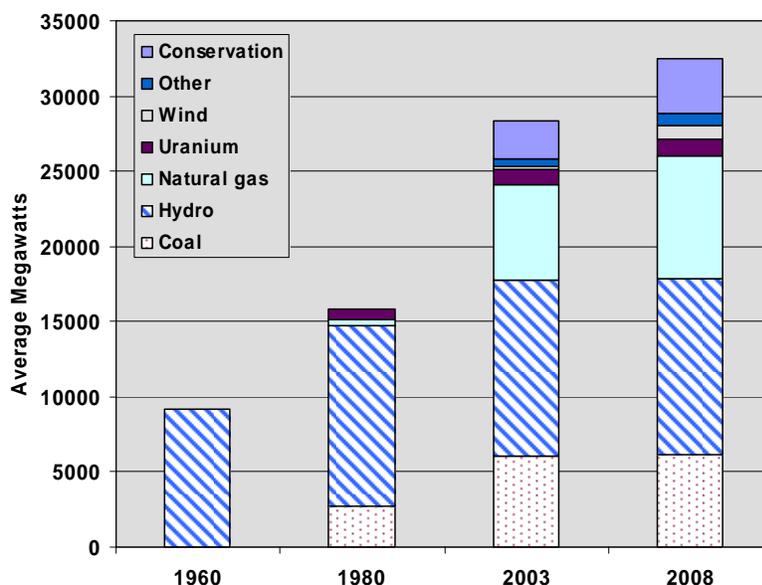
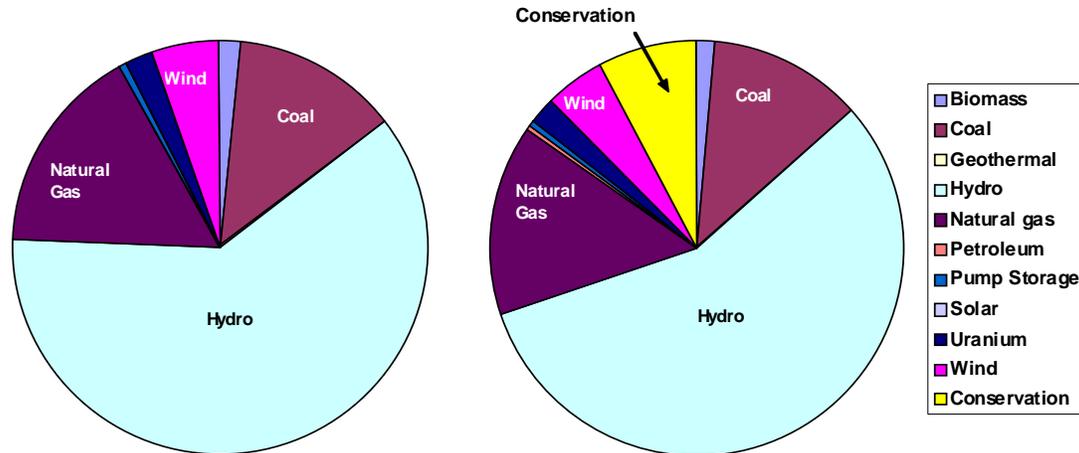


Figure 1-4 shows the mix of electricity capacity in the region.⁶ Capacity refers to the ability to produce energy during peak demand hours. Figure 1-3 shows contributions to “energy,” which refers to the sources of electricity used to meet average demand over a year typically. Compared to the energy mix, installed capacity shows much higher hydropower and wind shares. The left side of Figure 1-4 shows generation only; the right side includes the effect of conservation on peak loads.

However, hourly capacity as shown in Figure 1-4 can be misleading for the assessment of adequacy of electricity supplies. For example wind is a variable resource and has very little dependable capacity value because its generation cannot be counted on reliably over short periods of time. Likewise, the hydroelectric system's capacity value must be reduced because of its limited ability to sustain energy production over several days of high loads. In both cases, the generation that can be counted on is limited by the fuel supply -- that is, by the wind or, in the case of hydroelectric generation, by available water. In April 2008, the Council adopted a resource adequacy standard, which acts as an early warning system to alert the region when the power supply can no longer reliably supply annual energy or peak capacity needs.

⁶ Figure 1-4 shows installed generating capacity of resources. Installed capacity is the maximum amount of energy that could be generated during a peak hour. Dependable capacity is the amount of energy that can be counted on in a peak load hour. In the case of wind generation, dependable capacity is only about 5 percent of the installed capacity shown in Figure 1-4. Conservation has been increased by the system load factor, that is peak energy consumption relative to average annual consumption.

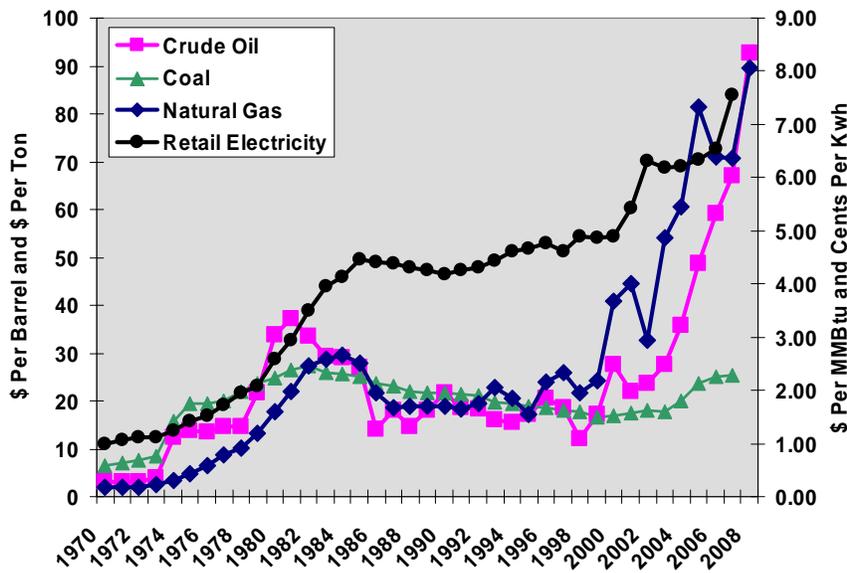
Figure 1-4: Electrical Capacity Resources in the Pacific Northwest

Energy Cost Trends

Energy, like many other commodities, tends to experience price cycles. At the time the Council was developing its first power plan in the early 1980s, energy prices were at a high point. Oil prices were high due to OPEC policies and war in the Middle East. Natural gas prices were high as a result of regulatory policies that impeded development of new supplies. Electricity costs in the Pacific Northwest had just experienced a huge increase due to overbuilding new nuclear generation capacity exacerbated by the high inflation and interest rates of the late 1970s.

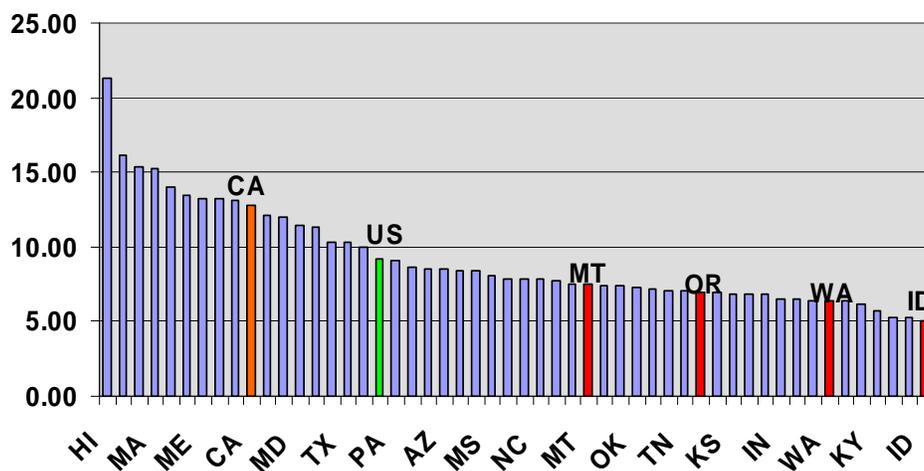
In the mid-1980s fuel prices fell, but retail electricity prices in the region remained high. The new millennium brought another commodity price cycle for oil, natural gas, and coal. For example natural gas prices, which had averaged \$2 per million Btu in the 1990s, increased to an average of nearly \$6 during the first decade of the new millennium. In addition, fuel prices have become more volatile. The wholesale market price of electricity is more closely linked to cycles in fuel prices than in the past because more of the region's generation is based on natural gas and coal now. Figure 1-5 illustrates these historical trends in fuel and electricity prices.

Figure 1-5: Energy Price Trends



In spite of price increases over the past 30 years, the cost of electricity to Pacific Northwest consumers remains lower than costs to consumers in other parts of the country. In 2007, Idaho was the lowest-price state in the nation, Washington rated seventh-lowest, Oregon was 15th, and Montana 22nd. Taken together, retail electricity prices in the four Northwest states in 2007 were a little more than two-thirds of the national average, and only half of electricity prices in California. Although prices have increased substantially since 1980, the Northwest still enjoys relatively low electricity prices.

Figure 1-6: Average Retail Electricity Prices by State, 2007



An important factor in California’s higher electricity prices is the cost of resources for peak demand. California electricity demand is more variable than in the Pacific Northwest. Peak electricity loads in California are about 70-percent higher than average annual electricity use. In comparison, peak loads in the Pacific Northwest are typically 25 percent higher than average

annual electricity use. But more importantly, California uses fuel-based peaking resources to meet its requirements to a much larger extent than in the Pacific Northwest. The capital and fuel costs of these peaking resources must be recovered over very few operating hours a year when they are used to meet these periods of high demand. In the Pacific Northwest, the hydroelectric system provides much of the peaking capacity and ancillary services for the region at very low cost.

The hydropower system's use as a base resource and its inexpensive flexibility together keep Northwest electricity prices low. As the region outgrows the hydropower system's capability to provide peaking and flexibility, other resources will be necessary and the cost of electricity will likely increase. Preservation of the hydropower system's flexibility and capacity is key to keeping Northwest prices low, and also to maintaining a low carbon footprint. Developing cost-effective demand response also can contribute to meeting peak loads and providing flexibility.

A VISION FOR THE SIXTH POWER PLAN

For nearly 30 years, the Council's mission – to assure the region of an adequate, efficient, economical, and reliable power supply, while also protecting, mitigating and enhancing fish and wildlife affected by the Columbia River Basin hydroelectric system – has not changed.

The Northwest's energy environment is complex, and this is a time of profound change. From concerns about the increasing cost of electricity to the effects of greenhouse gases on climate and the operation of the region's hydroelectric and transmission systems to meet peak demand, integrate wind generation, and recover endangered salmon and steelhead, the challenges are many, and they are interrelated.

The Council's Sixth Power Plan recognizes and responds to this new environment. It lays out a strategy for moving toward the power system of the future while maintaining a reliable and affordable system.

How will these challenges be addressed, and what will the energy system of the future look like? The Council's Sixth Power Plan envisions a cleaner and more efficient system for the region, with these attributes:

- Nearly 6,000 average megawatts of achievable energy efficiency that will greatly reduce the Northwest's electricity demand and carbon-dioxide production over the next 20 years.
- Improved operation of the regional power system that will help accommodate diverse and variable-output renewable generation and promote the efficient use and expansion of the regional transmission system.
- Conventional coal plants that will operate with effective carbon-reducing technologies or be displaced by resources that emit less or no carbon.
- Smart grid and other technologies that will make the energy system more efficient and decentralized, maintaining its reliability and safety, and potentially transforming power system operations. It will facilitate instant notification and location of outages, provide

flexibility and energy storage, and help integrate variable-output wind power and plug-in hybrid cars into the regional power system.

- A hydroelectric system whose capability is preserved and improved in order to provide low-cost power for the region, providing both flexibility to help integrate wind and other variable-output resources and improved conditions for salmon and steelhead.
- A regional power system that does its part through the above actions to achieve the carbon-reduction goals that have been adopted by three of the four states in the Pacific Northwest.
- Access by Pacific Northwest citizens to better information about their electricity supply so that they can participate in the formation and implementation of important regional policies.

Today, the road to this vision means addressing many new questions. The Sixth Power Plan is a map to that future.

Chapter 2: Key Assumptions

Summary of Key Findings	1
Introduction.....	2
Economic Growth.....	2
Alternative Economic Scenarios.....	4
Fuel Prices.....	5
Carbon Dioxide Prices	9
Renewable Portfolio Standard Resource Development.....	10
Wholesale Electricity Prices	12
Retail Electricity Prices.....	16
History.....	16
Forecast of Retail Electricity Prices.....	17
Sector Retail Prices	17

SUMMARY OF KEY FINDINGS

Pacific Northwest population and energy costs are expected to increase over the next 20 years. Regional population is likely to increase from 12.7 million in 2007 to 16.7 million by 2030. This 4.0 million increase compares to a 3.8 million increase between 1985 and 2007. The population growth will be focused on older-age categories as the baby-boom generation reaches retirement age. While the total regional population is projected to increase by over 28 percent, the population over age 65 is expected to nearly double. Such a large shift in the age distribution of the population will change consumption patterns and electricity use. Some possible effects could include increased health care, more retirement and elder-care facilities, more leisure activities and travel, and smaller-sized homes.

The cost of energy (natural gas, oil, and electricity) is expected to be significantly higher than during the 1990s. Although prices have decreased significantly since the summer of 2008, current levels, especially for natural gas, are depressed by the effects of the recession. Nonconventional natural gas production has increased in the last few years, encouraged by higher prices. The technology to retrieve these supplies cost-effectively has been a recent development that continues to improve, making expectations for adequate future supplies more certain. Nevertheless, the cost of finding and producing these new supplies is higher than for conventional supplies, which increases the estimated future price trend for natural gas.

Carbon-emission taxes or cap-and-trade policies are likely to raise energy costs further. Wholesale electricity prices are expected to increase from about \$30 per megawatt-hour in 2010 to \$74 per megawatt-hour by 2030 (2006\$). These electricity prices reflect carbon costs that start at zero and increase to \$47 per ton of CO₂ emissions by 2030. Higher electricity prices reduce demand, advance new sources of supply and efficiency, and make cost-effective more efficiency measures.

INTRODUCTION

The Northwest Power Act requires the Council's power plan to include a forecast of electricity demand for the next 20 years. Demand, to a large extent, is driven by economic growth, but it is also influenced by the price of electricity and other fuel.

The power plan treats energy efficiency as a resource for meeting future demand. In order to understand and properly assess its potential, demand forecasts must be developed in great detail considering specific uses of electricity in various sectors. Such assessments require significant detail in their underlying economic assumptions; the number and types of buildings, their electrical equipment, and their current efficiency levels are all critical to accurately assessing potential efficiency improvements.

Most of the assumptions and forecasts for the demand forecast are also important for other parts of the power plan. For example, fuel prices affect not only electricity demand, but also the cost of electricity generation from natural gas, oil, and coal-fired power plants. Because of this, fuel price forecasts help determine the wholesale electricity price and the avoided cost of alternative resources when considering the cost-effectiveness of improved efficiency. In addition, sector-specific economic forecasts of building and appliance stocks, their expected growth over time, and their pattern of energy use over different seasons and times of the day are factors in determining efficiency potential and cost-effectiveness. Basic financial assumptions such as rates of inflation, the cost of capital for investments by various entities, equity-to-debt ratios, and discount rates are used throughout the planning analysis.

For many of these assumptions, there is significant uncertainty about the future. That uncertainty creates risk that is addressed in the Council's power plan. These risks and uncertainty include long-term trends, commodity and business cycles, seasonal variations, and short-term volatility.

ECONOMIC GROWTH

Demand for energy is driven by demand for services needed in homes and places of work. In the long-term, the region's economic growth is a key driver of demand. One general measure of the size of the regional economy is its population. As the regional population increases, the number of households increases, the number of jobs increases, and goods and services produced in the economy increase, all driving the need for energy. This is not to say there is a one-to-one relationship between growth in the economy and growth in demand. Other factors, such as energy prices, technology changes, and increased efficiency can all change the relationship between economic growth and energy use.

The residential demand forecast is driven by the number of homes and the amount and types of appliances they contain. Commercial sector demand is determined by square feet of buildings of various types, and industrial demand depends on projections of industrial output in several manufacturing sectors. The expected electricity use in aluminum smelters is forecast independently. A brief overview of the forecast assumptions for each of the key economic drivers of demand follows:

Population. Population in the Northwest states grew from about 8.9 million in 1985 to about 13 million in 2007, increasing at about 1.6 percent per year. The growth in population is projected

to slow to about 1.2 percent annually, resulting in a total regional population of 16.7 million by 2030.

Homes. The number of homes is a key driver of demand in the residential sector. Residential units (single family, multifamily, and manufactured homes) are forecast to grow at 1.4 percent annually from 2010-2030. The current (2008) stock of 5.7 million homes is expected to grow to 7.6 million by 2030, or approximately 83,000 new homes per year.

Appliances. In the residential sector, lifestyle choices affect demand. As more homes are linked to the Internet, and as the saturation rate for air conditioning and electronics increases, residential sector demand increases. Over 80 percent of all new homes in the region now have central air conditioning, and the growth rate in home electronics has been phenomenal--over 6 percent per year since 2000, and it is expected to continue growing at about 5 percent per year.

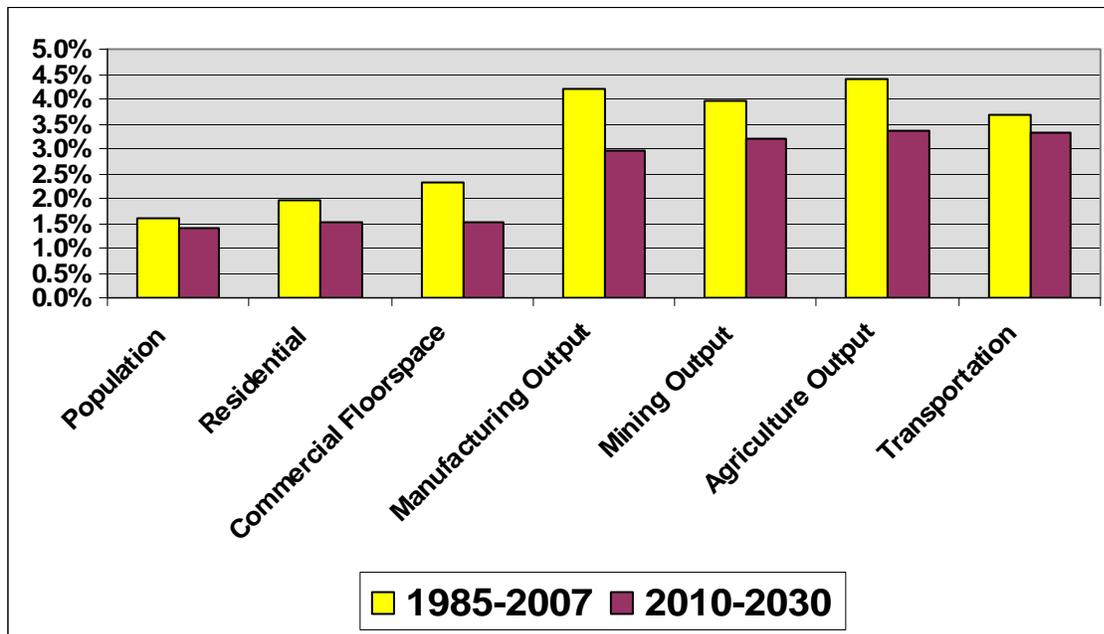
Commercial Square Footage. Demand for electricity in the commercial sector is driven by demand for commercial floor space that requires lighting, air conditioning, and services to make occupants comfortable and productive. The square footage of commercial buildings is forecast to grow at 1.2 percent annually from 2010-2030. The current 2007 commercial building stock of 2.9 billion square feet is expected to grow to 3.9 billion square feet by 2030, or at a rate of about 40 million square feet per year. A growing portion of this commercial floor space is for elder-care facilities.

Industrial Output. The key driver of demand for the industrial and agricultural sectors is dollars of value added (a measure of output) in each industry. Industrial output is projected to grow at 3 percent per year, growing from \$83 billion (2006 constant dollars) in 2007 to \$149 billion by 2030. Agricultural output, which drives irrigation electricity use, is projected to grow at 3.2 percent per year, from \$13 billion (2006 constant dollars) in 2007 to \$25 billion by 2030.

Direct Service Industries. Demand for Bonneville's direct service industries (mainly aluminum smelting operations) is projected to be nearly constant, rising from 764 average megawatts in 2007 to 770 average megawatts in 2012, and then remaining constant from 2012 through 2030.

The main source of data for the economic drivers is HIS Global Insight's quarterly forecast of the national and regional economy and Global Insight's U.S. business demographic forecast. Third quarter 2009 data was used in developing the Council's Sixth Power Plan. The Council's financial assumptions, such as the inflation rate, are also drawn from the same economic forecast. Figure 2-1 shows both the historic and medium case growth rate assumed for the development of the Sixth Power Plan. In general, the medium forecast reflects a slowdown in key economic drivers compared to the last 20 years. The impact of the current recession was incorporated into the plan using Global Insight's long-term October 2009 forecast.

Figure 2-1: Comparison of Key Economic Drivers



Alternative Economic Scenarios

Three alternative scenarios are considered in the demand forecast. In the medium-case scenario, the key economic drivers project a long-term, healthy regional economy (albeit with a slower growth rate than in the recent past). In addition to the medium case, two alternative scenarios are considered: one representing a low-economic-growth scenario and the other a high-growth projection of the future. The low-case scenario reflects a future with slow economic growth, weak demand for fossil fuel, declining fuel prices, a slowdown in labor productivity growth, and a high inflation rate. On the other hand, the high-case scenario assumes faster economic growth, stronger demand for energy, higher fossil fuel prices, sustained growth in labor productivity, and a lower inflation rate.

It is assumed in the medium, low, and high scenarios that climate change concerns and demand for cleaner fuel lead to a carbon tax, which pushes fuel prices to a higher trajectory. Table 2-1 summarizes the average growth rate for key inputs in each of the alternative scenarios.

Table 2-1: Historic, Medium-Case, and Alternative Scenarios for Growth Rates

Key Economic Drivers	1985-2007 (Actual)	2010-2030 (Low)	2010-2030 (Medium)	2010-2030 (High)
Population	1.60%	0.49%	1.20%	1.5%
Residential Units	1.90%	0.49%	1.40%	1.5%
Commercial Floor Space	2.30%	0.67%	1.20%	1.43%
Manufacturing Output \$	4.10%	0.00%	1.70%	2.11%
Agriculture Output \$	4.40%	3.0%	3.60%	4.2%
Light Vehicle Sales	-	2.52%	2.40%	3.05%
Inflation Rate	2.20%	2.70%	1.70%	1.50%
Average Annual Growth Rate in Price (2010-2030)*				
Oil Prices	1.70%	-1.00%	1.04%	2.30%
Natural Gas Prices	1.80%	0.90%	2.80%	3.50%
Coal Prices	-4.80%	-0.50%	0.50%	1.20%

* Fuel price assumptions are consistent with the Council's fuel price and electricity price forecast.

FUEL PRICES

The future prices of natural gas, coal, and oil have an important effect on the Council's power plan. As the Pacific Northwest's electricity system has diversified beyond hydropower, it has become more connected to national and global energy markets. Fuel price assumptions affect demand, choice of fuel, and the cost of electricity generation. The effect on demand is primarily through retail natural gas prices to consumers, but natural gas prices may also affect electricity consumption because of its effect on cost. Oil and coal are not used extensively by end users in the Pacific Northwest. Coal is, however, an important fuel for electricity generation; it affects the wholesale market price of electricity in some hours and the overall cost of electricity for utilities that rely on coal-fired generation.

The connection between fuel costs and electricity planning has been strengthened by changes in energy regulation and the development of active trading markets for energy commodities. Less regulation and mature commodity markets have also made the price of energy more volatile. The volatility of natural gas prices, in particular, is an important factor when considering the use of natural gas for electricity generation. Price volatility creates risks that the Council evaluates in developing a resource plan.

Because natural gas is the primary energy source affecting both the demand and supply of electricity, forecasts of natural gas prices receive far more detailed attention than oil or coal prices. Fuel price forecasts start with global, national, or regional energy commodity prices, depending on the fuel. Oil is a global commodity, natural gas is still primarily a North American commodity (although this could change as liquefied natural gas imports grow), and coal prices tend to be regional in nature. All of these commodities have experienced periods of high and volatile prices since the Fifth Power Plan was issued in 2004. Natural gas prices have collapsed since the summer of 2008. This reduction in price is partly due to natural supply-and-demand responses to a period of high prices, but also to a great extent is a result of the current recession

and financial crisis.¹ The Council's forecast of natural gas prices assumes prices will rebound from recent recession-induced lows.

Long-term fuel price trends are uncertain, as reflected in a wide range of assumptions. The Council's power plan reflects three distinct types of uncertainty in natural gas prices: 1) uncertainty about long-term trends; 2) price excursions due to supply-and-demand imbalances that may occur for a number of years; and 3) short-term and seasonal volatility due to such factors as temperatures, storms, or storage levels. This section discusses only the first uncertainty. Shorter-term variations are addressed in the Council's portfolio model analysis as discussed in Chapter 9.

The high and low forecasts are intended to be extreme views of possible future prices from today's context. The high case wellhead natural gas price increases to \$9 by 2025 and increases to \$10 by 2030. The Council's forecasts assume that rapid world economic growth will lead to higher energy prices, even though the short-term effects of a rapid price increase can adversely affect the economy. For the long-term trend analysis, the need to expand energy supplies, and its effect on prices, is considered the dominant factor. The high natural gas scenario assumes rapid world economic growth. This scenario might be consistent with very high oil prices, high environmental concerns that limit use of coal, limited development of world liquefied natural gas (LNG) capacity, and slower improvements in drilling and exploration technology, combined with the high cost of other commodities and labor necessary for natural gas development. It is a world where both alternative sources of energy and opportunities for reduced demand are limited.

The low case assumes slow world economic growth that reduces the pressure on energy supplies. Wellhead natural gas prices in the low case fall to levels between \$4 and \$5 per million Btu; still double the prices during the 1990s. It is a future where world supplies of natural gas are made available through the aggressive development of LNG capacity, favorable nonconventional supplies and the technologies to develop them, and low world oil prices that provide an alternative to natural gas use. The low case would also be consistent with a scenario of rapid progress in renewable generating technologies, reducing demand for natural gas. In this case, the normal increases in natural gas use in response to lower prices would be limited by aggressive carbon-control policies. It is a world with substantial progress in efficiency and renewable technologies, combined with more stable conditions in the Middle East and other oil- and natural gas-producing areas.

Many of the assumptions that lead to high or low fuel prices are independent of one another or have offsetting effects. Those conditions lead to the medium-fuel-price cases being considered more likely. Figures 2-2 through 2-4 illustrate the forecast ranges for natural gas, oil, and Powder River Basin (Wyoming) coal prices compared to historical prices. Tables 2-2 through 2-4 show the forecast values for selected years. Appendix A provides a detailed description of the fuel price forecasts.

¹ The fuel price forecast used for the plan does not completely reflect the current recession and the recent collapse in commodity prices. Therefore, the near-term prices through 2012 are likely higher than the most likely range. These short-term differences are not expected to affect the Council's resource portfolio or planning results significantly, but will be modified for the final power plan.

Most of the cases show fuel prices increasing from their recent depressed levels in the early years of the forecast. Following this near-term recovery, longer-term trends in most of the cases show real fuel prices increasing gradually. All prices, even in the lowest cases, remain well above prices experienced during the 1990s.

The fuel-price-forecast ranges are both higher and broader than the Council’s Fifth Power Plan, reflecting greater uncertainty about long-term trends. The smooth lines for the price forecasts should not be taken as an indication that future fuel prices will be stable. Price cycles and volatility will continue. These variations, and the risks they impose, are introduced into the Council’s planning by the Resource Portfolio Model analysis.

Figure 2-2: U.S. Wellhead Natural Gas Prices: History and Forecast Range

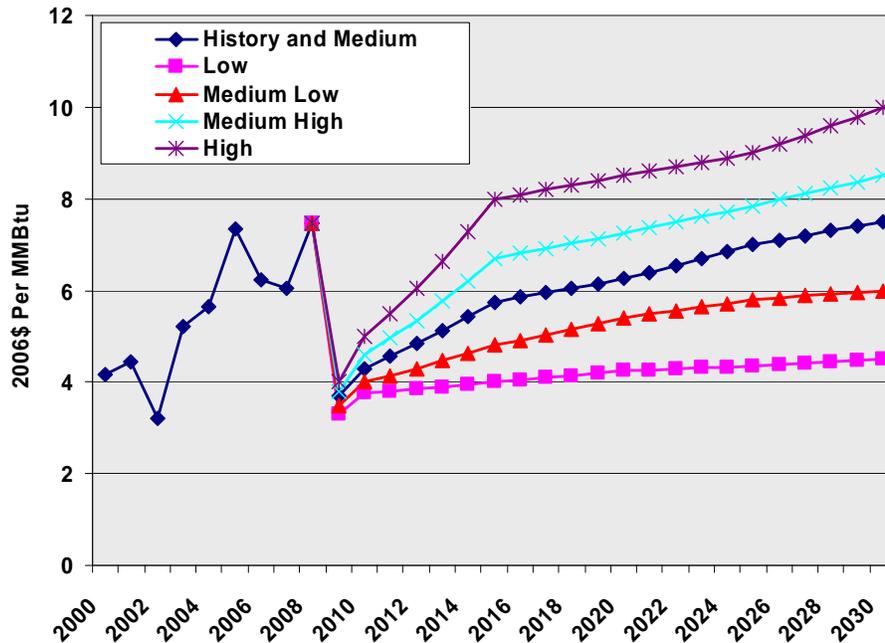


Table 2-2: U.S. Wellhead Natural Gas Price Forecast Range (2006\$ per MMBtu)

	Low	Medium Low	Medium	Medium High	High
2008			7.47		
2010	3.75	4.00	4.30	4.60	5.00
2015	4.00	4.80	5.75	6.70	8.00
2020	4.25	5.40	6.25	7.25	8.50
2025	4.35	5.80	7.00	7.85	9.00
2030	4.50	6.00	7.50	8.50	10.00
Growth Rates					
2007 - 15	-7.51%	-5.38%	-3.22%	-1.35%	0.86%
2007 - 30	-2.18%	-0.95%	0.02%	0.56%	1.22%

Figure 2-3: World Oil Prices: History and Forecast Range

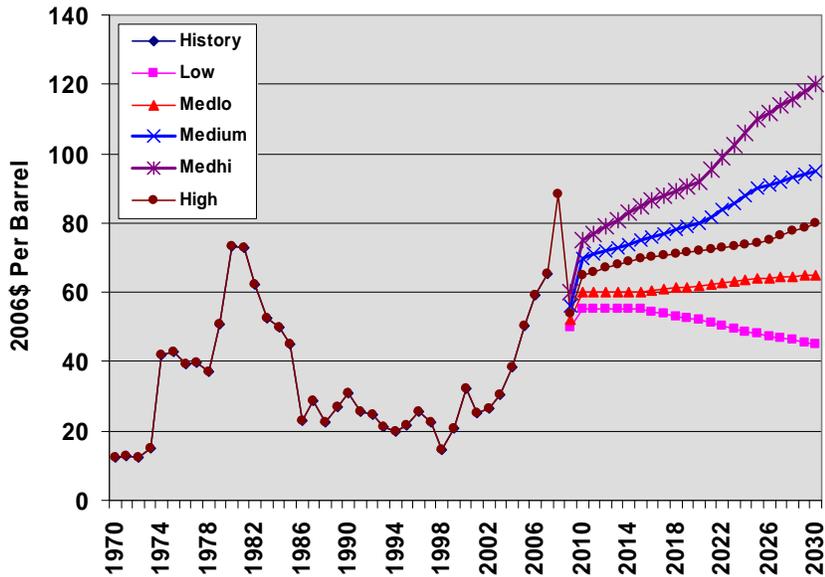


Table 2-3: World Oil Price Forecast Range (2006\$ per Barrel)

	Low	Medium Low	Medium	Medium High	High
2007			65.29		
2008			88.42		
2010	55.00	60.00	65.00	70.00	75.00
2015	55.00	60.00	70.00	75.00	85.00
2020	52.00	62.00	72.00	80.00	92.00
2025	48.00	64.00	74.00	90.00	110.00
2030	45.00	65.00	80.00	95.00	120.00
Growth Rates					
2007 - 15	-2.12%	-1.05%	0.88%	1.75%	3.35%
2007 - 30	-1.60%	-0.02%	0.89%	1.64%	2.68%

Figure 2-4: Powder River Basin Minemouth Coal Prices: History and Forecast

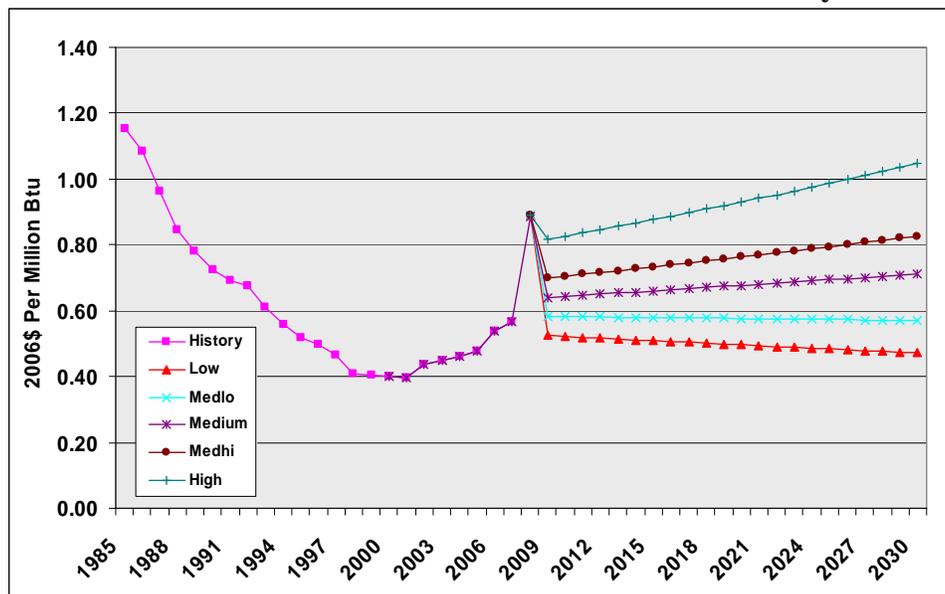


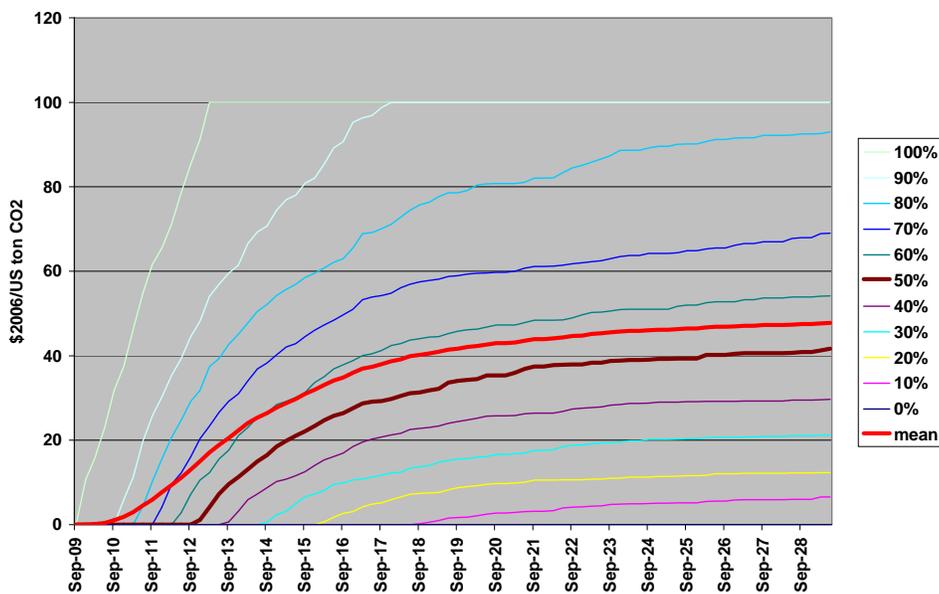
Table 2-4: Powder River Basin Minemouth Coal Price Forecasts (2006\$ per MMBtu)

	Low	Medium Low	Medium	Medium High	High
2007	-	-	0.56	-	-
2010	0.52	0.58	0.64	0.70	0.83
2015	0.51	0.58	0.66	0.73	0.88
2020	0.50	0.58	0.68	0.76	0.93
2025	0.48	0.57	0.69	0.79	0.99
2030	0.47	0.57	0.71	0.83	1.05
Growth Rates					
2007-2015	-1.29%	0.32%	1.98%	3.33%	5.65%
2007-2030	-0.78%	0.05%	1.01%	1.67%	2.73%

CARBON DIOXIDE PRICES

The risk of carbon-pricing policies is one of the key uncertainties addressed in the Council’s Sixth Power Plan. Such policies have been proposed by the Western Climate Initiative and in proposed federal legislation. Whether, when, and at what level such policies might be implemented are all unknown at this time. Therefore, the plan treats these policies as a risk that should be considered in making electric resource choices made for the region.

The carbon risk scenario captures the carbon pricing risk by modeling both the adoption of a policy and the amount of the carbon price, or penalty, as random variables. The carbon price can be thought of as a carbon tax or the cost of a carbon-emission allowance under a cap-and-trade system. Once a carbon-pricing policy is implemented, the price is assumed to fall between \$0 and \$100 per ton of carbon emissions. The modeling approach is described in Chapter 9. Figure 2-5 shows a decile chart of the range of resulting carbon prices. The average of the carbon prices begins at zero and increases to above \$40 by midway through the forecast period ending at \$47 per ton in 2030.

Figure 2-5: Decile Chart of Carbon Prices Used in the Carbon Risk Analysis

The choice of the range of carbon prices to be considered was informed by research and review of the results of studies done by various organizations on the likely cost of carbon allowances that would result under various cap-and-trade policies. The Council commissioned a study by EcoSecurities Consulting Limited to review the literature on carbon-pricing studies and develop a range of likely prices under different policy scenarios. The range of estimates is very wide. Results depend on the study methodology, the carbon-reduction targets assumed, and the assumed scope and role of carbon-credit trading. However, the bulk of the estimates fell between \$10 and \$100 per ton of CO₂. Understanding that there is some chance that no carbon pricing policy will be agreed on, the Council used a range from \$0 to \$100 for its carbon-risk analysis.

In addition to this range of prices, a number of fixed-price levels and other price ranges were explored in the draft and final plan. The Council is not taking a position on carbon policy for the region by exploring various levels of carbon prices. The analysis is intended to provide information on what would be required to meet existing goals in some states, and to provide information to the region on possible actions to mitigate the risks of unknown future carbon-pricing policies. Chapters 10 and 11 discuss climate change analysis and issues further.

RENEWABLE PORTFOLIO STANDARD RESOURCE DEVELOPMENT

Renewable resource portfolio standards (RPS) mandating the development of certain types and amounts of resources have been adopted by eight states within the Western Electricity Coordinating Council region: Arizona, California, Colorado, Montana, New Mexico, Nevada, Oregon, and Washington². In addition, British Columbia has adopted an energy plan with

² Utah's *Energy Resource and Carbon Emission Reduction Initiative* adopted in 2008 has characteristics of a renewable portfolio standard, but mandates acquisition of qualifying resources only if cost-effective. Because

conservation and renewable-energy goals similar to an RPS. RPS laws are complex with great variation between states regarding target amounts, qualifying resources, resource “set-asides,” existing resource qualification, in-state credits, price caps, and other provisions. State-by-state assumptions used for this forecast are described in Appendix D.

Mandatory development of low-variable-cost renewable resources can significantly affect wholesale power prices and the need for discretionary resources. A forecast of the types of renewable resources that may be developed and the success in achieving the targets is needed for the wholesale-power price forecast and the resource-portfolio analysis. The resulting estimate of need for new renewable energy to meet state RPS obligations is provided in Table 2-5.

Table 2-5: Estimated Committed and Forecast Incremental RPS Generating Resource Requirements (MWa)

	AZ	BC	CA (33%)	CO	MT	NM	NV	OR	WA
Committed	87	366	3954	454	65	111	273	465	520
Cumulative new (100% achievement of standards)									
2010	32	0	425	0	0	0	21	0	0
2011	77	0	1,068	0	0	0	63	0	0
2012	115	0	1,774	0	19	0	137	0	0
2013	157	0	2,416	0	24	112	277	0	0
2014	196	17	2,863	280	31	147	339	0	218
2015	240	85	3,329	368	37	184	452	0	367
2016	313	136	3,401	450	37	214	463	0	511
2017	390	185	3,477	537	37	243	496	0	662
2018	471	239	3,551	626	37	273	508	0	812
2019	555	296	3,602	718	37	304	524	0	958
2020	642	351	3,674	813	37	335	537	0	953
2021	733	406	3,745	836	37	341	551	0	941
2022	826	462	3,816	860	37	346	566	478	939
2023	925	520	3,885	885	37	353	580	538	939
2024	1,027	579	3,954	910	37	359	595	599	941
2025	1,134	638	4,026	935	38	366	610	662	944
2026	1,163	698	4,099	961	38	372	626	670	950
2027	1,192	758	4,171	987	39	379	641	677	956
2028	1,223	819	4,244	1,014	39	385	657	685	965
2029	1,254	882	4,318	1,041	40	392	672	697	977
Total	1,341	1,248	8,272	1,495	105	503	945	1,162	1,497

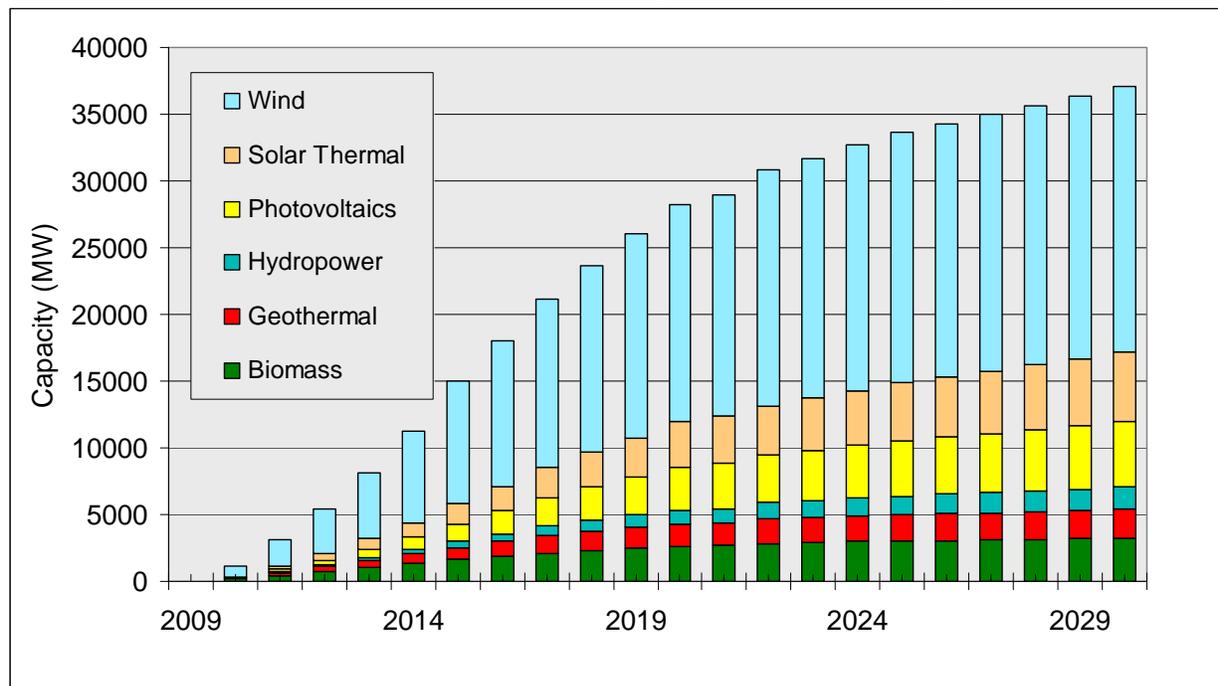
Table 2-5 shows the estimated qualifying energy needed to fully achieve current renewable portfolio standards. Because of price caps and other limiting factors, the forecast used for this plan assumes 95 percent achievement of standards. All energy from potentially qualifying existing capacity is assumed to be credited. Energy-efficiency measures, in states where credited, are assumed to be employed to the extent allowed. The remaining generating resource obligations (i.e., 95 percent of the new energy of Table 2-6) will be met by a mix of new resources, determined by state-specific resource eligibility criteria, new resource availability, resource cost, RPS policies governing use of out-of-state resources, state-specific resource set-asides and special credit and other factors. The resource mix in the near-term was assumed to resemble the mix of recent qualifying resource development. Over the planning period,

resource acquisitions based on cost-effectiveness are simulated by the capacity expansion logic of the AURORA^{xmp}® Electricity Market Model used for the wholesale power price forecast, it was not necessary to separately forecast renewable resource development for Utah.

development is assumed to shift toward locally abundant, but relatively undeveloped resources such as solar thermal. Figure 2-6 illustrates the assumed incremental capacity additions needed to provide 95 percent of the cumulative energy requirements of Table 2-5.

To simplify the forecast, the Council assumed that all new resource requirements would be met in-state, although it is clear that states such as California, with substantial need for qualifying RPS resources, will secure much of its RPS needs from out-of-state sources.

Figure 2-6: Forecast RPS capacity by resource type



WHOLESALE ELECTRICITY PRICES

The Council prepares and periodically updates a 20-year forecast of wholesale electric power prices, representing the future price of electricity traded on the wholesale, short-term (spot) market at the Mid-Columbia trading hub. The forecast establishes benchmark capacity and energy costs for conservation and generating resource assessments and serves as the equilibrium wholesale power prices for the Resource Portfolio Model. In addition, the forecast is used for the ProCost model to assess the cost-effectiveness of conservation measures. The Council's electricity price forecast is also used by other organizations for assessing resource cost-effectiveness, developing resource plans, and for other purposes.

An overview of the development of the wholesale electricity price forecast and a summary of the results are provided in this section. A complete description is provided in Appendix D.

The Council uses the AURORA^{xmp}® Electricity Market Model³ to forecast wholesale power prices. Electricity prices are based on the variable cost of the most expensive generating plant or

³ Supplied by EPIS, Inc. (www.epis.com)

increment of load curtailment needed to meet load for each hour of the forecast period. AURORA^{xmp®}, as configured by the Council, simulates plant dispatch in each of 16 load-resource zones making up the Western Electricity Coordinating Council (WECC) electric reliability area. The Northwest is defined as four of these zones: Western Oregon and Washington; Eastern Oregon and Washington, Northern Idaho and Western Montana; Southern Idaho; and Eastern Montana. The 16 zones are defined by transmission constraints and are each characterized by a forecast load (net of conservation), existing generating units, scheduled project additions and retirements, fuel price forecasts, load curtailment alternatives, and a portfolio of new-resource options. Transmission interconnections between the zones are characterized by transfer capacity, losses, and wheeling costs. The demand within a load-resource zone may be served by native generation, imports from other zones, or (rarely) load curtailment.

Three factors are expected to significantly influence the future wholesale power market: the future price of natural gas; the future cost of carbon dioxide (CO₂) production; and renewable resource development associated with state renewable portfolio standards (RPS). These factors will affect the variable cost of the hourly marginal resource and hence the wholesale power price.

Because natural gas is a relatively expensive fuel, natural gas-fired plants are often the marginal generating unit, and therefore determine the wholesale price of electricity during most hours of the year. CO₂ allowance prices or taxes will raise the variable cost of coal-fired units more than that of gas-fired units because of the greater carbon content of coal. Lower CO₂ costs will raise the variable cost of both gas and coal units, but not enough to push coal above gas to the margin. High CO₂ costs will move coal to the margin, above gas. In either case, the variable cost of the marginal unit will increase. As described earlier in this chapter, state renewable portfolio standards are expected to force the development of large amounts of wind, solar, and other resources with low-variable costs, in excess of the growth in demand. This will force fossil-fueled generators with lower variable costs to the margin, tending to reduce market prices.

A base case forecast, four sensitivity studies, and two bounding-scenario cases were run. The base forecast assumes medium-case fuel prices and mean CO₂ prices. All forecast cases assume 95-percent achievement of state renewable portfolio standards, average hydropower conditions, medium load growth and achievement of all cost-effective conservation. The changing case assumptions are shown in Table 2-6.

Table 2-6: Price Forecast Case Changing Assumptions

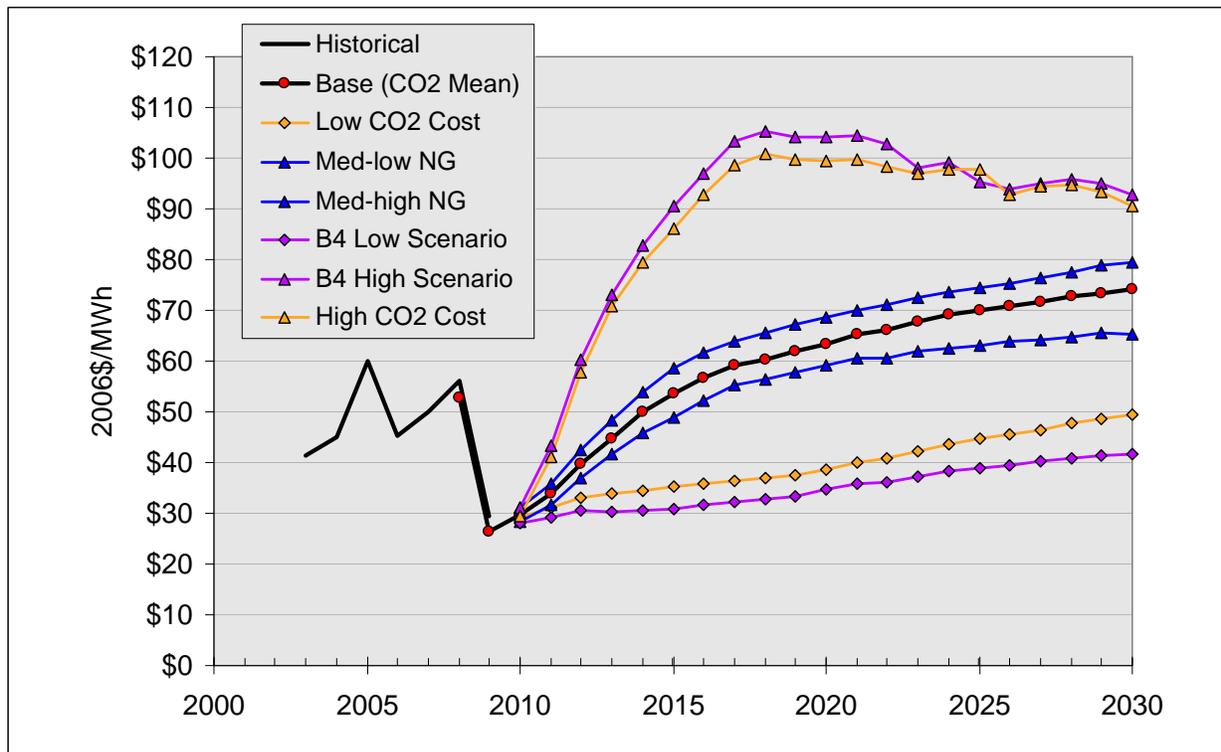
Case	Fuel Prices	CO ₂ Cost
Base (mean CO₂)	Medium Case	Mean
Low CO₂ Cost	Medium Case	90% prob. of exceedance decile
High CO₂ Cost	Medium Case	10% prob. of exceedance decile
Medium-Low Natural Gas	Medium-low NG	Mean of RPM cases
Medium-High Natural Gas	Medium-high NG	Mean of RPM cases
Low Scenario	Medium-low NG	90% prob. of exceedance decile
High Scenario	Medium-high NG	10% prob. of exceedance decile

For the base forecast, wholesale power prices at the Mid-Columbia trading hub are projected to increase from \$30 per megawatt-hour in 2010 to \$74 per megawatt-hour in 2030 (in real 2006 dollar values). For comparison, Mid-Columbia wholesale power prices averaged \$56 per megawatt-hour in 2008 (in real 2006 dollars), dropping abruptly to \$29 in 2009 with the collapse

of natural gas prices and reduction of demand due to the economic downturn. The levelized present value of the 2010-29 base case forecast is \$56 per megawatt-hour.

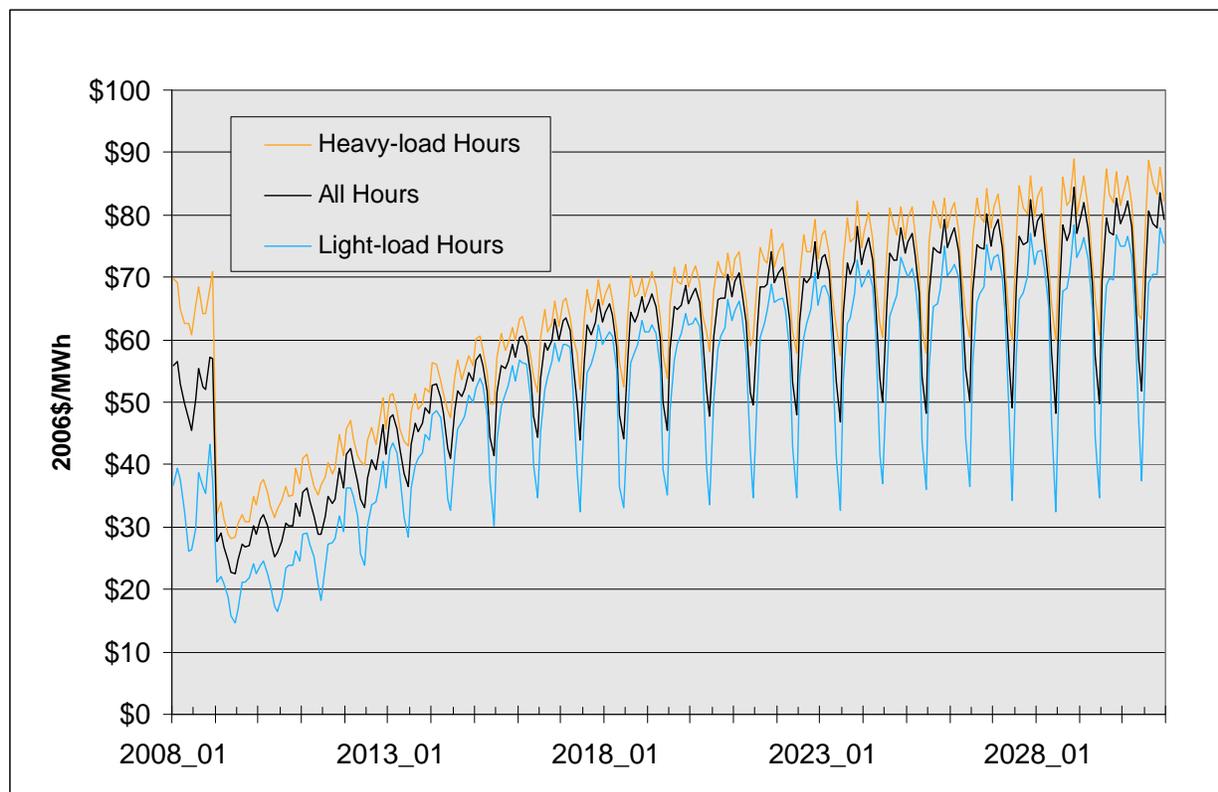
Figure 2-7 illustrates recent and forecast wholesale power prices for the various cases. Comparing the shape of the power price forecasts with the mean CO₂ price forecast of Figure 2-5 clearly demonstrates the significant effect of CO₂ costs on prices. This is particularly evident in the high CO₂ and high-scenario cases. In these cases, prices rise rapidly early in the planning period as CO₂ prices increase, then stabilize and decline as CO₂ prices reach a steady-state of \$100/ton of CO₂ and additional low-carbon resources are deployed.

Figure 2-7: Historical and Forecast Annual Average Mid-Columbia Wholesale Power Prices



Northwest electricity prices tend to exhibit a seasonal pattern associated with spring runoff in the Columbia River Basin and lower loads as the weather moderates. The forecasts exhibit this pattern when viewed on a monthly average basis. Figure 2-8 shows the monthly average heavy-load hours, all-hours, and light-load-hours prices for the base forecast. A flattening of prices during high-runoff, lower-load seasons, becoming evident in the mid-term of the planning period, is likely attributable to the increasing proportion of must-run resources with low variable costs.

The levelized 2010-29 forecast values and values for selected years are shown in Table 2-7. The full monthly price series are provided in Appendix D.

Figure 2-8: Monthly Average Base Case (Mean CO₂) Forecast of Mid-Columbia Wholesale Power Prices**Table 2-7: Forecast of Mid-Columbia Wholesale Power Prices (2006\$/MWh)**

	Base	Low-CO ₂	High CO ₂	Med-Low NG	Med-High NG	Low Scenario	High Scenario
2010	\$30	\$29	\$29	\$28	\$31	\$28	\$31
2015	\$54	\$35	\$86	\$49	\$59	\$31	\$90
2020	\$63	\$39	\$99	\$59	\$69	\$35	\$104
2025	\$70	\$45	\$98	\$63	\$74	\$39	\$95
2030	\$74	\$49	\$91	\$65	\$79	\$42	\$93
Levelized (2010-29)	\$56	\$38	\$82	\$51	\$60	\$34	\$85
Growth Rates							
2010-2029	4.4%	4.6%	2.6%	5.9%	4.3%	4.7%	2.0%

Forecast wholesale power prices have often been used to determine the avoided cost of new resources. Wholesale energy price forecasts, in general, must be used with caution in setting avoided costs because of capacity and risk considerations. However, this price forecast in particular is not a suitable stand-alone measure of avoided resource costs.⁴ This is because the Northwest, with the exception of Southern Idaho, enters the planning period with an energy

⁴ Market price adders representing the risk mitigation and capacity value of specific resource types can be calculated. The resulting sum of energy market prices, capacity credit and risk mitigation credit represents the avoided cost of the resource in question. This is the approach taken in this plan to establish the value of energy efficiency measures.

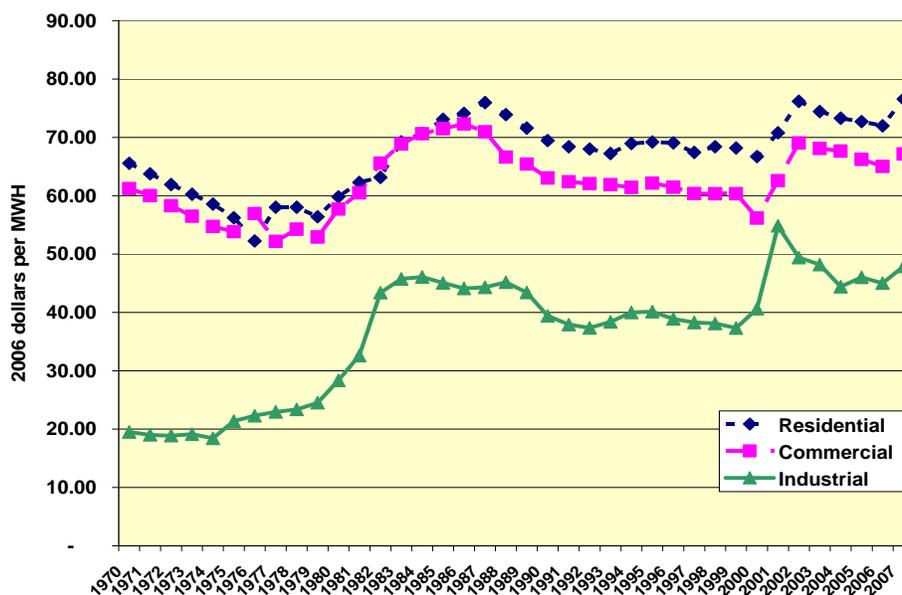
surplus, and remains so throughout the planning period because of the addition of resources to meet renewable-resource-portfolio requirements. Because of this continuing surplus, no discretionary (non-RPS) resources are added by the model and therefore the resulting energy prices do not reflect the avoided cost of any new resource. The actual avoided-resource costs for the three Northwest states with renewable portfolio standards are the costs of the renewable resources added to meet RPS requirements and any capacity additions needed to supply balancing reserves (balancing-reserve requirements are not tracked in the model). Southern Idaho is the exception. Here, about 570 megawatts of simple-cycle gas turbines are added during the planning period to maintain capacity reserves. Because this capacity only contributes incidental energy, even the energy price forecast for Southern Idaho does not represent the avoided cost of needed resources.

RETAIL ELECTRICITY PRICES

History

In the first half of the 1970s, consumers in the Northwest experienced declining electricity prices. However, by mid-1970 and into the 1980s, the region experienced dramatic increases in the price of electricity, followed by an economic recession that hit the region particularly hard. In the latter half of the 1980s, electricity prices began a decade-long decline, in real (inflation-adjusted) terms. But in late 2000, the region again experienced large increases in the price of energy, accompanied by a moderate recession. Since the sharp increase in 2000, electricity prices have stabilized, and even declined in inflation-adjusted prices. However, since 2006, another round of more moderate price increases has begun to be reflected in increases in fuel prices and other commodities. Figure 2-9 illustrates this price history.⁵

Figure 2-9: Average Retail Electricity Price by Sector (2006\$/MWh)



⁵ Prices in Figure 2-7 are expressed in constant year 2006 dollars, as are many other tables and graphs throughout the plan.

Forecast of Retail Electricity Prices

Typically, the price of electricity for investor-owned utilities is determined through a regulatory-approval process, with utilities bringing a rate case to their regulatory authority and seeking approval of future rates. Future rates depend on the cost of serving electricity to customers and the level of sales. The approved rates should cover the variable *and* fixed-cost components of serving customers, plus a rate of return on invested capital. For customer-owned utilities, rates are set by elected boards to recover the costs of serving the electricity needs of their customers.

The methodology used for forecasting future electricity prices in the Sixth Power Plan is a simplified approach, where fixed and variable costs of the power system are estimated for each period and then divided by the volume of sales of electricity. The annual growth rate in average revenue requirement derived from the least-risk plan was applied to sector-level electricity prices.

Sector Retail Prices

The estimated price of electricity by sector and state is presented in Tables 2-8 through 2-10. The annual real growth rate of electricity prices is expected to be about 1 percent per year for the 2010-2030 period. It should be noted that these forecasts are at the state level, and within each state, individual electric utility rates may be higher or lower than the figures presented here. Also, individual utilities may have significantly higher or lower rate increases than these average statewide figures would indicate.

Table 2-8: Price of Electricity for Residential Customers (2006\$/MWh)

	Oregon	Washington	Idaho	Montana
1985	74	60	68	74
2005	75	68	65	84
2010	89	79	74	96
2015	101	90	83	109
2020	109	97	90	117
2030	108	96	89	116
Annual Growth				
1985-2000	-0.3%	0.0%	-0.3%	0.1%
2000-2007	2.9%	3.9%	0.3%	2.7%
2010-2030	1.0%	1.0%	1.0%	1.0%

Table 2-9: Price of Electricity for Commercial Customers (2006\$/MWh)

	Oregon	Washington	Idaho	Montana
1985	81	57	65	67
2005	67	65	56	77
2010	79	71	60	89
2015	89	80	67	101
2020	97	86	73	109
2030	93	83	70	104
Annual Growth				
1985-2000	-1.3%	-0.2%	-1.2%	-0.4%
2000-2007	3.2%	3.6%	-0.3%	3.5%
2010-2030	1.0%	1.0%	1.0%	1.0%

Table 2-10: Price of Electricity for Industrial Customers (2006\$/MWh)

	Oregon	Washington	Idaho	Montana
1985	56	34	42	40
2005	50	44	40	50
2010	51	55	45	60
2015	58	62	51	67
2020	63	67	55	73
2030	60	64	53	70
Annual Growth				
1985-2000	-1.3%	0.6%	-0.6%	0.7%
2000-2007	4.8%	3.2%	-0.1%	8.1%
2010-2030	1.0%	1.0%	1.0%	1.0%

Chapter 3: Electricity Demand Forecast

Summary of Key Findings	1
Introduction.....	2
Historic Demand Growth.....	2
Sixth Power Plan Demand Forecast.....	4
Demand Forecast Range	4
Sectoral Demand.....	5
Load Forecast and Peak Load.....	6
Peak Load.....	6
Load Forecast Range.....	7
Alternative Load Forecast Concepts.....	8
Portfolio Model Analysis of Non-DSI Load.....	10
Impact on Revenue Requirement.....	11
Demand From Plug-in Hybrid Electric Vehicles (PHEV).....	12
Opportunities and Challenges	14
Environmental Impacts	15
Assessment of Needs - Utility Perspective	16
Annual Needs.....	16
Hourly Needs	18
Annual Load Forecast Tables	21

SUMMARY OF KEY FINDINGS

The Pacific Northwest consumed 19,000 average megawatts or 166 million megawatt-hours of electricity in 2007. That demand is expected to grow to 25,000 average megawatts by 2030 in the Council's medium forecast. Between 2009 and 2030, load is expected to increase by a total of 7,000 average megawatts, growing on average by about 335 average megawatts, or 1.4 percent, per year.¹ This forecast has been influenced by expected higher electricity prices that reflect a rapid rise in fuel prices and emerging carbon-emission penalties. For example, residential consumer retail electricity prices are expected to increase by 1.0 percent per year in addition to general inflation. If achieved, cost-effective efficiency improvements identified in the Sixth Power Plan will help to meet a substantial portion of this projected demand growth.

The electricity demand increase is driven primarily by significant growth in two areas: home electronics and elder-care facilities. Demand for home electronics--a new component to the Council's residential sector--is expected to double in the next 20 years. In the commercial sector, the elder-care segment is increasing as the population ages. While the industrial sector is growing at a relatively slow pace, custom data centers (Google, etc.) are a relatively new end-use that has been seeing significant growth as well.

The Northwest has always been a winter-peaking power system. However, due to growing summer load, mostly because of the increased use of air conditioning, the difference between winter- and summer-peak load is expected to shrink over time. Assuming normal weather conditions, winter-peak demand in the Sixth Power Plan is projected to grow from about 34,000 megawatts in 2010 to around 43,000 megawatts by 2030, an average annual growth rate of 1 percent. Summer-peak demand is forecast to grow from 29,000 megawatts in 2010 to 40,000

¹ Demand for electricity, measured at consumer location, is projected to grow by about 6,000 average megawatts growing on average by about 300 megawatts or 1.4 percent per year.

megawatts by 2030, an annual growth rate of 1.7 percent. By the end of the planning period, the gap between summer-peak load and winter-peak load has narrowed.

The projected growth of demand is comparable to the actual growth rate experienced during the 1990s. When new cost-effective conservation is subtracted, the need for additional generation will be quite small compared to past experience. However, summer supply needs will likely increase as summer-peak demand continues to grow. In addition, the growing share of variable wind generation may change the types of generation needed to meet demand. There is likely to be an increased need for resources that can provide reliable capacity to meet high load conditions and that can operate flexibly to accommodate variable, but non-CO₂ emitting, wind energy.

INTRODUCTION

The 2001 energy crisis in the West refocused the region on long-term demand forecasting. There has been a renewed interest and concern about generating capacity and flexibility as well. To deal with these issues, the Council replaced its end-use forecasting models with a new end-use forecasting and policy analysis tool and, working with Bonneville, adapted it to the regional power system and the Council's planning requirements. The new demand forecasting system is based on the Energy 2020 model and generates forecasts for electricity, natural gas, and other fuel.

The Energy 2020 model is an integrated end-use forecasting model. The Council will use the demand module of Energy 2020 to forecast annual energy and peak loads for electricity as well as other fuels. The model has been used extensively by several utilities, and within the region the Bonneville Power Administration uses a version of it.

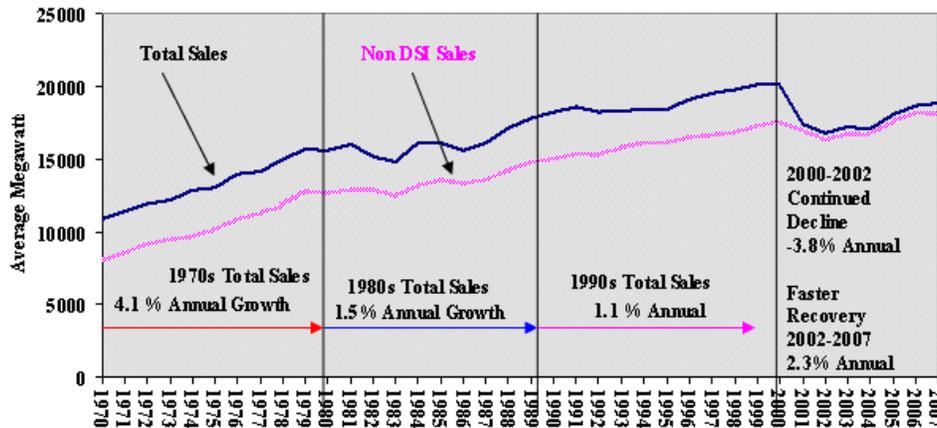
Three electricity demand forecasts were developed in the Sixth Power Plan. Each scenario corresponds to an underlying set of economic drivers, discussed in Chapter 2 and Appendix B. The high and low ranges of the load forecasts are not explicitly used in the development of the Power Plan, but rather are used as loose guidelines for the regional portfolio model when creating the 750 alternative load forecasts. These demand scenarios reflect an estimate of the impact of the current recession.

Historic Demand Growth

It has been 26 years since the Council's first Power Plan in 1983. In the decade prior to the Northwest Power Act, regional demand was growing at 4.1 percent per year and the non-direct-service industry (DSI) load was growing at an annual rate of 5.2 percent. Back in 1970, regional demand was about 11,000 average megawatts. In the decade between 1970 and 1980, it grew by about 4,700 average megawatts. During the 1980s, demand growth slowed significantly, falling to about 1.5 percent per year and load increased by about 2,300 average megawatts. In the 1990s, another 2,000 average megawatts were added to regional demand, making growth in the last decade of the 20th century only about 1.1 percent per year. The energy crisis of 2000-2001 increased electricity prices dramatically. As a result, regional demand decreased by 3,700 average megawatts between 2000 and 2001, and eliminated much of the growth since 1980. The bulk of this decline was in the region's aluminum industry and other energy-intensive industries. Since 2002, however, regional demand has begun to recover, growing at an annual rate of 2.5 percent. This growth has been driven by increases in commercial and residential sector demand. Nevertheless, demand remains well below levels of the late 1990s. Table 3-1 and Figure 3-1 illustrate regional electricity demand from 1970-2007.

Table 3-1: Historical Growth Rate of Regional Electricity Sales²

Annual Growth	Total Sales	Non DSI
1970-1979	4.1%	5.2%
1980-1989	1.5%	1.7%
1990-1999	1.1%	1.5%
2000-2007	-0.8%	0.5%
2002-2007	2.5%	2.2%

Figure 3-1: Total and Non-DSI Regional Electricity Sales (MWa)

The dramatic decrease in demand after the Power Act was not due to a slowdown in economic growth in the region. The region added more population and more jobs between 1980 and 2000 than it did between 1960 and 1980. The decrease was the result of a shift in the regional economy as the number of energy-intensive industries declined, largely because of the dramatic increase in electricity prices that followed the region's over-investment in nuclear generation in the 1970s and increased investment in conservation. As shown in Table 3-2, electricity intensity in terms of use per-capita increased between 1980 and 1990, but has been declining since 1990.

Table 3-2: Changing Electricity-Use Intensity of the Regional Economy (Non-DSI Sales Per Capita Adjusted for the weather)

Year	Electricity Use per Capita (MWa / Thousand Person)
1985	1.50
1990	1.57
2000	1.52
2007	1.45

The upswing in demand since 2002 has been mainly due to growth in residential and commercial sector sales. By the end of 2007, the residential sector had added about 888 average megawatts and the commercial sector had added 285 average megawatts, whereas the industrial sector saw a reduction of 337 average megawatts. The industrial sector represented 6,300 average megawatts of demand in 2000, but by 2002 the demand from the industrial sector was reduced to 3,300 average megawatts. The bulk of the drop in demand was due to the closure of aluminum smelting plants, which accounted for nearly 40 percent of industrial electricity use. The demand from this industrial group dropped from 2,543 megawatts in 2000 to about 410 megawatts in 2002. Large users in a few industrial sectors such as pulp and paper, food processing, chemicals, primary metals other than aluminum, and lumber and wood products dominate the remainder of the industrial sector's electricity use. Many of these sectors have declined or are experiencing

² 2007 is the last year for reliable data on regional sales. Reliable 2008 data are not available at this time.

slow growth. These traditional, resource-based industries are becoming less important to regional electricity demand, while new industries, such as semiconductor manufacturing, are growing faster.

SIXTH POWER PLAN DEMAND FORECAST

Demand is forecast to grow from about 19,000 average megawatts in 2007 to 25,000 average megawatts by 2030 in the medium-case forecast. The average annual rate of growth in this forecast is about 1.2 percent. This level of growth does not take into account reductions in energy from new conservation resources. To the extent conservation is used to meet demand growth, the forecast will decrease.

Assuming normal weather conditions, the winter-peak load for power is projected to grow from about 34,000 megawatts in 2010 to around 43,000 megawatts by 2030 at an average annual growth rate of 1 percent. Summer-peak load is projected to grow from 29,000 megawatts in 2010 to 40,000 megawatts by 2030, an annual growth rate of 1.6 percent.

The medium-case forecast means that the region's electricity needs would grow by about 6,000 average megawatts by 2030, absent any conservation, an average annual increase of 267 average megawatts. Most of the growth is from increased electricity use by the residential and commercial sectors, with slower growth in the industrial sector, especially for energy-intensive industries. Higher electricity and natural gas prices have fundamentally shifted the energy intensity of industries in the region. As a result of the 2000-01 energy crisis and the mild recession of 2002, the region lost about 3,500 average megawatts of industrial demand, which it has not regained. The region is projected to surpass the 2000 level of demand by 2013. However, the depth of the 2008-09 recession may prolong this recovery.

Demand Forecast Range

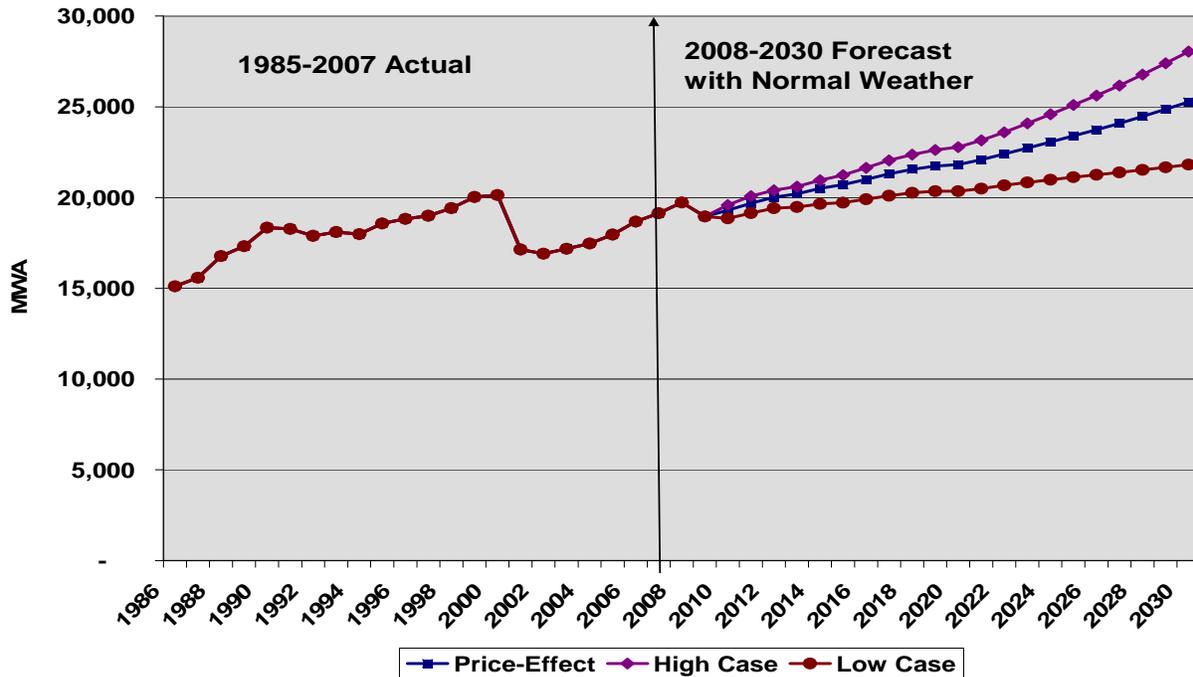
Uncertainty about economic and demographic variables, along with uncertainty about fuel prices, adds to uncertainty about demand. To evaluate the impact of these economic and fuel-price uncertainties in the Sixth Power Plan, two alternative demand forecasts were produced. The Sixth Power Plan's low to high range is based on Global Insight's October 2009 range of national forecasts. To forecast demand under each scenario, the appropriate economic and fuel projections were used. Table 2-1, presented in Chapter 2, shows a range of values for key economic assumptions used for each scenario. The resulting range in the demand forecast is shown in Table 3-3 and Figure 3-2.

Two alternative scenarios were developed for the Sixth Power Plan. The most likely range of demand growth (between the low and high forecasts) is between 0.8 and 1.5 percent per year. The low scenario reflects a prolonged recovery from the recession, and the high scenario reflects a more robust recovery and future growth.

Table 3-3: Sixth Northwest Power Plan Electricity Demand Forecast Range (MWA)³

	Actual 2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2020-2030	Growth Rate 2010-2030
Low	19,140	18,860	20,463	22,010	0.8%	0.7%	0.8%
Medium	19,140	19,292	21,820	25,275	1.2%	1.5%	1.4%
High	19,140	19,591	22,651	27,761	1.5%	2.1%	1.8%

Figure 3-2: Historical Sixth Northwest Power Plan Sales Forecast (MWA)



Sectoral Demand

The Sixth Power Plan forecasts demand to grow at an average annual rate of 1.4 percent in the 2010 through 2030 period. The residential sector is expected to grow at 1.4 percent per year, which, on average, translates to about 125 megawatts each year. Increased growth in the residential sector reflects a substantial increase in demand for home electronics, categorized as information, communication, and entertainment (ICE) and the increased use of air conditioning.

Table 3-4 shows the actual 2007 demand for electricity and the forecast for selected years, as well as the corresponding annual growth rates. These demand forecasts do not include any new conservation initiatives.

³ Sales figures are electricity use by consumers and exclude transmission and distribution losses.

Table 3-4: Medium-Case Sector Forecast of Annual Energy Demand (MWa)

	Actual 2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2020-2030	Growth Rate 2010-2030
Residential	7,424	7,499	8,335	9,987	1.06%	1.82%	1.44%
Commercial	6,129	6,705	8,214	9,170	2.05%	1.11%	1.58%
Industrial Non-DSI	3,904	3,724	3,715	4,360	-0.03%	1.62%	0.79%
DSI*	764	693	772	772	1.09%	0.00%	0.54%
Irrigation	848	599	696	873	1.52%	2.29%	1.90%
Transportation	71	72	87	113	1.91%	2.62%	2.27%
Total	19,140	19,292	21,820	25,275	1.24%	1.48%	1.36%

* Long-term DSI forecast developed by RPM, projects a lower DSI load than the values reflected here.

Commercial sector electricity consumption is forecast to grow by 1.6 percent per year between 2010 and 2030. During this period, commercial sector demand is expected to increase from 6,700 average megawatts to 9,200 average megawatts. This increase is higher than the 1.2 percent per year that was forecast in the Fifth Power Plan (May 2005). The Sixth Power Plan cases have been adjusted upward to reflect the fact that there has been a tendency to under-forecast commercial demand. The forecast for 2025 is about 1,700 average megawatts higher than the 2025 medium forecast in the Fifth Power Plan. On average, this sector adds about 110 average megawatts per year.

Industrial electricity demand is difficult to forecast with much confidence. Unlike the residential and commercial sectors, where energy use is predominately for buildings, and therefore reasonably uniform and easily related to household growth and employment, industrial electricity use is extremely varied. Also, industrial electricity use tends to be concentrated in relatively few, very large users instead of spread among many relatively uniform users.

Industrial (non-direct-service industries) consumption is forecast to grow at 0.8 percent annually. Electricity consumption in this sector is forecast to grow from 3,900 average megawatts in 2007 to 4,400 in 2030. One segment of the industrial sector that has experienced significant growth is that of custom data centers. Although these businesses do not manufacture a tangible product, they are typically classified as industrial customers because of the amount of electricity they use. The Council's estimates show that there are currently about 300 average megawatts of connected load for these businesses. Demand from this sector is forecast to increase by about 7 percent per year. However, considering existing opportunities to improve the energy efficiency of custom data centers, it was assumed that demand from these centers will grow about 3 percent per year.

In the Sixth Power Plan, DSI consumption was assumed to be around 600-700 average megawatts for the forecast period. Although the portion of Alcoa's Wenatchee aluminum smelter that is served from non-BPA sources is not technically a DSI (it is not served by BPA), that load is included in the DSI category for convenience in the Sixth Power Plan.

LOAD FORECAST AND PEAK LOAD

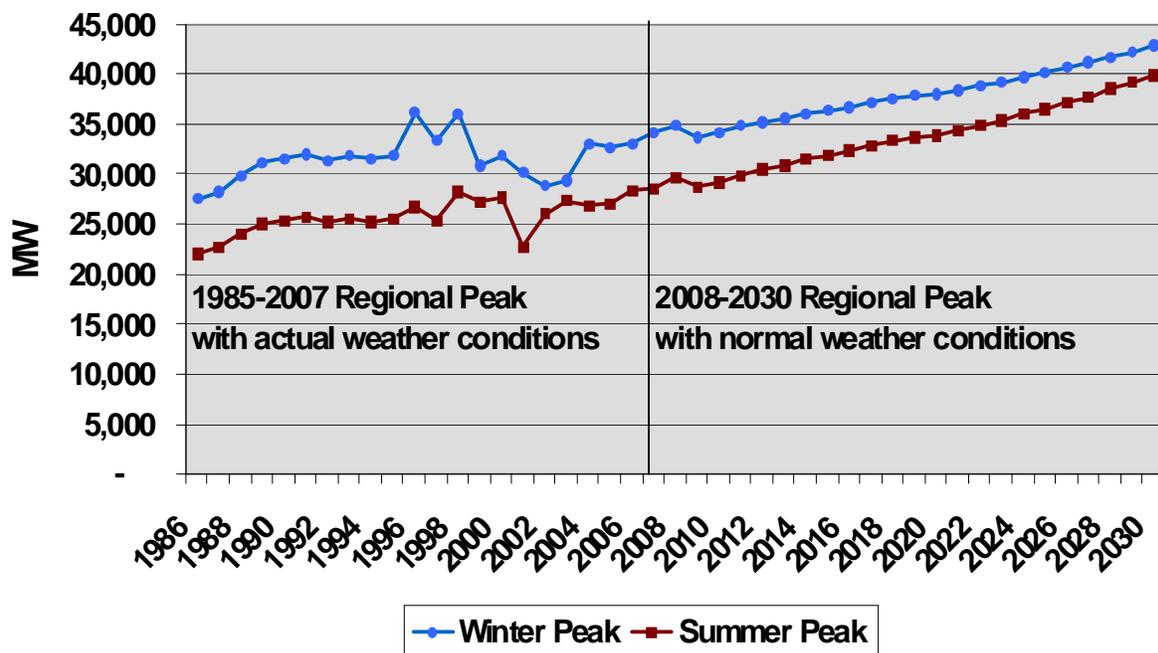
Peak Load

The Council's new long-term demand forecasting system forecasts annual sales, as well as monthly energy and peak load. The Council often refers to electricity sales to consumers as demand, following the Northwest Power Act's definition. The difference between sales and load is transmission and distribution losses on power lines. Regional peak load is determined from

the end-use level for each sector. The regional peak load for power, which has typically occurred in winter, is expected to grow from about 34,000 megawatts in 2010 to around 43,000 megawatts by 2030 at an average annual growth rate of 1.1 percent. Assuming normal historical temperatures, the region is expected to remain a winter-peaking system, although summer peaks are expected to grow faster than winter peaks, significantly narrowing the gap between summer-peak load and winter-peak load.

The forecast for regional peak load assumes normal weather conditions. There are no assumptions regarding temperature changes incorporated in the Sixth Power Plan’s load forecast at this time. Sensitivities will be conducted to help assess the potential effects of climate change on electricity use (See Appendix L). Figure 3-3 shows estimated actual peak load for 1985-2007, as well as the forecasts for 2008-2030. Note that load growth looks very steep due to the graph’s smaller scale.

Figure 3-3: Historical and Forecast Regional Peak Load (MW)



Load Forecast Range

Figure 3-5 shows forecast winter and summer peak load under the three alternative cases. Assuming the high-growth scenario, regional summer-peak load is expected to grow from about 28,000 megawatts in 2007 to about 43,000 megawatts by 2030. Between 2010 and 2030, the growth rate in summer-peak load is 1.9 percent per year. The growth rate of winter-peak load in the high case is lower than the growth in average annual energy demand. Assuming normal weather, the region is forecast to remain a winter-peaking system. However, the difference between winter and summer peak loads shrinks over time.

Table 3-5: Total Summer and Winter Peak Load Forecast Range (MW)

	Actual 2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2020-2030	Growth Rate 2010-2030
Low - Winter	33,908	33,572	35,412	36,949	0.5%	0.4%	0.5%
Low - Summer	28,084	28,517	32,027	35,559	1.2%	1.1%	1.1%
Medium - Winter	33,908	34,184	37,977	42,814	1.1%	1.2%	1.1%
Medium - Summer	28,084	29,211	33,800	39,865	1.5%	1.7%	1.6%
High - Winter	33,908	34,611	39,397	46,788	1.3%	1.7%	1.5%
High - Summer	28,084	29,706	34,923	43,360	1.6%	2.2%	1.9%

In the low case, summer-peak load is expected to grow from 28,000 megawatts in 2007 to 35,000 megawatts in 2030. Winter-peak load grows from 34,000 in 2007 to 37,000 in 2030. Other patterns between summer and winter peaks are similar to the other cases. Winter peaks grow more slowly than average energy load, and summer peaks grow faster.

Alternative Load Forecast Concepts

Three different but related load forecasts are produced for use in the Council's resource planning process. The first of these forecasts is called a "price-effect" forecast, which is the forecast that has been presented up to this point. The price-effect forecast is the official demand forecast required by the Northwest Power Act.

The price-effect forecast reflects customers' choices in response to electricity and fuel prices and technology costs, without any new conservation initiatives. This forecast does not include new conservation resources. However, expected savings from existing and approved codes and standards are incorporated in the price-effect forecast, consequently reducing the forecast and removing the potential from the new conservation supply curves.

To eliminate double-counting the conservation potential, the load-forecasting model produces two other long-term forecasts that are required for estimating conservation potential and running the resource portfolio model.

1. **Frozen-efficiency forecast.** A "frozen-efficiency" forecast is when load is calculated based on fixed or frozen efficiency levels as of the base year of the plan. This forecast attempts to eliminate the double-counting of conservation savings. The frozen technical-efficiency levels form the conservation supply model's starting point. In the frozen-efficiency forecast, the fuel efficiency choice is held constant at the base-year level and not changed over time, except where there is a known increase due to codes or standards.
2. **Sales forecast.** A "sales"⁴ forecast represents the actual expected sales of electricity after all cost-effective conservation has been achieved. It incorporates the effects of electricity prices and the cost-effective conservation resources that are selected by the regional portfolio model. The sales forecast captures both price effects and take-back effects (due to increased usage as efficiency of usage increases).

The difference between the price-effect and frozen-efficiency load forecasts is relatively small. The frozen-efficiency forecast typically is higher than the price-effect forecast; in the Sixth Power Plan the two forecasts differ by about 400 average megawatts by 2030. Figures 3-4 through 3-6 show these three forecasts for energy and for summer and winter capacity in the

⁴ The "sales" forecast, as well as price-effect and frozen efficiency, can be measured at a consumer or generator site (which would include transmission and distribution losses). Demand is measured at the customer site, and load is measured at the generator site.

Sixth Power Plan. Conservation resource program savings incorporated⁵ in the sales forecast reduce 2030 average annual load by about 5,900 megawatts and reduces summer peak load by about 6,000 megawatts, or roughly by 15 percent. Winter peak loads are reduced by about 11,000 megawatts or about 24 percent.

Figure 3-4: Average Annual Load Forecasts (MWa)

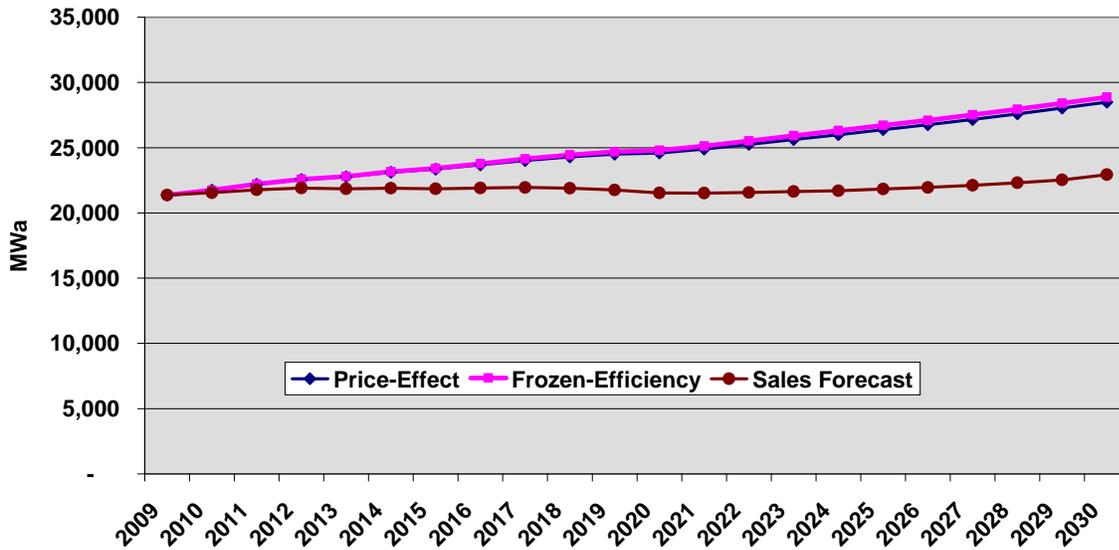
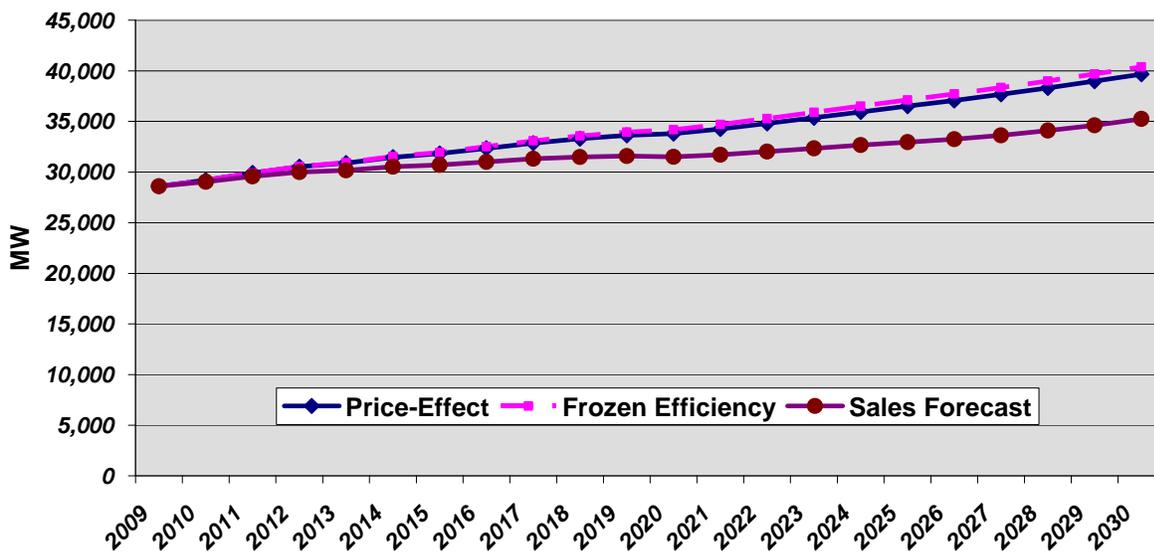
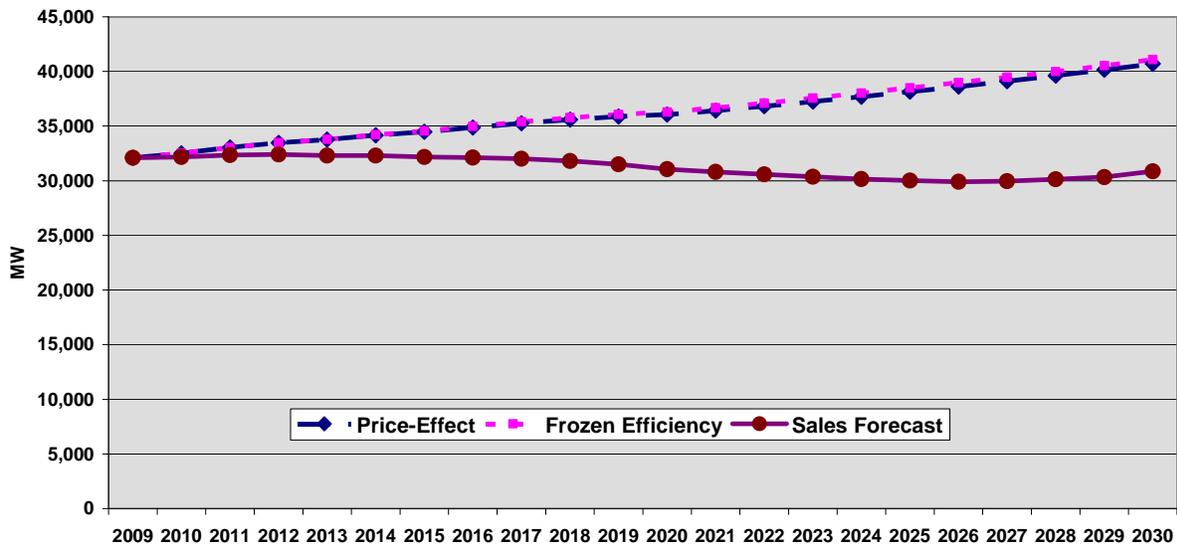


Figure 3-5: July Peak Load Forecasts (MW)



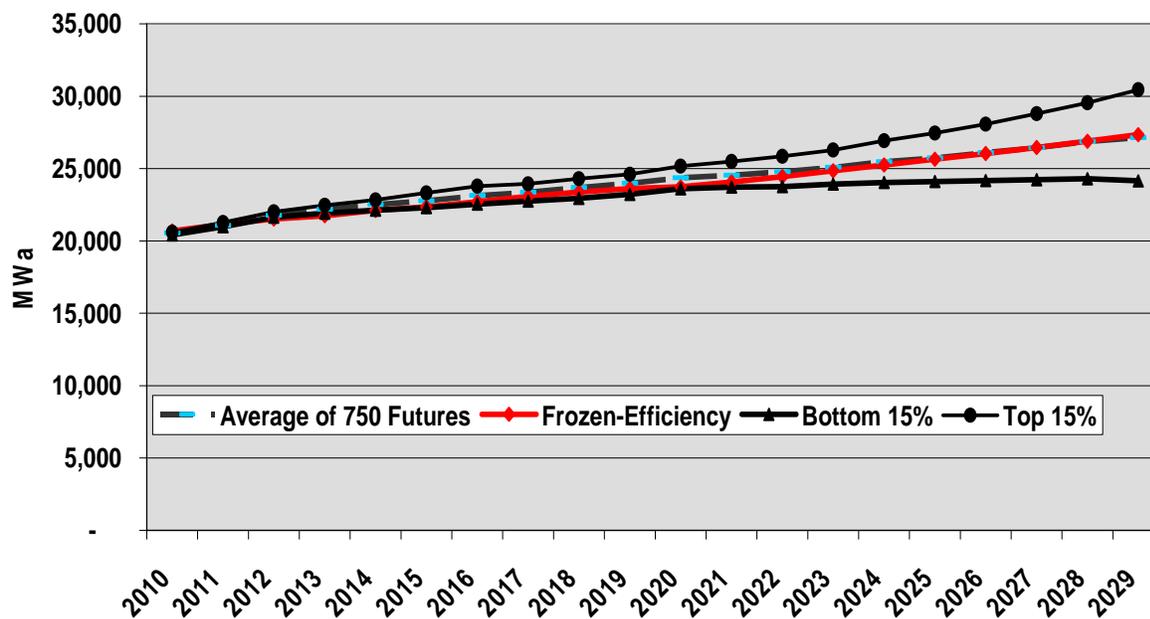
⁵ Anticipated annual impacts of conservation programs, by sector and end-use, are netted out of the frozen-efficiency loads for that year, sector, and end-use.

Figure 3-6: January Peak Load Forecasts (MW)



Portfolio Model Analysis of Non-DSI Load

While the Council uses three types of long-term load forecasts, the monthly frozen-efficiency load forecast is the primary forecast used in the regional portfolio model (RPM) for developing alternative future load-growth paths. The RPM takes the frozen-efficiency load forecast and introduces short-term excursions that simulate such events as business and energy commodity price cycles and load variations that could be caused by weather events. In any given period, the RPM may deviate from the long-term load forecast; however, on average the loads created by the RPM are very close to the frozen-efficiency load forecasts. The following table shows a comparison between the frozen-efficiency load forecast and the RPM-generated loads. The graph shows a representative range of load forecasts developed. The RPM generates 750 different future load-growth paths; to graphically represent all these futures would not be possible. Here, the averages of the highest 15 percent and lowest 15 percent of the 750 load paths, as well as the average of all the 750 growth paths, are compared with the frozen-efficiency forecast. It should be noted the loads presented in this graph are for non-DSI loads. A more robust discussion of the RPM is presented in Chapter 9 and Appendix J.

Figure 3-7: Load Forecasts (MWa)

Impact on Revenue Requirement

What is the impact of the plan's resource recommendations on customers' electricity costs and how do predicted costs compare to historic trends?

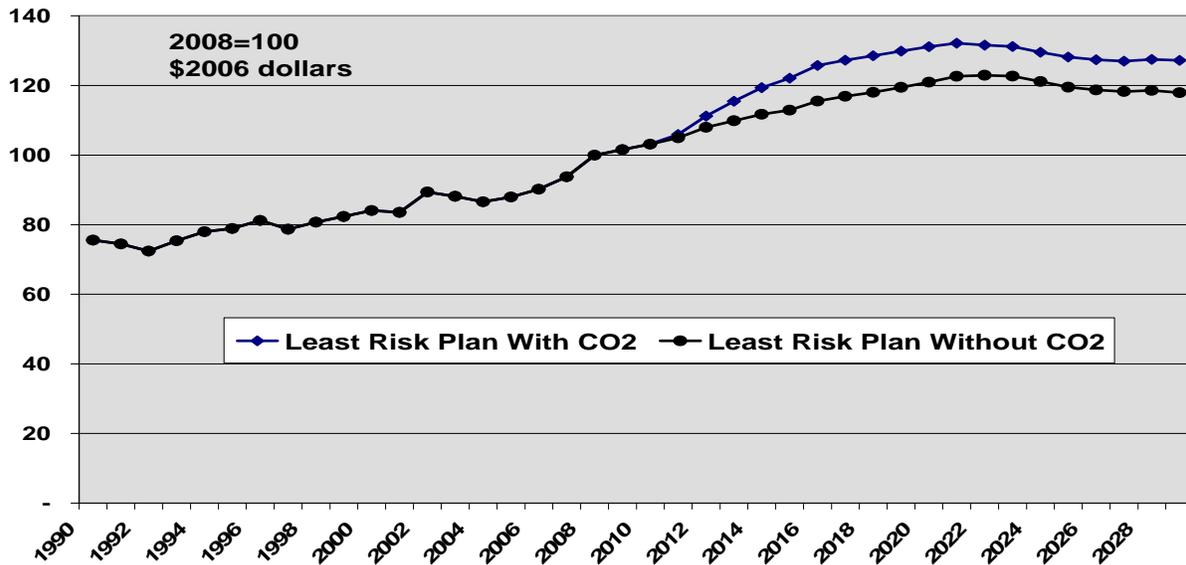
Customers' bills are expected to decrease by 0.2 percent to 0.7 percent per year depending on treatment of CO₂ costs. If the CO₂ penalty is not included in the revenue requirement, customers' electricity bills are expected to decline at an average annual rate of 0.7 percent. If CO₂ costs are included, customers' electricity bills are expected to decline at an average annual rate of 0.2 percent. It should be noted that over time residential customer bills and the revenue requirement change at different rates, due to an increasing number of households. The average revenue requirement grows at an average annual rate of 0.5 percent,⁶ and the number of households grows at a rate of 1.2 percent, resulting in bills decreasing at 0.7 percent per year.

To compare the future trend in costs with the historic trend, we need to create comparable numbers by removing the effects of inflation. The dollars of revenue collected by electric utilities for each year between 1990 and 2008 were converted to 2006 dollars. The future projected revenue requirement under the carbon risk scenario was compared to historic levels. The historic and future revenue requirement was indexed to 2008 by setting 2008 revenues to 100. Analysis shows that during the 1990-to-2008 period the revenue requirement increased at an average annual rate of 1.6 percent. In the 2010-to-2030 period, under the carbon-risk scenario, the revenue collected from customers is projected to increase at an average annual rate of 0.5 percent to 1.0 percent per year, depending on the incidence of the CO₂ tax. More detail

⁶ The calculation of future revenue requirements includes an assumption that current fixed costs of resources, transmission, and distribution systems remain fixed in real dollars. Implicit in this assumption is that the cost of new transmission and distribution infrastructure expansion is offset by the depreciation of existing infrastructure assets. Eastern Montana wind, however, is assumed to require additional transmission investment and that cost is explicitly added to the cost of the Montana wind resource.

regarding the impact of the plan on average revenue and customer bills can be found in Appendix O.

Figure 3-8: Indexed Revenue Requirement



Demand From Plug-in Hybrid Electric Vehicles (PHEV)

Over 70 percent of automakers⁷ are introducing plug-in hybrid electric vehicles (PHEV). Between 2010 and 2030 we estimate that more than 13 million new passenger and light vehicles will be purchased in the Northwest, of which 600,000 to 3.5 million could be PHEV.

To better understand the potential impact of PHEV on the system load, a limited “what-if” sensitivity study was conducted.⁸ The Council assumed a range of penetration of these cars into the market, with the result that regional electricity use increases by between 100 and 550 average megawatts.

The estimated effects on electricity bills and rates were small. The impact on rates to a large extent depends on when the PHEV is recharged. In the Council’s analysis, it was assumed that 95 percent of PHEV recharge would occur at night or on weekends, during system off-peak hours. To encourage and ensure off-peak recharge would require regulatory and technological changes. Technological change in the form of smart grid and uniform recharge protocols would enable the owners of PHEV to know the optimum recharge period. Regulatory rates would need to provide incentives for off-peak charging.

The forecast of new light vehicles in the four Northwest states indicates that between 2010 and 2030 about 13 million new vehicles will come on to the roads. Some of these vehicles would replace existing vehicles and some would meet new transportation requirements of a growing population. The PHEV share of this market would depend on a number of factors such as gasoline prices, tax on CO2 emissions, and the price and reliability of PHEV. In the sensitivity analysis, it was assumed that all these factors translate into a market share factor. Three

⁷ By market-share, from E-source presentation on “Building the plug-in Vehicle Infrastructure” Nov 2009.

⁸ This sensitivity study was not included in the base case (price effect) analysis for the plan.

different long-term market-share factors were assumed. Case 1 assumes 10-percent market share, while cases 2 and 3 assume 28 percent and 40 percent, respectively.

The following figures show the year-by-year market-share assumptions as well as annual and off-peak energy requirements for PHEV. It was assumed that market acceptance of PHEV will be small in the first five years of their introduction. By the 15th year, the assumption is that market acceptance will level off at 10-40 percent. Figure 3-9 shows the assumed annual new-vehicle market-penetration rates for PHEV. We also have assumed that the efficiency of the PHEV and conventional fossil-fuel vehicles would improve over time. Figures 3-10 and 3-11 show the annual demand for electricity for PHEV. PHEV are expected to add between 100-550 average megawatts to regional load and about twice as much to the off-peak demand. A detailed discussion of PHEV analysis is presented in Appendix C of the power plan.

Figure 3-9: Assumed New Car Market Share for PHEV

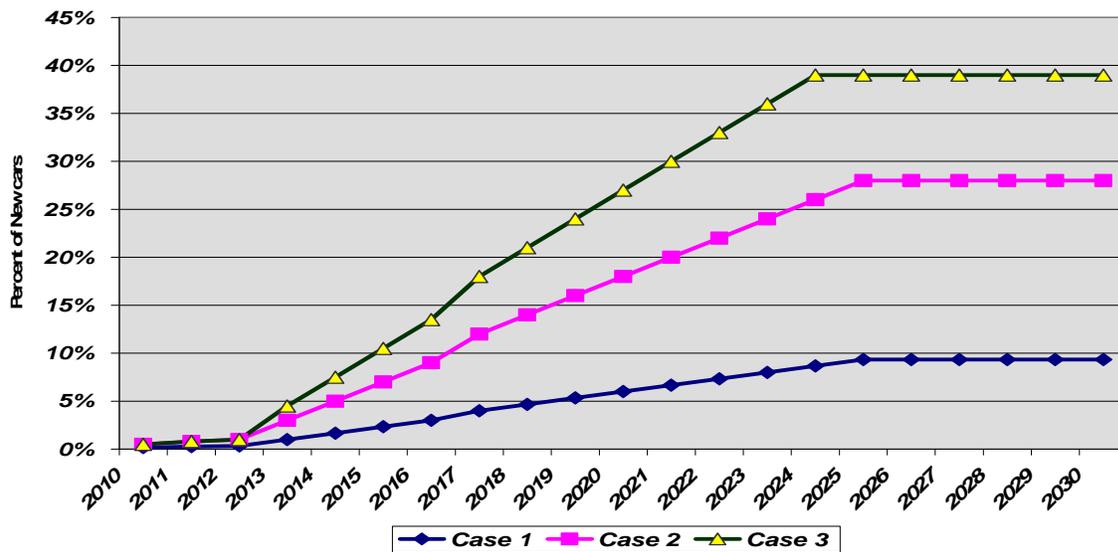


Figure 3-10: Projected Load from Plug-in Hybrid Vehicles

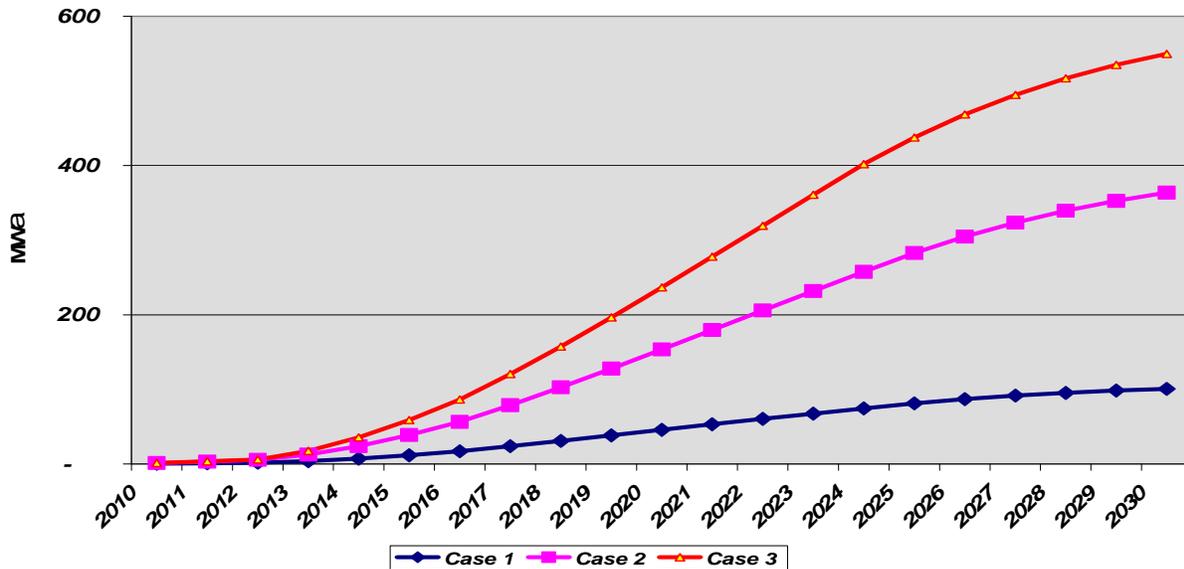
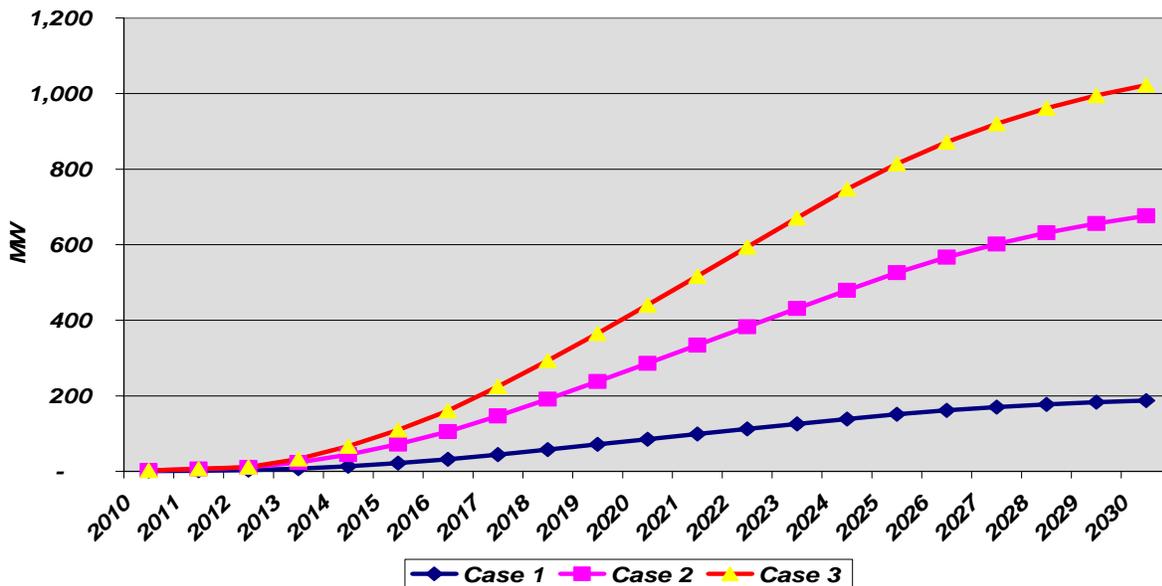


Figure 3-11: Project Off-peak Load from Plug-in Hybrid Vehicles



Opportunities and Challenges

The projected levels of PHEV penetration represent both opportunities and challenges for the power system in the Northwest. If fully subscribed, by 2030, the PHEV fleet potentially could store the equivalent of between 2 and 10 percent of the energy and between 3 and 20 percent of the eight-hour sustained peaking capacity of the hydropower system in the Northwest.

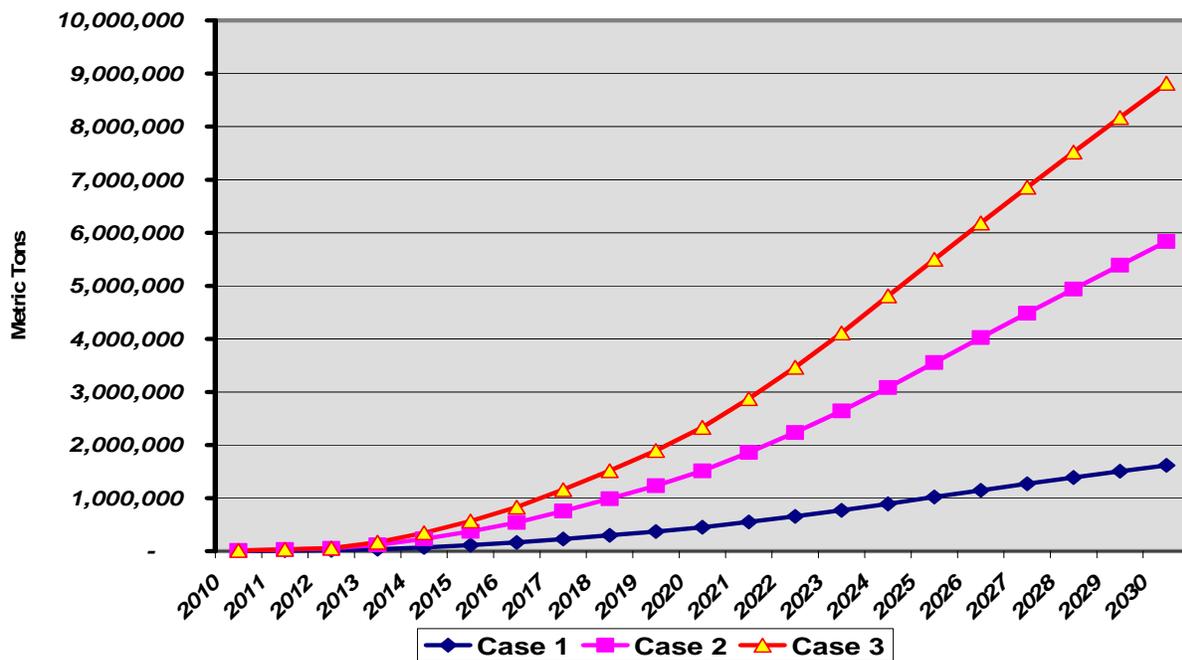
However, integration of potentially millions of PHEVs into the power grid will require building an intelligent bi-directional telecommunication infrastructure that would optimize recharge schedules based on consumers’ driving habits and power utilities’ needs. What is needed is an

integration of three sectors- transportation, information, and electric power. To make possible the communication between local utilities, millions of dispersed vehicles, and thousands of recharge stations, common national communication standards along with local utilities' incentivized rates and a seamless recharge infrastructure are necessary. The utilities will need to provide incentives to PHEV drivers to subscribe to smart charging programs, where the utility could manage the timing and pace of the recharge.

Environmental Impacts

The impact of PHEV on the emissions from electricity generation depends on the timing of recharge and future mix of generation. In the regional portfolio model, by 2030 the difference in CO2 emissions from the power system was 0.8 million metric tons higher⁹ due to PHEV loads. But the increase in CO2 emissions from power plants is more than offset by the decrease in emissions by vehicles. The US Department of Energy estimates that in the four states of Oregon, Washington, Idaho, and Montana, tail-pipe emissions in 2007 were about 90 million metric tons. The Council's estimates show that, depending on market acceptance of PHEV and response from conventional-fuel vehicles,¹⁰ by 2030 tail-pipe emissions could be lower by 2 to 9 million metric tons.

Figure 3-12: Potential Reduction in Tail-pipe CO2 due to Plug-in Hybrid Vehicles



Meeting the energy requirement of PHEV may not require new resources.. Council analysis shows that if the plan's conservation targets are met, by 2030 the off-peak demand for energy could be reduced by about 3,800 megawatts. This amount of off-peak demand reduction would be sufficient to power an all-PHEV new vehicles fleet in the region.

⁹ 37.8 million metric tons compared to 37 million in the least-risk scenario.

¹⁰ This assumes that as a result of national standards, higher fuel prices and availability of PHEV, conventional fuel vehicles would improve their fuel efficiency from 21.7 miles per gallon in 2010 to 35 miles per gallon by 2030.

ASSESSMENT OF NEEDS - UTILITY PERSPECTIVE

Regional utilities have consistently used the annual average load/resource balance as a quick and simple metric to get an indication of their resource needs. For the region, the load/resource balance reported in PNUCC's Northwest Regional Forecast (NRF) provides an aggregate look at utility-resource needs. That calculation assumes firm loads and resources,¹¹ which include critical-water hydropower generation but no market resources. A general conclusion that can be made from this metric is that when the average annual load is greater than the firm supply, additional resources likely are needed.

However, this utility-perspective metric is very limited and requires assessment. The Council and utilities must use more sophisticated analyses, which take other uncertainties into account, in order to develop a more comprehensive needs assessment and, more importantly, a robust resource-acquisition strategy (more commonly referred to as an integrated resource plan). The Council's methodologies for assessing the region's needs and for developing a resource strategy are described in Chapter 9 (Developing a Resource Strategy) and in Chapter 10 (Recommended Resource Strategy), respectively.

The Council's assessment of power supply adequacy, developed by the Resource Adequacy Forum, uses a more sophisticated methodology than simply comparing firm loads and resources. Adopted by the Council in 2008, it uses probabilistic tools to assess the likelihood of potential problems given firm, non-firm, and market resources. A more detailed description and a summary of results are provided in Chapter 14 (Resource Adequacy Standards).

Yet, in spite of the limitations of the simple firm-load/resource-balance metric for assessing resource needs, this perspective is beneficial in that it is readily available to all utilities and provides a starting point for further discussion. Also, by reconfiguring Council assessments to fit this perspective, results can be compared with other utility-published reports. The following section illustrates the Council's assumptions for loads and resources portrayed in a utility perspective.

Annual Needs

As a starting point for assessing regional resource needs based on a utility perspective, it is necessary to identify long-term load uncertainty and existing firm-resource capability. Existing resources include those that are owned or operated by regional utilities to serve regional loads, regardless of their physical location. The generating capability of existing resources is adjusted for maintenance and for the likelihood of forced outages. It is also adjusted to reflect utility operating assumptions. For example, a utility may own a 100-megawatt capacity simple-cycle combustion turbine, which it intends to use for hourly peaking needs only. Because of the way in which the utility expects to operate this resource, it may only use 5 percent (or 5 average megawatts) to count toward the annual average firm-resource generating capability. The existing resource capability shown in the following charts has been adjusted for this effect.

The range of uncertainty in long-term loads (through the year 2030), was derived from the regional portfolio model, which takes into account a wide variation in potential future economic growth. The high end of the load uncertainty range represents the average load for

¹¹ Firm loads are net of firm exports and imports. Firm resources consist of firm non-hydropower and critical-water hydropower resources.

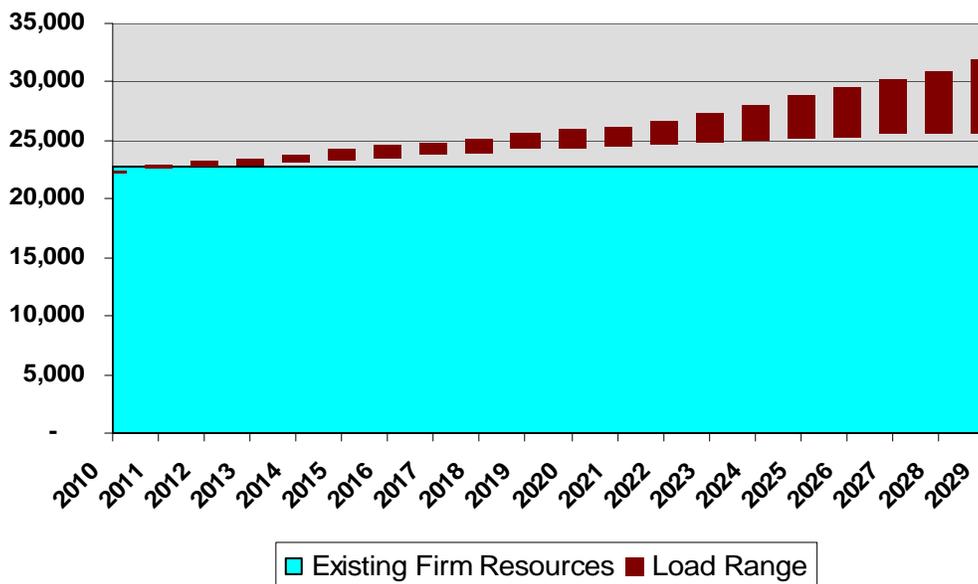
approximately the highest 15 percent¹² of the load paths from the model. The low end of the range represents the average load for approximately the lowest 15 percent of the load paths from the model. This load range includes the net effect of firm contractual imports and exports.

The following graphs compare existing firm-resource generating capability (as defined above) with the high and low range for future loads. The floating blocks in Figure 3-13 represent the range of uncertainty in load growth through the end of the study horizon. In 2029, for example, annual regional firm load can range from a low of about 23,000 average megawatts to a high of about 31,000 average megawatts.

Based on a utility perspective, as depicted in Figure 3-13, existing firm resource capability is only sufficient to satisfy regional needs through 2012. However, this does not mean that our power supply is inadequate. What it does mean is that counting only firm resources (in a way defined by utilities) and critical hydropower generation, the power supply cannot serve the anticipated firm load. This gap can be filled in a number of ways. Utilities could choose to build or acquire additional firm resources, purchase from the electricity market, operate their existing resources at levels above their planning dispatch levels, or any combination of the three. The optimum strategy must be derived from a comprehensive integrated resource-planning process, which takes many other factors into account.

The data presented in Figure 3-13 is consistent with information provided in PNUCC’s NRF. Unfortunately, it provides a relatively narrow view of potential regional needs because it excludes independent power-producer resources and potential access to resources outside the region. In addition, it offers little guidance in terms of developing a cost-effective resource-acquisition strategy. It does, however, indicate that a potential need for new resources exists and that further analysis is required.

Figure 3-13: Utility-Perspective Energy Needs Assessment (MWa)



¹² More precisely, the high end range of load uncertainty for each year is the average of the yearly loads for the lowest 100 simulations (out of 750 total) sorted by load in the last year of the study (2030).

Hourly Needs

Although not used as often in the past, capacity load/resource balances are becoming more important for assessing the need for new resources. The combination of rapidly growing summer loads and decreasing summer hydroelectric capability is pushing the region to consider more carefully its peaking needs in summer months. Traditionally, capacity load/resource balances have been measured as surplus reserve margins, in units of percent. To calculate a capacity reserve margin, surplus firm-generating capability for the peak-load hour of the day is divided by the load during that hour. This surplus capacity must be sufficient to cover operating- and planning-reserve requirements, fluctuations in load due to temperature, and the potential loss of a generating resource. In regions that are dominated by thermal resources, the desired reserve margin typically is in the range of 15 to 17 percent.

The Northwest, however, is a hydroelectric-dominated system that has limited storage capability. The aggregate storage capacity of all reservoirs is only about 30 percent of the annual average runoff volume in the Columbia River. Because of this storage limitation and other factors, the Northwest power system cannot sustain its single-hour generating capability over long periods. A more appropriate measure of hourly capability is the generation that the system can sustain over a three-day period, which approximates the duration for cold snaps or heat waves in the Northwest. This sustained-peak capability then can be compared to the sustained-peak load. However, to date, no standard has been established for a utility-perspective (firm only) sustained-peak reserve-margin requirement.¹³

Using the same methodology as for the energy-needs assessment above, the utility-perspective January and July sustained-peak capacity needs assessments are illustrated in Figures 3-14 and 3-15. These results cannot be compared directly to PNUCC's Northwest Regional Forecast because it currently does not report capacity data. For January, existing firm resources fall below the high end of the sustained-peak load range by the year 2028; for July, resources fall short of the high end of the load range by the year 2026. However, the loads shown in these figures do not include any reserve-margin requirements. Adding those requirements to the load range will result in an earlier need for resource acquisition. But, as discussed above, utility-perspective, sustained-peak reserve requirements are not clear.

Figure 3-14: Utility-Perspective January Capacity Needs Assessment (MW)

¹³ The Resource Adequacy Forum has developed minimum sustained-peak reserve-margin thresholds using a loss-of-load probability analysis (as defined in the Council-adopted adequacy standard). But these thresholds were developed under the assumption that some non-firm resources would be available for dispatch during emergency periods. Because of that, the Forum's thresholds cannot be compared to reserve margins calculated using firm resources only.

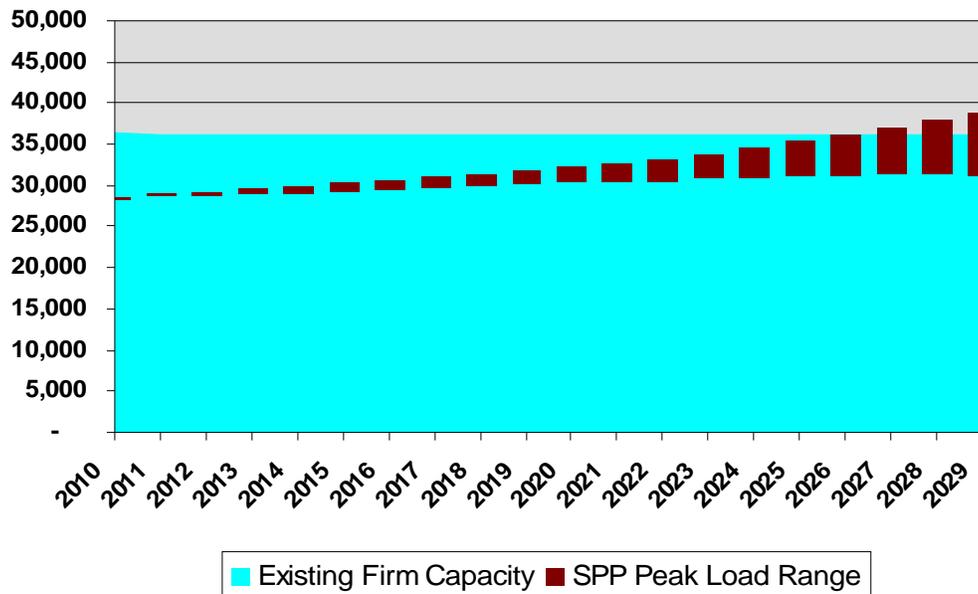
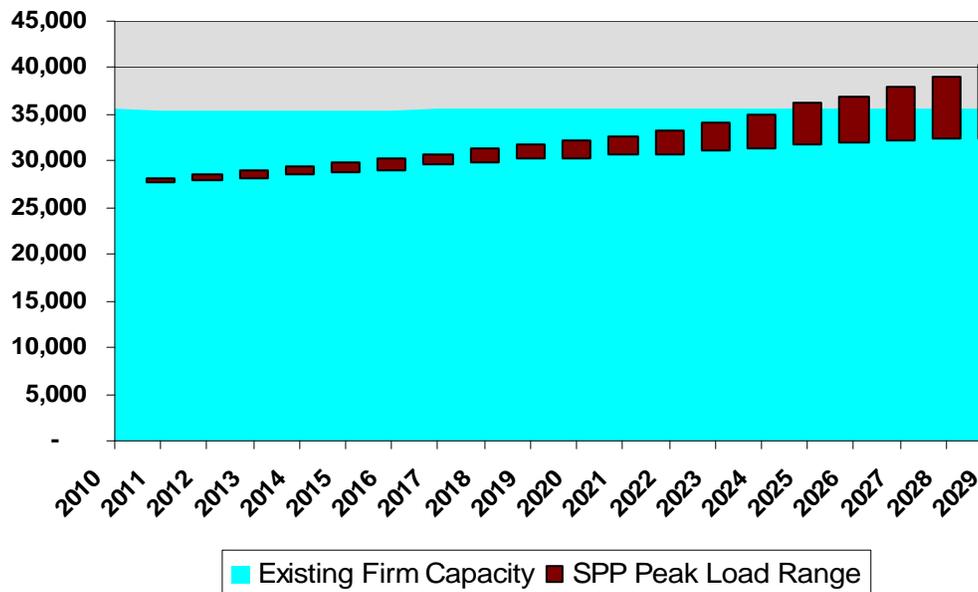


Figure 3-15: Utility Perspective July Capacity Needs Assessment (MW)



An alternative way to display the utility-perspective hourly needs assessment is to graph the sustained-peak reserve margins calculated from data shown in Figures 3-14 and 3-15. Figures 3-16 and 3-17 show the resulting sustained-peak reserve margin ranges for January and July, respectively, using existing firm resources only. If the minimum required reserve margins for January and July were known, these figures would indicate the years in which new resources would be needed. Using 17 percent¹⁴ as a surrogate for the utility-perspective sustained-peak reserve-margin threshold, the need for new resources occurs in 2016 for January and in 2015 for July (when the reserve margins drop below 17 percent). However, these results do not provide an accurate assessment of hourly needs.

¹⁴ California utilities historically have used a 15-to-17-percent reserve-margin requirement for long-term resource planning. However, that requirement is only appropriate for a thermal-based power system, which focuses on single-hour needs as opposed to sustained-peak needs.

Figure 3-16: Utility-Perspective January Reserve Margins (%)

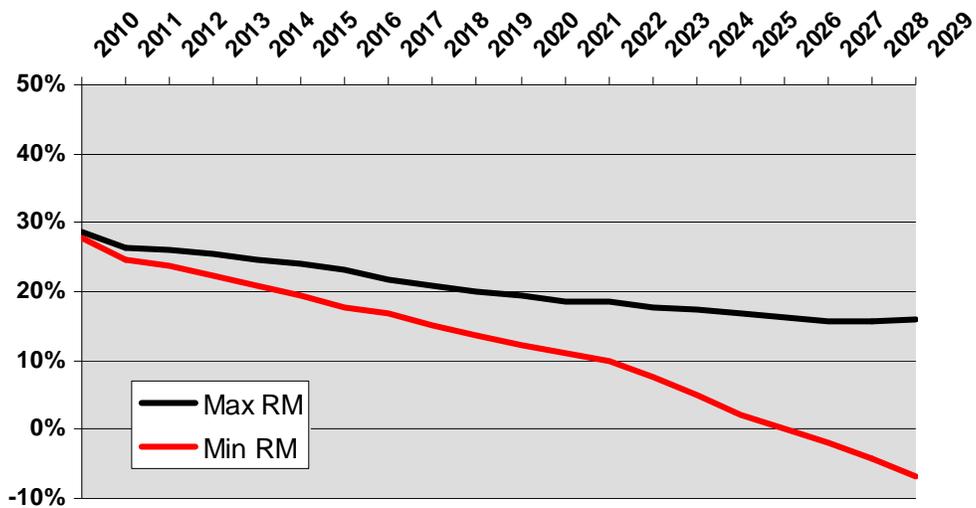
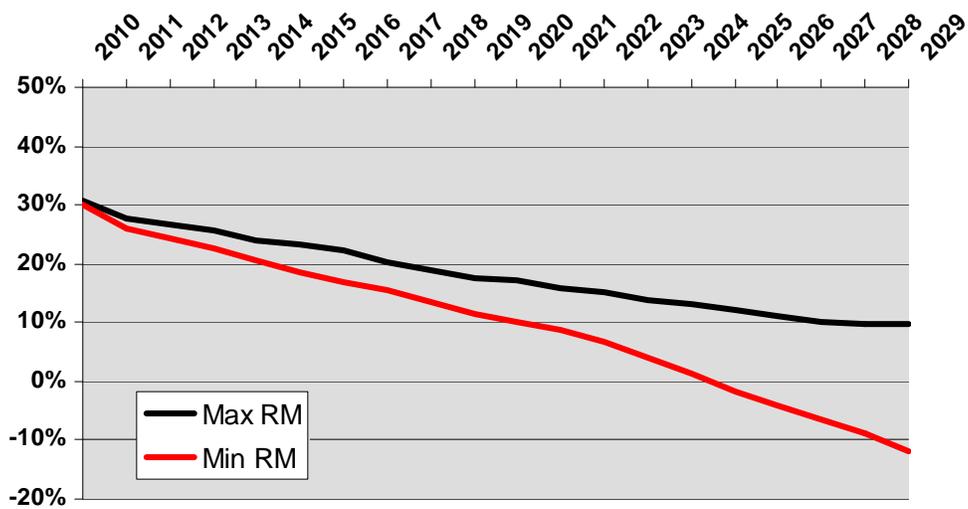


Figure 3-17: Utility Perspective July Reserve Margins (%)



ANNUAL LOAD FORECAST TABLES**Table 3-5: Annual Load under Various Scenarios (MWa)**

	Low Case	Price-Effect (Medium Case)	High Case	Sales Forecast (Loads Net of Conservation)
1986		18,272		
1987		18,751		
1988		19,842		
1989		20,681		
1990		20,922		
1991		21,258		
1992		20,807		
1993		21,097		
1994		20,875		
1995		21,140		
1996		21,836		
1997		21,591		
1998		21,902		
1999		22,382		
2000		22,443		
2001		19,321		
2002		19,835		
2003		20,010		
2004		20,204		
2005		20,582		
2006		21,054		
2007		21,575		
2008		22,239		
2009	21,367	21,369	21,371	21,369
2010	21,258	21,745	22,081	21,557
2011	21,580	22,194	22,626	21,800
2012	21,903	22,566	22,982	21,950
2013	21,985	22,774	23,188	21,919
2014	22,181	23,116	23,574	22,009
2015	22,286	23,346	23,875	21,978
2016	22,508	23,675	24,299	22,036
2017	22,745	24,015	24,743	22,084
2018	22,933	24,292	25,091	22,032
2019	23,053	24,499	25,364	21,900
2020	23,063	24,593	25,530	21,652
2021	23,232	24,890	25,932	21,610
2022	23,433	25,246	26,422	21,631
2023	23,631	25,618	26,963	21,673
2024	23,802	25,990	27,512	21,708
2025	23,977	26,374	28,080	21,755
2026	24,135	26,753	28,650	21,803
2027	24,288	27,153	29,255	21,948
2028	24,458	27,582	29,915	22,172
2029	24,627	28,028	30,593	22,422
2030	24,806	28,488	31,291	22,815
2010-2030	0.77%	1.36%	1.76%	0.28%%

Table 3-6: Regional Winter and Summer Peak Load Forecast Range (MW)

	Regional Winter Peak (MW)				Regional Summer Peak (MW)			
	Low Case	Price-effect	High Case	Sales Forecast (Net of Conservation)	Low Case	Price-effect	High Case	Sales Forecast (Net of Conservation)
1986		27,515				22,069		
1987		28,241				22,651		
1988		29,885				23,970		
1989		31,150				24,985		
1990		31,515				25,277		
1991		32,021				25,683		
1992		31,340				25,137		
1993		31,775				25,486		
1994		31,440				25,217		
1995		31,840				25,538		
1996		36,118				26,644		
1997		33,292				25,287		
1998		35,971				28,198		
1999		30,753				27,156		
2000		31,910				27,636		
2001		30,215				22,697		
2002		28,883				26,002		
2003		29,395				27,391		
2004		32,936				26,752		
2005		32,654				26,961		
2006		32,951				28,275		
2007		33,908				28,084		
2008		34,811				29,702		
2009	33,700	33,704	33,707	33,704	28,591	28,591	28,592	28,591
2010	33,572	34,184	34,611	33,823	28,517	29,211	29,706	29,039
2011	33,948	34,774	35,347	34,029	29,074	29,912	30,513	29,548
2012	34,280	35,248	35,841	34,092	29,649	30,530	31,080	29,959
2013	34,376	35,559	36,185	33,970	29,865	30,896	31,419	30,106
2014	34,571	35,995	36,699	33,953	30,249	31,457	32,022	30,438
2015	34,678	36,323	37,132	33,793	30,476	31,825	32,473	30,575
2016	34,898	36,741	37,681	33,700	30,875	32,336	33,107	30,849
2017	35,130	37,167	38,249	33,577	31,299	32,862	33,763	31,122
2018	35,313	37,525	38,718	33,322	31,660	33,295	34,274	31,267
2019	35,420	37,807	39,109	32,970	31,922	33,629	34,676	31,307
2020	35,412	37,977	39,397	32,479	32,027	33,800	34,923	31,193
2021	35,557	38,350	39,926	32,191	32,359	34,262	35,513	31,378
2022	35,734	38,783	40,550	31,948	32,734	34,805	36,224	31,667
2023	35,907	39,237	41,235	31,731	33,102	35,371	37,008	32,004
2024	36,056	39,698	41,937	31,501	33,431	35,934	37,799	32,341
2025	36,211	40,177	42,666	31,365	33,764	36,509	38,615	32,647
2026	36,352	40,655	43,405	31,244	34,106	37,101	39,432	32,950
2027	36,487	41,159	44,187	31,293	34,441	37,740	40,320	33,355
2028	36,637	41,693	45,033	31,466	34,808	38,423	41,305	33,855
2029	36,786	42,245	45,898	31,668	35,174	39,133	42,317	34,392
2030	36,949	42,814	46,788	32,202	35,559	39,865	43,360	35,043
2010-2030	0.5%	1.1%	1.5%	-0.25%	1.1%	1.6%	1.9%	0.94%

Chapter 4: Conservation Supply Assumptions

Summary of Key Findings	1
Recent Changes Since the Fifth Power Plan.....	2
Federal Standards.....	3
New Sources of Potential Savings	4
Estimating the Cost of Conservation	4
Resource Potential Estimates by Sector.....	6
Residential Sector	6
Agriculture Sector.....	8
Commercial Sector.....	9
Industrial Sector	11
Utility Distribution Systems	12
Consumer Electronics	13
Estimating the Availability of Conservation Over Time	14
The Pace of Historic Conservation Achievements	15
Estimating the Annual Availability of Future Conservation Development.....	17
Testing Annual Pace Constraints for the Portfolio Model.....	19
Council Methodology	20
Implications for the State of Washington’s I-937 Requirements.....	22

SUMMARY OF KEY FINDINGS

The Council defines conservation as improved energy efficiency. This means that less electricity is used to provide the same level of services. Conservation resources are measures that ensure that new and existing residential buildings, household appliances, new and existing commercial buildings, commercial-sector appliances, commercial infrastructure such as street lighting and sewage treatment, and industrial and irrigation processes are energy-efficient. These efficiencies reduce operating costs and ultimately decrease the need to build new power plants. Conservation also includes measures to reduce electrical losses in the region's generation, transmission, and distribution system.

The Council identified nearly 7,000 average megawatts of technically achievable conservation potential in the medium demand forecast by the end of the forecast period. Most of this potential, about 6,000 average megawatts, is available at a levelized (net) life-cycle cost of up to \$200 per megawatt-hour (2006 dollars). Sources of achievable potential savings are about 50 percent higher than in the Fifth Power Plan.¹ The assessment is higher for two principle reasons. First, the Council identified new sources of savings in areas not addressed in the Fifth Power Plan: consumer electronics, outdoor lighting, and the utility distribution system. Second, savings potential has increased significantly in the residential sector as a result of technology improvements and in the industrial sector as a result of a more detailed conservation assessment.

¹ For purposes of comparison, the Council’s Fifth Power Plan estimated that the achievable conservation was approximately 3,900 average megawatts at cost up to \$120 per megawatt-hour. This plan’s estimate of achievable potential is 5,860 average megawatts at an equivalent levelized life-cycle cost.

Not all of the nearly 7,000 average megawatts identified are cost-effective to develop. The Council uses its portfolio model to identify the amount of conservation that can be economically developed. The results presented in this chapter serve as an input to the resource portfolio model (RPM) which will test varying amounts of conservation against other resource options across a wide range of future conditions. The results of the RPM analysis are presented in Chapter 10.

The achievable savings at cost up to \$200 per average megawatt break down as follows:

- About 2,600 average megawatts of conservation are technically achievable in the residential buildings and appliances sector. Most of the savings come from improvements in water-heating efficiency and heating, ventilating, and air-conditioning efficiency.
- Over 800 average megawatts of potential savings are estimated in the fast-growing consumer electronics sector. These savings come from more efficient televisions, set top boxes, desktop computers, and monitors primarily in homes but also in businesses.
- Approximately 100 average megawatts of conservation are available in the agriculture sector through irrigation system efficiency improvements, improved water management practices, and dairy milk processing.
- Over 1,400 average megawatts of potential savings are available from the commercial sector. Nearly two-thirds of commercial savings are in lighting systems. New technologies like light-emitting diodes and improved lighting fixtures and controls offer added potential savings in both outdoor and indoor lighting.
- Potential savings in the industrial sector are estimated to be nearly 800 average megawatts by the end of the forecast period. The industrial assessment found that effective business management practices could significantly increase savings from equipment and system optimization measures.
- Finally, potential savings from improved efficiency in utility distribution systems are estimated to be about 400 average megawatts by the end of the forecast period.

While there are a number of barriers to achieving these savings, the Council believes these challenges can be met.

RECENT CHANGES SINCE THE FIFTH POWER PLAN

The Fifth Power Plan recommended that the region develop at least 700 average megawatts of conservation savings from 2005 through the end of 2009. Based on surveys conducted by the Council's Regional Technical Forum, regional conservation programs already achieved savings of 700 average megawatts by the end of 2008 and are likely to achieve a total savings of over 900 average megawatts by the end of 2009.

Federal Standards

Since the Fifth Power Plan was adopted, Congress enacted the 2007 Energy Independence and Security Act (EISA) and the Department of Energy has promulgated several new standards. The EISA legislation revised several existing federal efficiency standards and established new standards as well. The most significant EISA standard requires “general service lighting” (40 - 100 watt lamps) to be at least 30 percent more efficient beginning in 2012, and 60 percent more efficient beginning in 2020. The Fifth Power Plan estimated that converting standard incandescent bulbs to compact fluorescent light bulbs (CFL) could save the region 625 average megawatts by 2025. The EISA standard does not cover all incandescent bulbs. For example, bulbs over 100 watts, parabolic reflector lamps, candelabra, and 3-way light bulbs are exempt. These standards phase in beginning with a 30 percent improvement in efficiency for 100 watt general service lamps in 2012 and end with a 60 percent improvement in efficiency for all 60 to 100 watt general service lamps in 2020. The Council estimates that approximately 285 average megawatts of regional conservation potential remains to be captured in residential lighting prior to 2020 and from lamps not covered by those standards. Savings from lamps covered by the initial phase of EISA should count toward the region’s conservation target in 2010 and 2011.

EISA also sets minimum standards for certain commercial lighting products that were incorporated into the conservation assessment and load forecast. In addition, new efficiency standards were developed and adopted since 2004 for a suite of residential and commercial appliances regulated by federal law or state standards. Baseline assumptions for energy use of new appliances and equipment have been updated in the new conservation assessment to reflect these improved standards. Table 4-1 shows a summary of all the federal standards that have changed since the adoption of the Fifth Power Plan and the effective dates of these new and/or revised standards.

**Table 4-1: New or Revised Federal Standards Incorporated in Sixth Power Plan
Conservation Assessment Baseline Assumptions**

Product Regulated	Effective Date
Battery Chargers and External Power Supplies	July 1, 2008
Clothes Washers (Residential)	January 1, 2007
Clothes Washers (Commercial)	January 1, 2011
Consumer dehumidifier products	October 1, 2012
Dishwashers (Residential)	January 1, 2010
Ice Makers (Commercial)	January 1, 2010
Motors	December 17, 2010
Distribution Transformers (Low Voltage)	January 1, 2007
Distribution Transformers (Medium-voltage, dry-type and Liquid-immersed distribution transformers)	January 1, 2010
Packaged Air Conditioners and Heat Pumps (Commercial - $\geq 65,000$ Btu/h)	January 1, 2010
Refrigerators and Freezers (Commercial)	January 1, 2010
Single-Package Vertical Air Conditioners and Heat Pumps	January 1, 2010
Walk-In Coolers and Walk-In Freezers (Commercial)	January 1, 2009
Ceiling Fan Light Kits	January 1, 2007
Compact Fluorescent Lamps (Efficacy and Rated Life)	January 1, 2006
Exit Signs	January 1, 2006
Fluorescent Lamp Ballasts	Beginning October 1, 2009 and phasing in through July 2010
Incandescent General-Service Lamps	Beginning January 1, 2012 and phasing in through 2014
Incandescent Reflector Lamps	June 1, 2008
Metal Halide Lamp Fixtures	January 1, 2009
Torchieres	January 1, 2006

New Sources of Potential Savings

Additional savings were identified from utility distribution systems. Distribution system savings, including voltage management and system optimization, add about 400 average megawatts of conservation potential not included in the Fifth Power Plan assessment.

A more in-depth analysis of the industrial sector more than doubled the conservation potential identified in the Fifth Power Plan.

Along with these major adjustments, the conservation assessment incorporates new conservation opportunities brought about by technological advances. For example, recent advances in solid-state lighting--light-emitting diodes (LED) and organic light-emitting diodes (OLED)--appear to offer significant opportunities for savings in televisions and some lighting applications. The arrival in the U.S. market of ductless heat pumps for space heating also provides new savings opportunities.

ESTIMATING THE COST OF CONSERVATION

The Council determines the total resource cost of energy savings from all measures that are technically feasible. This process requires comparing all the costs of a measure with all of its benefits, regardless of who pays those costs or who receives the benefits. In the case of efficient clothes washers, the cost includes the difference (if any) in retail price between the more efficient

Energy Star model and a standard efficiency model, plus any utility program administrative and marketing costs. On the other side of the equation, benefits include the energy (kilowatt-hour) and capacity (kilowatt) savings, water and wastewater treatment savings, and savings on detergent costs.² While not all of these costs and benefits are paid by or accrue to the region's power system, they are included in the evaluation because ultimately, it is the region's consumers who pay the costs and receive the benefits.

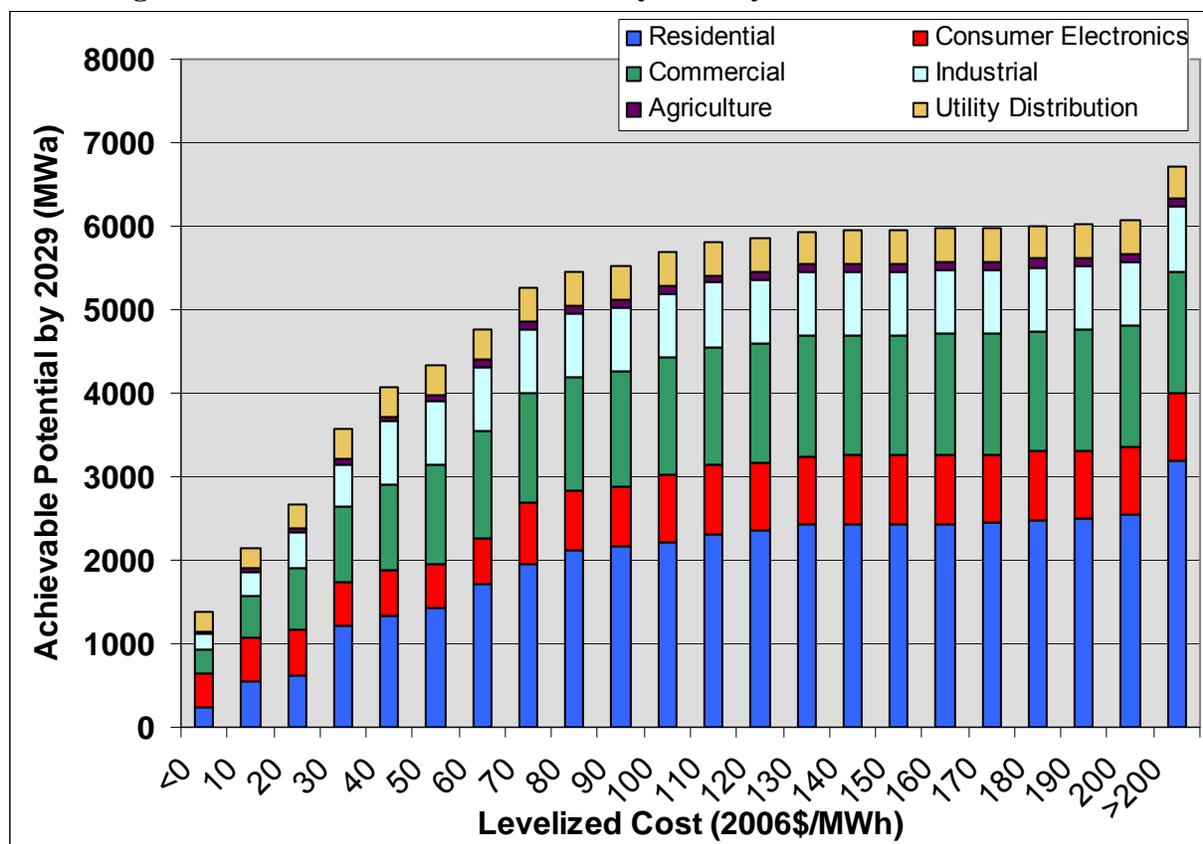
Once the *net cost* (levelized over the life of the conservation resource) of each of the conservation technologies or practices is determined, the technologies are ranked by cost in two supply curves that depict the amount of conservation resource available in the region. These net levelized costs of conservation are calculated the same way that levelized costs of new generating resources are calculated so they can be compared.

One supply curve represents all of the retrofit or non-lost opportunity resources. The other represents all the lost-opportunity conservation resources.³ The Council divides conservation resources into these two categories because their patterns of deployment are different. Non-lost opportunity conservation resources can be deployed at any time. Lost-opportunity resources are only available during specific periods; for example, when new buildings are built with improved insulation. Savings from most appliances are available only as appliance stock turns over. If the savings from these lost-opportunity resources are not acquired within this limited window of opportunity, they are treated as lost and no longer available at that time or cost.

Figure 4-1 shows the Sixth Power Plan's estimate of the amount of conservation available by sector and levelized life-cycle cost. The Council identified about 6,000 average megawatts of achievable conservation potential in the medium demand forecast by the end of the forecast period at a levelized life-cycle cost of up to \$200 per megawatt-hour (2006 dollars). New sources of potential savings result in about 50 percent more achievable potential compared to the Fifth Power Plan. Slightly less than half of the potential is from lost-opportunity measures.

² Energy-efficient clothes washers use less water and require less detergent.

³ Lost-opportunity resources can only be technically or economically captured during a limited window of opportunity, such as when a building is built or an industrial process is upgraded.

Figure 4-1: Achievable Conservation by 2029 by Sector and Levelized Cost

RESOURCE POTENTIAL ESTIMATES BY SECTOR

Residential Sector

In the Fifth Power Plan, the Council estimated that approximately 1,600 average megawatts of conservation potential was technically available in the residential sector from improvements in lighting, appliances, and water-heating technologies at a levelized cost of less than \$120 per megawatt-hour (2006 dollars). The Sixth Power Plan's estimate for these same end-uses places the remaining technically achievable conservation at nearly 2,600 average megawatts at an equivalent cost.

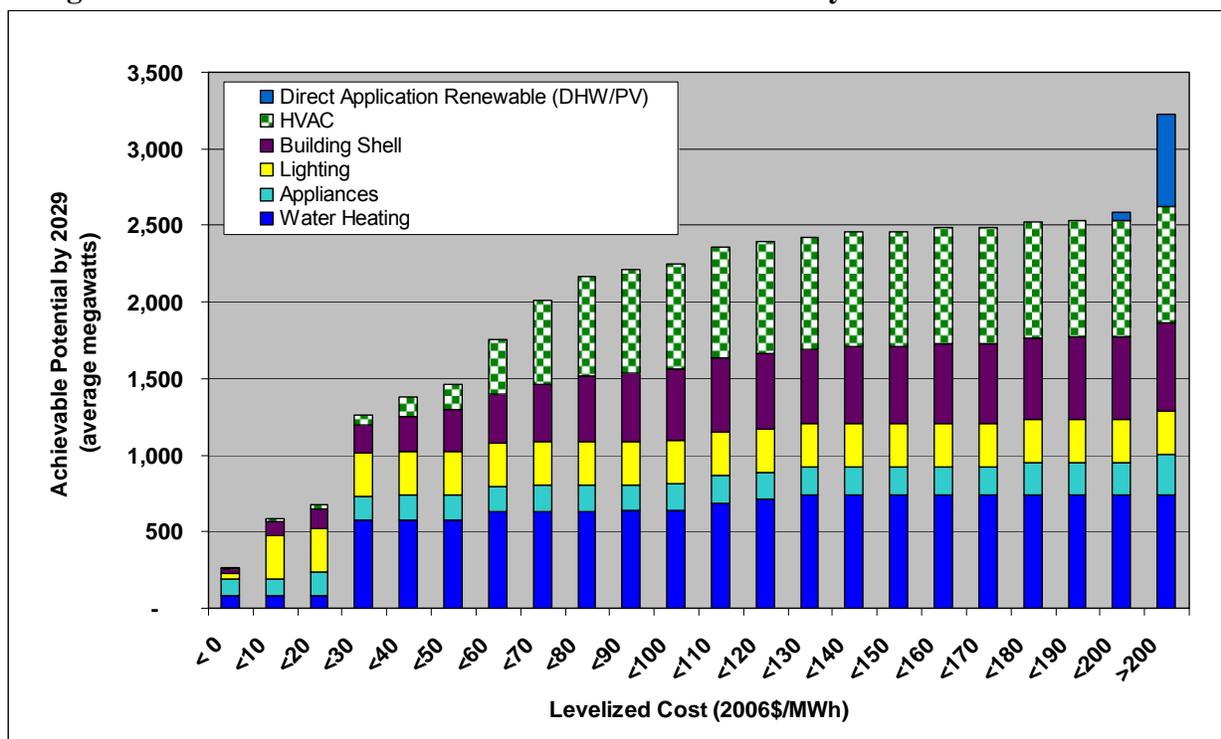
The largest decrease (475 average megawatts) in residential-sector potential came from the new federal efficiency standards for lighting. Figure 4-2 shows the residential resource potential by major category and cost. The figure shows that the largest remaining savings come from improvements in water-heating efficiency and heating, ventilating, and air conditioning (HVAC) efficiency. These increases in residential sector potential stem from greater availability of heat pump water heaters, the introduction of ductless heat pumps to the U.S. market, and cost reductions for high-efficiency heat pumps.

Since the adoption of the Council's Fifth Power Plan, the Northwest Energy Efficiency Alliance (NEEA), with the support of the Bonneville Power Administration and other regional utilities, and in cooperation with the Energy Trust of Oregon, launched a regionwide market

transformation program to encourage the installation of split-system heat pumps. These systems, referred to as “ductless heat pumps,” do not use forced-air ducts to perform their heating and cooling function. Instead, they distribute the hot or cold refrigerant created by an outside unit to inside units through refrigerant lines. The advantage of these systems is that they can be more easily installed in homes with electric resistance zonal heating systems (baseboard, ceiling radiant, or wall fan units). While these systems are used throughout Northern Europe and all across Asia, Australia, and New Zealand, they have only recently been promoted in the U.S. If the savings and cost estimates adopted by the Regional Technical Forum are confirmed through NEEA’s market transformation venture, this technology has the potential to reduce regional space-heating use by approximately 200 average megawatts at a cost of less than \$60 per megawatt-hour.

The Council’s Fifth Power Plan estimated that regional electric water-heating use could be reduced by approximately 200 average megawatts through the installation of heat pump water heaters commercially available at the time of the plan’s adoption.⁴ However, since there were no major water heater manufacturers producing heat pump water heaters, the Council’s estimate of potential savings from these heaters fell short.

Figure 4-2: Residential-Sector Achievable Conservation by Sector and Levelized Cost



Three major U.S. water heater manufacturers began producing heat pump water heaters in 2009. Consequently, the Council raised its estimate of the maximum penetration of these systems from 25 percent of single family and manufactured homes with electric water heat to 50 percent. Nevertheless, since these are new products, it is likely that their initial market penetration rates will be modest. The Council assumes that by the end of 2014 the market share of these heaters

⁴ A heat pump water heater uses a compressor that circulates hot refrigerant through a heat exchanger in a water tank to heat water rather than electric resistance elements.

will be just over 1 percent. However, by 2030 heat pump water heaters could reduce regional electric water heating use by over 490 average megawatts at a cost less than \$30 per megawatt-hour.

The third largest increase in residential sector potential came from the lower costs of high-efficiency heat pumps for space heating. When the Fifth Power Plan was adopted, the minimum federal standards for heat pumps and air conditioners had just gone into effect. As a result, there was little price competition among products that exceeded these new standards. Based on program data obtained from the Energy Trust of Oregon, high performance heat pump costs have come down. Moreover, it now appears that heat pumps with a minimum performance level of 17 percent above the federal standards are more cost competitive than those that only exceed the federal standards by 10 percent. At a levelized life-cycle cost of less than \$80 per megawatt-hour, there are almost 375 average megawatts of savings available from converting new and existing single family and manufactured homes with electric forced-air furnaces to high-performance heat pumps. At less than \$80 per megawatt-hour, the potential savings from upgrading new and existing homes with higher efficiency heat pumps are 100 average megawatts.

Agriculture Sector

The Fifth Power Plan identified approximately 100 average megawatts of conservation potential available in the region through efficiency improvements in irrigation system hardware. Since the Fifth Power Plan, almost 685,000 acres have been added as land irrigated by pressurized sprinkler systems. However, due to improvements in system efficiency, such as the conversion to low-pressure delivery systems and improved water management, total estimated regional electricity use for irrigation decreased from 655 average megawatts to 645 average megawatts.

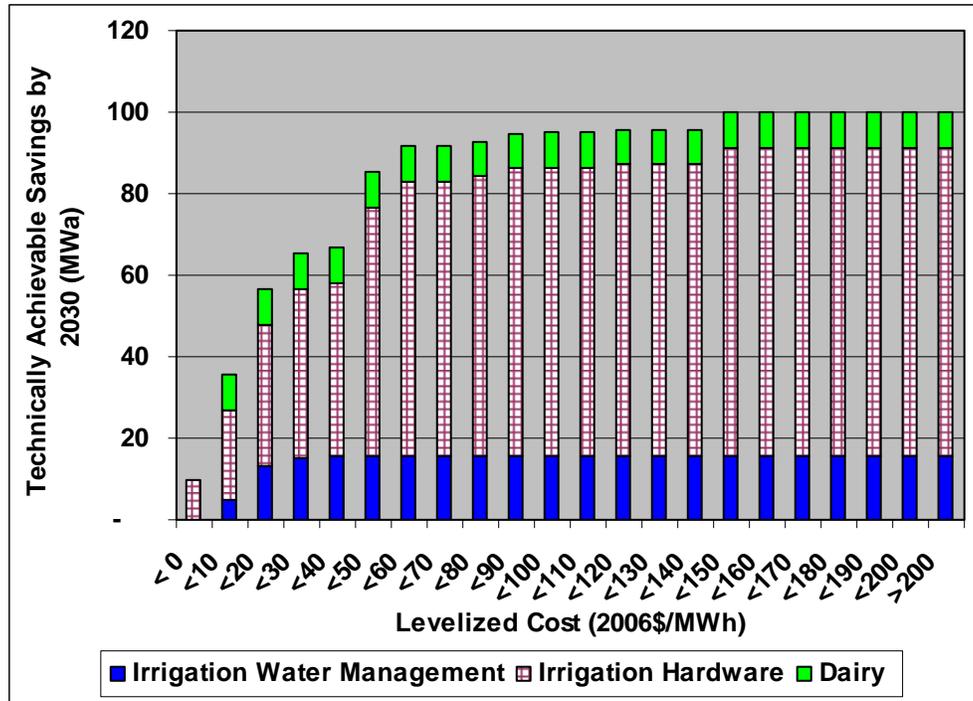
After accounting for these changes, the Council estimates that approximately 75 average megawatts of conservation remains available through hardware efficiency improvements such as pump efficiency, leak reduction, conversion to lower pressure applications, and better sprinkler/nozzle management practices at costs significantly below \$100 per megawatt-hour.

Along with improving irrigation system hardware, better water management practices could also reduce the energy consumed in irrigation. Despite some of the measure's limitations due to state-specific water laws, over 15 average megawatts of conservation potential are available in the region through scientific irrigation water scheduling. More potential exists if mechanisms can be found to ensure that irrigation water savings on one farm are not consumed by additional irrigation on farms with junior water rights.

Non-irrigation "on farm" electricity use in the remainder of the agriculture sector is dominated by dairy milk production. According to the Department of Agriculture, the region produced approximately 20 billion pounds of milk in 2007. Idaho and Washington rank among the top 10 states in milk production and Oregon ranks 18. The Council estimates that 2007 electricity use for dairy milk production was approximately 55 average megawatts. Many of the dairies in the region, and particularly in Idaho, were established and/or enlarged within the last decade. Consequently, many already have energy-efficient lighting, pumps, and milk cooling equipment. Nevertheless, the Council estimates that approximately 10 average megawatts of conservation potential is available through improvements such as variable-speed drives on milking machine

vacuum pumps, the use of flat-plate heat exchangers for pre-cooling milk prior to refrigeration, and improved lighting. A summary of the technically achievable conservation in the agriculture sector is shown in Figure 4-3

Figure 4-3: Agriculture Sector Achievable Conservation by 2030 (MWa) by Sector and Levelized Cost



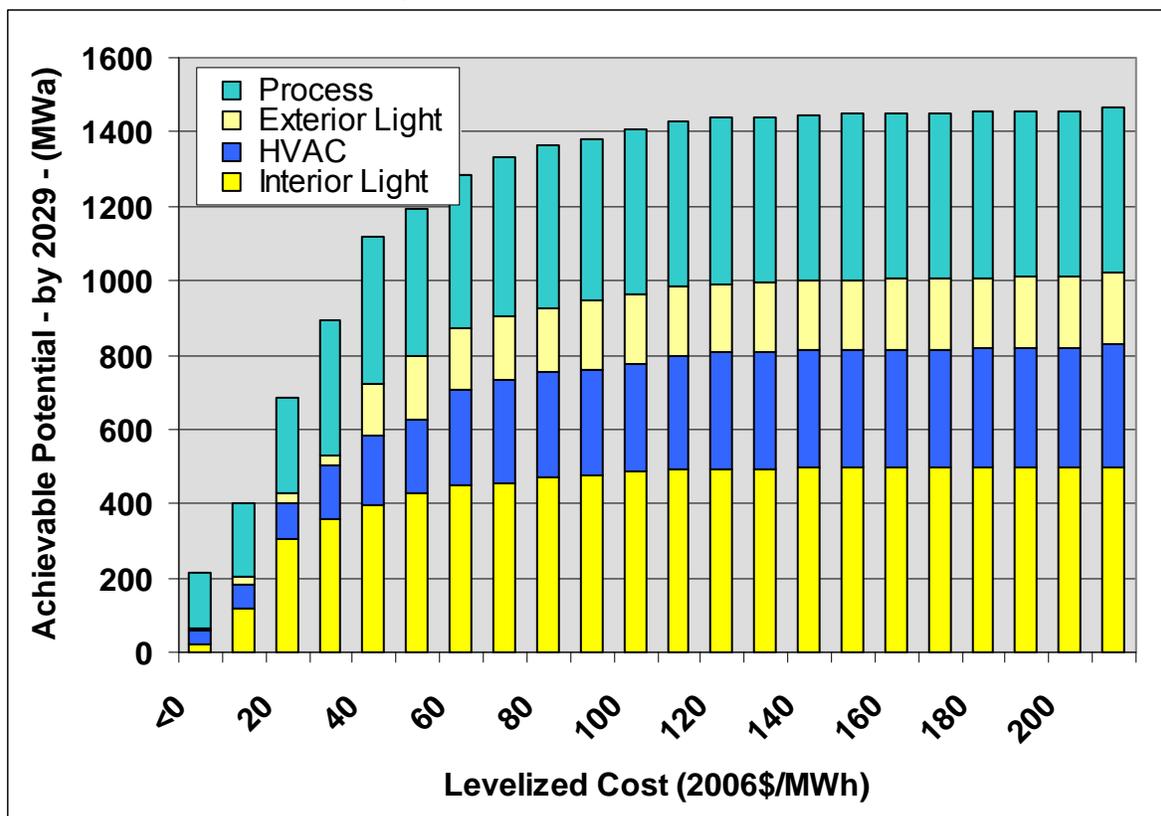
Commercial Sector

Over 250 commercial-sector conservation measures were analyzed to develop the conservation potential for the Sixth Power Plan. The assessment includes lighting, heating, ventilation, and air conditioning (HVAC), and envelope measures in 19 separate building types such as offices, retail stores, warehouses, and schools. The assessment covers several classes of electricity-intensive process equipment used in buildings such as refrigerators, computers, and ventilation hoods. The assessment also covers infrastructure activities such as street and highway lighting, municipal sewage treatment, and municipal water supply.

The aggregate Sixth Power Plan conservation potential is similar to what was identified in the Fifth Power Plan, over 1,400 average megawatts. However, the allocations by measure and end use are different. For the Sixth Power Plan, there is more conservation potential in lighting and less in HVAC. Updated analysis has reduced conservation potential for several key HVAC measures that appeared in the Fifth Power Plan. However, new technology and design practices in lighting offer more potential than identified five years ago. In addition, the Sixth Power Plan identifies savings in areas not addressed in the Fifth Power Plan, including interior lighting controls, outdoor lighting, street and highway lighting, and computer server rooms. A summary of the supply curves by major end-use category is shown in Figure 4-4.

Lighting efficiency measures top the list of commercial conservation potential. Improvements in fluorescent lights, fixture efficiency, lighting controls, and improved lighting design contribute to the large and low-cost potential available for indoor lighting. The availability of new lights such as light-emitting diodes (LED) and improved emerging technologies such as ceramic metal halide lighting also contribute to the large lighting conservation potential. For example, streetlight, parking lot, and outdoor-area lighting can now take advantage of emerging LED technology in certain applications and reduce consumption 25 to 50 percent.

Figure 4-4: Achievable Commercial Sector Savings Potential by 2029 (MWa) by End Use and Levelized Cost



Nearly two-thirds of commercial-sector conservation potential identified in the Sixth Power Plan is lost-opportunity conservation. The increase in lost-opportunity conservation compared to the Fifth Power Plan is primarily due to a revised approach to modeling natural lighting stock turnover as a lost-opportunity conservation measure. Retrofit conservation is more expensive than lost-opportunity conservation, so overall costs of commercial conservation are somewhat lower than in the Fifth Power Plan. Two-thirds of the conservation potential costs less than \$40 per megawatt-hour.

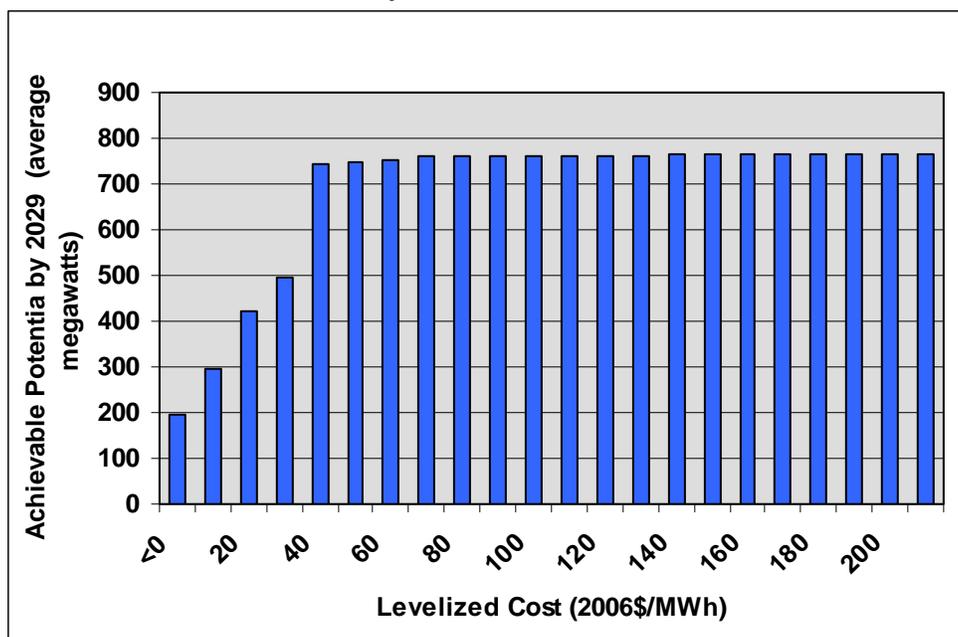
Much of the remaining conservation potential in the commercial sector requires a high degree of human intervention to achieve it. For example, careful choice of lamp, ballast, fixture, control, and layout are needed to install highly efficient lighting systems with excellent visual characteristics. In order to increase a building's efficiency beyond energy code requirements, improved building design practices are also needed. Relatively sophisticated HVAC engineering, smart control systems, and careful system operations are needed to harvest much of

the low-cost HVAC energy savings. In addition, the commercial sector is complex, with a variety of decision makers and market channels that can deliver high-efficiency equipment and well-trained designers and system operators. Implementation strategies will need to take these factors into consideration in the design of efficiency programs and market interventions.

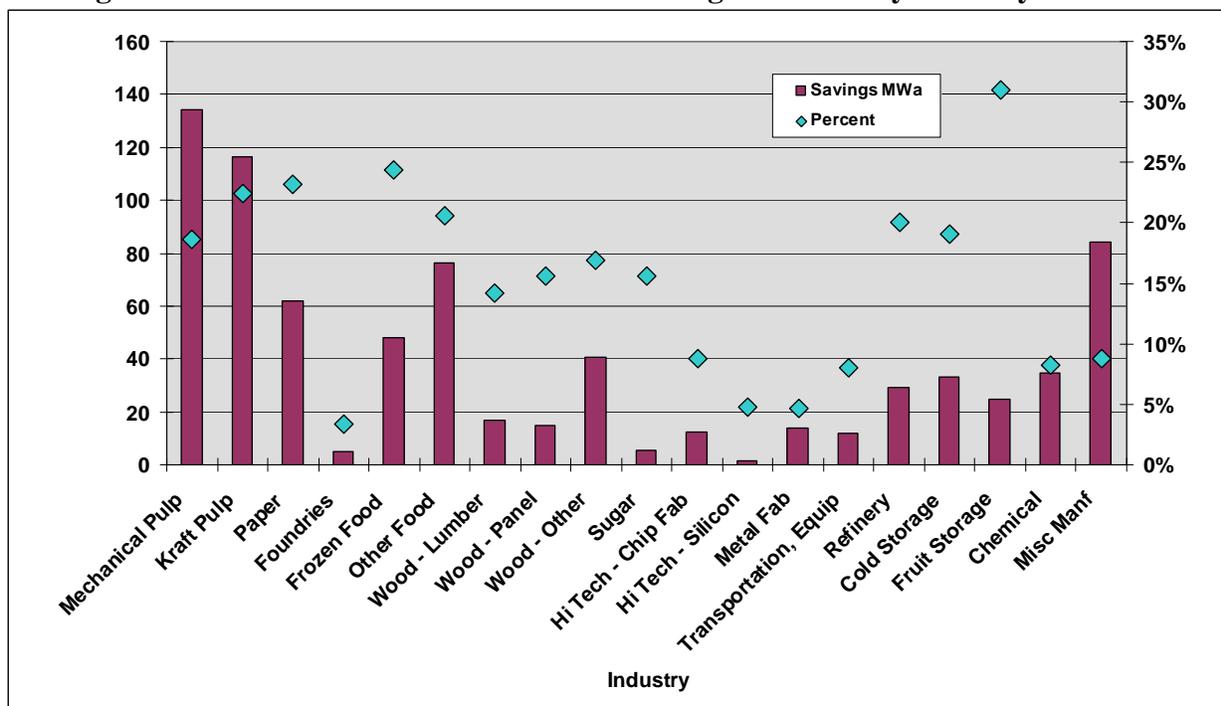
Industrial Sector

In the Fifth Power Plan, the industrial sector's potential was estimated to be 5 percent of 2025 sales, or 350 average megawatts. For the Sixth Power Plan, the Council, with financial support from the Bonneville Power Administration, contracted an in-depth study of industrial-sector potential. The industrial-sector conservation assessment evaluates 63 conservation measures and practices as they apply to 19 Northwest industries. This research indicates potential savings of nearly 800 average megawatts by 2029. Industrial savings are low cost. Nearly all of the savings have levelized costs of less than \$50 per megawatt-hour. Almost half the savings costs \$20 per megawatt-hour or less. Figure 4-5 shows the savings achievable by 2029 in the industrial sector.

Figure 4-5: Achievable Industrial Sector Savings Potential by 2029 (MWA) by Levelized Cost



Savings vary by industry both in average megawatts and as a fraction of industry electric use. The pulp and paper industry has the largest overall potential for electric savings, over 300 average megawatts. The food processing and food storage industries are the second largest with about 200 average megawatts of potential. Savings as a fraction of electricity use range from 4 percent in foundries to nearly 25 percent. Savings fractions are relatively high in the food processing and storage industries. These facilities use large amounts of electricity for refrigeration, freezing, and controlled-atmosphere storage. Significant efficiency improvements are available for those end-uses. Sectorwide, potential savings are about 15 percent of industry electric use. Figure 4-6 shows savings for the industry subsectors.

Figure 4-6: Achievable Industrial Sector Savings Potential by Industry Subsector

The 63 measures include an array of efficient equipment, improved operations and maintenance, demand reduction, system-sizing, system optimization, and improved business management practices. About one-quarter of the savings are specific to industry subsectors such as refiner plate improvements in mechanical pulping, or refrigeration improvements in frozen food processing. About three-quarters of the savings are applicable in pump, fan, compressed air, lighting, and material handling systems that occur across most industry subsectors. For these measures, the savings come primarily from more efficient equipment and system optimization. The assessment also found that effective business management practices can significantly increase equipment and operational savings.

Most industrial conservation measures are complex and require considerable design and careful implementation. Many measures and practices need continuing management and operational attention to ensure continued savings. The human factor to achieve these savings is also critical. Implementation strategies will need to take these factors into consideration in the design of efficiency programs and market interventions.

Utility Distribution Systems

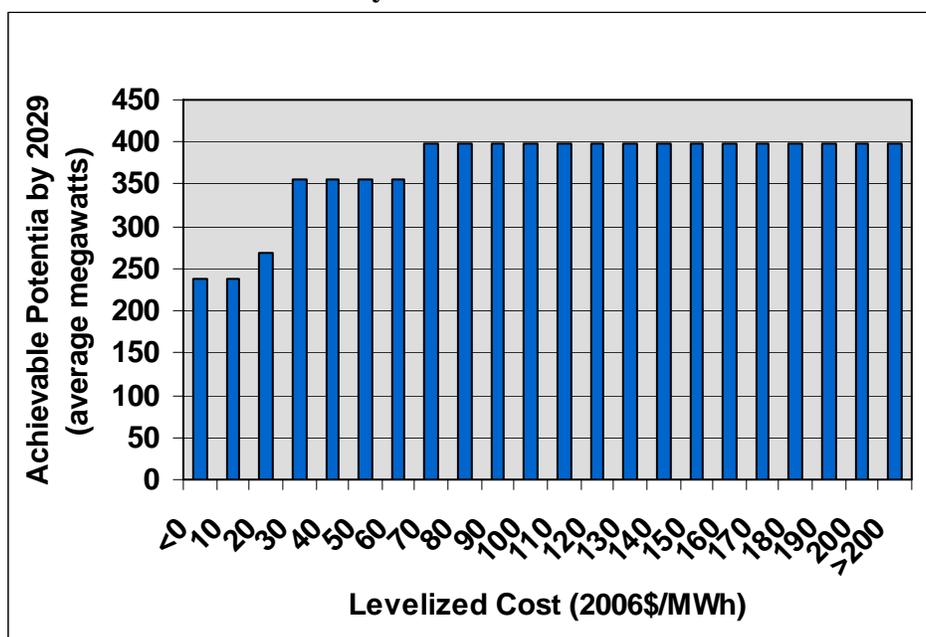
Potential savings from utility distribution systems come from a NEEA project to improve the efficiency of utility distribution systems. Based on the results of a pilot program in six utilities across the region, the study demonstrated that operating a utility distribution system in the lower portion of the acceptable voltage range (120-114 volts) saves energy, reduces demand, and reduces reactive power requirements without hurting the customer. As a package, these measures are referred to as conservation voltage reduction.

Reducing excess voltage saves energy for both the customer and the utility. Savings could amount to about 400 average megawatts by 2029. Levelized costs for distribution savings are low. Figure 4-7 shows that two-thirds of potential savings cost less than \$30 per megawatt-hour.

These savings stem from several types of changes to distribution equipment and operations. They include system improvements that reduce primary and secondary line losses, optimize reactive power management on substation feeders and transformers, and balance feeder voltage and current. These improvements help limit the total voltage drop on the feeder from the substation to the customer's meter while staying within industry standards. The NEEA study results indicate energy savings of 1 to 3 percent, a kilowatt peak-demand reduction of 2 to 5 percent, and a reactive power reduction of 5 to 10 percent. Approximately 10 to 40 percent of the savings are on the utility side of the meter.

There are a number of barriers, however, to implementing voltage regulation. These include regulatory disincentives, the need for outside assistance, lack of verification protocols to prove savings, and organizational challenges within utilities. The Council believes most of these barriers can be addressed and that near-term savings are achievable.

Figure 4-7: Achievable Utility Distribution System Efficiency Savings Potential (MWA) by Levelized Cost



Consumer Electronics

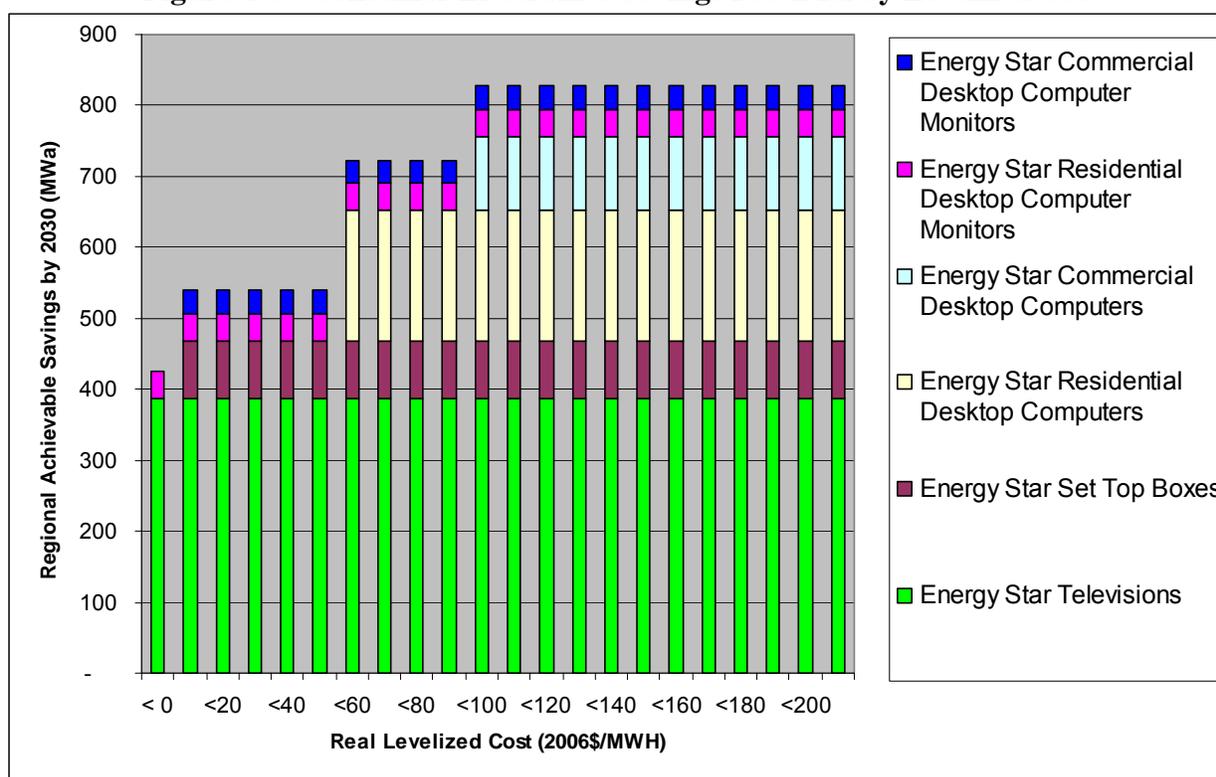
Consumer electronics, such as televisions, set top boxes (digital video recorders, satellite and cable television tuners, digital television converters), computers and monitors, is one of the fastest growing segments of electricity use in the region. This increase is driven by both the growth of these devices and the additional features that increase energy use. For example, in 2007, the number of televisions in the average home exceeded (2.73) the average number of occupants (2.6) for the very first time. If current trends continue, it is anticipated that by 2015

over 90 percent of the televisions sold will have screen sizes exceeding 32 inches. Energy consumption increases with screen size.

There are a significant number of options available to increase the efficiency of these devices. Some of these options simply involve better power management of this equipment when it is not in use. Other options, especially for televisions and computer monitors, will involve the transition from plasma and liquid crystal display (LCD) screens to LED and OLED screens. LED televisions already on the market consume 40 percent less than comparably sized models using LCD technology, while also producing a higher quality picture.

Figure 4-8 shows the achievable potential from improvements in consumer electronics totaling 825 average megawatts by the year 2029. Most of the savings potential, over 700 average megawatts, is available at a levelized life-cycle cost of less than \$60 per megawatt-hour. Moreover, as can be seen in this figure, over half of these savings are from improving the efficiency of televisions.

Figure 4-8: Consumer Electronics Savings Potential by Levelized Cost



ESTIMATING THE AVAILABILITY OF CONSERVATION OVER TIME

The Council establishes constraints on the availability of the conservation in these supply curves, which are used in the Council’s portfolio modeling process. The portfolio model selects the quantity and timing of both generating and conservation resource development. Because significant quantities of conservation are available at costs below most forecasts of future market

prices, the portfolio model would deploy all of the low-cost conservation immediately, unless the pace of conservation deployment is constrained to achievable rates.

Therefore, the Council establishes two types of constraints on the amount of conservation available for development. The first constraint is the maximum achievable potential over the 20-year period covered by the Council's power plan. The Sixth Power Plan assumes that no more than 85 percent of the technically feasible and cost-effective savings can be achieved.⁵

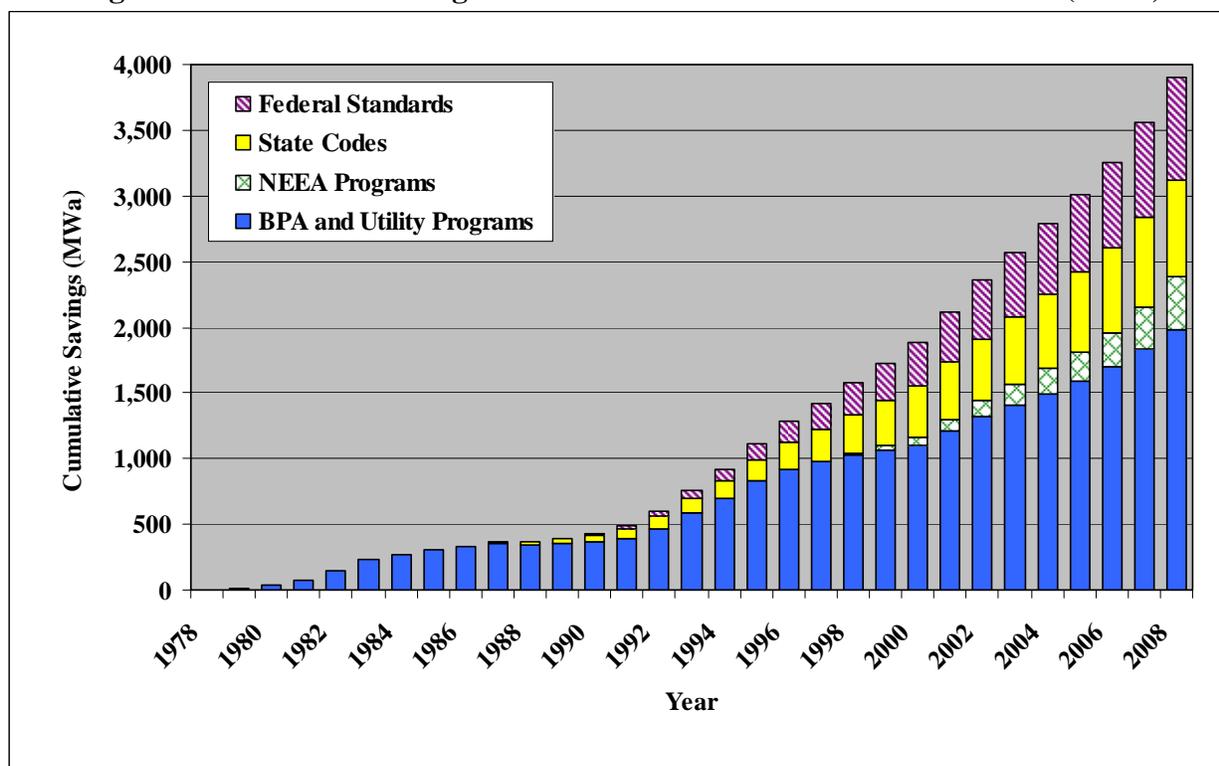
The second constraint is the rate of annual deployment, which represents the upper limit of annual conservation resource development based on implementation capacity. Such constraints include the relative ease or difficulty of market penetration, regional experience with the measures, likely implementation strategies and market delivery channels, availability of qualified installers and equipment, the number of units that must be addressed, the potential for adoption by building code or appliance standards, and other factors.

The upper limit of annual conservation resource development reflects the Council's estimate of the maximum that is realistically achievable. Since there is no perfect way to know this limit, the Council used several approaches to develop estimates of annual achievable conservation limits. First, the Council reviewed historic regional conservation achievements and considered total achievements, as well as year-to-year changes. The Council also considered future annual pace constraints for the mix of conservation measures and practices on a measure-by-measure basis. As in the Fifth Power Plan, annual deployment limits were developed separately for lost-opportunity and non-lost opportunity conservation.

The Pace of Historic Conservation Achievements

Over the last 30 years, the region acquired nearly 4000 average megawatts in energy savings. Annual rates of conservation acquisition vary considerably. Figure 4-9 shows the Council's estimate of cumulative regional conservation achievements since 1978. Figure 4-10 shows annual program conservation acquisitions since 1991, excluding savings from codes or standards.

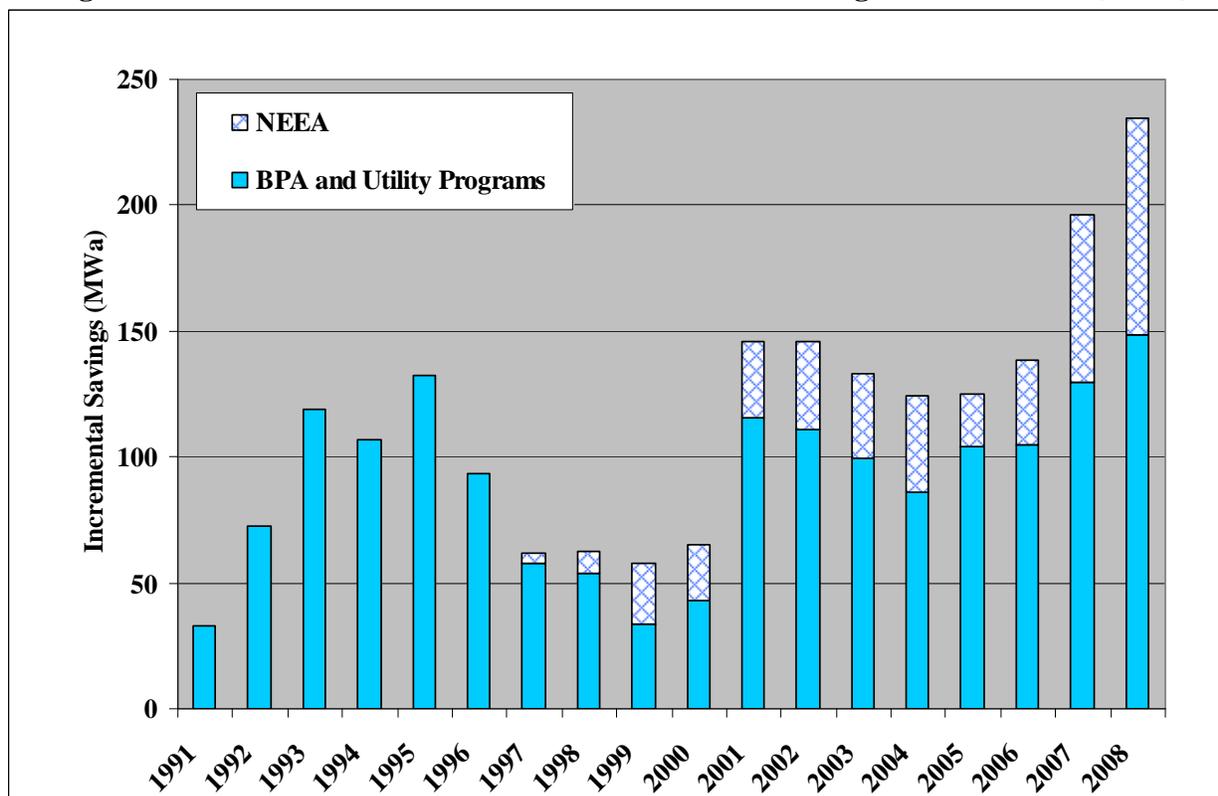
⁵ In 2007, Council staff compared the region's historical achievements against this 85 percent planning assumption. The results of this review supported continued use of the estimate, or perhaps even the adoption a higher one in the Sixth Power Plan. The paper is on the Council website at <http://www.nwcouncil.org/library/2007/2007-13.htm>.

Figure 4-9: Cumulative Regional Conservation Achievement 1978-2008 (MWa)

Over this 30-year period, the mix of measures has changed significantly. Early years were dominated by residential programs. In the 1990s, commercial and industrial programs were added. Starting in the mid-1980s, state building codes began to capture significant savings. About five years later, federal appliance standards also added savings. Fluctuations in annual achievements, shown in figure 4-10, were caused by many factors. For example, response to the energy crisis of 2000-2001 brought on a surge in conservation achievement, more than doubling the annual conservation acquisition rate between 2000 and 2001. And the threat of retail competition in the late-1990s was a key factor in the drop in utility-sponsored conservation activity in that period.

Over the last 20 years, state building codes and federal and state appliance standards have accounted for over one-third of all savings. Savings from codes and standards accumulate slowly over time. They do not result in large annual jumps in acquisition because they apply only to new buildings or replacement equipment. Furthermore, code and standard savings would not have been possible without utility programs that demonstrated the savings could be achieved.

Bonneville, utility, and Energy Trust of Oregon conservation programs, Oregon tax credits, NEEA market transformation, and other programs have delivered the bulk of the savings over time. Annually, these program savings ranged from lows of about 60 average megawatts per year to 235 average megawatts per year in 2008, the most recent year reported. Since 2001, regional programs, without codes and standards, delivered about 150 average megawatts per year on average. Annual rates of program acquisition since 2001 have been between 115 to 235 average megawatts per year, which is consistently higher than long-term annual rates for program delivery.

Figure 4-10: Annual Conservation Achievements from Programs 1991-2008 (MWa)

There were three historic periods when program savings showed fast acceleration. The 1991-1993 period, the 2000-2001 period, and more recently the 2005-2008 period. During these periods, regional program activities increased by over 40 average megawatts year-to-year, not counting codes and standards.

The Regional Technical Forum's survey of 2008 conservation achievements indicate that regional program savings alone are 235 average megawatts. Consequently, recent savings exceed the targets established in the Fifth Power Plan by a wide margin. The Fifth Power Plan's called for a cumulative 700 average megawatts between 2005 and 2009 through all mechanisms. If conservation acquisition continues to accelerate, it appears that the region will capture over 900 average megawatts through just Bonneville and utility programs alone, exceeding the targets by about 30 percent.

Estimating the Annual Availability of Future Conservation Development

To gauge the pace for future conservation development, the Council estimated how fast the region could develop the remaining conservation measures identified in the Sixth Power Plan. To do this, the Council estimated year-by-year acquisition rates for each of the measure bundles identified in the conservation assessment.

The results of this year-by-year and measure-by-measure analysis are only one indication of how fast the region could deploy conservation. Clearly, deployment efforts could shift from the assumptions made in this analysis. Acquisitions of specific measure bundles could accelerate or

slow down. Nevertheless, the annual limits give some idea of how fast conservation could be brought on line with multi-year acquisition strategies, ramp-up rates for new programs, and a more or less steady pace in the long run.

There are about 200 measure bundles that were considered in this analysis. Details of these assumptions are in the conservation appendices.

In estimating the level of conservation that could be achieved in the future, the Council considered several factors. For all measure bundles, the Council assumed multi-year acquisition plans. Depending on the measure, getting to full penetration could take as little as five years or as long as 20 years. The Council also considered retrofit and lost-opportunity measures differently. Table 4-2 shows the results of the year-by-year, measure-by-measure approach used to estimate the pace of conservation development. Energy savings represent total potential, regardless of cost.

**Table 4-2: Achievable Pace of Future Conservation Development
Approximate Savings Potential by Time Period (MWa)**

	Lost Opp	Non-Lost Opp	Total
20-Yr Cumulative	3,400	3,300	6,700
5-Yr Cumulative (2010-2014)	390	990	1,380
5-Yr Annual Ramp Up	35 to 120	170 to 220	200 to 340
5-Yr Annual Average	80	200	280

Most retrofit measures were paced at annual acquisition rates that require 15 to 20 years to accomplish. However, it was assumed that some retrofit measure bundles with simple, proven delivery mechanisms, like low-flow showerheads, could be accomplished in as little as five years. Annual acquisition rates for new retrofit initiatives or measures that have not been targeted previously, such as distribution-efficiency, were estimated to start slowly and accelerate to a steady annual pace. As a result, these new retrofit measures account for only about 20 percent of this five-year total because low penetration rates were assumed in the early years.

Measures that are already targeted by current programs were assumed to accelerate from a higher starting point. Across all retrofit opportunities the available potential increases from about 170 average megawatts in 2010 to 220 average megawatts per year by 2014. In aggregate, this results in nearly 1,000 average megawatts of retrofit conservation viewed as available potential in the first five years. This is about one-third of the Council's 3,300 average megawatt retrofit supply curve. At an average pace of only 160 average megawatts per year, it would take about 15 years to acquire the 2,400 average megawatts of retrofit potential that has an average cost less than \$30 per megawatt-hour.

For lost-opportunity measures, it was assumed that the maximum achievable pace of acquisition never exceeds 85 percent of the annual units available. The bulk of lost-opportunity measures were assumed to take five to 15 years to reach this 85 percent annual penetration rate. Lower (0.5 to 15 percent) first-year penetration rates were assumed for lost-opportunity resources new to regional programs because acquiring these measures is slower given the relative difficulty of deploying them. For lost-opportunity measures where the region has experience and for ongoing programs, such as residential appliances, first-year penetration rates were set relatively higher and with a faster ramp-up rate over time.

The annual acquisition for all lost-opportunity conservation measures start at a penetration rate of about 15 percent, increases to around 80 percent in 12 years, and reaches the assumed maximum 85 percent in 15 years. In aggregate, this results in about 390 average megawatts of available savings potential from lost-opportunity conservation resources over the first five years covered by the Sixth Power Plan. About one-third of these savings are from new measures in the plan. The maximum annual pace for lost-opportunity conservation accelerates from 35 average megawatts per year in 2010 to 120 average megawatts per year five years out, and to 200 average megawatts per year 10 years out.

In combination, this analysis indicates that nearly 1,400 average megawatts of lost-opportunity and retrofit conservation are available over the 2010-2014 action plan period. Maximum annual average acquisitions increase from 200 average megawatts per year in 2010 to almost 350 average megawatts per year within five years. The estimates of acquisition rates produced by this analysis are used to estimate annual pacing constraints in the portfolio model. Along with information on historic performance, and utility and NEEA plans, these estimates also help inform the Council's near-term conservation targets for the region.

Testing Annual Pace Constraints for the Portfolio Model

Because the maximum annual pace of conservation achievement is to a major extent a function of the level of resources dedicated to acquiring conservation, the Council performed sensitivity tests to estimate the impact of achieving conservation faster and slower than assumed in the base case. For a high-case sensitivity, the Council assumed a 10-year period to develop the first 2,400 average megawatts of retrofit conservation, instead of the 15 years assumed in the base case. This means an average pace of 220 average megawatts per year for retrofit conservation and no increase in the ramp-up for lost-opportunity conservation. For the low-case sensitivity, the Council assumed that no more than 100 average megawatts per year of retrofit conservation could be developed, and the lost-opportunity ramp-up would take 20 years to reach 85 percent annual penetration, instead of 15 years in the base case. At the high-case sensitivity, 1,500 average megawatts could be developed over the first five years of the action plan. For the low-case only about 800 average megawatts would be developed in the five years of the action plan. The results of these sensitivity tests are discussed in Chapter 10.

Figures 4-11 and 4-12 show the maximum annual conservation rates used as the base case assumptions and the high- and low-conservation sensitivity cases.

Figure 4-11: Maximum Conservation Acquisition Rates Tested for Non-Lost-Opportunity Conservation

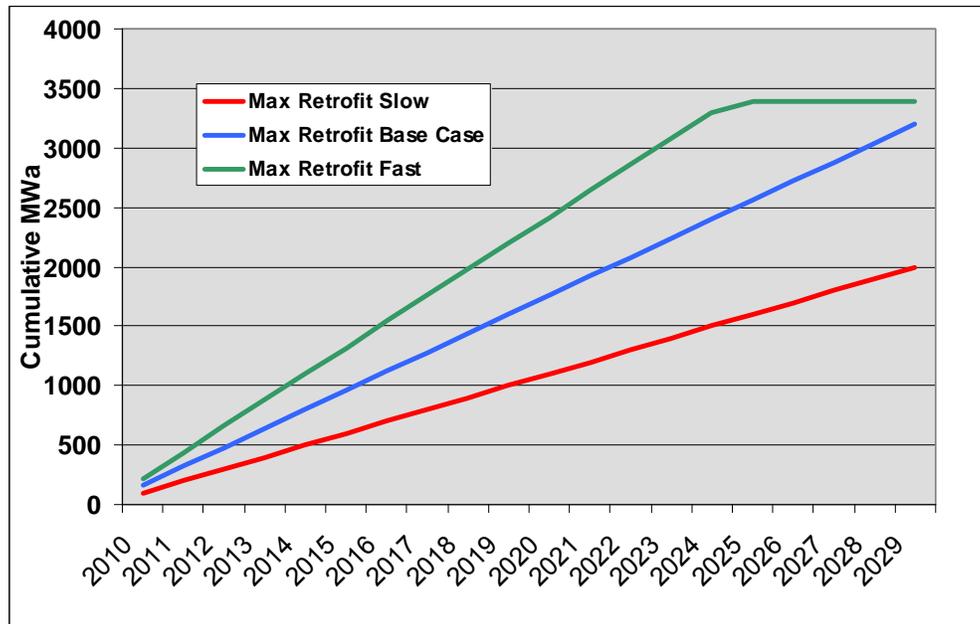
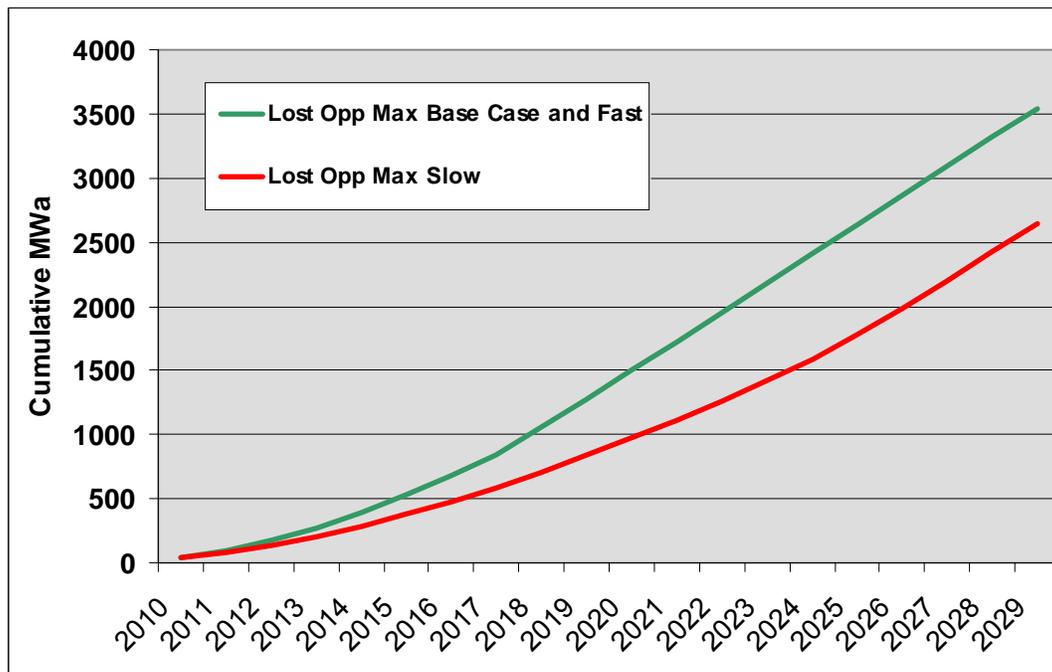


Figure 4-12: Maximum Conservation Acquisition Rates Tested for Lost-Opportunity Conservation



COUNCIL METHODOLOGY

The Northwest Power Act establishes three criteria for resources included in the Council’s power plans: resources must be 1) reliable, 2) available within the time they are needed, and 3) available at an estimated incremental system cost no greater than that of the least-cost similarly

reliable and available alternative.⁶ Beginning with its first power plan in 1983, the Council interpreted these requirements to mean that conservation resources included in the plans must be:

- Technically feasible (reliable)
- Economically feasible (lower cost)
- Achievable (available)

Development of the conservation potential assessment takes into account an assessment of what has been accomplished and what remains to be done. The first step in the Council's methodology is to identify all of the technically feasible potential conservation savings in the region. This involves reviewing a wide array of commercially available technologies and practices for which there is documented evidence of electricity savings. Over 300 specific conservation measures were evaluated in developing the conservation potential for the Sixth Power Plan. This step also involves determining the number of potential applications in the region for each of these technologies or practices. For example, electricity savings from high-efficiency water heaters are only "technically feasible" in homes that have, or are forecast to have, electric water heaters. Similarly, increasing attic insulation in homes can only produce electricity savings in electrically heated homes that do not already have fully insulated attics. At the conclusion of this step, the Council's load forecast and conservation assessment are adjusted and calibrated to reflect changes in baseline conditions since the adoption of the Fifth Power Plan.

The Sixth Power Plan's assessment reflects program accomplishments, changes in codes and standards, technological evolution, and the overall adoption of more energy-efficient equipment and practices since the Fifth Power Plan was adopted in 2004. There are five significant changes:

1. Accounting for utility conservation program savings since 2004.
2. Adjusting both the load forecast and the conservation assessment to reflect improvements in federal and state standards for lighting and appliances.
3. Adding potential savings from utility distribution efficiency improvements and consumer electronics.
4. Increasing potential industrial savings from a more in-depth analysis.
5. Adding potential savings from new technologies and practices that have matured to commercial readiness since the Fifth Power Plan's estimates were developed.

⁶ See Section 839a(4)(A)(i) and (ii) of the Northwest Power Planning and Conservation Act. (http://www.nwcouncil.org/library/poweract/3_definitions.htm or <http://www.nwcouncil.org/LIBRARY/poweract/poweract.pdf>)

Implications for the State of Washington's I-937 Requirements

Initiative 937 (I-937) in the state of Washington, approved by the voters in 2006, obligates 17 utilities that serve 88 percent of the retail load in that state to “pursue all available conservation that is cost-effective, reliable, and feasible.” By January 2010, each utility the law applies to must develop a conservation plan that identifies its “achievable cost-effective potential” for the next 10 years, “using methodologies consistent with those used by the Pacific Northwest electric power and conservation planning council in its most recently published regional power plan.” Every succeeding two years, the utility must review and update its assessment of conservation potential for the subsequent 10-year period.

I-937 is a matter of state law, and does not alter or obligate the Council in its conservation and power planning under the Northwest Power Act. Similarly, the Council has no authority to interpret, apply or implement I-937 for the utilities and regulators in the state of Washington. But because the two mandates intersect--the state's utilities are to engage in conservation planning “using methodologies consistent with” the conservation planning methodology used by the Council--it is helpful to understand some of the issues raised by the two planning processes.

There is some misunderstanding that I-937 requires Washington utilities to meet some pro-rata share of the conservation targets in the power plan. In fact, I-937 does not require the state's utilities to adopt or meet conservation targets set forth in the Council's plan, nor does the plan identify any particular utility's “share” of regional conservation targets. However, I-937 does require utilities to develop their own plan using methods “consistent with” the methodology used in the Council's plan, leaving it to the utilities' discretion to adapt the planning methods to their particular circumstances. To assist Washington consumer-owned utilities in this effort, the Washington Department of Commerce (Commerce),⁷ with the assistance of the Council staff and others, adopted rules in 2008 outlining the methodology the Council uses in its conservation planning. Although one sub-section of these rules allows utilities to adopt a share of the Council's regional targets, this is an option, not a requirement. The Washington Utilities and Transportation Commission (UTC) also adopted rules to guide the investor-owned utilities. These rules are not as prescriptive and, per the law, integrate I-937 requirements into ongoing regulatory practice.

Concern has also been expressed about the fact that utilities will need to produce their first I-937 conservation plans at the precise moment the Council is making the transition from the Fifth to the Sixth Regional Power Plan. On this issue we should point out that the Council's methodology is essentially the same in the Sixth and Fifth Power Plans and is clearly described in Chapter 4 of this draft. The conservation targets are higher in the Sixth Power Plan because of changes in prices, technology, and other factors, not because of a change in methodology.

The Council's plan describes the analytical methods used to identify cost-effective achievable conservation and provides a menu of possible cost-effective measures for utilities to consider. Neither I-937 nor the Council's plan requires utilities to choose any of the plan's particular measures in particular amounts. The utilities may make that judgment based on their own loads (composition, amounts, and growth rates) and their own determination of avoided cost and the measures available to them.

⁷ Formerly the Washington Department of Community Trade and Economic Development (CTED)

There are two issues—“ramping” and “penetration rates”—that may present potential inconsistencies between I-937 and the Council’s conservation methodology. An important element in the Council’s methodology is the principle that it takes time to develop certain conservation measures to their full potential, while other measures are available right away. Consequently, conservation potential ramps up and on occasion ramps down. The Council uses its ramp rate assumptions, along with other information and the results of its regional portfolio model, to establish five-year cumulative conservation targets for the region. The end result is that achievable conservation potential under the Council’s planning assumptions will not be evenly available across each year in the period. I-937 separately instructs the utilities to identify not just cost-effective potential over the 10-year life of the utility’s conservation plan for I-937, but also to identify and meet biennial conservation acquisition targets that must be “no lower than the qualifying utility’s pro rata share for that two-year period of its cost-effective potential for the subsequent 10-year period.” Having to acquire 20 percent of any 10-year target in any two-year period under I-937 may produce different two-year targets than would result using ramp rates consistent with the Council’s methodology. Commerce rules do not address what is meant by “pro-rata share,” but the UTC rules state that “‘pro rata’ means the calculation used to establish a minimum level for a conservation target based on a utility’s projected ten year conservation potential.” Because the provisions of I-937 are a matter of state law, this issue is not one that the Council can resolve in its plan.

A related, but distinct, issue concerns conservation measure “penetration” rates. Part of the Council’s methodology is to estimate the extent of total penetration of a conservation measure in the area of study over the total period analyzed. The Commerce rules address this issue, calling on utility conservation plans to “[i]nclude estimates of the achievable customer conservation penetration rates for retrofit measures and for lost-opportunity (long-lived) measures.” Because, as with “ramp rates,” I-937 requires a ten-year plan while the Council produces a twenty-year plan, the rules needed to harmonize the potential difference between penetration rates over ten years versus penetration rates over twenty years. As a result, the Commerce rules then go on to describe the Council’s 20-year and 10-year penetration rates (from the Fifth Plan, although they do not differ in the Sixth Plan), “for use when a utility assesses its” conservation potential. The UTC rules are silent on penetration rates.

One final point to consider is the treatment of savings achieved through building codes and other standards. The Council’s conservation methodology calculates the conservation potential for measures that might, at some point, be covered by building codes or energy codes, and then assumes that the savings will be accomplished over time by either utility programs or codes. If codes are adopted that ensure the capture of the potential savings, then those savings are “counted” against the regional target. The rules adopted by Commerce for I-937 do not appear to be inconsistent with this approach while the UTC rules do not address this issue specifically.

Chapter 5: Demand Response

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

SUMMARY OF KEY FINDINGS

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

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

This plan assumes, based on experience in the region and elsewhere, that the achievable technical potential for demand response in the region is around 5 percent of peak load over the 20-year plan horizon. The plan assumes 1,500 to 1,700 megawatts of load reductions in the winter and summer, respectively, and 2,500 to 2,700 megawatts of load reductions together with dispatchable standby generation. This achievable technical potential was included in analysis by the Council’s Regional Portfolio Model¹ to determine how much demand response is included in the preferred-resource portfolios identified by the model.

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

¹ See Chapter 9 for a description of this analysis.

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

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

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

DEMAND RESPONSE IN THE FIFTH POWER PLAN

The Council first took up demand response as a potential resource² in its Fifth Power Plan (May 2005).³ The Fifth Power Plan explained that concern with demand response rises from the mismatch between power system costs and consumers’ prices. While power system costs vary widely from hour to hour as demand and supply circumstances change, consumers generally see prices that change very little in the short term. The result of this mismatch is higher consumption at high-cost times, and lower consumption at low-cost times, than is optimal. The ultimate result of the mismatch of costs and prices is that the power system needs to build more peaking capacity than is optimal, and uses base-load generation less than is optimal. Programs and policies to encourage demand response are efforts to correct these distortions.

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

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

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

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

Progress Since the Fifth Power Plan

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

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

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

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

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

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

DEMAND RESPONSE IN THE SIXTH POWER PLAN

Estimation of Available Demand Response

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

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

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

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

⁴ The methodology for estimating conservation potential is described in more detail in Appendix E.

⁵ See Appendix K.

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

Demand Response Assumptions

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

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

Studies of Potential

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

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

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

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

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

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

The studies of demand-response potential for PacifiCorp and Portland General Electric had not been completed at the time the Council issued the Sixth Power Plan.

Experience

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

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

Idaho Power had about 60 megawatts of demand response in 2008, made up of direct load control of residential air conditioning and timers on irrigation pumps. The company is committed to achieving a total of 307 megawatts by 2013, pending the expected approval of this plan by the Idaho Public Utilities Commission. This level of demand response would be accomplished by converting much of their irrigation demand response to dispatchable⁹ and adding demand response from the commercial and industrial sectors. This level would be 8.1 percent of their projected peak demand in 2013 of 3,800 megawatts. In the longer run the company is planning on reaching 500 megawatts of demand response by 2021, which would make demand response equal to 11.4 percent of its 2021 forecasted peak demand of about 4,400 megawatts.

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

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

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

to provide demand response up to 50 megawatts by 2012. These responses make the company confident that it can actually secure 50 megawatts of new demand response by 2012. Finally, PGE has 10 megawatts of interruptible contracts with industrial customers. The sum of these three components, 185 megawatts, is equal to 4.1 percent of the company's projected peak load of 4,500 megawatts in 2012.

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

The New England Independent System Operator (ISO) cited 1,678 megawatts of demand response without dispatchable standby generation and 2,278 megawatts of demand response with dispatchable standby generation for 2007. These figures were 6.1 and 8.3 percent of the ISO's average-weather summer peak load of 27,400 megawatts (winter peak load is 22,775 megawatts).¹⁰

PJM Interconnection is a regional transmission organization that manages a wholesale market and the high-voltage transmission system for 13 mid-Atlantic Coast and Midwest states and the District of Columbia. PJM estimated 4,460 megawatts of demand response in its control area in 2008 compared to a forecasted peak load of 137,950 megawatts¹¹ or about 3.2 percent of peak load. There may be some demand response in the utilities of states that have been recently added to PJM (Illinois, Ohio, Michigan, and Kentucky) that is not included in this total.

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

¹⁰http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf Table 5-7 page 47, Table 5-8 page 49, and Table 3-3 page 25

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

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

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

Table 5-1: Demand Response Achieved by System Operator

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

Council Assumptions

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

The Council based its assumptions in part on the evidence that demand response of at least 5 percent of peak load has been accomplished by a number of utilities and system operators in periods of five to 10 years. Therefore, accomplishing a similar level of total demand response over 20 years in the Northwest is reasonable. The total assumed potential brackets the 5-percent level, depending on whether the dispatchable standby generation is included or not. Without dispatchable standby generation, the assumed potential is 1,500 megawatts in the winter and 1,700 megawatts in the summer (about 3.8 percent and 4.3 percent of the forecast 40,000-megawatt peak load forecast for 2030, respectively). With dispatchable standby generation, the totals are 2,500 megawatts in the winter and 2,700 megawatts in the summer, or 6.3 percent and 6.8 percent of forecast peak load, respectively.

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

¹⁴ For more information about the portfolio model, see Chapter 9.

Table 5-2: Demand Response Assumptions

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

The resource programs are described below.

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

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

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

Aggregators. Increasingly, aggregators facilitate demand response by acting as middlemen between utilities or system operators on the one hand and the ultimate users of electricity on the

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

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

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

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

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

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

The dispatchable standby generation component is expected to be used for contingency reserves, which cannot be represented in the regional portfolio model. The other programs were simulated in the portfolio model, with schedules based¹⁶ on those in Table 5-3. The air conditioning and irrigation programs were treated as one program, since their costs and dispatch constraints were identical. That program, the space and water heating program, the aggregator’s component, and the interruptible contracts component were modeled similarly.

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

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

Caveats for Demand Response Assumptions

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

Ongoing Analysis with the Regional Portfolio Model

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

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

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

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

Pricing Structure

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

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

Providing Ancillary Services with Demand Response

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

But demand response can do more than help meet peak load. It can help provide ancillary services such as contingency reserves and regulation and load following. Historically ancillary services have not been considered a problem in the Pacific Northwest, but as loads have grown, and especially as wind generation has increased, power system planners and operators have become more concerned about ancillary services (see Chapter 12). Not all demand response can provide such services because they have different requirements than meeting peak load.

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

Contingency Reserves

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

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

Regulation and Load Following

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

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

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

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

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

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

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

Another example is the charging load for plug-in hybrid vehicles (PHEV). Many parties have suggested this possibility, and the general outline of the potential interaction of PHEV with the power system is common to most proposals -- vehicle batteries together act as a large storage battery for the power system whenever they are connected to the grid -- at home, at work, or elsewhere. This aggregate battery accepts electricity when the cost of electricity is low (e.g. at night) and gives electricity back to the system when the cost is high (e.g. hot afternoons or during cold snaps). The Smart Grid could coordinate²⁰ this exchange.²¹

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

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

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

Water heating can help absorb this temporary surplus of energy and make productive use of it. Water heating loads can be increased up to the maximum connected load, but the duration of the increase will be limited by the allowable increase in water temperature above the normal setting. If, for example, the temperature is allowed to increase from 120 degrees Fahrenheit to 135

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

²¹ One such description of how PHEV could contribute to the power system is at the Regulatory Assistance Project's web site www.raponline.org under the title "Plug-In Hybrid Vehicles, Wind Power, and the Smart Grid."

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

degrees Fahrenheit, 3.4 million 50-gallon water heaters can accept 6,198 megawatt-hours of energy, store it (at the cost of roughly 24 megawatt-hours per hour higher standby losses) and return it to the system in the form of a reduction in hot water heating requirement in a later hour.²³

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

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

²³ This increase could result from an increase in load of 6,198 megawatts for an hour, or an increase in load of 3,099 megawatts for two hours, etc.

Chapter 6: Generating Resources and Energy Storage Technologies

Summary of Key Findings	2
Introduction.....	3
Generating Resource Applications & Services.....	9
Energy	9
Firm Capacity.....	12
Regulation and Load-following	13
Combined Heat and Power	14
Distributed Generation.....	16
Hydroelectric Power	16
Existing Hydropower System	17
Integrating Fish & Wildlife and Power Planning	17
New Hydropower Development	19
New Hydropower Projects.....	19
Upgrades to Existing Hydropower Projects.....	19
Non-hydro Renewable Energy Resources	19
Biofuel.....	19
Landfills	20
Agricultural and Food Wastes	20
Waste Water Energy Recovery.....	21
Woody Residue.....	21
Pulping Chemical Recovery	22
Geothermal Power Generation.....	22
Conventional Geothermal Power Generation	23
Enhanced Geothermal Power Generation.....	23
Marine Energy	24
Ocean Currents.....	24
Thermal Gradients	24
Salinity Gradients.....	24
Tidal Energy.....	25
Wave Energy.....	25
Solar	26
Photovoltaics.....	26
Solar Thermal Power Plants.....	27
Wind.....	28
Waste Heat Energy Recovery	30
Fossil Fuels	31
Coal.....	31
Coal-fired Steam-electric Plants	32
Coal-fired Gasification Combined-cycle Plants	33
Natural Gas	34
Natural Gas Supply and Price.....	34
Natural Gas Generating Technologies	35
Petroleum	38

Petroleum Coke.....	38
Nuclear.....	39
Energy Storage Technologies.....	40
Compressed Air Energy Storage.....	41
Flow Batteries.....	42
Pumped-storage Hydropower.....	42
Sodium-sulfur Batteries.....	43
Summary of Reference Plant Characteristics.....	43

SUMMARY OF KEY FINDINGS

Generating resource development will be driven by the need for reliable, economic, and low-carbon energy supplies, supplemented as needed with firm capacity to maintain system reliability and to provide balancing reserves to complement variable-output energy resources.

Economical and reliable low-carbon energy generation resources available in abundance in the near-term (2010 - 2015) include “local”¹ wind and natural gas combined-cycle plants. These technologies are commercially mature, economically competitive and relatively easy and quick to develop. Energy from these resources costs from about \$90 - \$110 per megawatt-hour². Other low-to-moderate carbon energy generation resources available in the near-term, but in limited quantities include bioresidue energy recovery projects, natural gas and bioresidue cogeneration, conventional geothermal, new hydropower and energy from upgraded existing hydropower projects. These resources are commercially mature and in many cases economically competitive. They are, however, often small and challenging to develop. Solar photovoltaics, while commercially mature, low-carbon, easy to develop, and available in large quantity, is very expensive.

Wind power in the Northwest has relied on the existing surplus of firm capacity and balancing reserves. Continued wind development and other variable-output energy resources (wave power, tidal current power, and solar photovoltaics) will eventually require adding firm capacity and balancing reserves to maintain the reliable operation of the power system. Simple- and combined-cycle gas turbines, reciprocating engine-generators, compressed air energy storage, flow batteries, pumped storage hydropower, and sodium-sulfide batteries can provide firm capacity and balancing reserves. Further analysis is needed to identify the best alternatives for the Northwest for these technologies, as well as transmission operation efficiencies and smart grid opportunities (see Chapter 12 and Appendix K).

In the medium-term (2015 - 2020), remote resources could be accessed via expansions to the transmission system. These include wind from Montana, Alberta or Wyoming and concentrating solar power from Nevada and other Southwest areas. These resources are typically 40 to 100 percent more expensive than comparable local resources because of the transmission investment and low transmission load factor. The “lumpiness,” capital cost, and lead time of the transmission adds investment risk to these options.

¹ “Local” wind refers to wind power that does not rely on the development of high-capacity, long-distance dedicated transmission.

² Levelized resource costs appearing in this chapter are for 2015 service, unless otherwise indicated. A more complete discussion of resource costs, including cost estimates for years ranging from 2010 to 2030 is provided in Appendix I.

Conventional coal plants are unlikely to be developed in the near-term because of state CO₂ performance standards and climate policy uncertainty. Additional resources available long-term (2020 - 2030) include advanced nuclear and coal gasification combined-cycle plants. Emerging technologies such as wave power, tidal current power, enhanced geothermal, deep water wind turbines, compact nuclear plants, commercial-scale carbon sequestration, and technologies that capture carbon from steam-electric coal-fired plants may become commercial during this decade.

Construction costs increased 60 to 100 percent between 2004 and mid-2008, driven by increased commodity costs, the declining value of the dollar against overseas currencies, and market incentives for wind and other renewable technologies. The weakening global economy and the difficulty in securing credit has reversed this trend and costs are declining for most technologies. Future costs, however, are highly uncertain. Significant risks associated with power generation include natural gas price volatility and uncertainty (combined-cycle plants), greenhouse gas control policies (coal-fired plants), plant size and lead time (geothermal, nuclear, coal gasification plants, and transmission for importing wind or solar), and technology performance (coal gasification, advanced nuclear plants).

Climate policies will increase the cost of fossil-fueled power generation in proportion to fuel carbon content and plant efficiency. Estimated increases under the mean forecast carbon dioxide allowance prices range from about 20 percent (\$18 per megawatt-hour) for gas combined-cycle plants to 40 percent (\$42 per megawatt-hour) for coal steam-electric plants.³ While carbon dioxide separation and sequestration could reduce the cost of compliance, current estimates of the cost and performance of plants so equipped suggest that these features would not be economic compared to other resource alternatives.

INTRODUCTION

This chapter describes the various generating and energy storage alternatives available to the Northwest to meet needs during the planning period. Additional details regarding these alternatives and assumptions regarding cost, performance, and availability are provided in Appendix I.

Electricity is a high value form of energy produced from naturally occurring primary energy sources. These include the fossil fuels (coal, petroleum, and natural gas), geothermal energy, nuclear energy, solar radiation, energy from solar radiation (wind, hydropower, biomass production, ocean waves, ocean thermal gradients, ocean currents, and salinity gradients), and tidal energy.

The energy of these primary resources is captured, converted to electricity, and delivered to the end-user by means of energy conversion systems. An energy conversion system may include fuel extraction, fuel transportation and fuel processing, power generation, and transmission and distribution stages. Most power generation technologies are mechanical devices that capture the energy contained in heated, pressurized or moving fluids, and use this energy to drive an electric power generator. Exceptions include fuel cells (solid-state devices that convert the chemical energy of hydrogen into electric power) and photovoltaics (solid-state devices that convert solar radiation to electric power).

³ Values are for 2015 service.

Many primary forms of energy are found in the Northwest, including various types of biofuel, coal, geothermal, hydropower, marine energy resources, solar, and wind. Others, including natural gas, uranium, and petroleum are readily transported into the region. The few resources not available in the Northwest include ocean thermal differentials and ocean currents (both insufficient in the Northwest for practical application) and adequate direct normal solar radiation for concentrating solar thermal plants.⁴

This chapter reviews all resources potentially available to meet Northwest electrical needs within the next 20 years; however, only proven resources were further evaluated for the recommended resource portfolio (Chapter 10). The Power Act requires priority be given to resources that are cost-effective, defined as a resource that is available at the estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative.⁵ Since resources using reliable, commercially available technologies can meet the region's forecast needs over the 20-year planning period, unproven resources, including those whose availability and quantity is poorly understood or that depend on immature technology were not considered for the portfolio risk analysis. Certain unproven resources, including salinity gradient energy generation, deep water wind power, wave energy, tidal currents, and enhanced geothermal have substantial Northwest potential. Actions to monitor and support development of these technologies are included in this plan.

Energy storage technologies decouple electricity production from consumption and can be used to shift energy from lower value to higher value periods and to provide firm capacity, balancing reserves, and other capacity-related services. Storage technologies that have the greatest value for the Northwest are those that can provide extended (multi-day) energy storage, firm capacity, and balancing reserves. These include compressed-air energy storage, flow batteries, pumped storage hydro, and sodium-sulfur batteries.

Characteristics of potential Northwest generating resources and energy storage technologies are summarized in Table 6-1. The far left column of Table 6-1 lists primary energy resources. The second column shows the leading energy conversion technologies. The third column lists the services available from each resource/technology combination including firm capacity for system reliability, electric energy production, balancing (fast-response) capacity for regulation and load-following, shaping, cogeneration, and polygeneration (production of fuel and other products). The fourth column contains estimates of undeveloped potential in the Northwest. In many cases the available potential is a function of cost; additional resource is available at additional cost. The next column shows the earliest service date for new resources, assuming that project development commences January 2010. Many proposed wind, hydropower, and other projects are at various stages of preconstruction development in the Northwest and could be brought into service prior to the earliest service dates shown. The Reference Capacity Cost column shows the levelized fixed cost of those resources typically used for capacity-related services. The Reference Energy Cost column shows levelized electricity cost for resources primarily used for electricity production. On the far right of the table are listed the principal risks and other issues associated with each resource.

⁴ Satellite data suggests that local areas in southwestern Idaho and southeastern Oregon may be suitable for concentrating solar power. Further ground data is needed to confirm this.

⁵ Regional Act 3.(4)(A)

Table 6-1: Summary of Generating Resources and Energy Storage Technologies

Resource	Leading Technology	Services	Estimated Undeveloped Potential	Earliest Service	Capacity Cost (\$/kW-yr) ⁶	Energy Cost (\$/MWh) ⁵	Key Issues
Renewable Resources							
Hydropower	New projects	Firm capacity Energy	Low hundreds of MWa?	2016	--	\$60 and up	Siting constraints Development cost & lead time
	Upgrades to existing projects	Firm capacity Energy Balancing	Low hundreds of MWa?	Project-specific	Project-specific	Project-specific	
Wastewater treatment gas	Reciprocating engines	Firm capacity Energy	7 - 14 MWa	2012	--	\$104	Cost (smaller treatment plants)
Landfill gas	Reciprocating engine	Firm capacity Energy	70 MWa	2012	--	\$73	Competing uses of biogas
Animal manure	Reciprocating engine	Firm capacity Energy	50 - 110 MWa	2012	--	\$80 - \$140	Cost Competing uses of biogas
Woody residues	Steam-electric	Firm capacity Energy Cogeneration	665 MWa	2014	--	\$88 - \$125	Cost CHP revenue Reliable fuel supply
Geothermal	Binary hydrothermal	Firm capacity Energy	370 MWa	2017	--	\$81	Investment risk (Exploration & well field confirmation)
	Enhanced geothermal	Firm capacity Energy	Thousands of MWa?	Uncertain	--	Not available	Immature technology
Tidal current	Water current turbines	Energy	Low hundreds of MWa?	Uncertain	--	Not available	Immature technology Environmental impacts Competing uses of sites
Wave	Various buoy & overtopping devices	Energy	Low thousands of MWa?	Uncertain	--	Not available	Immature technology Competing uses of seaspace
Offshore Wind	Floating WTG	Energy	Thousands of MWa?	Uncertain	--	Not available	Immature technology Competing uses of seaspace
Solar	Utility-scale Photovoltaic arrays	Energy	Abundant	2013	--	\$280	Cost Poor load/resource coincidence Availability and cost of

⁶ 2015 service except as indicated; values above \$125/MWh rounded. See Appendix I for more detail.

							balancing services
Solar (Nevada)	Parabolic trough	Firm capacity Energy	600 MWa/500kV circuit	2015	--	OR/WA \$230 ID \$190	Cost Lack of suitable PNW resource Availability and cost of transmission
Wind (Local)	Wind turbine generators	Energy	OR/WA - 1410 MWa ID - 215 MWa MT - 80 MWa	2013	--	OR/WA \$103 ID \$109 MT \$89	Availability and cost of balancing services
Wind (Alberta)		Energy	760 MWa/+/-500kV DC Ckt	2015	--	OR/WA \$140	Availability and cost of balancing services Availability and cost of transmission
Wind (Montana)		Energy	570 MWa/new 500kV Ckt Via CTS Upgrade	2015	--	ID \$116 OR/WA \$150 OR/WA \$130	Availability and cost of balancing services Availability and cost of transmission
Wind (Wyoming)		Energy	570 MWa/500kV Ckt	2015	--	ID \$121 OR/WA \$150	Availability and cost of balancing services Availability and cost of transmission
Waste Heat							
Waste heat	Bottoming Rankine cycle	Energy	Tens to low hundreds of MW?	2014	--	\$63	Suitable host facilities Host facility viability
Fossil Fuels							
Coal	Steam-electric	Firm capacity Energy	Abundant	No CSS 2017 CSS Uncertain	--	No CSS OR/WA \$108 (2020) CSS MT > OR/WA via CTS repower \$140 (2025)	GHG policy Immature CO ₂ separation technology Lack of commercial CO ₂ sequestration facility
	Gasification combined-cycle	Firm capacity Energy Balancing Polygeneration	Abundant	No CSS 2017 CSS Uncertain	--	No CSS OR/WA - \$118 (2020) CSS MT > OR/WA via CTS repower \$140 (2025)	Investment risk Reliability GHG policy Lack of commercial CO ₂ sequestration facility
Petroleum coke	Gasification combined-cycle	Firm capacity Energy Balancing	Abundant	No CSS 2017	--	No CSS WA/OR - \$120	Investment risk Reliability GHG policy

		Polygeneration		CSS Uncertain		(2020) CSS MT > OR/WA via CTS repower \$140 (2025)	Lack of commercial CO ₂ sequestration facility
Natural gas	Combined-cycle gas turbine	Firm capacity Energy Balancing Cogeneration	Abundant	2014	Baseload increment \$166 Duct-firing increment \$113	Baseload \$87 Duct-firing increment \$117 ⁷	Gas price volatility & uncertainty
	Aeroderivative gas turbine	Firm capacity (fast- start) Balancing Cogeneration	Abundant	2012	\$164	\$130	Gas price volatility & uncertainty
	Frame gas turbine	Firm capacity Balancing Cogeneration	Abundant	2012	\$134	\$140	Gas price volatility & uncertainty
	Hybrid intercooled gas turbine	Firm capacity (fast- start) Balancing Cogeneration	Abundant	2012	\$164	\$125	Gas price volatility & uncertainty
	Reciprocating engine	Firm capacity (fast- start) Energy Balancing Cogeneration	Abundant	2012	\$172	\$135	Gas price volatility & uncertainty
Nuclear Fission							
Nuclear	Advanced light water reactor	Firm capacity Energy	Abundant	2023	--	\$108 (2025)	Public acceptance Cost escalation Construction delays Regulatory risk "Single shaft" reliability risk
	Small modular reactor	Firm capacity Energy Cogeneration	Abundant	Uncertain	--	Not available	Immature technology
Energy Storage							
Electricity	Compressed air energy storage	Firm capacity Balancing Diurnal shaping	Uncertain	Not evaluated	Uncertain & site-specific	--	Confirming suitable geology Monetizing system

⁷ 4,000 hours/year.

							benefits
	Flow batteries	Firm capacity Balancing Diurnal shaping	No inherent limits	Uncertain	Uncertain	--	Immature technology Monetizing system benefits
	Pumped storage hydro	Firm capacity Balancing Diurnal shaping	Thousands of MW	2016	\$324	--	Project development Monetizing system benefits
	Sodium-sulfur batteries	Firm capacity Balancing Diurnal shaping	No inherent limits		Uncertain	--	Early commercial technology Monetizing system benefits

GENERATING RESOURCE APPLICATIONS & SERVICES

Energy production has been the primary focus of the generating resource assessments of previous power plans because the Northwest's hydropower system is capacity-rich and energy-limited. Increasing demand for balancing reserves⁸ to integrate wind power and a prospective firm-capacity shortfall in coming years has broadened to scope of this plan to consider resource capacity as well as energy characteristics. Generation technologies differ in their ability to provide these services and at what cost. Capacity issues are further discussed in Chapter 12.

The principal power system services of significance to long-term planning are energy, balancing reserves, and firm capacity (the ability to contribute to meeting peak load).⁹ Some power plants also provide cogeneration (also referred to as combined heat and power or CHP) or polygeneration. A cogeneration power plant simultaneously produces electricity and thermal energy for industrial and commercial processes or for space conditioning. In addition to providing an additional revenue stream, cogeneration increases the thermal efficiency of fuel use and can reduce the net carbon dioxide production and other environmental effects of electricity production. A polygeneration plant produces chemical products (fertilizer and liquid or solid fuel, for example) in addition to electric power.

Energy

Power plants with low variable-production costs are run primarily to produce electric energy (baseload plants). Little can be saved by curtailing their operation, so they are typically dispatched to the extent that they are available for operation. Because non-fuel variable costs are generally a minor element of production costs, baseload units tend to be those with low (or no) fuel costs such as coal, hydropower, geothermal, biogas, wind, solar, and nuclear plants. Natural gas combined-cycle plants, while using a relatively expensive fuel, are very efficient, so they typically operate as intermediate load units, producing energy at times of higher demand and prices, but curtailed during periods of low energy prices. Cogeneration plants, though often using expensive fuel (natural gas or residue biomass), are efficient and normally have a steady thermal load, so they also operate as baseload plants.

The estimated levelized cost of electricity from new generating resources is shown in Figures 6-1A-C. These costs represent the revenue requirements needed to generate and deliver electricity to the wholesale delivery point (substation) of a local utility. The costs include all costs of providing electricity to the end-user except for distribution costs and losses. Distribution costs and losses are credited to conservation in this plan for comparability to generating resource options.

Four elements of delivered wholesale electricity costs are shown in the charts for each resource option: Plant costs – the cost of constructing and operating the power plant; Integration cost –

⁸ Balancing reserves provide regulation and load-following to integrate variable-output renewable energy resources. This is also referred to as system flexibility.

⁹ In addition to energy, seven capacity related ancillary services are needed to reliably operate a power system and are therefore commercially significant. These include: regulation, load-following, spinning reserves, non-spinning reserves, supplemental or replacement reserves, voltage support, and black start. See Kirby, B. *Ancillary Services Technical and Commercial Insights*, July 2007 for additional discussion.

the cost of balancing reserves for variable resources; Transmission costs – the costs, including cost of losses to deliver the electricity to the utility; and, CO₂ costs – the forecast cost of securing carbon dioxide allowances. Further discussion of the resource cost estimates is provided in Appendix I.

Figure 6-1A shows resources that could be brought into service in the near-term (2010-14). These include resources with short development and construction lead times such as wind and simple-cycle gas turbines, and longer-lead time plants such as geothermal and new hydropower for which development work¹⁰ is underway. The costs shown in the figure are for projects entering service in 2015 (in 2006 dollar values).

Figure 6-1B includes additional resources that could be brought into service in the mid-term period (2015-19). These include remote wind and solar resources that need new long-distance transmission, and technologies such as coal-fired steam-electric and gasification plants, needing a long time to develop and construct. Although illustrated in the chart for comparative purposes, the coal-fired options are currently precluded by Montana, Oregon, and Washington carbon dioxide performance standards and the Idaho moratorium on coal-fired generation. The costs in the figure are for projects entering service in 2020 (in 2006 dollar values). The effects of forecast technological improvements and fuel prices on the relative cost of certain resources are evident in this and in Figure 6-1C. Several resource alternatives with low and stable costs that appear in Figure 6-1A have been omitted from Figure 6-1B for clarity.

Figure 6-1C shows resources that could be brought into service in the long-term period (2020-29). Nuclear plants and commercial-scale carbon dioxide sequestration facilities using depleted oil and gas fields are assumed to be available by this period. Carbon dioxide sequestration facilities using depleted oil and gas fields could be located in Montana, Wyoming or Saskatchewan and accessible to coal-fired plants located in eastern Montana via high-pressure carbon dioxide pipelines. This could offer the possibility of repowering the Colstrip Transmission System (CTS) with wind power or with coal gasification plants with carbon dioxide separation (Colstrip 1 and 2 will have been in service for 50 years by 2025). The costs shown in the figure are for projects entering service in 2025 (in 2006 dollar values). As in Figure 6-1B, low-cost resource alternatives with relatively stable costs have been omitted for clarity, as have more costly versions of competing technologies (e.g., sub-critical coal steam technology has been omitted in favor of ultra-supercritical technology, for example). These are fully described in Appendix I.

Although the levelized energy costs shown in the figures are often used for initial comparison of resources, evaluating resources for acquisition must consider the needs and characteristics of the system using the resource, the capacity and energy services provided by the resource, and the costs and risks incurred acquisition and operation of the resource. These factors are considered in the resource strategy (Chapters 9 and 10).

¹⁰ “Development” is used in this chapter as the process of preparing to construct a power plant, including site selection; feasibility assessment; environmental, geotechnical and resource assessment; permitting; and preliminary engineering. Project development is generally akin to the resource optioning process referred to elsewhere in the plan.

Figure 6-1A: Levelized Lifecycle Electricity Cost for Generating Options Available in the Near-term (2010-14)¹¹

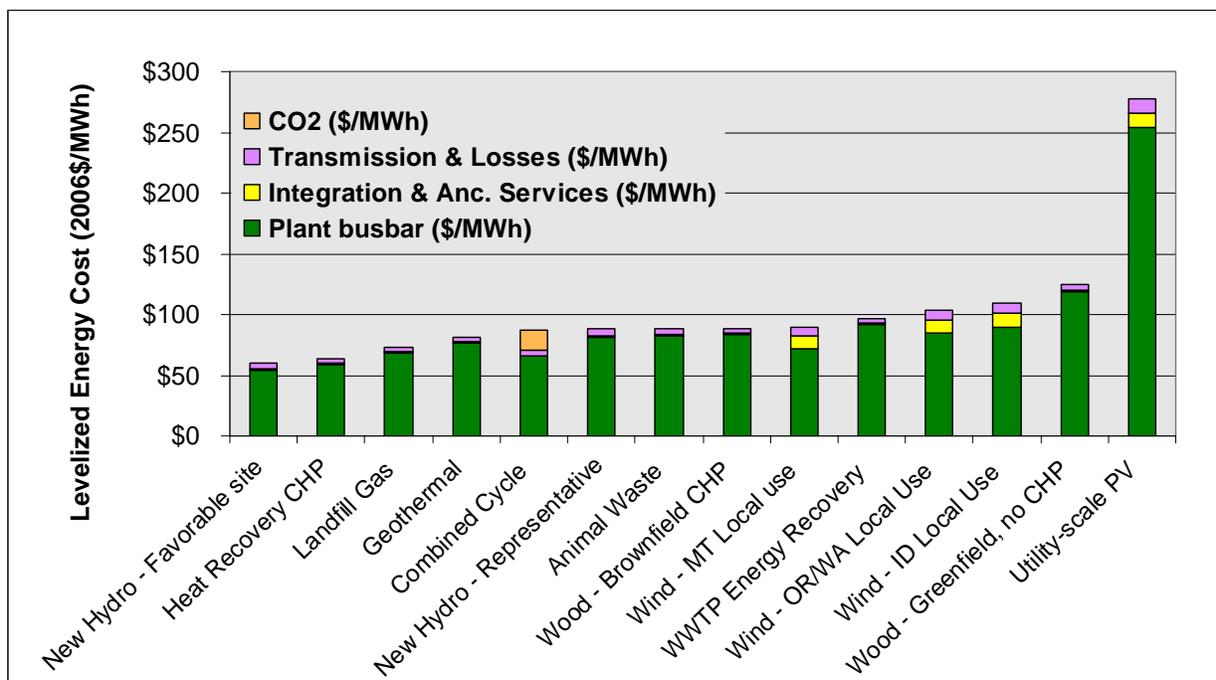
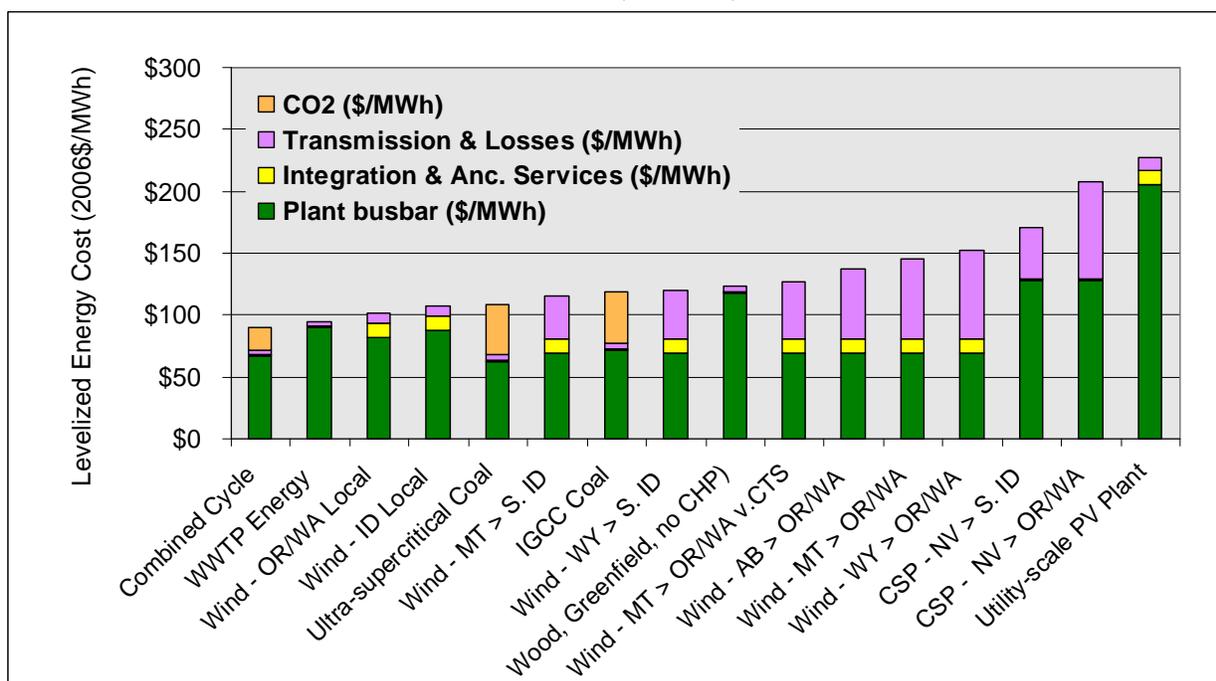


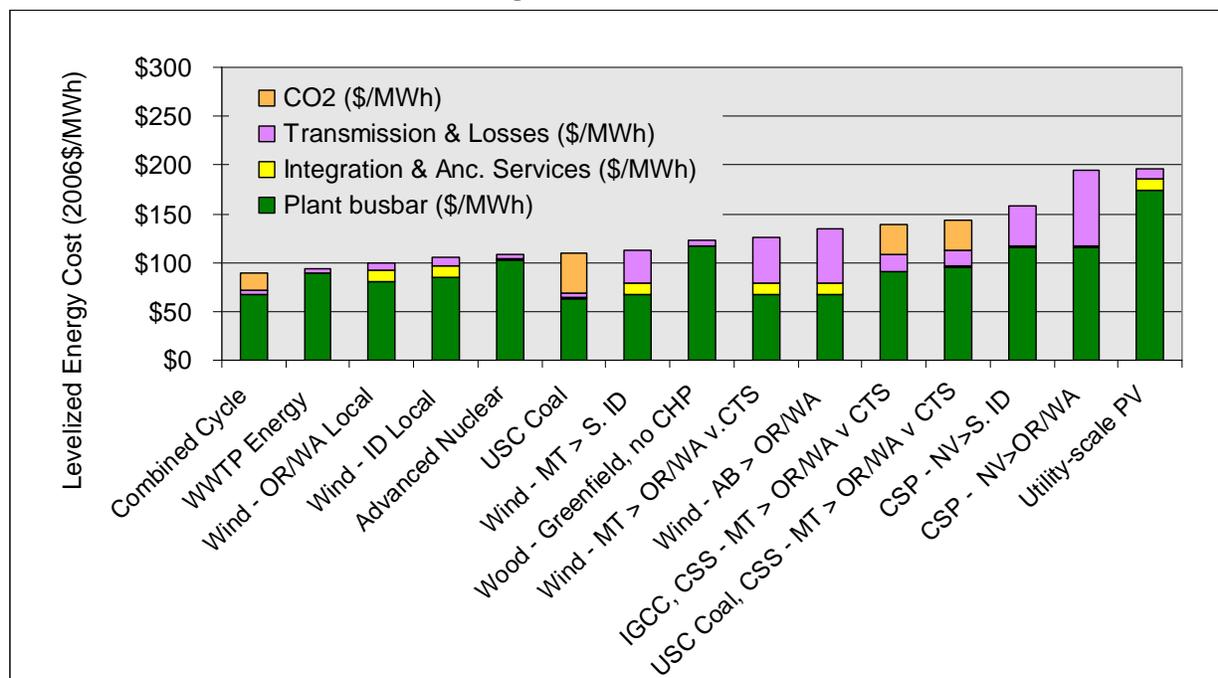
Figure 6-1B: Levelized Lifecycle Electricity Cost for Generating Options Available in the Mid-term (2015-19)¹²



¹¹ Assumptions: 2015 service, investor-owned utility financing, medium fuel price forecast, wholesale delivery point. CO₂ allowance costs at the mean values of the portfolio analysis. Incentives excluded, except accelerated depreciation. Actual project costs may differ because of site-specific conditions and different financing and timing.

¹² Assumptions as in Figure 6.1A except 2020 service.

Figure 6-1C: Levelized Lifecycle Electricity Cost for Generating Options Available in the Longer-term (2020-25)¹³



Firm Capacity

With the exception of wind and other variable-output resources, most power plants provide firm capacity to meet peak load and provide contingency reserves.¹⁴ In general, non-variable plants can provide capacity up to their net installed capacity less an allowance for forced (unscheduled) outages, though in some cases, contractual, fuel, permitting, and environmental conditions may limit the firm capacity contribution.

Some resources are developed primarily to provide firm capacity. Because they are operated infrequently, variable cost is less important than fixed costs. Also, units intended for peaking service may need rapid startup and load-following ability to avoid displacing generation with a lower variable cost. A comparison of the fixed costs of several resources typically developed for capacity is provided in Figure 6-2. In the case of the combined-cycle option, the cost shown is the incremental cost of duct firing. Duct firing is an inexpensive option for increasing plant output (though at some sacrifice of efficiency) and is usually provided on combined-cycle units. But duct firing capability is limited and other capacity resources are sometimes needed.

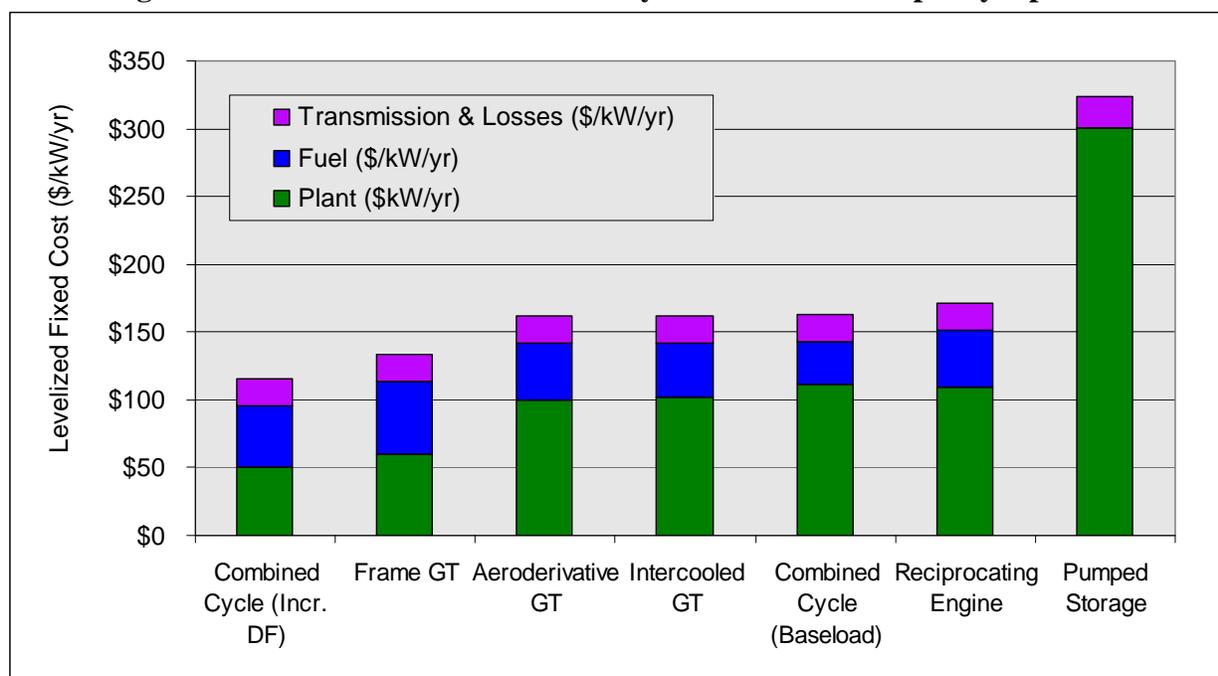
As with levelized energy cost estimates, the levelized capacity cost estimates of Figure 6-2 is not the sole criterion for choosing among these options. The technologies shown have different attributes, possibly leading to different choices depending on needs. Aeroderivative and intercooled gas turbines and reciprocating engines, for example, have very rapid start times (less than 10 minutes), allowing them to provide “spinning” reserve, even when shut down. Duct firing and intercooled gas turbines require cooling water, whereas other types of simple-cycle gas

¹³ Assumptions as in Figure 6.1A except 2025 service.

¹⁴ Capacity held for use in case of a contingency event such as unplanned loss of generation.

turbine and reciprocating units require very little water, a factor of importance in arid regions. Reciprocating engines and intercooled gas turbines have attractive “turndown” characteristics, meaning that plant operating efficiency remains high even at very low loading. Moreover, anticipated operating conditions can affect fixed costs. Gas turbines, if located in a non-attainment area may need expensive air emission controls.

Figure 6-2: Fixed Cost of Commercially-available Firm Capacity Options¹⁵



Regulation and Load-following

The large amount of wind power added to the Northwest’s power system has increased demand for regulation and load-following services. Regulation is the continuous balancing of generation to load on a second-to-second basis and is typically supplied by fast-response generating units equipped with automatic generation control. Hydropower units are normally used to provide regulation in the Northwest. Though wind power at low penetration does not significantly increase the net second-to-second variability of load and generation, incremental variation is introduced as wind penetration increases. However, the incremental demand for regulation introduced by wind, even at high penetration levels is relatively small compared to the incremental increase in load-following requirements.

Load-following services make up the difference between scheduled (forecasted) generation and actual load. Load-following is currently provided by operating capacity set to provide either upward (incremental) regulation (“Inc”) or downward (decremental) regulation (“Dec”). The need to prepare for unpredicted rapid upward and downward ramps in wind output is increasing demand for load-following capability.

¹⁵ 2015 service.

A related service is shaping. Shaping involves the shifting of energy from low value off-peak hours to higher value on-peak hours on a diurnal or multi-day basis. Shaping can also be used to level load on transmission lines serving remote renewable resource areas, thereby reducing incremental transmission costs.

Resources suitable for providing regulation and load-following services have rapid and flexible response capability, good turndown characteristics and, ideally, near-market operating costs (to reduce economic losses during load-following operation). Other desirable attributes include siting flexibility and low part-load emissions. Among new generating resources, the most attractive options for supplying regulation and load-following services are combined-cycle gas turbines, aeroderivative and intercooled simple-cycle gas turbines, and reciprocating engines. Long-duration storage technologies including pumped-storage hydro, compressed-air energy storage, flow batteries, and sodium-sulfur batteries offer similar capability.

Because the balancing capability of the existing system may need to be augmented in future years to support expansion of wind and other variable resources, the cost and value of the various options augmenting balancing capability for the Northwest's system should be explored. Action GEN-6 calls for this effort, which should consider combined-cycle plants, gas turbine generators, reciprocating engines, pumped-storage hydro, compressed-air energy storage, flow batteries, sodium-sulfur batteries, and demand-side options.

Combined Heat and Power

Combined heat and power (CHP or cogeneration) plants produce both electricity and thermal or mechanical energy for industrial processes, space conditioning or hot water. The fundamental attribute of CHP is higher thermodynamic efficiency compared to the separate production of electricity and thermal or mechanical services. Improved efficiency is achieved through higher initial temperatures and pressures and by use of otherwise wasted thermal energy. Typical benefits of CHP include a net reduction in cost, carbon dioxide, and other environmental impacts; improved economic viability of the host facility; improved system reliability; and reduced transmission and distribution-system costs.

CHP includes diverse combinations of fuel, technologies, and applications, making it difficult to characterize a definitive CHP project. Fuel used for CHP includes waste heat from industrial equipment and processes, natural gas, wood residue, biogas, and spent pulping liquor. Technologies include gas turbine generators, combined-cycle power plants, steam-electric plants, and reciprocating-engine generator sets. Several examples of the expected cost of resources and technologies configured for CHP are described in this Chapter and in Appendix I.

About 3,970 megawatts of CHP is installed in the Northwest. About 1,790 megawatts of this capacity is industrial CHP, closely integrated with the host facility and sized to the thermal load. The remaining 2,180 megawatts are utility-scale combined-cycle plants where steam is extracted to serve an "over-the-fence" thermal load. The operation of industrial CHP is generally determined by thermal demand (i.e., the operation of the thermal host), whereas the operation of utility-scale combined-cycle CHP is largely determined by fuel and electricity prices. Fifteen CHP plants, totaling 143 megawatts of capacity, have been constructed in the Northwest since the release of the Fifth Power Plan in 2004. All of these new plants are industrial CHP and most are fueled by bio-residue.

The greatest near-term CHP potential in the Northwest is at energy-intensive industrial facilities and commercial facilities that have large space conditioning and hot water load. While technical potential exists in the commercial and residential sectors, these tend not to be cost-effective given the current technology. A growing CHP application is energy recovery from agricultural and other bio-residue where the reject heat of the generating unit is used to maintain the waste-digester operating temperatures.

A 2004 assessment¹⁶ identified 14,425 megawatts of technical CHP potential for Idaho, Oregon, and Washington.¹⁷ Under “business-as-usual” assumptions (little improvement in technology, no incentives, and standby charges) the economic potential through 2025 was estimated to be about 1,030 average megawatts of energy. No applications using woody biomass residue were considered, nor were any applications involving capturing waste energy such as gas pipeline compressor stations, cement kilns or metal remelt furnaces. These are promising applications and this estimate of economic potential may be low because of these omissions.

Unfortunately, the full benefits of CHP are rarely seen by the individual parties (utility, host facility, developer) involved in the decision to develop CHP. Many of the barriers to CHP stem from these differing perspectives and include:

- The required return on investment of the host facility is often higher than that of a utility.
- Unless participating as an equity partner, the utility sees no return, and a loss of load.
- Limited capital and competing investment opportunities often constrain the host facility’s ability to develop CHP.
- Energy savings benefitting the host facility may not be worth the hassle of installing and operating a CHP plant.
- Difficulty establishing a guaranteed fuel supply for wood residue plants.
- Uncertainties regarding the long-term economic viability of the host facility.
- The location value of CHP is often not reflected in electricity buy-back prices.
- The relative complexity of permitting and environmental compliance for small plants.

Actions to help resolve these issues were identified in the Fifth Power Plan. These remain valid and include:

- Routine surveys to identify CHP and small-scale renewable energy resource development opportunities.

¹⁶ Energy and Environmental Analysis, Inc. *Combined Heat and Power in the Pacific Northwest: Market Assessment*, B-REP-04-5427-004. July 2004.

¹⁷ CHP opportunities in Montana were not assessed in the Energy and Environmental Analysis study.

- Resource evaluation criteria that fully reflects CHP costs and benefits, including the value of energy, capacity, and ancillary services, avoided transmission and distribution costs, and losses and environmental effects.
- Eliminating disincentives to utility acquisition of power from customer-side projects such as the inability of investor-owned utilities to receive a return on investment in generation owned or operated by others.
- Uniform interconnection agreements and technical standards.
- Equitable standby tariffs.
- Provisions to allow the sale of excess customer-generated power through the utility's transmission and distribution system.

Distributed Generation

Distributed generation is located at or near electrical load. Distributed generation can provide: standby power for critical load; regulation of voltage or frequency beyond grid standards; cogeneration; local voltage support; an alternative to expanding transmission or distribution capacity; service to remote load; peak shaving to reduce demand charges; and an alternative source of supply for times of high power prices or system islanding. Distributed energy storage technologies can provide many of the same services and emerging “smart grid” controls can synchronize the operation of numerous individual units to create a virtual large-scale storage facility. The modularity and small-scale of distributed technologies may lead to rapid technological development and cost reduction.

Distributed generation installations are smaller than central-station plants, ranging from tens of kilowatts to about 50 megawatts in capacity. The benefits of distributed generation can best be secured with technologies that are flexible in location and sizing such as small gas-turbine generators, reciprocating-engine generators, boiler-steam turbines, solar photovoltaics, microturbines, and fuel cells. However, distributed generation applications are often uneconomic sources of bulk power compared to central-station generation because of the higher cost of equipment, operation and maintenance, fuel, and their lower thermodynamic efficiency. Still, distributed generation can be an attractive alternative for all the reasons listed earlier.

HYDROELECTRIC POWER

The mountains of the Pacific Northwest and British Columbia experience heavy precipitation, much of which falls as snow, producing large volumes of annual runoff that create the great hydroelectric power resource for the region. The theoretical potential has been estimated to be about 68,000 megawatts of capacity and 40,000 average megawatts of energy. Nearly 33,000 megawatts of this potential capacity has been developed at about 360 projects. Though the remaining theoretical hydroelectric power potential is large, most economically and environmentally feasible sites have been developed. The remaining opportunities are, for the most part, small-scale.

Hydroelectric power is by far the most important generating resource in the Pacific Northwest, providing about two-thirds of the generating capacity and about three-quarters of electric energy on average. The annual average runoff volume, as measured at The Dalles Dam, is 134 million acre-feet but it can range from a low of 78 million acre-feet to a high of 193 million acre-feet. The combined useable storage in U.S. and Canadian reservoirs is only 42 million acre-feet. This means that the system has limited capability to reshape river flows to yield energy better matching the seasonal electricity demand. The Pacific Northwest is a winter-peaking region, yet river flows are highest in spring (during the snow melt) when electricity demand is generally the lowest. Because of this, the region has historically planned its resource acquisitions based on critical hydro conditions, the historical water year¹⁸ with the lowest runoff volume over the winter-peak demand period. Under those conditions, the hydroelectric system produces about 11,800 average megawatts of energy. On average, it produces nearly 16,000 average megawatts of energy, and in the wettest years it can produce over 19,000 average megawatts. For perspective, the annual average regional demand is about 22,000 average megawatts. In order to reflect the important variability of hydroelectric production as water conditions change, the Council's analysis uses a 70-year water record in its analysis.

Existing Hydropower System

The current hydroelectric system has a capacity of about 33,000 megawatts, but it operates at about a 50 percent annual capacity factor because of limited water supply and storage. The Northwest's power supply must be sufficient to accommodate increased demand during a sustained cold snap, heat wave or the temporary loss of a generating resource. The hydroelectric system provides up to 24,000 megawatts of sustainable peaking capacity for the six highest load hours of a day over a consecutive three-day period.

These assumptions for the annual and hourly capability of the hydroelectric system are sensitive to fish and wildlife operations, which have changed in the past and could change in the future. There remain a number of uncertainties surrounding these operations, which could have both positive and negative effects. For example, spillway weirs offer the potential to reduce bypass spill while providing the same or better passage survival. Climate change has the potential to alter river flows, which affect both power production and fish survival. Dam removal or operating reservoirs at lower elevations would further reduce power production.

For the Sixth Power Plan, hydroelectric system capability is based on fish and wildlife operations specified in the 2008 biological opinion. How climate change might affect hydroelectric generation and its impact on the resource strategy is examined via scenario analysis. However, it should be noted that the range of potential changes to hydroelectric generation is relatively small compared to other planning uncertainties.

Integrating Fish & Wildlife and Power Planning

The Power Act requires that the Council's power plan and Bonneville's resource acquisition program assure that the region has sufficient generating resources on hand to serve energy

¹⁸ The water year or hydrologic year is normally defined by the USGS from the beginning of October through the end of September and denoted by the calendar year of the final nine months. The water year of the Columbia River system, however, is modeled from the beginning of September (beginning of operation for reservoir refill) through the end of August.

demand and to accommodate system operations to benefit fish and wildlife.¹⁹ The Act requires the Council to update its fish and wildlife program before revising the power plan, and the amended fish and wildlife program is part of the power plan. The plan then sets forth “a general scheme for implementing conservation measures and developing resources” with “due consideration” for, among other things, “protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival and propagation of anadromous fish.”²⁰

On average, fish and wildlife operations reduce hydroelectric generation by about 1,200 average megawatts relative to operation with no constraints for fish and wildlife.²¹ This energy loss represents about 10 percent of the hydroelectric system’s firm generating capability.²² Bonneville estimates its total financial obligation for the fish and wildlife program to be between \$750 to \$900 million per year, combining ordinary and capital expenditures, power purchases, and foregone revenues associated with operations to benefit fish and wildlife.

These impacts would definitely affect the adequacy, efficiency, economy, and reliability of the power system if they had been implemented over a short time. However, this has not been the case. Since 1980, the region has periodically amended fish and wildlife related hydroelectric system operations and, in each case, the power system has had time to adapt to these incremental changes. The Council’s current assessment²³ indicates that the regional power supply can reliably provide actions specified to benefit fish and wildlife (and absorb the cost of those actions) while maintaining an adequate, efficient, economic, and reliable energy supply. This is so even though the hydroelectric operations for fish and wildlife have a sizeable impact on power generation and cost. The power system has addressed this impact by acquiring conservation and generating resources, by developing resource adequacy standards, and by implementing strategies to minimize power system emergencies and events that might compromise fish operations.

The Council recognizes the need to better identify and analyze long-term uncertainties that affect all elements of fish and power operations. In the action plan, the Council proposes creating a public forum that would bring together power planners and fish and wildlife managers to explore ways to address these uncertainties. Long-term planning issues include climate change, alternative fish and wildlife operations, modifications to treaties affecting the hydroelectric system, and the integration of variable-output resources, in particular how they affect system flexibility and capacity. The forum would provide an opportunity to identify synergies that may exist between power and fish operations and explore ways of taking advantage of those situations.

¹⁹ For more information please see Appendix M: Fish and Wildlife Interactions.

²⁰ Northwest Power Act, Sections 4(e)(2), (3)(F), 4(h)(2)

²¹ The comparison study, which includes no actions for fish and wildlife, is represented by hydroelectric operations prior to 1980.

²² Firm hydroelectric generating capability is about 11,900 average megawatts (2007 Bonneville White Book) and is based on the critical hydro year, which is currently defined to be the 1937 historical water year.

²³ See <http://www.nwcouncil.org/energy/resource/Adequacy%20Assessment%20Final.doc>.

New Hydropower Development

New Hydropower Projects

Though the remaining theoretical hydroelectric power potential is large, most economically and environmentally feasible capacity appears to have been developed. The remaining opportunities for new projects are, for the most part, small-scale. Among these are: adding generating equipment to irrigation, flood control, and other non-power water projects; adding generation to existing hydropower power projects with surplus stream flow; and a few projects at undeveloped sites. A comprehensive assessment of new hydropower potential has not been attempted by the Council since the Fourth Power Plan. In that plan, the Council estimated that about 480 megawatts of additional hydropower capacity was available for development at costs of 9.0 cents per kilowatt-hour or less. This capacity could produce about 200 megawatts of energy on average. Few projects have been developed in the intervening years, and it is likely that the Fourth Power Plan estimate remains representative. Hydropower development costs are sensitive to project configuration, size, and site characteristics. A review of recent projects shows costs ranging from \$65 to over \$200 per megawatt-hour and a weighted average cost for committed and completed projects of \$88 per megawatt-hour. Demand for low-carbon resources and resources qualifying for state renewable portfolio standards has increased interest in hydropower development, and the Council recommends that current efforts to reassess new hydropower potential be continued to improve understanding of the current cost and potential of the resource.

Upgrades to Existing Hydropower Projects

Renovations to restore the original capacity and energy production of existing hydropower projects, and upgrades to yield additional capacity and energy are often much less costly than developing new projects. Most existing projects date from a time when the value of electricity was lower and equipment efficiency less than now, and it is often feasible to implement upgrades such as advanced turbines, generator rewinds, and spillway gate calibration and seal improvement. Even a slight improvement in equipment efficiency at a large project can yield significant energy. The last comprehensive assessment of regional hydropower upgrade potential was completed more than 20 years ago and many renovations and upgrades have been completed in the intervening years. Much like end-use efficiency, improved technology and higher electricity values are likely to have increased the undeveloped potential even as renovations and upgrades have been completed. Informal surveys suggest that several hundred average megawatts or more are potentially available from renovations and upgrades. The Council recommends that a comprehensive assessment of hydropower upgrade potential be undertaken to gain a better understanding of the cost and potential of this resource.

NON-HYDRO RENEWABLE ENERGY RESOURCES

Biofuel

Biofuel includes combustible organic residue from producing and consuming food, fiber, and materials and fuel from dedicated energy crops. Northwest bio-residue includes woody residue (forest, logging, and mill residue and the biogenic components of municipal solid waste), spent pulping liquor, agricultural field residue, animal manure, food processing residue, landfill gas, and wastewater treatment plant digester gas. Hybrid poplar plantations have the greatest

potential for dedicated bio-energy production for the electrical sector in the Northwest, but historically have had greater fiber than fuel value.

Landfills

The anaerobic decomposition of organic matter from landfills produces a low-grade (~450 Btu/scf) combustible gas that largely consists of methane and carbon dioxide. Gas production usually begins one or two years following waste emplacement and may last for several decades. The gas is collected and flared for safety reasons and to reduce its greenhouse gas potential.²⁴ Increasingly, the gas is used directly as a low-grade fuel, upgraded to pipeline-quality gas, or for on-site power generation. A typical power generation facility consists of gas cleanup equipment and one or more reciprocating engine-generator sets. A common business model is third-party development of the gas cleanup and power generation facilities with purchase of the raw gas from the landfill operator.

Seven landfill gas recovery projects totaling 30 megawatts of capacity are in operation in the Northwest. The estimated feasible undeveloped power generation potential in the Northwest is about 70 average megawatts, representing about 80 megawatts of installed capacity. Because several landfill operators are considering injecting the upgraded gas into the natural gas system, a portion of this potential is unlikely to be available for power generation. The reference 3-megawatt project would operate as a must-run baseload project and produce electricity at an estimated cost of \$73 per megawatt-hour. Specific projects will vary in cost due to economies of scale, gas quality, and gas production rates. Barriers to developing landfill gas for power generation include competing uses of the gas, low financial incentives²⁵, and cost, especially for smaller landfills.

Agricultural and Food Wastes

A combustible gas (largely consisting of methane and carbon dioxide) produced by anaerobic digestion of animal manure, food waste, and similar biogenic organic material can be used to generate power. A typical animal manure or food waste energy-recovery plant uses enclosed slurry-fed anaerobic digesters for gas production and reciprocating engine generators for power generation. Heat recovered from the engine-generator is used to maintain digester temperature and dry the residual fiber for animal bedding or soil amendment. These projects provide must-run, baseload, carbon-neutral electricity from an otherwise wasted resource. The most economically feasible facilities for installing energy recovery are large-scale confined animal feeding operations including dairies, swine and poultry facilities using slurry manure handling. European dry fermentation technology, currently being introduced to North America, could broaden energy recovery to feedlots and other operations using dry manure handling.

At least eight large-scale (0.5 megawatts and larger) animal manure energy recovery projects and one food-processing residue project totaling about 13 megawatts are known to be in operation or under construction in the Northwest. The undeveloped potential, primarily at large-scale dairy operations, is estimated to be 50 to 110 average megawatts. Additional potential might be secured through cooperative facilities serving smaller dairy or food processing operations. Power generation costs vary widely and are sensitive to project size and the type of digester. The

²⁴ Methane has about 21 times the greenhouse warming potential than the carbon dioxide product of its combustion.

²⁵ Biogas power generation facilities receive a federal production tax credit of about \$10 per megawatt-hour for the first ten years of operation - one-half the credit received by wind projects.

reference cost of electricity is \$88/megawatt-hour. Costs might range from \$80 per megawatt-hour for a large 2.5 megawatt project (~16,000 head of cattle) to about \$139 per megawatt-hour for a 450 kilowatt project (~ 2,900 head). Cost and collecting a sufficient supply of manure or other agricultural waste to support economically feasible projects are the biggest obstacles to growth. Aggregating sufficient biomass for an economically-sized plant, and cost in general, particularly for smaller facilities, are the primary barriers to the growth of food waste as a resource.

Waste Water Energy Recovery

In many wastewater treatment facilities, sludge is processed in anaerobic digesters that produce a moderate quality (600 - 650 Btu/kWh) combustible biogas consisting largely of methane and carbon dioxide. Anaerobic digesters require additional heat for optimal operation, and the common method of disposing of the biogas is to use it as a fuel to maintain digester temperature. Surplus is flared. A more productive alternative is to clean the biogas to use as fuel for a cogeneration plant where the heat from the generating unit is used to maintain digester temperature. Reciprocating engines are typically used for this application.

Nineteen wastewater treatment energy recovery projects totaling 22 megawatts are in operation or under construction in the Northwest. Though an estimate of the remaining regional potential was not located, a 2005 assessment prepared for the Oregon Energy Trust estimated 2 megawatts to 4 megawatts of undeveloped near-term potential for Oregon. Extrapolating this estimate to the region based on population suggests a remaining undeveloped near-term potential of 7 megawatts to 14 megawatts.

The reference plant is an 850-kilowatt reciprocating engine generator fueled by gas from the anaerobic digesters of a wastewater treatment plant. Reject engine heat is captured and used to maintain optimal digester temperatures. The reference cost of electricity is \$104 per megawatt-hour with the plant operating in baseload mode (seasonal fluctuations may occur due to wastewater treatment plant loading). Capacity, site conditions, financing, and incentives can lead to wide variation in cost. Electricity production costs might range from about \$85 per megawatt-hour for larger (1 - 2 megawatts) installations to \$120 for smaller installations. The electricity is typically used to offset treatment plant load so electricity production costs compete with retail rates. Cost for smaller treatment plants is the primary barrier to fully developing the remaining potential.

Woody Residue

The largest source of woody residue in the Northwest has been the forest products industry. Currently, there are 23 projects (with 283 megawatts of capacity) using woody residue as a primary fuel operating in the Northwest, a slight increase since the Fifth Power Plan. Surveys indicate that nearly all woody residue produced in the forest products sector are used for fuel or other purposes. Some undeveloped potential is available by separating the biogenic material from municipal solid waste, but the major new potential is forest thinning residue from ecosystem recovery and wildfire hazard reduction efforts, and from more intensively managed commercial timberlands. This additional woody residue could provide about 90 TBtu of fuel energy annually on a reliable, sustained basis. Its price will vary depending on the source, alternative uses, and prevailing economic conditions; but it is expected to average about \$3.00 per million Btu in the near-term. Expected introduction of specialized collection and

transportation equipment for bulk low-density fuel should result in an annual average real price reduction, estimated to be 1 percent over the period of the plan.

Conventional steam-electric plants with or without CHP will be the chief technology for electricity generation using wood residue in the near term. A sustained annual region-wide fuel supply of 90 TBtu is sufficient to generate about 665 average megawatts using conventional technology. Modular biogasification plants are under development and may be introduced within the next several years. Modular units would open the possibility of “bringing the plant to the fuel” thereby expanding the potential fuel supply, reducing fuel transportation costs and improving the economics of plant operation.

Two reference plants were characterized: one representing favorable development conditions resulting in relatively low power cost, and a second representing longer-term marginal conditions and consequent higher power costs. Favorable development factors that could reduce project costs include the availability of refurbished equipment, sources of low-cost mill or urban wood residue, CHP revenue, a brownfield site with established infrastructure, low-cost financing, and financial incentives. These factors could result in power production costs of \$88 per megawatt-hour, or less, within the competitive range for new generating resources.

The longer-term marginal plant is a 25 megawatt stand-alone unit using conventional steam-electric technology, located at a greenfield site and operating primarily on forest thinning residue. This plant would produce electricity at \$125 per megawatt-hour. Capital and fuel costs are both major components of the energy cost.

The principal barriers to developing woody biomass plants include high capital and fuel costs, the availability of CHP load, and ensuring an adequate, stable, and economical fuel supply.

Pulping Chemical Recovery

Chemical recovery boilers recover the chemicals from spent pulping liquor. Lignins and other combustible materials in the spent liquor create the fuel. Recovery boilers--usually augmented by power boilers fired by wood residue, natural gas or other fuel--supply steam to the pulping process. Greater efficiency is possible by producing the steam at high pressure and extracting it at the desired pressures from a steam-turbine generator. When the Fourth Power Plan was prepared, eight of the 19 mills then operating in the Northwest were not equipped for cogeneration. Estimates prepared for that plan indicated that an additional 280 average megawatts of electric power could be produced by installing cogeneration equipment at recovery boilers without it. Mills have closed since then and upgrades have been undertaken at several of the remaining plants, including the recent addition of a 55-megawatt generating plant at the Simpson Tacoma Kraft mill. The remaining Northwest potential has not been recently assessed. Limited capital availability, short pay-back periods, and the uncertain economic conditions in the industry typically constrain development.

Geothermal Power Generation

The crustal heat of the earth, produced primarily by the decay of naturally-occurring radioactive isotopes, may be used for power generation. Conventional hydrothermal geothermal electricity generation requires the coincidental presence of fractured or highly porous rock at temperatures of about 300° Fahrenheit or higher and water at depths of about 10,000 feet or less. The most

promising Northwest geologic structure for hydrothermal generation is the basin and range province of southeastern Oregon and southern Idaho. Here, natural circulation within vertical faults brings hot fluid toward the surface. Basin and range geothermal resources have been developed for generation in Nevada, Utah, and California, and recently in Idaho. The 13-megawatt Raft River project in Idaho is the first commercial geothermal power plant in the Northwest. Earlier models of the geology of the Cascades Mountains suggested the presence of large geothermal potential. More recent research suggests that while local hydrothermal systems may exist in the Cascades, geothermal potential for generation outside of these local systems is limited or absent. Moreover, development of much of the Cascades potential would be precluded by land-use constraints. Newberry Volcano (Oregon) and Glass Mountain (California) are the only Cascades structures offering geothermal potential not largely precluded by existing land use. These structures may be capable of supporting several hundred megawatts of geothermal generation.

Conventional Geothermal Power Generation

Depending on resource temperature, flashed-steam or binary-cycle geothermal technologies could be used with the liquid-dominated hydrothermal resources of the Pacific Northwest. A preference for binary-cycle or heat-pump technology is emerging because of modularity, applicability to lower temperature geothermal resources, and the environmental advantages of a closed geothermal-fluid cycle. In binary plants, the geothermal fluid is brought to the surface using wells and passed through a heat exchanger where the energy is transferred to a low boiling point fluid. The vaporized low boiling point fluid is used to drive a turbine generator, then condensed and returned to the heat exchanger. The cooled geothermal fluid is re-injected to the geothermal reservoir. This technology operates as a baseload resource. Flashed steam plants typically release a small amount of naturally occurring carbon dioxide from the geothermal fluid, whereas the closed-cycle binary plants release no carbon dioxide. The reference geothermal plant is a binary-cycle plant consisting of three 13-megawatt units. The estimated cost of electricity from this plant is \$81 per megawatt-hour--among the lowest-cost generating resources identified in this plan.

A recent U.S. Geological Survey assessment²⁶ yielded a mean total Northwest hydrothermal electricity generating potential of 1,369 average megawatts. However, geothermal development has historically been constrained by high-risk, low-success exploration and well field confirmation. Using historical Nevada development rates as guidance, the Council has adopted a provisional estimate of 416 megawatts of developable hydrothermal resource for the period of the plan. This would yield about 375 average megawatts of energy. These assumptions should be revisited at the biennial assessment of the Sixth Power Plan.

Enhanced Geothermal Power Generation

The natural presence of the high-temperature permeable rock and fluid conditions required for conventional geothermal plants at feasible drilling depths is uncommon. Much more common are high-temperature, but insufficiently permeable, formations. Enhanced geothermal systems (EGS)²⁷ create the necessary permeability by fracturing or other means. EGS technology is one

²⁶ United States Geological Survey. *Assessment of Moderate- and High-Temperature Geothermal Resources of the United States*, 2008.

²⁷ Also known as engineered geothermal systems.

of several emerging geothermal technologies²⁸ that could vastly increase the developable geothermal resource. A 2004 MIT assessment of geothermal potential²⁹ identified three areas of special EGS interest in the Northwest. Two (Oregon Cascades and Snake River Plain) are unique to the Northwest. The USGS study identified 104,000 average megawatts of EGS potential at a 95 percent confidence level in the four Northwest states. Because EGS technology has not been commercially proven, it is not included among the resources evaluated for the portfolio of this plan. Because of its potential, the Council encourages Northwest utilities to support efforts to develop and demonstrate EGS technology.

Marine Energy

Ocean Currents

The kinetic energy of flowing water can be used to generate electricity by water-current turbines operating on a principal similar to wind turbines. Conceptual designs and prototype machines have been developed and an array of current turbines is being installed in New York City's East River (a tidal current rather than an ocean current application). Turbine energy yield is very sensitive to current velocity and little electrical potential is available from the weak and ill-defined currents off the Northwest coast.

Thermal Gradients

An ocean thermal energy conversion (OTEC) power plant extracts energy from the temperature difference that may exist between surface waters and waters at depths of several thousand feet. OTEC technology requires a temperature differential of about 20 degrees Celsius (36 degrees Fahrenheit). Temperature differentials of this magnitude are limited to tropical regions extending to 25 to 30 degrees of latitude. Ocean thermal temperature differentials in the Northwest range from 0 to 12 degrees Celsius (0 - 20 degrees Fahrenheit,) precluding of OTEC technology.

Salinity Gradients

Energy is released when fresh and saline water are mixed. Conceptually, the energy potential created by fresh water streams discharging to salt water bodies can be converted to electricity. Concepts include osmotic hydro turbines, dilytic batteries, vapor pressure turbines, and polymeric salinity gradient engines. Development of salinity gradient generation is underway in Europe with a focus on osmotic technology. The Norwegian utility Statkraft has completed a 4 megawatt prototype osmotic hydro turbine power plant near Oslo with the intention of developing a commercial-scale plant by 2015. A key to commercialization is reducing the cost of the osmotic membrane. Because the theoretical resource potential in the Northwest is substantial, salinity gradient technology should be monitored and an assessment of Northwest potential undertaken when the characteristics and operating requirements of commercial units become better understood.

²⁸ Others include "Hidden" hydrothermal resources, supercritical volcanic geothermal, oil and gas co-production and geopressured reservoirs.

²⁹ Massachusetts Institute of Technology. *The Future of Geothermal Energy*, 2004.

Tidal Energy

Tidal energy originates from the loss of the earth's rotational momentum due to drag induced by the gravitational attraction of the moon and other extraterrestrial objects. The conventional approach to capturing tidal energy is through hydroelectric "barrages" constructed across bays or estuaries. These admit water on the rising tide and discharge water through hydro turbines on the ebb. The extreme tidal range, preferably 20 feet or more, required by this technology precludes their application to very few locations where the landform greatly amplifies the tidal range. Environmental considerations aside, developing economical tidal hydroelectric plants in the Northwest using barrage technology is precluded by insufficient tidal range. Mean tidal ranges in the Pacific Northwest are between 4.5 and 10.5 feet with the greatest mean tides found in bays and inlets of southern Puget Sound. A more promising approach to capturing tidal energy in the Northwest is to use kinetic energy of tide-induced currents to generate electricity by water-current turbines. Intermittent tidal currents of three to eight knots occurring locally in Puget Sound and channels within the San Juan Islands may be sufficient to support tidal current generation. Water current turbine technology is in the demonstration stage of development and several Northwest utilities have secured preliminary permits to explore this potential.

Wave Energy

The Northwest coast is one of the better wave energy resource areas in the world. The theoretical wave energy potential of the Washington, Oregon, and Northern California coast is estimated to be about 50,000 average megawatts. The practical potential will be much smaller because of the competing uses of sea space, environmental constraints, and conversion losses. Nonetheless, the developable potential is likely to be substantial, and could provide the Northwest with an attractive source of low-carbon renewable energy. While highly seasonal and subject to storm-driven peaks (winter energy flux may exceed summer rates by a factor of 20), wave energy is continuous and is more predictable than wind, characteristics that may reduce integration costs. Though it would be impractical to capture the full winter energy flux, the seasonal output of a wave energy plant would generally coincide with winter-peaking regional load. A further attribute of wave energy is its location close to westside load centers.

Numerous and diverse wave energy conversion concepts have been proposed and are in various stages of development ranging from conceptualization to pre-commercial demonstration. It is too early to say which technologies will eventually prove best for particular conditions. Wave energy conversion devices will need to perform reliably in a high-energy, corrosive environment, and demonstration projects will be needed to perfect reliable and economic designs. Successful technology demonstration will be followed by commercial pilot projects that could be expanded to full-scale commercial arrays. Because of potential environmental issues and the competition for sea space from commercial and sport fisheries, wildlife refuges and wilderness areas, shipping, undersea cables, and military exclusion zones, site suitability should be assessed and siting protocols established in advance of large-scale commercial development. An important role of demonstration projects will be to gain understanding of site suitability, potential conflicts, impacts, and remediation measures. Assessments of interconnection and integration requirements are also essential. Northwest utilities are encouraged to support these efforts.

Conversion technology, depth, ambient wave energy, ocean floor conditions, and the distance from shore all affect the cost of this resource. A 2004 estimate of the capital and operating costs and electrical productivity of a 90-megawatt commercial-scale plant using Pelamis wave energy

converters optimized to Northwest conditions yields costs of \$140 to \$270 per megawatt-hour³⁰ for the first array. Experience and economies of production will reduce costs as installed capacity increases. Given the installation of 1,600 megawatts of wave energy plants globally, an amount appearing feasible by the 2020s, technology learning curves from experience in the wind, solar, and other industries yield expected costs of \$80 to \$150 per megawatt-hour. Wave energy can compete with other generating resources if costs within the lower portion of this range can be achieved.

Solar

The amount of solar radiation available for electricity generation is a function of latitude, atmospheric conditions, and local shading. The best solar resource areas in the Northwest are the inter-mountain basins of south-central and southeastern Oregon and the Snake River plateau of southern Idaho. On an annual average, these areas receive about 75 percent of the irradiation received in Barstow, California, one of the best U.S. sites.

Because of its strong summer seasonality, the Northwest solar resource has potential for serving local summer-peaking load, such as irrigation and air conditioning, but is less suitable for serving general regional load which is forecast to continue to be winter-peaking for many years. There have been no comprehensive studies of site suitability for development, though the potential is large.

Solar energy can be converted to electricity using photovoltaic or solar-thermal technologies.

Photovoltaics

Photovoltaic plants convert sunlight to electricity using solid-state devices. Because no combustion or other chemical reactions are involved, power production is emission-free. No water is consumed other than for periodic cleaning. Power output is variable and battery storage or auxiliary power is required for remote load demanding a constant supply. Grid-connected installations require firm capacity and balancing reserves, though balancing reserve requirements may be mitigated by distributing many small plants over a wide geographic area, thus dampening cloud-driven ramp rates.

Photovoltaic technology is commercially established and is widely employed to serve small remote load too costly for grid service. Strong public and political support has led to attractive financial incentives, so despite the high cost and low productivity, grid-connected installations of several hundred kilowatts or more are becoming common in the Northwest. Multi-megawatt, utility-scale installations are appearing in the Southwest where economics are improved by high coincidence of plant output and load.

A low-cost photovoltaic plant employs thin film photovoltaic cells mounted on fixed racks. The energy conversion efficiency and overall productivity of such a design is low and thin film cells suffer from more rapid degradation than more expensive crystalline silicon cell technology. Crystalline silicon cells operate at higher efficiency and are more durable, but they are also more costly. Plant productivity can be improved by mounting cell arrays on tracking devices to improve daily and seasonal orientation. Maximum productivity is achieved by using

³⁰ Using the reference cost assumptions used elsewhere in this chapter.

concentrating lenses focusing on high-efficiency multi-junction photovoltaic cells with wide spectral response, mounted on fully automatic dual-axis trackers. Concentrating photovoltaic plants operate on direct (focusable) solar radiation, so are best suited for clear southwestern desert conditions.

The reference plant is a 20-megawatt (AC net), utility-scale station employing flat-plate, non-concentrating crystalline photovoltaic cells and single-axis trackers. The direct-current output of the modules is converted to alternating current for grid interconnection. The relatively small size would permit interconnection at distribution system and sub-transmission voltages, facilitating a high degree of modularity and distribution across a wide geographic area. This would help reduce ramping events driven by cloud movement. The reference plant could yield capacity factors up to 26 percent at the best Northwest locations. If constructed in the near-term, this plant would deliver energy at about \$280 per megawatt-hour. Costs are expected to continue to decline at the historical average rate of about 8 percent per year.

Solar Thermal Power Plants

Solar thermal power generation technologies (also referred to as concentrating solar power or CSP) use lenses or mirrors to concentrate solar radiation on a heat exchanger to heat a working fluid. The working fluid is used directly or indirectly to power a turbine or other mechanical engine to drive an electric generator. CSP technologies are broadly categorized by the design of the concentrator and the type of thermal engine. The three basic types are parabolic trough, central receiver, and Sterling dish. Parabolic trough plants, the most mature, have been in commercial operation in California since the 1980s. Plants have been recently completed in Nevada and Spain.³¹ These plants employ arrays of mirrored parabolic cross-section troughs that focus solar radiation on a linear heat-exchange pipe filled with circulating heat transfer fluid. The hot fluid is circulated through heat exchangers to generate steam to supply a conventional steam-electric power plant. Parabolic trough plants can be equipped with auxiliary natural gas boilers to stabilize output during cloudy periods and to extend daily operating hours. Plants can also be equipped with thermal storage for the same purpose.

Central-receiver plants employ a field of tracking reflectors (heliostats) that direct solar radiation on an elevated central receiver where energy is transferred to a working fluid, usually a molten salt. The hot molten salt is circulated through heat exchangers to generate steam to supply a conventional steam-electric power plant. Molten salt storage tanks are provided to stabilize output during cloudy periods and to extend daily operating hours. Several demonstration plants have been constructed. The first commercial central receiver plant, a 17-megawatt unit, is scheduled for 2011 service in Spain.

A Stirling dish consists of a tracking parabolic mirror that concentrates solar radiation on the heat exchanger of a small Stirling reciprocating engine at the focal point of the mirror. Individual dishes are small, and utility-scale plants would consist of large arrays of individual dish units. Because of the small size of the individual units, Stirling dish technology may benefit from economies of standardization and production. However, Stirling dish technology is not suitable for thermal storage. The technology is in the demonstration stage.

³¹ An in-depth source of information regarding parabolic trough solar-thermal plants is at <http://www.nrel.gov/csp/troughnet/>.

Concentrating solar plants use direct solar radiation so are best suited for dry, clear sky locations. Though potentially suitable areas might be found in southern Idaho and southeastern Oregon, the most suitable locations are in the Southwest. The reference plant is a 100-megawatt parabolic trough concentrating solar thermal plant, with thermal storage, located in east-central Nevada in the vicinity of Ely. Power would be delivered to southern Idaho via the north segment of the proposed Southwest Intertie Project and then to the Boardman area via portions of the proposed Gateway West and the Boardman-to-Hemingway transmission projects. One 500 kilovolt transmission circuit could deliver about 1,500 megawatts of capacity and about 530 average megawatts of energy. Because of the time needed to construct the necessary transmission, it is unlikely that a solar-thermal plant would be available for serving Northwest load prior to 2015. A plant coming into service in 2015 could deliver energy to southern Idaho for about \$190 per megawatt-hour. The additional cost of new transmission from Idaho would raise the cost of delivery to Oregon or Washington to about \$230 per megawatt-hour. Technological improvements and economies of production are expected to result in lower power plant cost.

Solar-thermal technology can provide an abundant alternative source of low-carbon energy. Because they can be fitted with thermal storage and supplementary boilers, parabolic trough and central receiver technologies have the further advantage of providing reliable output through the peak load hours of the day. These technologies are particularly attractive in the Southwest where they can be sited near load at a cost approaching that of competing low-carbon resources. The added cost and investment risk of long distance transmission needed for these plants make them less attractive for the Northwest.

Wind

Northwest wind resource areas include coastal sites with strong but irregular storm-driven winter winds and summertime northwesterly winds. Areas lying east of gaps in the Cascade and Rocky mountain ranges such as the Columbia River Gorge, Snoqualmie Pass, and Marias Pass receive concentrated prevailing westerly winds, occasional wintertime northerly winds, and winds generated by east-west pressure differentials. Favorable winds are also found on the north-south ridges of southeastern Oregon and southern Idaho.

Beginning in 1998 with the 25-megawatt Vansycle Ridge project, commercial wind power has grown to exceed 4,000 megawatts of nameplate capacity, and is now the fourth largest component of the Northwest power system in terms of installed capacity. Though some geographic diversification has occurred, capacity remains concentrated in the area of the Columbia Basin east of the Columbia River Gorge. Nearly 80 percent of the total regional wind capacity is located in a 160 mile corridor from The Dalles, Oregon northeast to Pomeroy, Washington.

The rapid rate of development reflects the fundamental attributes of wind power as an abundant, mature, relatively low-cost source of low-carbon energy with local economic benefits. These attributes, combined with an array of market and financial incentives and strong political support within the Northwest and elsewhere in the WECC region are expected to sustain robust development of Northwest wind power.

Wind power in the Northwest has variable output and little firm capacity and therefore requires supplemental firm capacity and balancing reserves. An existing surplus of balancing reserves

and firm capacity within the Northwest has enabled the growth of wind power without the need or cost of additional capacity reserves. However, the concentration of installed wind capacity east of the Columbia River Gorge and within a single balancing area (Bonneville) has led to significant ramping events, putting pressure on Bonneville's ability to integrate additional wind development.

The least cost and quickest solutions to integrating additional wind development appear to be reducing the demand for system flexibility and fully accessing the flexibility of the existing system. Measures such as improved load forecasting, up-ramp curtailment, and sub-hourly scheduling can reduce the amount of flexibility required to integrate a given amount of wind capacity. Longer-term, increasing the geographic diversity of wind development by importing wind from remote areas could also reduce the demand for flexibility. Existing system flexibility, scattered across numerous Northwest balancing areas, can be more fully accessed by developing mechanisms to trade balancing services and by expanding dynamic scheduling capability both within the region and with other load areas. Issues of cost allocation will need to be resolved, especially now that substantial amounts (close to 50 percent of 2008 development) of Northwest wind power is marketed to California customers. Following these steps, new balancing reserves and firm capacity from generation, storage or demand-side sources may be required.

The abundance of compatible wheat and grazing land with good wind resources and available transmission has minimized environmental conflicts. As these prime sites are developed and pressure to geographically diversify wind development increases, environmental conflicts may become more common. Identifying sensitive areas and establishing transparent and comprehensive permitting criteria and procedures will help avoid potential conflicts.

The Council assessed the cost and potential for continued wind development to meet local needs in the Columbia Basin, Southern Idaho, and Montana. The Council also examined the cost of importing wind energy to Northwest load centers from Alberta, Montana, and Wyoming wind resource areas. It is unlikely that wind power from Alberta, Montana, or Wyoming would be available to serve Oregon or Washington load prior to 2015 because of the time needed to construct the necessary transmission. These options are summarized in Table 6-2.

Table 6-2: Cost and Availability of New Wind Power (2015)³²

Resource	Limiting Factor	Capacity (MW)	Energy (MWh)	Cost (\$/MWh)
Local Montana	20% peak load penetration	215	80	\$89
Columbia Basin > PNW Westside	Transmission at embedded cost	4060	1300	\$104
Other local OR/WA	20% peak load penetration	340	110	\$104
Local Southern Idaho	20% peak load penetration	725	215	\$109
Montana > ID	New 500kV AC transmission	1500/circuit	570	\$116
Wyoming > ID	New 500kV AC transmission	1500/circuit	570	\$121
Montana > OR/WA via CTS Upgrade	Upgrade potential of Colstrip Transmission System	659	244	\$128
Alberta > OR/WA	New +/-500kV DC transmission	2000/circuit	760	\$138
Montana > OR/WA	New 500kV AC transmission via S. ID	1500/circuit	570	\$147
Wyoming > OR/WA	New 500kV AC transmission	1500/circuit	570	\$154

To conserve model setup and run time, the four “local” wind resource blocks were consolidated into a single block for the resource portfolio model. For similar reasons, the Montana to Oregon/Washington case was selected as representative of imported wind.³³

WASTE HEAT ENERGY RECOVERY

Certain industrial processes and engines reject energy at sufficient temperature and volume to justify capturing the energy for electricity production, a process known as recovered energy generation (REG), a form of cogeneration. “Waste heat” is a third priority resource in the Regional Act.³⁴ Candidate sources of high and medium-temperature waste heat include: cement kilns, glass furnaces, aluminum smelters, metals refining furnaces, open hearth steel furnaces, steel heating furnaces, hydrogen plants, waste incinerators, steam boiler exhaust, gas turbines and reciprocating engine exhaust, heat treating and annealing furnaces, drying and baking ovens, and catalytic crackers. While many of these facilities are usually equipped with recuperators, regenerators, waste-heat recovery boilers, and other devices to capture a portion of the reject heat, bottoming-cycle cogeneration could also be installed on some of them. Recovered energy generation is attractive because of its efficiency, baseload operation, and little, if any, incremental air emissions or carbon dioxide production. Heat recovery boilers with steam-turbine generators are the conventional approach to using waste heat for electric power generation. However, small-scale, modular organic Rankine cycle power plants (Ormat and others) suitable for lower-temperature energy sources have expanded the potential applications for recovered energy generation.

The reference plant is a 5-megawatt organic Rankine-cycle generating unit using exhaust gas from the mechanical drive gas turbines of a natural gas compressor station. This unit would operate in baseload mode with some fluctuation due to seasonal variation in gas flow (coincident

³² Estimates of capacity and energy are of delivered potential, incremental to installed capacity operating or under construction as of end of 2008.

³³ A review of the cost estimates following this initial portfolio run suggested that Alberta wind has potential as the least-cost imported wind option for Oregon and Washington load. Because of the larger incremental size of imported Alberta wind (2,000 MW vs. 1,500 MW), further analysis is needed to confirm the least-risk/least cost imported wind option.

³⁴ Northwest Power Act, Section 4(e)(1).

with regional electrical load). At \$63 per megawatt-hour, electricity from the reference plant would be among the lowest-cost of the new generating resources identified for this plan.

An inventory of potential Northwest opportunities for the development of recovered energy generation was not located; however, such opportunities are known to exist. For example, more than 50 natural gas pipeline compressor stations are located in the Northwest. Recovered energy cogeneration facilities for trunkline compressor station applications are typically about 5 megawatts in capacity, suggesting significant potential. Cement kilns, steel processing facilities, and glass furnaces offer additional possibilities. The potential is sufficiently attractive to warrant an effort on the part of Bonneville and regional utilities to identify and develop them.

FOSSIL FUELS

Coal

Coal resources available to the Northwest include the Powder River basin fields of eastern Montana and Wyoming, the East Kootenay fields of southeastern British Columbia, the Green River basin of southwestern Wyoming, the Uinta basin of northeastern Utah and northwestern Colorado, and extensive deposits in Alberta. Coal could also be obtained by barge from the Quinsam mines of Vancouver Island or the Chuitna mines of Alaska. Mines at Centralia, Washington, have recently closed and the Centralia power plant is now supplied by rail.

Sufficient coal is available to the region to easily support all regional electric power needs through the planning period. Improvements in mining and rail haul productivity have resulted in generally declining constant dollar production costs. Climate policy and overseas demand are the important factors affecting future coal prices. Though carbon dioxide penalties would tend to depress future demand and prices, commercialization of technologies for separating and sequestering carbon dioxide would rejuvenate demand for coal. This plan uses Powder River Basin coal as the reference coal. The minemouth price of Powder River Basin coal is forecast \$0.64/MMBtu in 2010, increasing to \$0.71 in 2029 (medium case). Transportation adders based on rail costs are used to adjust prices to other locations. Further discussion of fuel prices is provided in Chapter 2 and Appendix A.

Coal is the major source of electricity in the United States as a whole, but constitutes only 13 percent (7,300 megawatts) of generating capacity and about 25 percent of the electric energy supply in the Northwest. Pulverized coal-fired steam-electric plants, though a mature technology, continue to improve by using higher temperatures and more efficient steam cycles. The preferred technology for new North American plants is shifting from subcritical steam cycles with thermal efficiency of about 37 percent to supercritical cycles with thermal efficiency of 37 percent to 40 percent. Ultra-supercritical units with thermal efficiencies of 41 percent to 43 percent are being constructed in Europe and Asia and have been proposed in the United States.

Continuing to use coal for power generation will hinge on efforts to reduce carbon dioxide production. While abundant in the United States, coal has the highest carbon content of all the major types of fossil fuel.³⁵ Moreover, conventional coal-fired plants operate at a lower

³⁵ The carbon content of petroleum coke is somewhat greater than that of coal.

efficiency than gas-fired plants. Despite the relatively small penetration of coal capacity in the Northwest, coal combustion is responsible for 85 percent to 90 percent of the carbon dioxide from the Northwest electricity sector. Reducing per megawatt-hour carbon dioxide production from coal-fired plants can be achieved by increased thermal efficiency, fuel switching, and carbon dioxide capture and sequestration. For new construction, increasing the efficiency of combustion is the least cost and logical first step to reducing carbon dioxide production. Ultra-supercritical plants, for example, produce about 80 percent of the carbon dioxide of conventional coal-fired units. Switching from sub-bituminous to certain bituminous coals can reduce carbon dioxide production from existing as well as new plants by several percent, but the economics and net impact on carbon dioxide production are case-specific because of coal production and transportation considerations. Co-firing biomass can reduce carbon dioxide production, but the biomass quantities and co-firing percentages are limited. Carbon capture and sequestration will be required to control carbon dioxide releases to the levels needed to achieve proposed greenhouse gas reduction targets if continued reliance on coal is desired. While carbon capture technology for coal gasification plants is commercially available, capture technology for steam-electric plants remains under development. Though legal issues remain, sequestration in depleted oil or gas fields is commercially proven. Suitable oil and gas reservoirs are limited in the Northwest and though other geologic alternatives are potentially available, including deep saline aquifers and possibly flood basalt sequestration, these remain to be proven and commercialized.

Coal-fired Steam-electric Plants

New steam-electric coal-fired power plants increasingly employ supercritical or ultra-supercritical technology utilizing increasingly higher steam pressure and temperature. Fuel prices and variable costs are low, and these plants operate as baseload units. The key challenge to continued use of coal-fired steam-electric technology is developing an economical technology to separate carbon dioxide from the products of combustion and establishing commercial-scale carbon sequestration facilities. One approach to carbon dioxide separation for steam-electric plants is oxy-firing, in which the furnace is supplied with pure oxygen, rather than air for combustion. This would produce a flue gas consisting largely of carbon dioxide and water vapor from which the carbon dioxide could be readily separated. An alternative approach is chemical separation of carbon dioxide from the flue gas of a conventional air-fired furnace. The latter appears to be the leading technology, but is unlikely to be commercially available before 2020.

Because of the lead time required to develop and construct a coal-fired, steam-electric power plant, it is unlikely that a new plant could be placed in service until the mid-term of the planning period. The reference plant for this period is a 450-megawatt supercritical unit. The plant would be equipped with a full suite of criteria air emission³⁶ control equipment and activated charcoal injection for reducing mercury emissions. Because the technology is not currently commercial, the reference plant is not provided with carbon dioxide separation equipment. The plant could provide firm capacity and energy services and limited balancing reserves. This plant would not comply with Washington, Montana or Oregon carbon dioxide performance standards, and currently could not be constructed in Idaho because of that state's moratorium on coal-fired power plant development. The estimated levelized lifecycle electricity cost for a this plant at an

³⁶ Emission controlled under the Clean Air act of 1990. These include sulfur dioxide, nitrogen oxides, particulates, hydrocarbons, and carbon monoxide.

eastern Oregon or Washington location is \$113 per megawatt-hour, including forecast levelized carbon dioxide allowance costs of \$44 per megawatt-hour (2020 service).

By the mid-2020s carbon separation technology for steam-electric plants may be commercially available. Likewise, commercial-scale carbon sequestration facilities may be available, particularly those using depleted oil and gas fields. Also by this time, new steam-electric plants are likely to employ higher-efficiency ultra-supercritical steam conditions. The reference plant for this period is a 450-megawatt ultra-supercritical unit, equipped for removal of 90 percent of flue gas carbon dioxide. This plant could comply with Washington, Montana or Oregon carbon dioxide performance standards and supplement or replace existing coal-fired units. The example is assumed to be a repower of the existing Colstrip transmission system. The estimated levelized lifecycle electricity cost is \$143 per megawatt-hour, including transmission costs of \$16 per megawatt-hour and carbon dioxide sequestration and residual allowance costs of \$31 per megawatt-hour (2025 service). Electricity from this plant would be much more expensive than the forecast cost of power from a gas combined-cycle plant without carbon separation; however, the coal plant would not bear fuel price volatility risk associated with natural gas-fired generation.

Coal-fired Gasification Combined-cycle Plants

Pressurized fluidized-bed combustion and coal gasification technologies allow the application of efficient gas turbine combined-cycle technology to coal-fired generation. This reduces fuel consumption, improves operating flexibility, and lowers carbon dioxide production. Of the two technologies, coal gasification is further along in commercial development and offers the benefits of low-cost mercury removal, superior control of criteria air emissions, optional separation of carbon for sequestration, and optional co-production of hydrogen, liquid fuel, or other petrochemicals. Several coal gasification project proposals were announced in North America during the early 2000s. However, escalating costs and refined engineering indicating that non-carbon emissions and plant efficiency would not be significantly better than supercritical steam electric plants has dampened enthusiasm. Uncertainties regarding the timing and magnitude of greenhouse gas regulation and the availability of carbon sequestration facilities have further clouded the future of these plants and only a handful of proposals remain active.

Because of the lead time required to develop and construct a coal gasification combined-cycle power plant, it is unlikely that a new plant could be placed in service until the mid-term of the planning period. The reference plant is a 623 megawatt integrated coal-fired gasification combined-cycle plant using an oxygen-blown Conoco-Philips gasifier, sulfur recovery, particulate filters, and carbon bed mercury control. The Conoco-Philips technology is thought to be suitable for sub-bituminous Powder River Basin coal, and could also be fired with bituminous coal or petroleum coke. The clean synthesis gas supplies a gas turbine combined-cycle power generation plant that would provide firm capacity, energy, and balancing reserves. This plant would not comply with Washington, Montana or Oregon carbon dioxide performance standards, and currently could not be constructed in Idaho because of that state's moratorium on coal-fired power plant development. The estimated levelized lifecycle electricity cost for an eastern Oregon or Washington location is \$118 per megawatt-hour, including forecast levelized carbon dioxide allowance costs of \$41 per megawatt-hour (2020 service).

The reference IGCC plant for the long-term is equipped to remove 88 percent of flue gas carbon dioxide. This plant could comply with Washington, Montana or Oregon carbon dioxide

performance standards and supplement or replace existing coal-fired units. The representative plant is a repower of the existing Colstrip transmission system. The estimated levelized lifecycle electricity cost is \$121 per megawatt-hour, including transmission costs of \$17 per megawatt-hour and carbon dioxide sequestration and residual allowance costs of \$31 per megawatt-hour (2025 service).

Natural Gas

Natural gas is a mixture of naturally occurring combustible gases, including methane, ethane, propane, butane, isobutene, and pentanes found in porous geologic structures, often in association with petroleum or coal deposits. Raw natural gas is recovered by means of wells, and is processed to remove the condensable fractions (propane, butane, isobutene and pentanes), carbon dioxide, water, and impurities. The resulting product, consisting of methane (~90 percent) and ethane is odorized and compressed for transport by pipeline to markets. The “natural” natural gas supply can be slightly augmented with methane recovered from landfills and from anaerobic digestion of organic wastes. Methane can also be synthesized from coal.

Natural gas is a valuable energy resource because of its clean-burning properties, ease of transportation, low carbon dioxide production and diversity of applications. Gas is used directly for numerous residential, commercial, and industrial end uses and to produce electricity using steam, gas turbine, and reciprocating engine technologies. Natural gas is also the principal feedstock in the manufacture of ammonia and ammonia-based fertilizers.

Low natural gas prices and the development of efficient, low-cost, environmentally attractive gas-fired combined-cycle power plants led to a surge of construction early in the 1990s and again following the 2000/2001 energy crisis. Natural gas power plants represent about 16 percent (9,100 megawatts) of Northwest generating capacity. Of this, 6,960 megawatts are combined-cycle units, 1,830 megawatts are peaking units, and 350 megawatts are industrial cogeneration units.

Natural Gas Supply and Price

Though natural gas has been produced in Montana, and to a limited extent in local areas west of the Cascades, the Pacific Northwest does not have significant indigenous gas resources. Rather, gas is imported by pipeline from the Western Canada Sedimentary Basin of Alberta and British Columbia, the Rocky Mountain Basin of Wyoming and Colorado, and the San Juan Basin of New Mexico. Rising natural gas prices following the energy crisis of 2000-01 prompted interest in constructing liquefied natural gas (LNG) terminals to secure access to lower-cost overseas supplies. Interest in LNG facilities has waned because of declining gas prices due to falling demand, expansion of unconventional sources such as coal-bed methane and tight formations, and new conventional discoveries in British Columbia.

Worldwide, the proven reserves-to-production ratio of natural gas has declined in recent years, from a recent high of about 68 years in 2001 to 60 years in 2008.³⁷ With limited LNG-transfer capacity, North America is largely a self-contained market with a much lower reserves-to-production ratio, about 10 years. However, a significant amount of natural gas remains undiscovered and reserves have trended upward for many years, more than offsetting increasing

³⁷ BP *Statistical Review of World Energy*, June 2009.

consumption.³⁸ New sources of supply, including “Frontier Gas” from the Alaskan North Slope and the McKenzie Delta, unconventional sources such as coal bed methane and tight sands, U.S. and Canadian offshore fields, and LNG are expected to make up shortfalls and set North American marginal prices in the long-term. Natural gas delivered on a firm basis to a power plant east of the Cascades is forecast to increase from \$4.48/MMBtu in 2010 to \$7.72/MMBtu in 2029 in the medium case (about 2.2 percent/year in constant 2006 dollars). Westside prices are expected to run about 50 to 60 cents per MMBtu higher. Unpredictable periods of price volatility are likely to occur during this period. The natural gas price forecast is further discussed in Chapter 2 and Appendix A.

Natural Gas Generating Technologies

Natural gas and liquid petroleum products are the most flexible of energy resources in terms of technologies and applications. Generating technologies that can be fueled by natural gas include steam-electric plants, gas turbine generators, gas turbine combined-cycle plants, reciprocating engine generators, and fuel cells. Applications run the gamut: base-load energy production, regulation and load-following, peaking, cogeneration, and distributed generation. Gas turbine generators, combined-cycle plants, and reciprocating engines are expected to continue to play a major role in electricity production. Fuel cells and microturbines may see some specialized applications, but appear unlikely to be major players in the near- to mid-term because of cost and reliability issues.

Simple-cycle Gas Turbine Power Plants

Simple-cycle gas turbine power plants (also called gas turbine generators or combustion turbines) consist of one or two combustion gas turbines driving an electric generator. These are compact, modular generating plants with rapid-response startup and load-following capability, and are extensively used for meeting short-duration peak load. A wide range of unit sizes is available, from sub-megawatt to 270 megawatts. Low to moderate capital costs and superb operating flexibility make simple-cycle gas turbines attractive for peaking and grid support applications. Though the inherent operating flexibility of these units is suitable for providing regulation and load following, conventional frame or aeroderivative simple-cycle units are not often used for this purpose because of their relatively low efficiency and the cost of natural gas. Likewise, simple-cycle gas turbines are rarely been used for baseload energy production unless equipped with exhaust heat recovery cogeneration. Higher-efficiency intercooled gas turbines have recently been introduced with the objective of providing regulation and load-following services. All gas turbine generators feature highly modular construction, short construction time, compact size, and low water consumption.³⁹ Equipment is available to control air emissions to low levels.

Because of the ability of the hydropower system to supply peaking and flexible capacity, simple-cycle gas turbines have historically been a minor element of the Northwest power system. However, simple-cycle gas turbines have been added to the Northwest system in recent years to provide energy during poor water conditions, to support cogeneration loads, to support increasing summer peak loads and to provide regulation and load-following services.

³⁸ Energy Information Administration. *International Energy Outlook 2008 (DOE/EIA-0484(2008))*. June 2008. Fig. 43.

³⁹ Larger amounts of water are required for intercooled or cogeneration units and units using air inlet evaporative cooling or water injection for power augmentation or nitrogen oxide control.

Gas turbine generators are generally divided into three classes: heavy-duty industrial machines specifically designed for stationary applications (so-called “frame” machines), “aeroderivative” machines using aircraft gas-turbine engines adapted to stationary applications, and “hybrid” intercooled machines with high part-load efficiency (the GE LMS100) intended for intermediate and load-following applications. Gas turbines for power generation benefit from research driven by military and commercial aircraft applications, and though a mature technology, improvement in gas turbine performance is expected to continue in the coming decades.

The reference frame plant consists of a single 85-megawatt (nominal) capacity unit located at an existing gas-fired power plant site. Natural gas is supplied on a firm gas transportation contract with capacity-release capability. No backup fuel is provided. Air emission controls include water injection and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound reduction. This type of plant would normally serve peak load and provide replacement reserves. The levelized total fixed capacity cost (capital, fuel, O&M, and transmission) for 2015 service is \$134 per kilowatt-year.

The reference aeroderivative plant consists of two 45-megawatt (nominal) aeroderivative gas turbine generators located at an existing gas-fired power plant site. Natural gas is supplied on a firm gas transportation contract with capacity-release capability. No backup fuel is provided. Air emission controls include water injection and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound reduction. This type of plant would normally serve peak load. Its rapid startup (less than 10 minute) capability would also allow it to provide rapid-response reserves while shutdown. The levelized total fixed capacity cost (capital, fuel, O&M, and transmission) for 2015 service is \$164 per kilowatt-year. Levelized energy cost is estimated to be \$130 per megawatt-hour if the plant were operated as a 4000 equivalent full power hour per year intermediate load facility, as might be the case if providing balancing capacity.

The reference intercooled plant consists of a 100-megawatt (nominal) hybrid intercooled gas turbine generator located at an existing gas-fired power plant site. Natural gas is supplied on a firm gas transportation contract with capacity-release capability. No backup fuel is provided. Air emission controls include water injection and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound reduction. The higher efficiency and flatter heat rate curve of this type of plant would allow it to serve intermediate as well as peak load, and economically provide balancing reserves as well as rapid-response and replacement reserves. The levelized total fixed capacity cost (capital, fuel, O&M and transmission) for 2015 service is \$164 per kilowatt-year. Levelized energy cost is estimated to be \$126 per megawatt-hour if the plant were operated as a 4000 equivalent full power hour per year intermediate load facility, as might be the case if providing balancing capacity.

Reciprocating Engine-generators

Reciprocating-engine generators (also known as internal combustion engines, ICs or gen-sets) consist of a compression or spark-ignition reciprocating engine driving a generator, typically mounted on a frame and supplied as a modular unit. Unit sizes for power system applications range from about 1 to 15 megawatts. Conventionally, reciprocating generators are used for small, isolated power systems, emergency capacity at sites susceptible to transmission outages, and to provide emergency power and black start capacity at larger power plants. Other power system applications include units modified to operate on biogas from landfills or anaerobic

digestion of waste biomass, mobile units for emergency service, and “recip farms” installed as a hedge to high power prices during the 2000-2001 energy crisis. On the load side, reciprocating units are permanently installed to provide backup power for hospitals, elevators, and emergency lighting in high-occupancy buildings and other critical load. Except for biogas units, these applications typically use light fuel oil stored on site.

The introduction of more efficient and cleaner reciprocating generators in recent years, coupled with the increasing need for load-following services for wind generation, has increased interest in the use of arrays of gas-fired reciprocating generators to provide peaking and load-following services. A typical installation consists of five to 20 units of 3 to 16 megawatts capacity each. The resulting plant is highly reliable with high efficiency across a wide load range; ideal for load-following. Because the output of reciprocating engines is less sensitive to elevation than gas turbine output, reciprocating units may be advantageous for higher-elevation locations for peaking and load-following applications. Reciprocating units can also be fitted with exhaust, turbocharger, and lube oil heat recovery for low-temperature cogeneration load.

The reference plant consists of 12 8-megawatt units operating on natural gas supplied on a firm gas transportation contract with capacity release capability. Air emission controls include selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound reduction. This plant can provide regulation and load-following, contingency reserves, and other ancillary services. The relatively high efficiency (41 percent) allows the plant to economically serve peak and even intermediate loads. The capacity cost of this plant is estimated to be \$172/kW-year. Levelized energy cost is estimated to be \$135 per megawatt-hour if the plant were operated as a 4,000 equivalent full power hour-per-year intermediate load facility, as might be the case if providing balancing capacity.

Combined-cycle Gas Turbine Power Plants

Gas turbine combined-cycle power plants consist of one or more gas turbine generators provided with exhaust heat recovery steam generators. Steam raised in the heat recovery units powers a steam-turbine generator, increasing the overall thermal efficiency of the plant compared to simple-cycle gas turbines. The reference combined-cycle unit, for example, has a baseload efficiency of 49 percent compared to a full-load efficiency of 36 percent for the reference hybrid intercooled gas turbine. Combined-cycle plants can serve cogeneration steam load (at some loss of electricity production) by extracting steam at the needed pressure from the heat-recovery steam generator or steam turbine. Additional generating capacity (power augmentation) can be obtained at low cost by oversizing the steam turbine generator and providing the heat recovery steam generator with natural gas burners (duct firing). Because the resulting capacity increment operates at somewhat lower electrical efficiency than the base plant, it is usually reserved for peaking operation. Because of their reliability and efficiency, low capital costs, short lead-time, operating flexibility, and low air emissions, gas-fired combined-cycle plants have been the bulk power generation resource of choice since the early 1990s.

The reference plant is a single advanced “H-class” gas turbine generator and one steam turbine generator. The base-load capacity is 390 megawatts with an additional 25 megawatts of duct-firing power augmentation. Fuel is natural gas supplied on a firm transportation contract with capacity-release capability. No backup fuel is provided. Air emission controls include dry low-nitrogen oxide combustors and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound control. Condenser cooling is wet

mechanical draft. In the Northwest, this plant would operate in baseload mode during the summer and winter seasons and as a marginal plant during high hydro runoff and low load seasons. The plant could also operate at partial (80 – 90 percent) load to provide regulation and load-following, though at some sacrifice in efficiency. Year-round baseload operation (80 percent of full load capacity) would yield reference energy costs of \$92 per megawatt-hour including forecast carbon dioxide allowance costs of \$18 per megawatt-hour. More typical operation in the Northwest at capacity factors ranging from 65 percent to 35 percent would result in reference electricity production costs from \$97 to \$122 per megawatt-hour. Cogeneration revenues could slightly reduce electricity production costs.⁴⁰

Petroleum

Petroleum fuel, including propane, distillate, and residual fuel oils are universally available at prices largely determined by the global market. In general, other than for special uses such as for backup fuel, peaking or emergency service power plants, and power generation in remote areas where its transportability and storability are essential, petroleum-derived fuel cannot compete with natural gas for electric power generation. Forecast prices for petroleum fuel are discussed in Chapter 2 and Appendix A.

Petroleum Coke

Petroleum coke is a carbonaceous solid byproduct of cracking residual fuel oil in a delayed coker to extract higher value products. The supply of petroleum coke is increasing as refineries increasingly crack residual fuel oil to yield higher value products and draw upon lower quality crudes. The Energy Information Administration reports that the refinery yield of petroleum coke has increased from 4.3 percent in 1995 to 5.3 percent in 2008 (as percent of total refinery product slate). Higher purity petroleum coke is used for aluminum smelting anodes, whereas fuel-grade petroleum coke is primarily used for firing cement kilns and power plants. About two-thirds of the merchantable petroleum coke originating in U.S. refineries is exported, primarily to Latin America, Japan, Europe, and Canada. The remainder is gasified in refinery trigeneration plants or marketed to electric power generators, calciners, cement kilns, and other industries. Because of its low ash content and very high heating value (14,000 Btu/lb compared to 8,000 - 8,800 Btu/lb for Power River Basin coal), petroleum coke transportation costs are lower than for coal on a Btu basis. However, petroleum coke is usually priced at a discount to coal because of its typically higher sulfur and metals content. Because refineries can economically dispose of petroleum coke at a loss because of the added value of the lighter products obtained from cracking residual, there is a great deal of pricing flexibility and the discount to coal is highly variable. Further discounting may occur in the future because of the higher carbon content of petroleum coke compared to coal (225 vs. 212 pounds per million Btu). Based on limited available pricing information, the discount to subbituminous coal is about 80 percent.

Gasification combined-cycle plants would be the preferred technology for power generation using petroleum coke because of the superior ability to control sulfur and heavy metals, and in the longer term, to capture and sequester carbon dioxide. Because of possible supply limitations and fluctuating prices relative to coal, it is likely that a plant would be fueled using a blend of

⁴⁰ Combined-cycle cogeneration plants normally support a relatively small steam load.

petroleum coke and coal. This plant, however, would not comply with Washington, Montana or Oregon carbon dioxide performance standards.

NUCLEAR

Nuclear power plants produce electricity from energy released by the controlled fission of certain isotopes of heavy elements such as uranium, thorium, and plutonium. Commercial light water reactors used in the United States are normally fueled with a mixture of two isotopes of natural uranium, about 3 percent fissionable U-235 and 97 percent non-fissionable, but fertile U-238. The U-238 is transmuted to fissionable Pu-239 within the reactor by absorption of a neutron. Though reactors using thorium and “bred” plutonium have been developed in anticipation of eventual shortages of natural uranium, it appears that the industry can rely on abundant supplies of natural uranium for the foreseeable future. The price of fabricated nuclear fuel is forecast to be relatively stable, averaging \$0.73/MMBtu through the planning period.

Commercial nuclear plants in the United States are based on light water reactor (LWR) technology developed in the 1950s. One unit, the 1,200-megawatt Columbia Generating Station operates in the Northwest. Motivated by improved plant designs, the need for new low-carbon baseload resources and financial incentives of the Energy Policy Act of 2005, nuclear development activity has resumed in the United States following a three-decade hiatus. As of late 2009, developers have submitted applications to the Nuclear Regulatory Commission for combined construction and operating licenses for 27 new units at 17 sites, largely in the southeast. Most proposals are planned for service in the late teens, and construction of the initial units is expected to be contingent on federal incentives. The proposed plants employ evolutionary LWR designs with increased use of passively operated safety systems and factory-assembled standardized modular components. These features should improve safety, reduce cost, and increase reliability.

Work is also underway on developing small modular reactors (SMRs). SMRs are conceived as modular, scalable, largely factory-assembled plants of 25 to 350 megawatts generating capacity. Compared to 1,100 to 1,800 megawatt conventional reactors, the smaller size and modular construction of SMRs are intended to reduce capital cost and investment risk by employing a greater degree of factory assembly, shortening construction lead time and better matching plant size to customer needs through scaling of multiple units. Smaller plant size may also permit greater siting flexibility and cogeneration potential and can benefit system reliability through reduction in “single-shaft” outage risk. Proposed SMR designs offer improved safety through features such as integral construction (all reactor coolant systems contained within a single pressure vessel), below-ground emplacement, and lifetime, factory-installed fuel supplies. The SMR concept is not new or unique - over 50 SMR designs have been proposed - however, the enormous investment and long lead time needed to construct conventional reactor plants plus increasing interest in deploying carbon-free nuclear technology in developing countries has resulted in unprecedented interest in SMR technology. Completion of the first demonstration SMRs is at least a decade away. Designs must be completed, NRC design certification secured, and demonstration projects permitted, financed, constructed and tested.

Nuclear plants could be an attractive source of dependable capacity and baseload low-carbon energy that is largely immune to high natural gas prices and climate policy. However, a new nuclear unit would entail the risks of construction delay, regulatory uncertainty, escalating costs,

and the reliability risk associated with a large single-shaft machine. The reference plant is a single 1,100 megawatt advanced-light water reactor unit. The reference cost of power from this unit is estimated to be \$108 per megawatt-hour (2025 service). Construction of a new unit in the Northwest would likely require the successful completion and operation of at least one of the proposed new units elsewhere in the United States, established spent-nuclear fuel disposal policy, and aggressive development of equally cost-effective conservation and renewable resources. These conditions would likely preclude operation of a new conventional nuclear plant in the Northwest prior to the early to mid-2020s.

ENERGY STORAGE TECHNOLOGIES

A challenge to increasing the penetration of variable-output renewable resources like wind, solar, wave, and tidal current generation is shaping the variable and not fully predictable output of these resources to meet the power quality standards and load of the power system. One approach is to use dispatchable firm generation like hydropower, which is currently used to integrate wind power in the Northwest. An alternative is energy storage technologies. Energy storage technologies decouple the production and consumption of electricity, and can provide regulation, sub-hourly load-following, hour-to-hour storage and shaping, firm capacity, and other ancillary services. Storage projects located within a renewable resource zone could flatten the output of variable-output generation, thereby increasing transmission load factors and improving the economics of long-distance transmission.

A variety of storage technologies are commercially available or under development, including pumped storage hydropower, compressed air energy storage, numerous types of electrically rechargeable batteries, metal-air batteries, several types of flow batteries, flywheels, electromagnets, and capacitors. For the foreseeable future, only a subset of these have the “bulk” or “massive” energy storage potential needed to integrate utility-scale renewable energy resources.⁴¹ This requires megawatt-scale power ratings, run times of hours and extended charge/discharge capability. The most promising systems include compressed air energy storage, flow batteries, pumped-storage hydropower, and sodium-sulfur batteries.

A common constraint to deploying energy storage systems is that the project developer is unable to capture the full value of the system’s services. The generation, transmission and distribution sectors may each realize benefits, but it is often difficult for the developer of a storage project to fully capture the benefits of his project. No formal market exists in the Northwest for the services provided by energy storage systems, and with one exception,⁴² no successful example of non-utility development of a utility-scale storage project is found in the West.

A second constraint is the need for frequent cycling. Amortization of the capital cost of these technologies, which tends to be relatively high, requires that they be employed frequently and for as many services as they are capable of delivering. One reason little pumped storage capacity has been developed in the Northwest, despite favorable sites, is that most of the region does not experience strong daily summer-afternoon peaks in energy use, which would create a daily off-peak/on-peak arbitrage opportunity common to other areas of the country.

⁴¹ Individual units need not be at a megawatt/hour scale. Megawatt/hour scale could be achieved by deploying a large number of responsive grid-connected small-scale units, as for example provided by the aggregate storage capability of a fleet of plug-in hybrid vehicles.

⁴² The 40-megawatt Olevenhain - Hodges project near San Diego.

Compressed Air Energy Storage

A compressed-air energy storage (CAES) plant is an early commercial technology that can provide load-following and energy shaping over periods up to several days. “Conventional” compressed air energy storage plants consist of motor-driven air compressors that use low-cost, off-peak electricity to compress air into an underground cavern. During high-demand periods, the stored energy is recovered by releasing the compressed air through a natural gas-fired combustion turbine to generate electricity. The compressed air reduces or eliminates the normal gas turbine compression load, greatly reducing its fuel consumption. A CAES combustion turbine might have a heat rate of 4,000 Btu/kWh compared to the 9,300 - 12,000 Btu/kWh heat rate of a stand-alone simple-cycle gas turbine. The efficiency of the process is further improved by heating the compressed air with the combustion turbine exhaust prior to introducing it to the turbine combustors. The economics of a conventional CAES plant requires sufficient spread between on- and off-peak prices to cover compression and storage losses (about 25 percent) plus the cost of the natural gas used to fire the gas turbine. Economic amortization of the capital cost requires frequent cycling such as that needed to serve a daily summer peak load in a warm climate.

Two compressed-air energy storage plants are currently in operation. The first 290-megawatt plant was placed into operation in Germany in 1978. A 110-megawatt plant using an improved design, including turbine exhaust recuperators, was constructed in 1991 in Alabama. These plants were intended to shift energy from off-peak hours to on-peak hours in power systems with low-cost, coal-fired baseload energy. However, the inherently high degree of flexibility of CAES plants would make them capable of load-following and for shaping the output of wind generation. The Arkansas project has storage capacity for 26 hours of full-load operation, and can ramp from standby to full load in about five minutes. CAES plants located at remote wind resource areas could shape wind project output to improve the transmission load factor. The fast start and rapid ramp rate capability could provide decremental load following capability. High part-load efficiency could provide economic load-following capability compared to conventional simple-cycle gas turbines.

A variety of second generation CAES concepts have been advanced to integrate variable-output renewable resources. Unlike earlier designs, these plants would use standard industrial components, multiple motor-driven compressors, and separate multiple air expansion turbine-generators to improve efficiency, provide additional operating flexibility, and reduce cost. Concepts include a no-fuel adiabatic CAES in which the thermal energy of compression would be stored as a substitute for fuel in the expansion-generation process.

Potential locations are available in the Northwest. Solution-mined salt caverns, excavated hard rock chambers, depleted oil or natural gas fields, or other porous geologic media could be used for the compressed air storage reservoir. Recent proposals for small-scale (~ 15 megawatts) CAES would employ above-ground pressure vessels or buried high-pressure piping, further increasing siting flexibility, though at greater cost.

CAES technology has potential in the Northwest to improve the load factor of transmission used to deliver power from remotely located wind and solar generation, and for within-hour and hour-to-hour load-following and shaping services. An advantage compared to pumped storage hydropower is greater siting flexibility. A disadvantage (except for adiabatic concepts) is the

need for natural gas to fire the output generator and the resulting air emissions. The available cost information is not adequate to support a meaningful comparison of CAES with alternatives. Though cost estimates have been published for the various second generation CAES concepts, these are preliminary and suitable only for comparison among CAES alternatives. Moreover, CAES costs are sensitive to geology and storage volume. Second generation demonstration project results and a Northwest feasibility study would be required to accurately fix the relative cost of CAES and other sources of system flexibility.

Flow Batteries

First used in 1884 to power the airship *La France*, flow batteries are a rechargeable battery with external electrolyte storage. The electrolyte is pumped through a stack of electrolytic cells to charge or discharge the battery. External electrolyte storage permits independent scale-up of energy storage capability (governed by storage tank capacity) and power output (governed by cell area and electrolyte transfer rate). Flow batteries are characterized by rapid response, ability to hold charge, and longevity in terms of charge/discharge cycles. Three technologies are under development: vanadium redox, zinc bromine, and polysulfide bromine. Flow batteries offer modularity, sizing flexibility, siting flexibility, and zero emission operation. A potential disadvantage is their relatively low energy density, requiring large electrolyte storage facilities to achieve needed energy storage capability.

Flow battery technology is in the demonstration stage. Several installations up to 500 kilowatt capacity and five megawatt-hour storage capacity are reported in Japan and a 2-megawatt capacity demonstration project is under construction in Ireland. Cycle efficiency is 70 to 75 percent with the potential for improvement. Capital costs are relatively high--one U.S. demonstration plant of 250 kilowatts capacity and 2 megawatt-hours of storage is reported to have cost \$4,000 per kilowatt. However, current cost and performance is likely not representative of production units.

Pumped-storage Hydropower

Pumped-storage hydropower is an established commercially mature technology. A typical project consists of an upper reservoir and a lower reservoir connected by a water transfer system with reversible pump-generators. Energy is stored by pumping water from the lower to the upper reservoir using the pump-generators in motor-pumping mode. Energy is recovered by discharging the stored water through the pump-generators operating as turbine-generator mode. Cycle efficiency ranges from 75 percent to 82 percent. Seventeen pumped-storage projects constituting more than 4,700 megawatts of capacity are installed in WECC. One project is located in the Northwest--the 6-unit, 314 megawatt Grand Coulee pumped-generator at Banks Lake. This plant is primarily used for pumping water up to Banks Lake, the headworks of the Columbia Basin Irrigation System.

Most existing pumped-storage projects were designed to shift energy from nighttime low variable-cost thermal units to afternoon peak-load periods on a daily cycle. However, pumped storage can also provide capacity, frequency regulation, voltage and reactive support, load-following, and longer-term shaping of energy from variable-output resources without the fuel consumption, carbon dioxide production, and other environmental impacts associated with

thermal generation. Importantly for the Northwest, pumped storage could provide within-hour incremental and decremental response to wind ramping events.

Pumped-storage projects require suitable topography and geologic conditions for constructing upper and lower reservoirs at significantly different elevations within close proximity. Subsurface lower reservoirs are technically feasible, though much more expensive. A water supply is required for initial reservoir charge and makeup. Currently, 13 pumped storage projects ranging in size from 180 to 2,000 megawatts and totaling nearly 14,000 megawatts have been proposed in Idaho, Oregon, and Washington, suggesting no shortage of suitable sites. Construction costs are project-specific. Factors influencing cost include the availability of an existing water body that can be used for one of the reservoirs (usually the lower), storage capacity, and transmission interconnection distance. Though \$1,000 per kilowatt of installed capacity is often quoted as a representative cost of pumped storage hydro, a review of available cost estimates suggests that \$1,750 to \$2,500 per kilowatt⁴³ is more representative of current construction cost. The principal constraints to pumped storage development are the complexity and lead time of the development process, capital cost, and the recovery of revenues for the services provided.

Sodium-sulfur Batteries

A sodium sulfur battery is a high energy-density high-temperature rechargeable battery consisting of molten sodium and molten sulfur electrodes separated by a ceramic electrolyte. The technology is in the early commercial stage with about 190 installations in Japan, totaling about 270 megawatts capacity. About 9 megawatts of sodium-sulfur battery capacity is installed in the United States. The largest unit in operation is Rokkasho in Northern Japan, a 34-megawatt unit with a 245 megawatt-hours storage capability used to integrate wind power. Advantages of sodium-sulfur batteries include high energy density, high cycle efficiency (89 percent), modularity, siting flexibility in either centralized or distributed configurations. Sodium-sulfur batteries are currently moderately expensive with capital costs in the \$2,500 - 3,000 per megawatt range but increasing production rates are expected to lead to cost reductions.

SUMMARY OF REFERENCE PLANT CHARACTERISTICS

Key planning characteristics of the reference power plants are compiled in Table 6-3. Derivation of these values is described in Appendix I. The definitions of the values appearing in the table are as follows:

Plant size: The unit size (installed capacity) used in the Council's planning models.

Heat rate: The fuel conversion efficiency of fuel-burning technologies in Btu/kWh. Degraded lifecycle average. Higher heating value (HHV) for consistency with fuel pricing.

Availability/Capacity factor: Availability $((1 - \text{forced outage rate}) * (1 - \text{scheduled outage rate}))$ for firm capacity technologies. Expected capacity factor (adjusted for availability) for energy-limited technologies.

Total plant cost: The overnight (instantaneous) project development and construction cost in constant 2006 year dollar values as of mid-2008. Includes direct and indirect construction costs, engineering, owner's development and administration costs and contingencies. Excludes

⁴³ Overnight costs.

financing fees and allowance for funds used during construction. Construction costs must be adjusted as described in Appendix I to arrive at the expected cost for a given service year.

Capital and fixed operating costs are assumed to be fixed at start of construction.

Fixed O&M: Fixed operating and maintenance cost in constant 2006 year dollars as of mid-2008. Includes operating labor, maintenance costs and overhead. Interim capital replacement costs included if significant. Excludes property tax and insurance. Fixed O&M costs must be adjusted as described in Appendix I to arrive at the expected cost for a given service year.

Variable O&M: Variable operating and maintenance costs in constant 2006 year dollars as of mid-2008. Includes consumables such as water, chemicals and lubricants. Excludes the cost of CO₂ sequestration for examples with CO₂ separation and sequestration.

Integration cost: The cost of providing regulation and sub-hourly load-following services for system integration. These increase over the planning period. Forecast values are provided in Appendix I. Excludes the cost of storage for shaping to load.

Transmission cost: The cost of dedicated long-distance transmission, if any, plus within-region wheeling cost.

Transmission losses: Total transmission losses (Long-distance transmission plus point-to-point within-region delivery).

Plant development and construction: The first value is the time in months to develop a project from conception to first major expenditure (generally major equipment order); The second value is the time in months to complete construction of one unit from the first major expenditure. Excludes time required for developing and constructing long-distance transmission for remote resource examples.

Earliest service year: Assumed earliest service for new plants..

Developable potential: The estimated total developable potential of energy-limited resources over the 2010 - 2029 period.

Table 6-3: Key Planning Assumptions for Reference Power Plants

Reference Plant	Plant Size (MW)	Heat Rate (HHV Btu/kWh)	Capacity Factor/ Availability	Total Plant Cost (\$/kW)	Fixed O&M (\$/kW/yr)	Variable O&M (\$/MWh)	Integration Cost	Trans Cost ⁴⁴ (\$/kW/yr)	Trans Losses ⁴⁵	Plant Dev / Construction (mos)	Earliest Service	Developable Potential (MWa)
Animal manure energy recovery	0.85	10,250	75%	\$5000	\$45	\$15	--	\$17	1.9%	12/12	2012	50 - 110
Landfill gas energy recovery	2 x 1.6/unit	10,060	85%	\$2350	\$26	\$19	--	\$17	1.9%	18/15	2012	70
Waste water energy recovery	0.85	10,250	85%	\$5000	\$40	\$30	--	\$17	1.9%	18/15	2012	7 - 14
Woody residue - Greenfield, no CHP	25	15,500 ⁴⁶	80%	\$4000	\$180	\$3.70	--	\$17	1.9%	24/24	2014	665
Woody residue - Brownfield, CHP	25	19,300 ⁴⁷	80%	\$3000	\$194	\$0.73	--	\$17	1.9%	24/24	2014	Not separately estimated
Geothermal - binary	3x13/unit	28,500	90%	\$4800	\$175	\$4.50	--	\$17	1.9%	36/36	2017	375
Hydropower - new	10	--	50%	\$3000	\$90	Incl in fixed	--	\$17	1.9%	48/24	2016	100's
Solar - CSP (NV > ID)	100	--	36%	\$4700	\$60	\$1.00	--	\$102	4.0%	24/24	2015	530/500kV ckt
Solar - CSP (NV > OR/WA)	100	--	36%	\$4700	\$60	\$1.00	--	\$189	6.5%	24/24	2015	530/500kV ckt
Solar - Tracking PV	20	--	S. ID - 26% MT - 25% OR - 25% E. WA - 24%	\$9000	\$36	Incl in fixed	\$7.98	\$17	1.9%	12/24	2013	Ltd by integration capability
Solar - Tracking PV (NV)	20	--	30%	\$9000	\$36	Incl in fixed	\$7.98	\$96	4.0%	12/24	2015	435/500kV ckt
Wind (ID Local)	100	--	30%	\$2100	\$40	\$2.00	\$7.98	\$17	1.9%	18/15	2013	215
Wind (MT Local)	100	--	38%	\$2100	\$40	\$2.00	\$7.98	\$17	1.9%	18/15	2013	80
Wind (OR/WA Local)	100	--	32%	\$2100	\$40	\$2.00	\$7.98	\$17	1.9%	18/15	2013	1410
Wind (AB > OR/WA)	100	--	38%	\$2100	\$40	\$2.00	\$7.98	\$179	4.3%	18/15	2015	570/500kV ckt
Wind (MT > ID)	100	--	38%	\$2100	\$40	\$2.00	\$7.98	\$104	4.2%	18/15	2015	570/500kV ckt
Wind (MT > OR/WA)	100	--	38%	\$2100	\$40	\$2.00	\$7.98	\$198	6.4%	18/15	2015	570/500kV ckt
Wind (MT > OR/WA via CTS)	100	--	38%	\$2100	\$40	\$2.00	\$7.98	\$120	10%	18/15	2015	244/500kV ckt
Wind (WY > ID)	100	--	38%	\$2100	\$40	\$2.00	\$7.98	\$120	4.5%	18/15	2015	570/500kV ckt
Wind (WY > OR/WA)	100	--	38%	\$2100	\$40	\$2.00	\$7.98	\$219	7.0%	18/15	2015	570/500kV ckt
Waste heat recovery	5	38,000	80%	\$3500	Incl in var.	\$8.00	--	\$17	1.9%	24/24	2014	10's - 100's
Coal - Supercritical steam	450	9000	85%	\$3500	\$60	\$2.75	--	\$17	1.9%	36/48	2017	--
Coal - Ultra-Supercritical steam	450	8010	85%	\$3570	\$60	\$2.75	--	\$17	1.9%	36/48	2017	--
Coal - USC steam w/90% CSS	450	10,170	85%	\$5495	\$128	\$5.85	--	\$17	1.9%	36/48	2023	--
Coal - IGCC	623	8680	80%	\$3600	\$45	\$6.30	--	\$17	1.9%	36/48	2017	--
Coal - IGCC w/88% CSS	518	10760	80%	\$4800	\$60	\$8.50	--	\$17	1.9%	36/48	2023	--
NG - Frame gas turbine	85	11960	91%	\$610	\$11	\$1.00	--	\$17	1.9%	18/15	2012	--
NG - Aero gas turbine	2 x 47/unit	9370	91%	\$1050	\$13	\$4.00	--	\$17	1.9%	18/15	2012	--
NG - Intercooled gas turbine	99	8870	91%	\$1130	\$8	\$5.00	--	\$17	1.9%	18/15	2012	--
NG - Reciprocating engine plant	12 x 8.3/unit	8850	93%	\$1150	\$13	\$10.00	--	\$17	1.9%	18/15	2012	--
NG - Combined-cycle	Baseload - 390 Peak incr - 25	Baseload - 6930 Pk incr - 9500	89%	\$1120	\$14	\$1.70	--	\$17	1.9%	24/30	2014	--
Nuclear	1117	10,400	90%	\$5500	\$90	\$1.00	--	\$17	1.9%	48/72	2023	--

⁴⁴ Combined operating cost of local (in-region) transmission plus construction and operating cost of transmission (if any) to access remote resources, expressed as a fixed O&M cost. Excludes the \$1.00/MWh variable O&M cost of local transmission which should be added to all estimates.

⁴⁵ Combined local (in-region) transmission losses plus losses associated with transmission (if any) to access remote resources.

⁴⁶ Full plant heat rate.

⁴⁷ Full plant heat rate.

Chapter 7: Transmission

Summary of Key Findings 1
 Background 1
 Northwest Transmission Planning 6

SUMMARY OF KEY FINDINGS

For a number of years leading up to the Fifth Power Plan (May 2005), there was concern that there had been little progress on addressing the developing transmission issues in the region, both in operating the existing system and in planning for new major transmission lines. Since then, there has been significant progress in both areas. The Western Electricity Coordinating Council (WECC) has created two new reliability coordination centers in the West with new operating tools, which they share with the interconnection’s balancing authorities, to address operational reliability issues. Other operating challenges posed by the large increase in wind generation in the region and in the West are being addressed as well. That issue is explored in more depth in Chapter 12.

On the planning side, there have been major changes and significant progress in the last five years. Both regional and WECC-wide organizations have been created and are producing or developing plans or system assessments, partly in response to the needs of their members and partly in response to increased federal interest in transmission planning and development. A number of new projects are in the development and study stage, sponsored by utility members of the two regional planning groups, ColumbiaGrid and Northern Tier Transmission Group (NTTG), and by merchant developers.

On a case-by-case basis, the Federal Energy Regulatory Commission (FERC) is reviewing and modifying its financing and study process requirements, and the Bonneville Power Administration has taken advantage of this to propose a useful new approach to financing transmission for access to wind resources. Currently proposed legislation in Congress would increase the federal backstop siting authority that already exists in the Energy Policy Act of 2005 for projects that are supported by regional and interconnection-wide planning efforts.

Nonetheless, for the most part the region’s utilities are just getting to the stage when they have to address siting and construction of the projects that have been planned. Siting can present significant difficulties. Siting also can present challenges for utilities that may be depending on getting projects built on time, if there are delays. The utilities may be forced to rely on backstop plans in order to assure themselves of meeting their loads reliably. The Council supports and encourages regional transmission planning efforts, recognizing that new transmission investment can be key both to maintaining reliable load service and to bringing new renewable resources in to meet regional loads.

BACKGROUND

The regional transmission system is an integral part of the regional power system. It functions roughly like the highway system, allowing power to flow from generators all across the region (and outside the region in the rest of the Western Interconnection) to loads. Figure 7-1 below

shows a schematic of the entire Western high-voltage transmission system, which is operated in a coordinated fashion in order to maintain system reliability although it is constructed and built by individual utilities to meet their own needs. As can be seen from the map, the Northwest transmission system is closely integrated into the overall western system. The colors highlight the systems of the two Northwest subregional planning groups described below, ColumbiaGrid and Northern Tier Transmission Group.

Figure 7-1: Major Western Transmission



Despite the similarities, the transmission system differs from a highway system in key ways. When the highway system gets overloaded, traffic slows down or stops at one point or another. These conditions can persist for hours until the traffic volume drops down, as for instance, when an extended rush hour is over.

In the electric transmission system, however, the system is not actually allowed to get overloaded in normal circumstances, and in the case of an outage, either of a generator or of part of the transmission system, overloads are allowed to persist for only very short periods of time. Moreover, the amount of the allowed overload is limited by constraints on the amount of power that can be allowed to be generated and flow over the transmission lines (“scheduled”), in normal, non-outage, conditions.

This is done for reliability reasons because serious overloads will often lead to automatic load or generation disconnections that can in turn lead to wider, uncontrolled cascading losses of load, like the 2003 Northeastern blackout. Overloads can be created almost instantaneously by sudden generation or transmission outages. The limits that require these operator or automatic actions are set by transmission operators according to standards of the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) and are based on extensive computer simulations by system planners and operators of the behavior of the transmission system under many different operating conditions. Margins for reliable operation are built into operating standards, so that the system does not collapse when there is a sudden outage on the system. The operating standards may require that transmission schedules be cut in the event of a system outage in order to bring power flows and other system parameters within the acceptable limits of the reduced system.

Operating limits are set for and managed by system operators at a number of points or paths on the system. Figure 7-2 below shows the locations of the major constrained paths in the western transmission system. A path can often consist of several lines or sets of lines in parallel to each other (several examples of this occur in the Northwest, e.g. the “North of John Day” path). Most of the paths in the Northwest are constrained, in the sense that there is little to no capacity available to sell and under certain operating conditions they need to be monitored by system operators to ensure they do not exceed system operating limits. West of Hatwai, however, in the Spokane area is an example of a path that was upgraded by additional line construction several years ago.

Figure 7-2: Western Constrained Paths



When the loading on an individual path, controlled by individual balancing authorities in coordination with their neighbors (see Chapter 12 for more details on what balancing authorities do) reaches these predefined limits, operators do not allow additional transactions to be scheduled. The system can be said to be congested at that point, though it is not overloaded, but is operating normally.

Congestion can occur in a longer-term time frame as well. The amount of long-term transmission service that can be sold in advance is limited so that the total amount sold can actually be scheduled within the reliability limits. This case, when there is no more available

transmission capacity (ATC), is also a form of congestion, even though it does not necessarily lead to a congested operating condition if all of the transmission service that has been sold is not used fully at the same time.

The transmission system is built and upgraded incrementally to meet projected service requirements, so that new service for new loads or from new generation can be accommodated within reliable operating limits. Relieving congestion can be costly. Because of the high cost of transmission system upgrades (as a general approximation, 500 kilovolt transmission lines can cost in the range of \$2-\$3 million per mile to construct, depending on the terrain and land use), transmission is not constructed speculatively. It is constructed to meet forecast native load service requirements and to meet specific service requests from third parties¹ like independent generators or parties wishing to wheel power across a utility's transmission system to a load outside it.

The high cost of expanding the transmission system, particularly with long, high voltage lines and intermediate substations means that some congestion on the system, either on an operating basis or as shown by the absence of ATC for sale, may be an economically appropriate result. This is generally not the case for congestion that could impact reliable load service, but could be for projects designed to access cheaper or alternative energy supplies in order to reduce operating costs.

Transmission system improvements range from lower-voltage upgrades that may be part of an ongoing system-upgrade process at a utility to major high-voltage projects that can cost hundreds of millions of dollars and take five or more years to plan and construct. Typically the former do not get as much attention, as they cost less, are done on a more routine basis, and depend more on local conditions and requirements, though some higher-voltage local projects or those in sensitive areas can be expensive and difficult to site and can be subject to uncertainty. The latter, however, because of their cost and land-use impacts can get considerable attention.

For a number of years leading up to the Fifth Power Plan, there was little major transmission project development, although there continued to be upgrades to meet local reliability needs. Partly this was a result of the ability to site natural gas generation closer to load centers and with a smaller requirement for transmission. However, when the Council developed the Fifth Power Plan, there was reason to be concerned about the transmission system. There had been some progress on improving the operation of the transmission system to allow better use of limited existing capacity by implementing remedial action schemes (RAS), but there had been little activity in planning for major transmission system expansion. The regional transmission system was being loaded closer and closer to capacity.

These problems are now being addressed. There have been important changes in operations though WECC's creation of two new reliability coordination centers in the West and funding of new software that gives the reliability coordinators and the West's balancing authorities clearer and more current information on the instantaneous state of the system. Other operational changes are being considered and implemented in large part because of the pressure to integrate

¹These third-party service requests are governed by the FERC Open Access Transmission Tariff (OATT). The OATT specifies the study procedures and financial circumstances under which the transmission owner must respond to third-party service requests.

large amounts of variable generation, primarily wind. The operational changes related to wind integration are discussed in Chapter 12.

On the transmission-planning side, two subregional planning groups, ColumbiaGrid, centered on Bonneville and the Washington utilities, and Northern Tier Transmission Group, focused primarily on the east side of the region, have been formed and are conducting planning studies and coordinating transmission development efforts across the Northwest. They are also jointly leading efforts to address some of the operational changes mentioned above and described further in Chapter 12.

In addition, the Transmission Expansion Planning Policy Committee (TEPPC) has been formed by WECC to develop West-wide commercial transmission expansion planning studies and coordinate and provide information to subregional planning efforts. Finally, a number of projects are being proposed by both utilities and merchant developers, largely in response to the state RPS requirements and increasing emphasis on reducing carbon emissions across the West.

There has also been a significant increase in interest in transmission planning and siting at the federal level. In the Energy Policy Act of 2005, the federal Department of Energy (DOE) was required to conduct triennial transmission-congestion studies and allowed to designate National Interest Electric Transmission Corridors, and FERC was given a backstop siting role for transmission proposals in those corridors for which state siting authorities did not act promptly. At the time the Council adopted the Sixth Power Plan, Congress was considering energy legislation. The House of Representatives passed the American Clean Energy and Security Act of 2009 (known as the Waxman-Markey bill, for its sponsors) in June of that year. The bill contained provisions for regional transmission planning entities to submit plans to FERC, and gave FERC additional backstop siting authority in the Western Interconnection for projects vetted through and supported by a regional transmission plan.

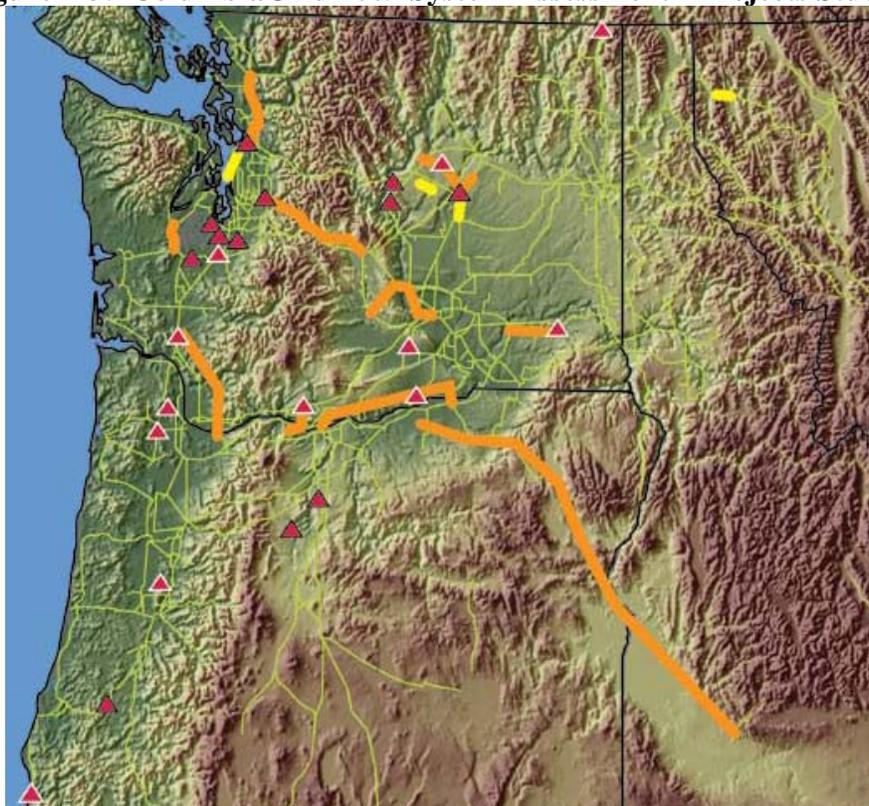
The American Recovery and Reinvestment Act (ARRA) provided DOE with funding for technical support of interconnection-based transmission plans, including support for state and relevant non-governmental organizations to participate, as well as support for state resource-planning efforts. WECC, through TEPPC, worked with the Western Governors' Association (WGA) to develop an application for funding, which was successful. Some of the WGA funding will be used to support completion of the Western Renewable Energy Zone (WREZ) project, which will help coordinate state and utility efforts to target specific areas for renewable development, along with the necessary transmission corridors. This is intended to provide basic input information into the TEPPC transmission planning effort.

NORTHWEST TRANSMISSION PLANNING

ColumbiaGrid, formed in 2006, along with its members develops a system assessment and biennial transmission plan for its members. It finished its first biennial plan in 2008, which was approved by its board of directors and published in February 2009. It has recently published a draft 2009 system assessment, highlighting the areas in its members' systems that need to be addressed, either by the individual owners, or in the case of issues involving several owners, by a ColumbiaGrid study team. Joint study teams are also formed to address issues and projects that overlap between ColumbiaGrid and adjacent planning groups like NTTG.

This current draft system assessment identified a number of potential reliability issues over the next five and 10 years that would need to be addressed by the transmission owners, ranging from relatively local issues such as service in the Olympic Peninsula over the 115-kilovolt system up to wider-scale issues such as service over the 500-kilovolt West of Cascades paths to loads in the I-5 corridor main grid. The transmission owners have identified potential mitigation projects for a number of these issues, which will be studied further in the ColumbiaGrid biennial plan. The main projects studied are shown on Figure 7-3 below. The underlying transmission system shown on the map comprises the facilities of ColumbiaGrid members. The Hemmingway - Boardman project is also in the study set, although its sponsor, Idaho Power, is not a ColumbiaGrid member.

Figure 7-3: ColumbiaGrid 2009 System Assessment - Projects Studied



Source: ColumbiaGrid

Bonneville, which is a member of ColumbiaGrid, has developed an innovative approach to identifying transmission development to provide long-term firm transmission service, which is particularly helpful for dispersed generation projects like wind farms. The first use of this network-open-season approach was in 2008, and a second open season was conducted in 2009. The Bonneville approach, approved by FERC, provides for a cluster study of requests in the transmission-service request queue, an offer of service at embedded-cost rates with Bonneville providing the financing (to be recovered through wheeling rates when service commences), and reordering of the queue positions for those requestors not willing to commit to take service with the proposed transmission project. This approach was very successful in 2008 and led to Bonneville's determination to move forward with several major transmission projects, including the West of McNary project and the I-5 corridor reinforcement project. Bonneville also was

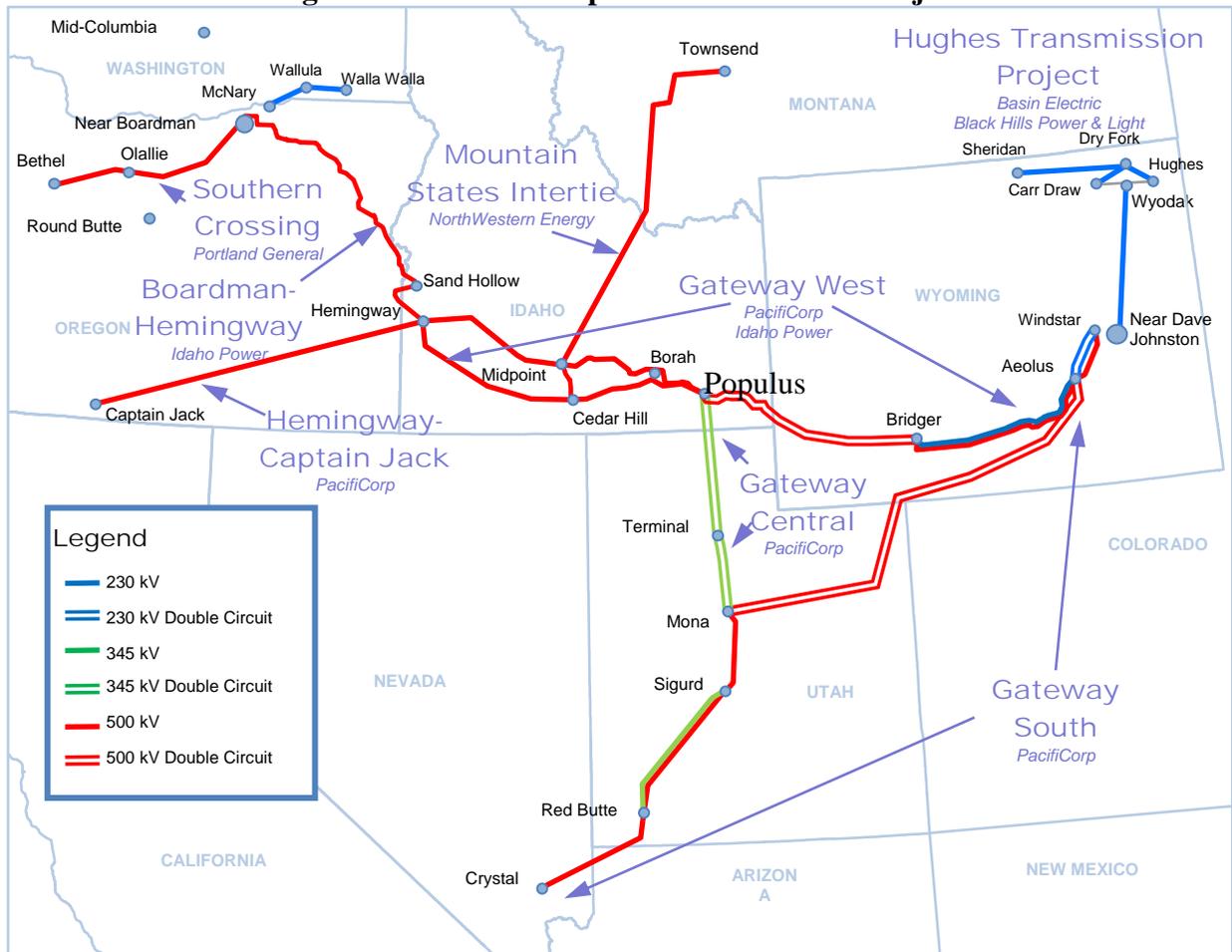
aided in the ability to finance these projects by the availability of federal economic-stimulus funding, which provided increased borrowing authority and allowed Bonneville to ramp up its capital-expenditures program.

This approach improves the default process, required by the FERC OATT, which both requires that service requests be studied in the order in which they were received and puts the financing burden primarily on the entity requesting transmission service. Both of these conditions served as significant impediments to development of large transmission projects to serve a number of smaller wind developments.

Bonneville's approach is one of several modifications to the OATT approach to financing new transmission for renewables that FERC approved. In a 2007 order on the California ISO, FERC allowed modifications to OATT financing requirements for a renewable collector project in the Tehachapi area of Southern California. In October 2008, FERC allowed an incentive rate of return on PacifiCorp's Energy Gateway projects (described below), taking into account their ability to move large amounts of renewable energy to load centers. In March 2009, FERC conducted a technical conference on integrating renewable resources into the transmission grid, which may result in modifications to the OATT itself, building on the case-by-case approach employed so far. The Council supports actions such as these to enhance the ability of the transmission system to support renewables and robust markets.

Northern Tier Transmission Group, formed in 2007, focuses its efforts on larger transmission projects that move power across its footprint, and connect with adjacent sub-regional groups' footprints (ColumbiaGrid and WestConnect). Lower-voltage, more local projects are addressed by the individual NTTG transmission-owning members. NTTG members have proposed a set of primarily 345-kilovolt and 500-kilovolt projects to meet native load service and transmission service requests under the OATT from potential exporters from the NTTG footprint. These projects are shown on Figure 7-4 below.

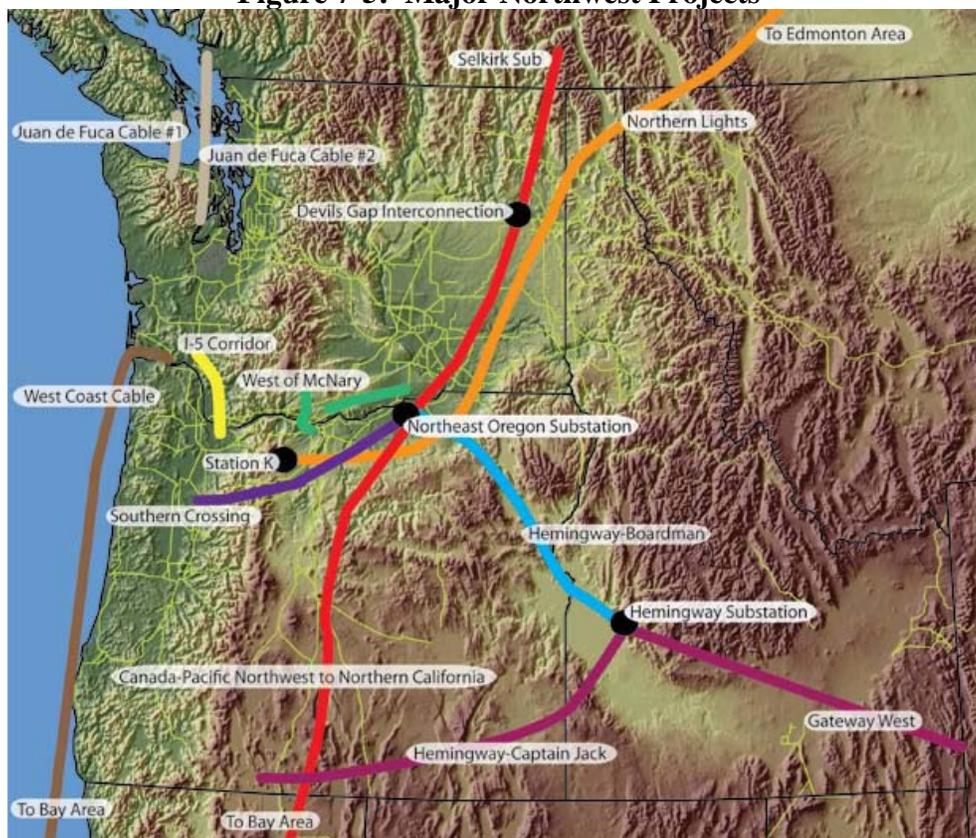
Figure 7-4: NTTG Proposed Transmission Projects



Source: NTTG

The Transmission Coordination Work Group or TCWG (composed of PGE, Avista, Idaho Power, PacifiCorp, Pacific Gas and Electric, TransCanada, Sea Breeze Pacific-RTS, and Bonneville) is sponsoring a project-review process to examine potential interactions among various major project proposals that connect with or pass through the McNary area of Northeastern Oregon. The examination of project interactions is a fundamental part of the process of getting an approved rating for a project under WECC procedures. The rating is a foundational part of the determination of reliable operating limits for transmission lines and paths.

The map in Figure 7-5 below shows projects sponsored by Columbia Grid members, like Bonneville’s West of McNary and I-5 Corridor projects, those sponsored by NTTG members, like the Gateway, Hemmingway - Boardman, Hemmingway - Captain Jack, and Southern Crossing projects, and those sponsored by others, like TransCanada’s Northern Lights, PG&E’s Canada - California project, and the Sea Breeze cable projects. There is some overlap between what is shown on Figure 7-4 and Figure 7-5.

Figure 7-5: Major Northwest Projects

Source: ColumbiaGrid

Although there has been a substantial improvement in coordinated regional transmission planning and development over the period since the Fifth Power Plan, some utilities still face difficulties in getting transmission access to market hubs and to resources they are planning on to meet future loads or to meet their transmission-service obligations to generators under their OATTs. Even the projects that are farthest along in development, like Bonneville's West of McNary project, have not yet surmounted all the possible problems on the path to completion.

Whether this situation comes from difficulties in siting large transmission lines or from the planning process itself taking longer than anticipated, it can leave utilities in the position of having to acquire back-stop resources to make up for those that they were not able to access reliably due to transmission limitations. The Council recognizes that this can also lead to differences in resource timing and acquisition strategy from those described for the overall region in the power plan. The inability to site needed transmission can also force utilities to make less-desirable resource choices than might otherwise be made, by precluding access to distant renewables and to regional and other markets. The Council supports and encourages regional transmission planning efforts, recognizing that new transmission investment can be key both to maintaining reliable load service and to bringing in new renewable resources to meet regional loads.

Chapter 8: Direct Use of Natural Gas

The Policy Question.....	1
Current Council Policy on the Direct Use of Gas.....	1
Analysis of the Direct Use of Natural Gas for the Sixth Power Plan	3

THE POLICY QUESTION

The appropriate role for the Council in promoting the direct use of natural gas for space and water heating has long been an issue in the region. The Council has analyzed the technical and the policy issues in a number of studies dating back to its very first power plan. While the specific issues have changed somewhat over time, three central questions remain:

1. Is the conversion from electricity to natural gas for residential space and water heating a lower-cost and lower-risk alternative for meeting the region’s load growth when compared to other options?
2. If so, how much cost-effective “fuel-switching” potential is there in the region?
3. Are fuel-choice markets working adequately?

During development of the sixth plan, a fourth question arose: How does the conversion from electricity to natural gas for space and water heating impact the region’s carbon emissions?

Current Council Policy on the Direct Use of Gas

The Council’s current policy on the direct use of natural gas is stated in the text box below. This policy was adopted with the Council’s Fourth Power Plan following a detailed analysis of fuel-conversion potential and cost in 1994.¹ The policy was reaffirmed in the Council’s Fifth Power Plan.²

¹ Northwest Power Planning Council. Fourth Northwest Conservation and Electric Power Plan. March 1996 (96-5). Pages 4-10,11.

² Pacific Northwest Power and Conservation Council. Fifth Northwest Electric Power and Conservation Plan. May 2005 (2005-7). Pages 3-45.

Council Policy Statement

The Council recognizes that there are applications in which it is more energy efficient to use natural gas directly than to generate electricity from natural gas and then use the electricity in the end-use application. The Council also recognizes that in many cases the direct use of natural gas can be more economically efficient. These potentially cost-effective reductions in electricity use, while not defined as conservation in the sense the Council uses the term, are nevertheless alternatives to be considered in planning for future electricity requirements.

The changing nature of energy markets, the substantial benefits that can accrue from healthy competition among natural gas, electricity, and other fuels, and the desire to preserve individual energy source choices all support the Council taking a market-oriented approach to encouraging efficient fuel decisions in the region.

The Council has not included programs in its power plans to encourage the direct use of natural gas, or to promote conversion of electric space and water heat to natural gas. This policy is consistent with the Council's view of its legal mandate. In addition, the Council's analysis has indicated that fuel-choice markets are working well. Since the large electricity price increases around 1980, the electric space-heating share has stopped growing in the region while the natural gas space-heating share in existing homes increased from 26 percent to 37 percent. A survey of new residential buildings conducted in 2004 for the Northwest Energy Efficiency Alliance found that nearly all new single-family homes constructed where natural gas was available had gas-fired, forced-air heating systems.³ The survey also found an increased penetration of natural gas heating in the traditionally electric-heat-dominated multi-family market, especially in larger units and in Washington.⁴ Fuel conversion of existing houses to natural gas has been an active market as well, often promoted by dual-fuel utilities.

The Council policy on fuel choice has consistently been that fuel conversions, while they do reduce electricity use, are not conservation under the Northwest Power Act because they do not constitute a more efficient use of electricity. However, the Council's analysis also has recognized that in some cases it is more economically efficient, and beneficial to the region and individual customers, to use natural gas directly for space and water heating than to use electricity generated by a gas-fired generator. However, this is very case-specific and depends on a number of factors including the proximity of natural gas distribution lines, the size and structure of the house, the climate and heating requirements in the area, and the desire for air conditioning and suitability for heat pump applications. In general, although direct use of natural gas is more thermodynamically efficient (except for the case of heat pumps), it is more costly to purchase and install. Therefore, its economic advantage depends on the ability to save enough in energy costs to pay for the higher initial cost.

³ Northwest Energy Efficiency Alliance. "Single-Family Residential New Construction Characteristics and Practices." Portland, OR, March 27, 2007. Prepared by RLW Analytics.

⁴ Northwest Energy Efficiency Alliance. "Multi-Family Residential New Construction Characteristics and Practices." Portland, OR, June 14, 2007. Prepared by RLW Analytics.

Analysis of the Direct Use of Natural Gas for the Sixth Power Plan

In 1994, the Council analyzed the economic efficiency of converting existing residential electric space and water heating systems to gas systems.⁵ The results of that study showed there were many cost-effective fuel-switching opportunities within the region, representing a potential savings of over 730 average megawatts. As stated above, the market, with its high rate of conversions from electric to gas systems, was performing many of the conversions on its own. Consequently, the Council has not included fuel switching or fuel-choice measures in its subsequent power plans.

With the financial support and cooperation of the Northwest Gas Association and Puget Sound Energy, the Council, working through its Regional Technical Forum, is conducting an updated economic analysis of fuel conversion for residential space and water heating equipment in existing homes and fuel choice for residential space and water heating equipment in new homes in the Pacific Northwest. While the study results were not available at the time the Council adopted the Sixth Power Plan, it is possible to forecast potential implications. Should the direct use of natural gas prove to be a lower-cost and lower-risk alternative for meeting the region's load growth, including potential cost and risk from carbon emissions, the Council will need to assess whether the fuel-choice markets are working adequately. If the markets appear to be working adequately -- i.e, consumers are selecting natural gas for space and water heating where it makes economic sense -- then the Council will retain its current policy, which leaves the choice of heating fuels to individual consumers. If however, the market is not working adequately, the Council may decide to make specific recommendations in the future including but not limited to providing information and promoting efficient pricing of electricity.

The Council's objective for this analysis is to recreate its 1994 study with up-to-date information. The scope of the analysis has been expanded to include new construction for single-family dwellings and both new construction and existing buildings for multi-family dwellings. The updated analysis is also testing the cost, risk, and carbon-emissions impact of converting from natural gas to electricity as well as conversions from electricity to natural gas. A major difference between the Council's 1994 study and the current analysis is that all direct use of natural gas alternatives will be modeled as "resources" directly in the Council's portfolio model. This will allow the Council to directly compare the cost and risk associated with meeting regional electricity loads with conservation and traditional generating resources (including those fired by natural gas) against meeting those same needs by using natural gas directly in the home.

Multiple space and water-heating technologies are being considered in the analysis. Individual residential customers have different combinations of these technologies. In addition, each customer has a number of technology options from which to choose when existing equipment fails and needs to be replaced. This analysis assumes that customers install new equipment only when existing equipment needs to be replaced because it has come to the end of its useful life. At that time, customers can install the same type of equipment they already have or install a different technology. In new construction, the customer has the choice of all technologies and energy sources, but once that choice is made, they must live with it for the life of the equipment.

⁵ Northwest Power Planning Council. "Direct Use of Natural Gas: Analysis and Policy Options". Issue Paper 94-41. Portland, OR. August 11, 1994.

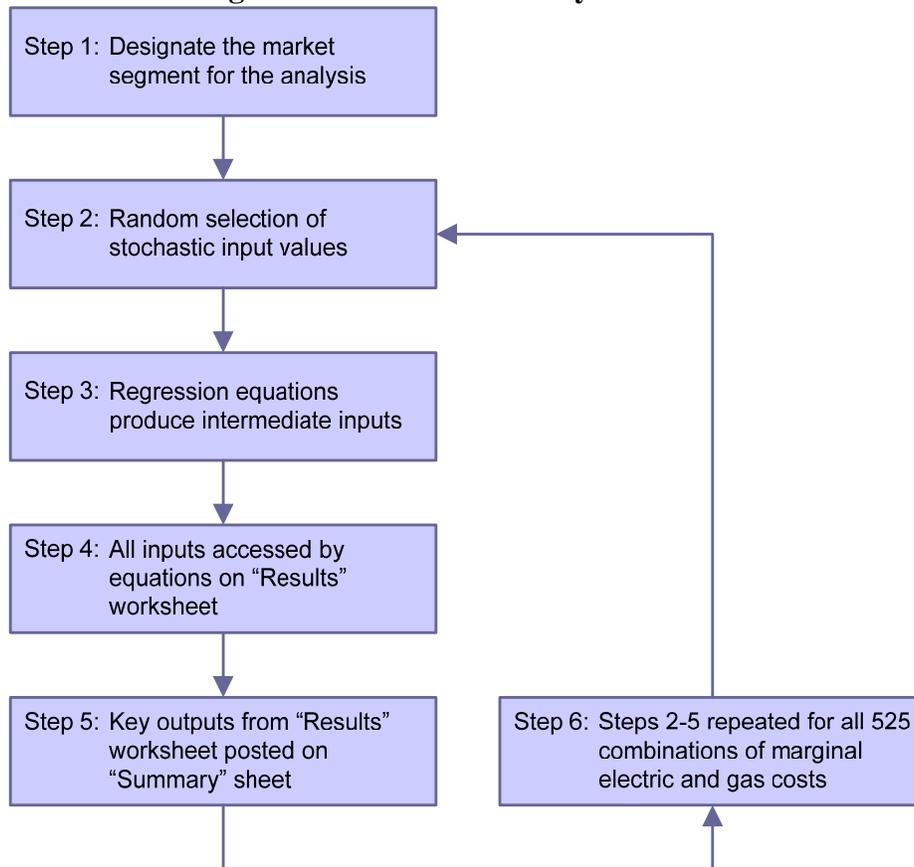
For example, in one identified market segment, the home has an electric forced-air furnace (FAF) for space heating and an electric-resistance water heater. This study assumes that when the electric FAF fails, it could be replaced with a gas FAF, a gas/heat pump hybrid, or a gas hydronic system. Likewise, when the electric-resistance water heater fails it could be replaced with the same type of water heater, a gas tank water heater, or an instantaneous gas water heater.

In this study each market segment consists of just one type of equipment for replacement of the failed existing equipment. Therefore, one market segment would include a gas FAF and a gas tank water heater as the retrofit equipment options for the electric FAF system and the electric resistance water heater, while another market segment would specify another combination of technologies.

Each of these technology choices comes at a cost to not only the individual customer, but more importantly, the entire region. Consistent with the Council's other analysis, this analysis accounts for both the money spent by customers to install a different type of new equipment and the resulting impact on natural gas or electricity consumption, changes in operations, and maintenance costs and changes in greenhouse-gas emissions.

The economics of these technology choices are highly dependent on the relative costs of natural gas and electricity and the capital cost of conversion. To address the wide range of conversion costs faced by consumers, a "Monte Carlo" model was developed similar to that used in the 1994 Council analysis. The flowchart in Figure 8-1 illustrates the six-step "Monte Carlo" process being used in this economic analysis. In Step One, the model designates one of the 91 market segments (inputs) for the analysis. Of the 91 inputs, 49 are stochastic, meaning they are randomly selected. In Step Two, the values for the 49 stochastic inputs are selected. In Step Three, values for four of the stochastic inputs are established by regression equations. In Step Four, the 49 stochastic inputs, the four regression inputs, 29 deterministic (fixed) inputs, and two decision inputs (marginal cost of electricity and marginal cost of gas) are accessed by the model's equations. After the completion of the calculations, the values for key outputs are displayed for summary viewing in Step Five. In Step Six, steps two through five are repeated as the model performs all the necessary calculations 1,000 times for each of the 91 market segments and for each of the 525 combinations of marginal electric and marginal gas costs.

A complete description of the direct use of natural gas economic model and the input assumptions used in the model are available on the Regional Technical Forum's website: <http://www.nwcouncil.org/energy/rtf/studies/rfp/directuse/GEPReport.pdf>.

Figure 8-1: Economic Analysis Process

Once the Monte Carlo model has identified the most economical market choices for fixed combinations of natural gas and electricity prices this information will be fed into the Regional Portfolio Model (RPM). The RPM will then be used to test the economics of each technology choice over the wide range of future natural gas and electricity price combinations. This analysis will seek to determine whether across the entire range of electric and gas cost combinations there are conversions to natural gas that are economically efficient and which result in lower risk to the region's power system.

The Council was unable to complete the RPM analysis of the economics and emissions impacts of the direct use of natural gas prior to the release of the Sixth Power Plan. Due to the significant regional interest in this analysis, the Council believes it should provide adequate opportunity for review and comment on the input assumptions and results of this work before considering changes to its current policy. Therefore, the Council included a specific task in the action plan (ANLYS-16) to complete this analysis during the first six months of 2010 and to consider any policy changes and action items related to the findings.

Chapter 9: Developing a Resource Strategy

Introduction.....	1
Developing a Resource Strategy.....	2
Resource Strategy is Tied to the Act.....	2
Portfolio Selection	4
Model Portfolios	7
Interpreting Portfolio Costs.....	8
Low-Risk Portfolios.....	9
Interpreting Carbon Emissions and Costs.....	10
Sources of Uncertainty.....	11
Wholesale Power Prices.....	11
Load Uncertainty	13
Fuel Prices.....	13
Hydropower Generation.....	14
Resource Construction Costs	14
Climate Change and Carbon Emission Goals.....	16
Plant Availability	18
Renewable Energy Production Incentives	18
Renewable Energy Credits.....	19
Other Assumptions.....	19
Existing Renewable Portfolio Standard Resources.....	20
Forced-in Renewable Portfolio Standard (RPS) Requirements.....	22
Conservation from New Programs, Codes, and Standards.....	23
Independent Power Producers' (IPP) Resources	24
New Generating Resource Options.....	24
System Flexibility and Capacity Requirements.....	25

INTRODUCTION

This chapter describes the Council's treatment of risk in its planning analysis. In particular it describes scenarios that use the Council's regional portfolio model. This computer model simulates the development and operation of the region's power system in an uncertain world.

The Council's plans always have recognized uncertainty. The Fifth Power Plan (May 2005), however, was the first of the Council's plans that used the portfolio model to analyze strategies over hundreds of futures.

The chapter describes the model's approach to evaluating and selecting portfolios. It discusses the interpretation of the results of testing thousands of portfolios against 750 futures. The chapter then describes each of the sources of uncertainty that are included in the portfolio model for the sixth plan. The chapter concludes with a discussion of several issues unrelated to sources of uncertainty, such as how peak-power requirements are accounted for in the plan's analysis.

DEVELOPING A RESOURCE STRATEGY

Risk assessment has been central to Council planning since the first power plan. The Council's resource portfolio and forecasts must, by statute, address regional requirements over the next 20 years. However, reliably forecasting factors on which the plan relies is difficult, if not impossible. Therefore, the Council must assess cost and risk, both to the power system and to the environment, under significant uncertainty.

Earlier plans looked at an array of uncertainties and sources of risk. Load uncertainty, fuel price uncertainty, and hydro generation variability figured prominently in the conclusions of the plans. Those plans incorporated gas- and coal-price excursions in forecasts and sensitivity analyses. They also considered capability to export and import various amounts of power to and from outside the region. Since the first power plan, the Council has analyzed the value of shorter lead times and rapid implementation of conservation and renewables. The Council also has valued “optioning” generating resources. Optioning refers to carrying out pre-construction activities and then, if necessary, delaying construction until conditions favor going ahead.

In the Fifth Power Plan, the Council extended its risk assessment and management capabilities. It developed a computer model that enabled the Council to look at decisions made without the perfect foresight that most models assume. The scenarios broadened the scope of uncertainty. New uncertainties included those associated with electricity market price, aluminum smelter loads, carbon-emission penalties, tax credits, and renewable energy credits. Scenarios evaluated thousands of resource portfolios and captured the costs associated with portfolios that adapted to changing circumstances and alternative scenarios.

This sixth plan builds on the lessons and techniques of the fifth plan. Council scenarios now incorporate uncertainty about power plant construction costs and availability. Scenarios track carbon production using several new techniques, and the impact of carbon penalties moves to center stage. The representation of conservation and demand response continues to evolve.

The study and treatment of risk requires a suitable framework. The next section describes how uncertainty, cost, and risk bear on the selection of a resource portfolio.

Resource Strategy is Tied to the Act

The Council's Power Plan identifies resource strategies that minimize the expected cost of the region's electricity future. The Act calls for a plan that assures an “adequate, efficient, economical, and reliable” power supply. Efficient and economical are interpreted to mean economically efficient, and net present-value (NPV) system cost is arguably the best indicator of such efficiency.

The Council's regional portfolio model (RPM) evaluates possible portfolios under 750 different possible futures. Each future is a distinct combination of conditions for carbon penalties, demand growth, electricity and fuel prices, hydroelectric generation, and other key sources of uncertainty. For each future, the values of each variable are specified hourly over the 20 years of a scenario.

The model uses the same set of 750 futures to evaluate each resource portfolio. The model selects a future before it begins its chronological simulation of a given resource portfolio. As the model moves forward through the scenario, it simulates the behavior and cost of every resource in the regional power system, including new resources in the specific portfolio being assessed. Once the model completes the last period in the scenario, it computes the net present value of the costs for that resource portfolio under that future. It then selects a different future and starts over at the beginning of the scenario. Only after a resource portfolio has been evaluated under all 750 futures and a distribution of net present-value costs has been constructed does the model consider a different resource portfolio.

The expected cost of meeting the region's requirements gives us an idea of the most likely cost outcome. Most futures will cluster around this value. Comparing average net present-value system costs gives us an indication of which portfolio is *most likely* to achieve the Act's goal of an economically efficient system.

Special care is exercised in using the expected costs from this model, however. The section below, **Interpreting Portfolio Costs**, discusses this issue in more detail.

A "good" resource plan, according to the Act, is one that is economically efficient and has low net present value. But a plan certainly would be considered unsuccessful if it failed to meet the other requirements of the Act, adequacy and reliability. Consequently, the Council's regional portfolio model screens out resource portfolios that do not prove adequate and reliable. That leaves, however, very many portfolios, including ones that are overbuilt and quite expensive. It stands to reason that a portfolio that met the other requirements of the Power Act still would be considered unsuccessful if it resulted in a *high* net present-value cost to the region.

Knowing that forecasts will be wrong and that the future that actually unfolds may be among those in which our plan performs poorly, what is the best course of action? Ultimately, there is only one irreversible set of conditions. Risk-averse decision-makers will try to find portfolios that minimize the chance of high costs.

One approach to finding such a resource portfolio is to test portfolios under many distinct, feasible conditions and note the worst outcomes for each resource portfolio. Different resource plans, after all, will perform poorly under different circumstances. However, *the* worst outcome is not a good risk measure because its cost can be limitless. The "likely" of the worst outcomes is better behaved. These ideas and concepts are reflected in the Council's risk measure.

The Council's risk measure, TailVaR₉₀, is the average of the highest 10 percent of the net present-value cost outcomes associated with a given portfolio across the 750 futures. To the extent the Council wants to minimize the likely cost of the future energy system and is indifferent to risk, it would prefer a resource portfolio that minimizes expected or average cost. To extent the Council is risk averse, it would tend to select a resource portfolio that may have higher expected cost but lower risk.

Using these definitions of cost and risk, therefore, maximizes the chance of identifying portfolios that achieve the Act's objectives. Such a resource portfolio is likely to be lowest-cost among those that minimize the chance of high power costs, even under the worst circumstances.

Portfolio Selection

To understand the Council's approach requires a little background. It is useful to expand on the concepts introduced in the previous section. Some familiarity with the meaning of several terms, as the Council uses them, is also helpful.

A **future** is a specific combination of values for uncertain variables, specified hourly over the 20-year planning period. For the Council's work, a future will be a specific sequence of hourly values for each uncertainty. A future is hourly electricity requirements for 20 years, combined with hourly electricity prices for 20 years, combined with hourly (or daily) natural gas prices for 20 years, and so forth. The number of sources of uncertainty considered in Council scenarios would render the enumeration here unwieldy, but the next section describes them generally.

Given a particular future, the primary measure of a portfolio is its net present-value total system cost. These costs include all variable costs, such as those for fuel, variable operation and maintenance (O&M), and long- and short-term market purchases. These costs also include the fixed costs associated with investment in new resources and with their operations and maintenance. The present value calculation discounts these future costs to September of 2009 and states them in constant 2006 dollars. Discounting and other financial assumptions are discussed in Appendix N of the plan.

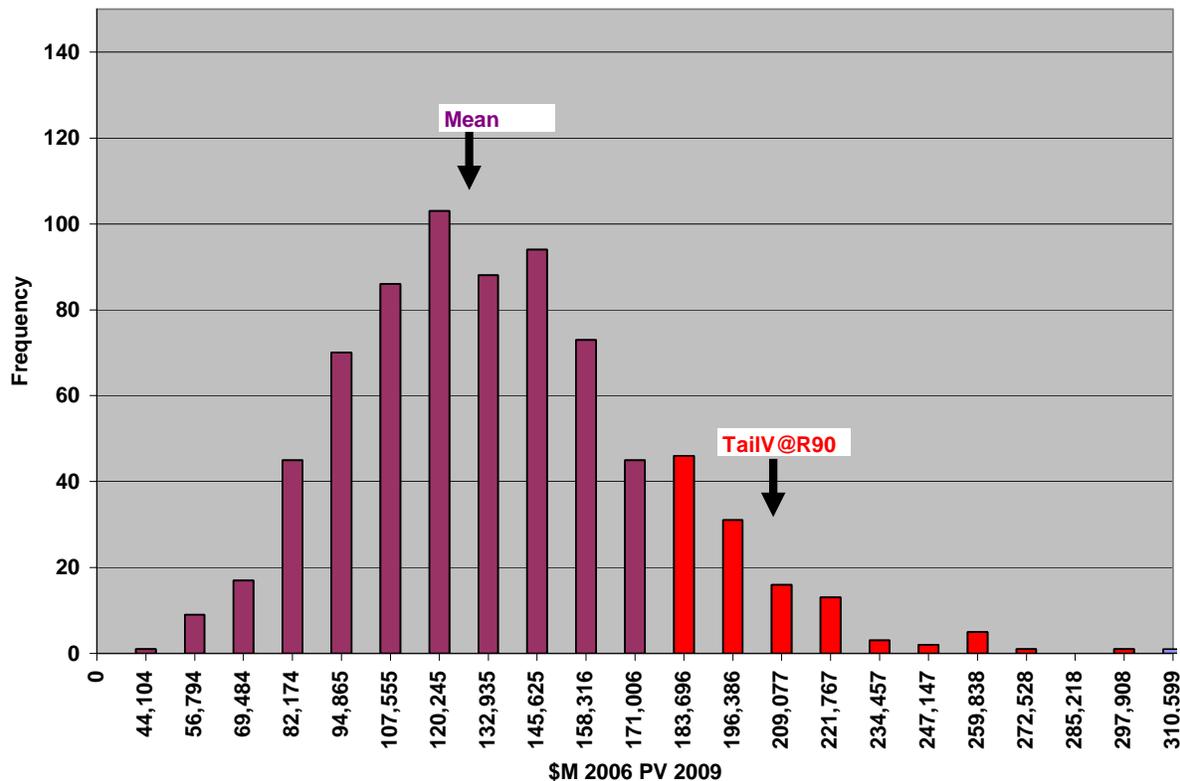
The futures differ significantly one from the other. While some planners would base future uncertainty on historical patterns, the Council recognizes that future markets and other sources of uncertainty rarely resemble the past. Some would refer to a Council future as a scenario. In the Council's modeling, futures typically include some historically unprecedented paths for prices, loads, and other variables. A small number may have an unlikely but not impossible future behavior.

The Council's treatment of uncertainty also reflects the potential for a larger pool of contributing factors than history provides. The model uses larger variation and weaker relationships among sources of uncertainty to achieve this effect. Past relationships often depend on markets, technologies, regulations, and other circumstances that could change in the future. The introduction of reserve-margin standards and renewable-portfolio-standard legislation in California, for example, has changed the traditional relationship between natural gas price and wholesale electricity price. Over the last 30 years, combined-cycle combustion turbines filled the role of providing new energy and capacity. Fundamental market economics assert that this role imposes a relationship between electricity prices and natural gas, the fuel that combustion turbines burn. Regulatory changes are upsetting that relationship. Renewables, built for purposes other than reducing expected cost or making a profit, are displacing combustion turbines. Non-renewable resources, added for reliability and flexibility, are also contributing. These innovations are changing the rules of the market.

Larger variation and weaker relationship among uncertainties in the Council's model therefore provide an opportunity to better understand the consequences of technological innovation, legislative and regulatory initiatives, transformation of markets, and other "unforeseeable" events. Combining futures in unlikely ways, moreover, reveals how different sources of uncertainty can combine to bring extraordinary risk. The next section describes the nature of specific sources of uncertainty.

The effect of different futures on the cost of a portfolio produces a distribution of portfolio costs. This distribution is the source of expected cost and risk attributed to that portfolio. Figure 9-1 represents the number of times the net present value cost for a single portfolio under all futures fell into specific ranges or “bins.” That is, each bin is a narrow range of net present-value total system costs.

Figure 9-1: Example of a Portfolio Cost Distribution



Source: "Costs Illustrated.xls", worksheet "distribution"

Figure 9-1 is an example of the cost distribution for a *single* resource portfolio. Each resource portfolio will have a distinct distribution like the one in the figure.

Because a simulation of a particular resource portfolio typically uses 750 futures, the resulting distributions can be complicated. Representative statistics make the task of capturing the nature of a complex distribution manageable.

The average of the distribution provides an idea of the most likely cost outcome for this resource portfolio. Comparing average net present-value system costs between two portfolios gives us an indication of which portfolio is most likely to have the lowest cost.

The *measure of risk* that the Council adopted is TailVaR₉₀. Briefly, TailVaR₉₀ is the average value for the worst 10 percent of outcomes.¹ It belongs to the class of “coherent” risk measures that possess special properties. These properties assure the measure reflects diversification benefits of resources in a portfolio. Coherent measures capture the magnitude and likelihood of

¹ See Appendix P of the Fifth Power Plan for a more detailed discussion of this risk measure and a comparison with other risk measures.

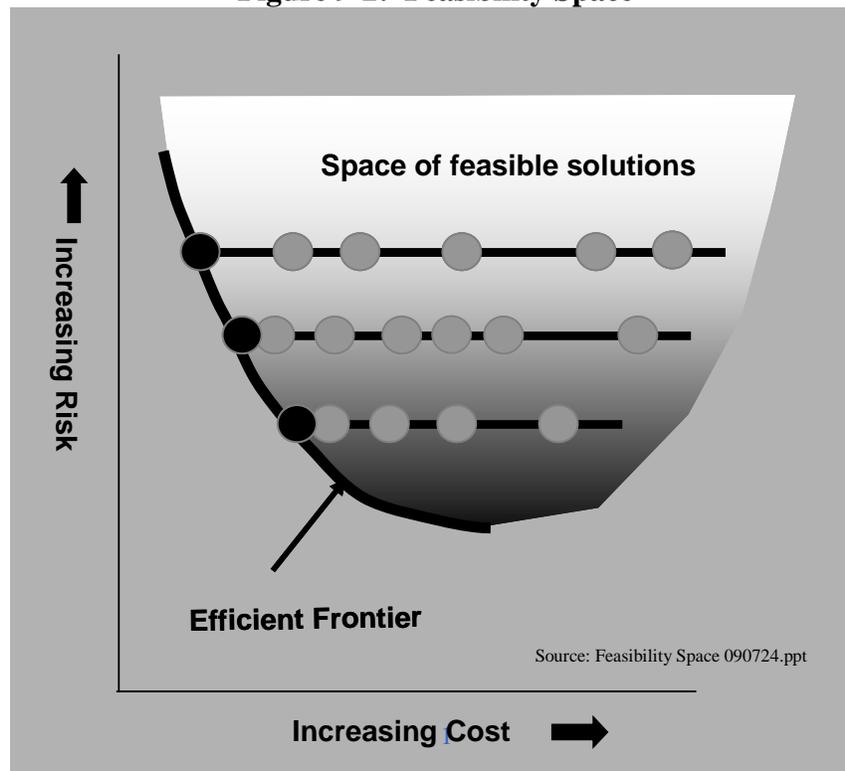
bad outcomes, rather than the predictability of, or the range of distribution for, an outcome. As mentioned above, use of TailVaR₉₀ is also consistent with avoiding high-cost outcomes.

Using these two statistics, each portfolio is associated with a point on a graph. The horizontal axis measures the portfolio's cost and the vertical axis measures the portfolio's risk. This way, a large number of resource portfolios can be compared on these two measures. A typical scenario evaluates 2,000 to 5,000 possible portfolios. The set of points corresponding to all portfolios is a *feasibility space*, an illustration of which appears in Figure 9-2.

For each level of risk, there is a level, horizontal line passing through the feasibility space. The left-most portfolio in the feasibility space on that line is the least-cost portfolio for that level of risk. The *efficient frontier* of the feasibility space will contain only least-cost portfolios.

Because the Council typically evaluates thousands of portfolios, the efficient frontier permits the Council to narrow its search, typically to a fraction of one percent of these portfolios. It does so without invoking weighting factors or other, more problematic schemes that have been used to assess decisions with multiple objectives.

Figure 9-2: Feasibility Space



The Council's approach to resource planning could be called "risk-constrained, least-cost planning." Given any level of risk tolerance, the efficient frontier finds portfolios that achieve that level at the lowest cost. In this sense, it is comparable with traditional utility integrated resource plans (IRPs), also referred to as "least-cost" plans. If risk is ignored, the "least-cost" plan is the upper-left-most portfolio on the efficient frontier.

Risk often stems from short-lived events. Again, a measure that relies on net present-value costs may miss this kind of risk. Consequently, additional study of portfolio behavior over time is necessary. An example of the evaluation of portfolio risk in particular futures appears in Appendix J. The section *Low-Risk Portfolios*, below, discusses risk in more detail.

Model Portfolios

The Council's resource portfolio does not look like a traditional firm resource plan to meet firm electricity demand. For example, it does not contain completion dates for new resources that will just meet load growth when needed.

The Council's definition of a resource portfolio consists of two elements. For most conventional resources, the portfolio specifies the option dates for specific types and amounts of generating resources. A resource is optioned when the design, siting, and licensing have been completed and it is ready for construction.

The second element of the portfolio consists of policies for conservation and demand response. Policies include cost-effectiveness "adders" or premiums over wholesale electricity market price for conservation acquisitions. For demand response, the policy consists of implementing one of several prescribed schedules for irrigation, heating, cooling, and other programs. These schedules specify the number of megawatts implemented at different times for each program over the 20-year scenario horizon.

The option schedules, conservation premiums, and demand-response deployment schedules for portfolios that lie on the efficient frontier are determined through a computerized search process. The model initially tries random portfolios, such as one where no resources can be added, one where all resources are available for construction at their maximum build rate, and so forth. For each of these, performance is simulated under the 750 futures, and the resulting average cost and risk are observed. After several hundred portfolios have been evaluated, the computer discovers which schedules of resources and policy choices tend to lower average cost and risk. By trying modifications of the more successful portfolios, it attempts to minimize the cost of the power system at different levels of risk.

The reason for using a plan defined by earliest construction start dates lies with the nature of generating resource construction risk. A significant source of risk to the region arises from inaccurate forecasts of the need for or the value of a generating resource. Both building too *few* and too *many* resources can be expensive and wasteful. The Council's model reflects the reality that decision-makers never can be sure how the future will work out.

The *opportunity* to construct a resource is prescribed by a given resource portfolio. Given such an opportunity, the model makes a decision – in each period of each future – whether to proceed with construction. This decision to construct is based on what the model thinks about the eventual value of and need for that resource under that particular future and at that particular time. The model's decision pays no attention to (does not "know" about) what will unfold in subsequent periods under this future. The model computes requirements and costs chronologically under each future so the model's decision-making has only a notion of the past. Thus, the decision must be based only on what price and requirement trends have been up to that point.

Constructing a plant does not guarantee the plant will be economical. Just as in life, circumstances change without notice. The model makes forecasting mistakes in some futures, and the costs – due to delays, emergency purchases, overruns, shortages, and cancellations – associated with those mistakes are captured in the portfolio’s net present-value costs. By this means, the model identifies resource portfolios with values that are less sensitive to assumptions about the future.

The conservation acquired and the generating resources constructed in a given portfolio will be different in each of the 750 futures. The construction of generating resources and the acquisition of conservation in each future therefore will depend on how that particular future unfolds.²

The resulting resource portfolio is one that addresses the risks inherent in the future, not one that has the lowest cost for one specific future. In a given future, portfolio resources will not necessarily cover their costs in the wholesale electricity market. Some will do very well in certain futures and poorly in others. This is particularly true with portfolios that are near the least-risk end of the efficient frontier, where the resources necessary to yield such low risk are so expensive to construct that they typically cannot cover their costs in the market. What determines whether a resource portfolio falls on the efficient frontier at the least-risk end is more determined by whether it reduces total cost in the worst futures. This often comes about by *reducing* market prices, which usually acts to *increase* the net cost of resources. Reducing market prices, however, also reduces the risk of expensive market purchases during times of unexpected need and thereby reduces expected cost.

A traditional resource plan cannot address such scenario risks. Alternative scenarios can be tested in a traditional sense. This gives an idea of how the ideal plan might change if the future turns out different. However, it will not show how best to prepare when it is not clear which future will occur.

Because the Council’s power plan directly addresses risk, some aspects of its portfolio may look contrary to a traditional approach to resource plans. In traditional planning, new resources are stacked up against growing loads so that new resources are scheduled at a particular date to meet requirements. Uncertainty about requirements is considered by looking at different levels of load growth. Uncertainty about hydropower conditions is addressed by planning for only critical-water conditions. These are not necessarily the most efficient plans, however, and they are based on how the world works today. These plans typically do not consider changing policies that could dramatically affect the cost of different strategies.

The Council’s plan recognizes, however, that it may be advantageous to develop a portfolio for simultaneous construction of different types of resources. In any given future, only one of these might be constructed. One consequence of this is that, from a traditional load/resource-balance perspective, the option schedule might suggest the power system would be overbuilt.

Interpreting Portfolio Costs

Future costs of the power system in the Council’s regional portfolio model are expressed in traditional planning terms. They are the net present value of future power system costs that can

² Animated graphs that illustrate how selected plans perform under the 750 futures are available from the Council’s website.

vary with resource choices made in each future for the portfolio. They include the operating cost of existing resources and the capital and operating costs of future resources. The capital costs of existing resources are sunk costs and are not affected by future resource choices.

An important distinction exists between the net present-value system costs shown in illustrations of the feasibility space and the *optioning cost* of a particular portfolio. The net present-value system costs include costs that are largely outside the control of decision-makers. They include, for example, carbon penalties and natural gas costs. Option costs are the costs for siting, planning, and licensing new generation. They also may include some above-market cost for conservation, depending on one's view. These costs, the optioning costs, *are* within the scope of what decision-makers control.

It is a common misinterpretation of the efficient frontier that the region is paying for the change in net present-value system costs to achieve the reduction in system risk represented by the frontier. The average cost and risk, however, are not like the cost and benefit in an economic study. Instead, they represent *distinct attributes of the distribution of outcomes*. The decision-maker can pay the optioning costs of the resources, but optioning costs typically are a *fraction of a percent* of the average costs illustrated on the efficient frontier. Depending on the future that actually materializes over the next twenty years, the benefits of optioning resources can, on the other hand, be much larger than the average cost along the efficient frontier.

The expected costs in other studies are often meaningful because they reflect a value to which average costs will trend over time. For example, average hydrogeneration energy and cost are meaningful in utility-production cost studies. The Council's price forecasts, for example, are based on average hydrogeneration. This use of expected energy is meaningful precisely because, over time, the energy and cost will trend to those values, even though they may differ significantly in any given year. That is not the case for many of the uncertain variables in this model. In fact, most futures consist of prices and requirements that move progressively away from today's forecasts. This behavior is important to risk modeling, but it makes expected cost harder to interpret.

The expected costs from the feasibility space differ from those in certain economic studies, too, in that typically they include only costs relevant to the selection of a resource portfolio. The fixed costs of the existing system, for example, are not included. Any decisions to modify the *existing* system of resources, therefore, cannot be based only on these costs.

The efficient frontier is a screen for portfolios, based on their relative performance. Their relative performance, in turn, relies only on independent aspects of the portfolio's distribution of possible cost outcomes. These aspects should not be interpreted like traditional economic cost and benefit.

Low-Risk Portfolios

The Council looks beyond expected net present-value cost and risk in distinguishing among portfolios. Often, risk originates from short-term events within a future. For example spikes in market electricity prices such as occurred in 2000-2001 can create huge cost increases if the region is overly exposed to the market. These short-term events are not apparent in net present-value costs. The imposition of a high carbon penalty can lead to high-cost futures if the region has become overly reliant on electricity generated at plants that burn coal. The regional portfolio

model is designed to assess such risks and help the Council build resource strategies that will help avoid the impacts of such events.

The portfolios along the efficient frontier are distinguished by cost and risk. At the low-risk end of the efficient frontier, a portfolio's behavior in its worst 10 percent of outcomes determines its selection. It follows therefore that the benefits of a low-risk portfolio are revealed in those futures. The events that transpire over time within futures determine how risky that future is and whether our risk metric is correctly identifying those futures. Principal sources of risk in those futures may suggest alternative risk-mitigation mechanisms.

Risk mitigation does not affect all futures equally. The average cost of the low-risk portfolio will be slightly higher, but it provides protection, similar to an insurance policy, against the most costly future events. Understanding why particular resources in the low-risk portfolio provide this protection yields insight into their value and into the kinds of futures that would be bad for the region under a given resource portfolio.

Other evidence of reduced risk is reduced rate volatility and reduced exposure to the wholesale power market during high-price excursions. These characteristics of portfolios along the efficient frontier were explored in more detail in the Council's Fifth Power Plan.³ A discussion of the model's calculation of revenue requirements appears in Chapter 3 and Appendix O of the Sixth Power Plan.

In general, portfolios near the lower-risk end of the efficient frontier contain more resources and rely less on the wholesale power market. By building more resources and reducing price volatility, these low-risk portfolios are more consistent with regulatory preferences and utility planning criteria than the lower-cost but higher-risk portfolios.

Interpreting Carbon Emissions and Costs

A new measure of power system performance is the emissions of carbon dioxide from generating plants that burn fossil fuels. It is important because of various greenhouse-gas-reduction targets and proposed policies to price carbon emissions through a tax or a cap-and-trade system.

Because electricity is generated and transmitted between and among regions of the country, measuring carbon emissions in any one region is difficult. Estimating the emissions from an individual power plant is relatively straightforward. But electricity trading creates a variety of options for counting emissions. One option is to count only the emissions of power plants actually located in the Pacific Northwest. Another is to count, in addition, the emissions of power plants that are located outside the Pacific Northwest but whose output is contractually committed to serve Northwest loads. A third is to count the carbon content of all electricity used to serve Northwest loads. This requires adding an estimated carbon content of imported power and subtracting the estimated carbon content of exported power from Northwest emissions.

The rules for such accounting have not been established, and proposed rules often vary by state and region. Such calculations are further complicated by the fact that electricity that is traded in wholesale markets is not typically identified as coming from a particular plant or technology. For example, what carbon content should be attributed to exported power? Is power exported

³ Northwest Power and Conservation Council. The Fifth Northwest Electric Power and Conservation Plan. Volume 2, Chapter 7.

from the Northwest free of carbon emissions because it is generated by hydroelectric projects, or does it have substantial carbon emissions because it is generated from the region's coal plants? Perhaps it should be considered free of carbon, because its price already reflects any carbon penalty paid by producers, directly or through re-dispatching of resources.

Because the accounting treatment is not settled, the Council's regional portfolio model reports carbon emissions in two different ways. One is based on generation located within, or contracted to, the Pacific Northwest (generation-based). The other is based on the consumption of electricity within the region (load-based).

For the purpose of calculating load-based carbon, the model assumes imported and exported power has the same amount of carbon -- 1,053 pounds of CO₂ per megawatt-hour of electricity generated. This corresponds to the number pounds of CO₂ per megawatt hour that a natural gas-fired combustion turbine would produce if it had a heat rate of 9,000 BTU per kilowatt-hour. This is typical of an older-generation gas-fired power plant. It actually is a proxy for the average carbon emissions across all generation in the Western Electricity Coordinating Council region on the short-run margin over an extended time period, such as a year. Northwest generation averages somewhat lower emissions, and surrounding areas average somewhat higher during periods when the Pacific Northwest is importing power. This amount of emissions does not reflect the fact that alternative carbon-control regimes may shift the effective carbon emissions. This assumption does have the advantage, however, of being simple and easy to understand. Moreover, it closely resembles the assumed carbon-emissions factor adopted by Washington State Department of Commerce⁴ and the California Energy Commission.

SOURCES OF UNCERTAINTY

Risk resides with a utility's overall portfolio of requirements and resources, rather than with one resource, one requirement, or one kind of fuel. Moreover, uncertainty does not necessarily lead to risk. Thermal-based utilities view fuel-price uncertainty and the variation of hydropower generation much differently than do hydropower-based utilities. Modeling the uncertainties that are traditionally the primary sources of risk, however, is the first step in a process to understanding economic risks to the region.

Wholesale Power Prices

It would be difficult and expensive for an individual utility to exactly match electricity requirements and generation at all times. Therefore, virtually all utilities participate in the wholesale market, directly or indirectly, as buyers and as sellers. This is particularly so for regional utilities because the region's primary source of generation, hydroelectricity, is highly variable from month to month and year to year.

Whether a utility has surplus generation or needs to purchase power affects the magnitude and direction of change in costs to electricity consumers when wholesale power prices rise. That is, if the utility needs power and if electricity market prices go up, consumers' costs can go up. If

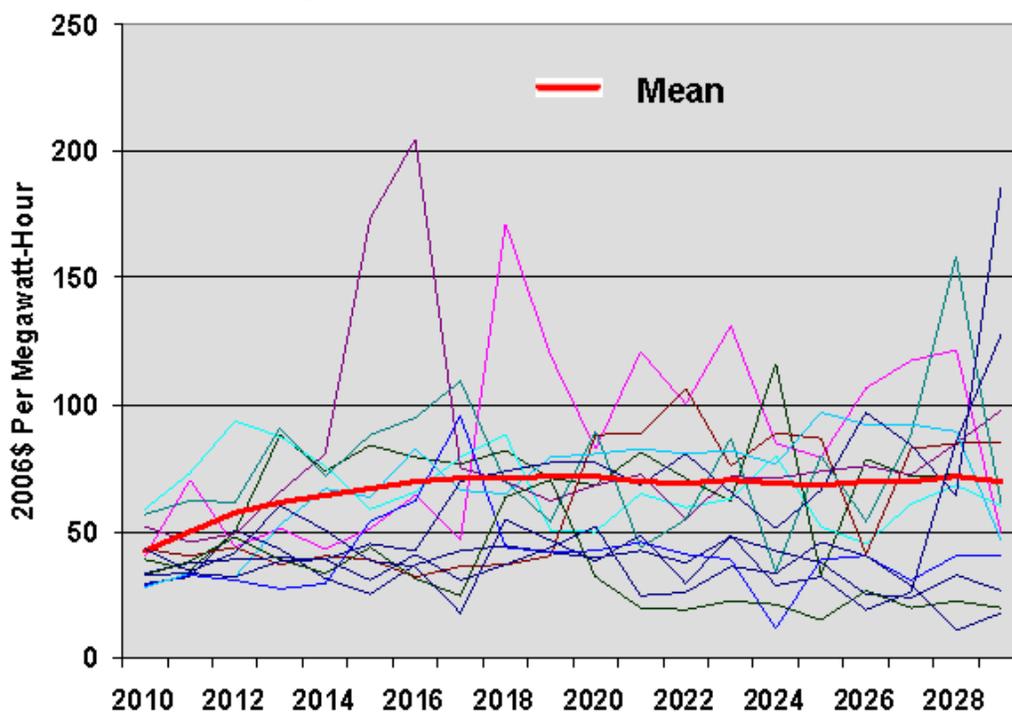
⁴ See final opinion on California Energy Commission (CEC) Rulemaking 06-04-009, issued September 12, 2008, which calls for a default value of 1,100 pounds per MWh; and Tony Usibelli, Assistant Director, Washington Department of Community, Trade and Economic Development, to the CEC regarding this rulemaking, dated July 10, 2007, which uses 1,014 pounds per MWh.

the utility has surplus power to sell into the market, however, and electricity market prices go up, the larger revenues mean the utility's net electricity production costs will come down. This *reduces* the revenue the utility needs to collect from the consumers.

Disequilibrium between supply and demand is commonplace for electricity markets. Disequilibrium results from less-than-perfect foresight about supply and demand, inactivity due to prior surplus, overreaction to prior shortages, and other factors. Periods of disequilibrium can last years. The resulting excursions from equilibrium prices can be large relative to the routine variation due to temperatures, fuel prices, plant outages, and hydro generation. These excursions are a significant source of uncertainty to electric power market participants, and they are therefore an important part of the Council's scenario analysis.

Figure 9-3 shows a sample of electricity price futures from among those that the Council's model uses. Description of the Council's electricity price forecast is in Chapter 2 and Appendix D. Typical of commodity price distributions, which are bounded below by the price of zero dollars per unit, the distribution in Figure 9-3 is quite skewed.

Figure 9-3: Electricity Price Future



Average prices for wholesale electricity over a quarter are capped at \$325 per megawatt in the model. This value corresponds to the \$400-per-megawatt-hour FERC price cap imposed over the Western power system. That is, the latter is the maximum hourly price the model would impute based on the former. Electricity prices rarely hit this level in the Council's portfolio model.

Load Uncertainty

The Council's model assumes a larger range of variation in loads than present in the Council's official load forecast for the sixth plan. The additional variation stems in part from seasonal and hourly patterns of load and from weather variation. A much larger source of variation, however, is uncertainty about changing markets for electricity, possible technology innovations, and excursions due to business cycles.

Figure 9-4: Load Futures

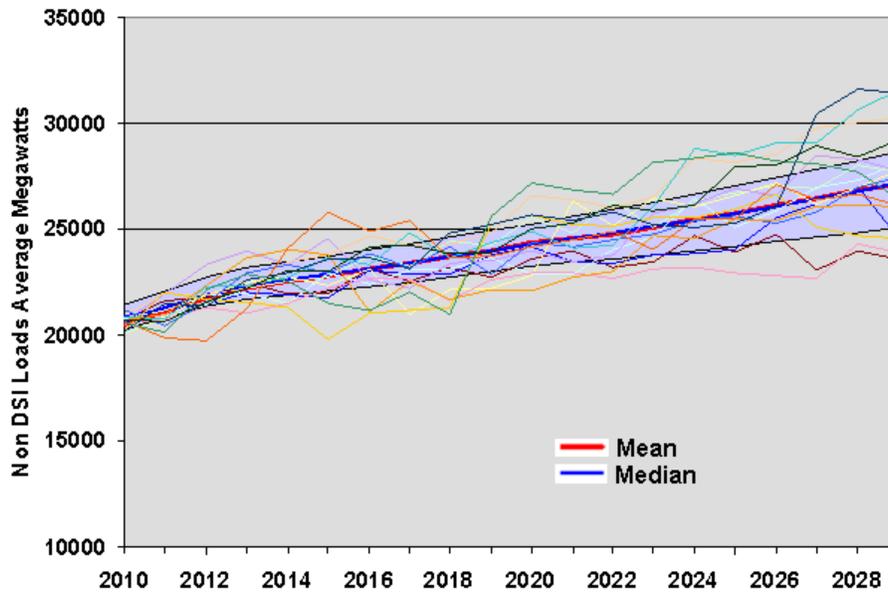
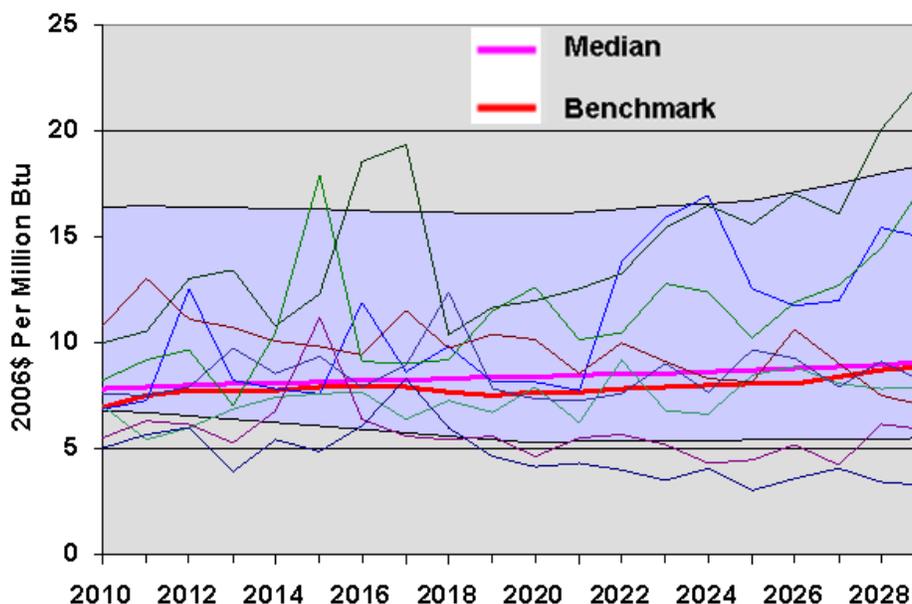


Figure 9-4 displays a sample of load futures from the Council's model simulations compared to the shaded trend forecast range. A detailed description of the Council's official load forecast and the treatment of aluminum smelter loads appears in Chapter 3.

Fuel Prices

The basis for uncertain natural gas price trends is the Council's fuel-price forecast range as described in Chapter 2 and Appendix A. In addition to uncertainty in long-term trends in fuel prices, the modeling representation uses seasonal patterns and brief excursions from these trends. These excursions may last from six months to four years and then recover back toward the trend path. The duration of the excursion and the duration of the price recovery are both functions of the size of the excursion. Figure 9-5 illustrates some natural gas price futures from the portfolio model simulations (2006\$).

As with electricity prices, the price distribution is quite skewed. The shaded area corresponds to the high and low ranges discussed in Chapter 2.

Figure 9-5: Gas Price Futures

Hydropower Generation

A 70-year history of streamflows and generation provides the basis for hydropower generation in the model. The hydropower generation reflects constraints associated with the NOAA Fisheries 2008 biological opinion. Moreover, scenarios evaluate resource choices assuming no emergency reliance on the hydropower system, even though such reliance might not violate 2008 biological opinion constraints.

In addition to meeting fish and wildlife requirements, hydropower operation must satisfy other objectives. These objectives include standard flood control, river navigation, irrigation, recreational, and refill requirements. All scenarios incorporate these constraints.

The modeling assumes no decline of output over the 20-year study period due to relicensing losses or other factors that might lead to capability reduction. Nor does it assume any increases due to deployment of removable spillway weirs or turbine upgrades. Chapter 10 does include, however, a study of the potential effects of removing the four Lower Snake River dams.

Resource Construction Costs

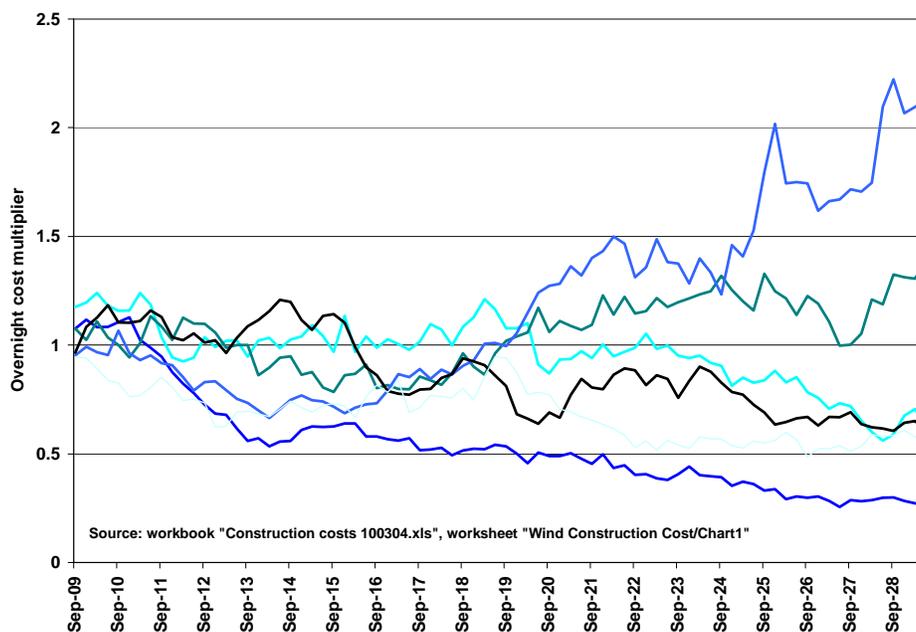
Recent resource development has revealed costs that are significantly higher than anticipated in earlier planning. The details of expected costs for resource technologies over time appear in Chapter 6. These expected costs, which typically trend downward over time, serve as the benchmark for resource construction cost futures the model uses to capture construction cost uncertainty. The Council's Generating Resource Advisory Committee assisted the Council in characterizing the types and likelihood of futures for construction costs.

The Council's model uses these futures to assess the likely future economic value of resources, among other things. Economic value is one aspect of the decision the model makes within a future whether or not to construct a resource.

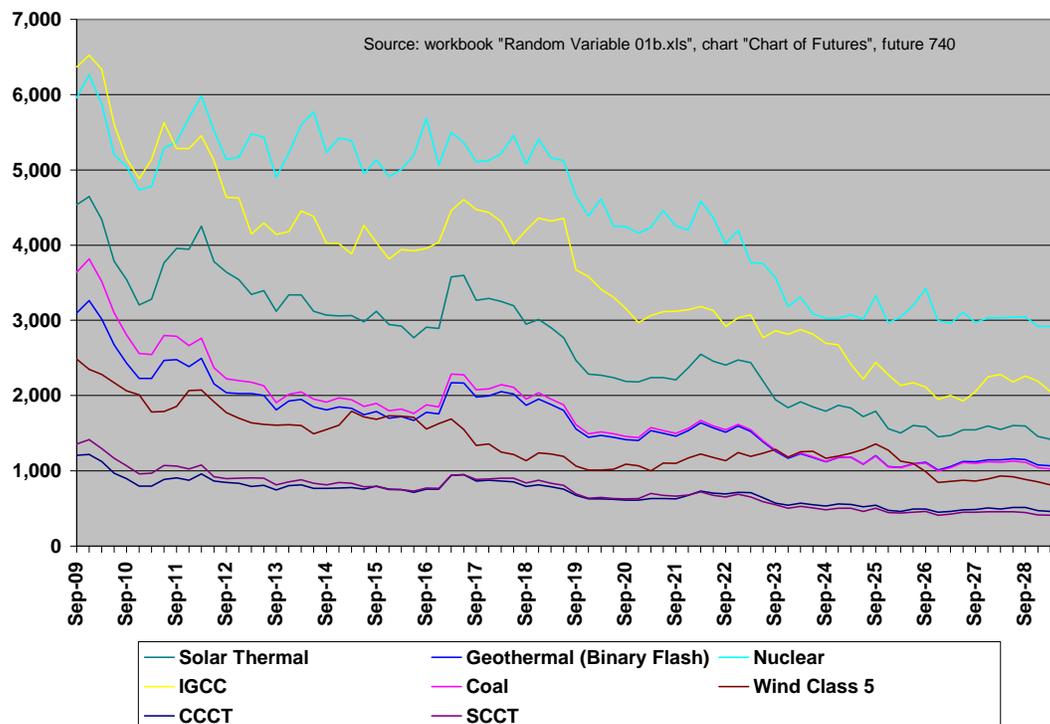
Several cost futures for wind generation resources appear in Figure 9-6. Each future is a sequence of cost multipliers for “overnight” construction. They are applied to a figure of dollars per kilowatt of capacity for a wind plant to determine the effective overnight construction cost for that plant. The overnight construction cost is the total dollars spent over the plant’s construction cycle, but it does not include any costs for financing or for delays in construction. Figure 9-6 therefore represents how the overnight cost for constructing a power plant will change over time. The model takes the cost available at the time of plant construction. The model then effectively places that cost in ratebase and customers continue to pay off the construction cost over the life of the plant. Subsequent changes in the multiplier have no effect.

A trend of decreasing real cost from the highs in 2007-2009 is evident in Figure 9-6. This reflects the expected price decreases anticipated over the September 2009 – August 2029 period.

Figure 9-6: Construction Cost Futures for Wind Generation



An example of a *single* construction cost future for several generation technologies appears in Figure 9-7. This figure illustrates how construction costs generally move together through time, reflecting their shared cost components, such as steel, concrete, and labor. Appendix J provides a more complete description of probability ranges of costs over time for each resource in Figure 9-7.

Figure 9-7: Construction Cost Multipliers

Climate Change and Carbon Emission Goals

A number of industrialized nations are taking action to limit the production of carbon dioxide and other greenhouse gasses. Within the United States, a number of states, including Washington and Oregon, have initiated efforts to control carbon dioxide production. It appears that the region could see control policy materializing at the federal or state level, or through means such as the Western Climate Initiative (WCI) in which Washington, Oregon, and Montana are participants.

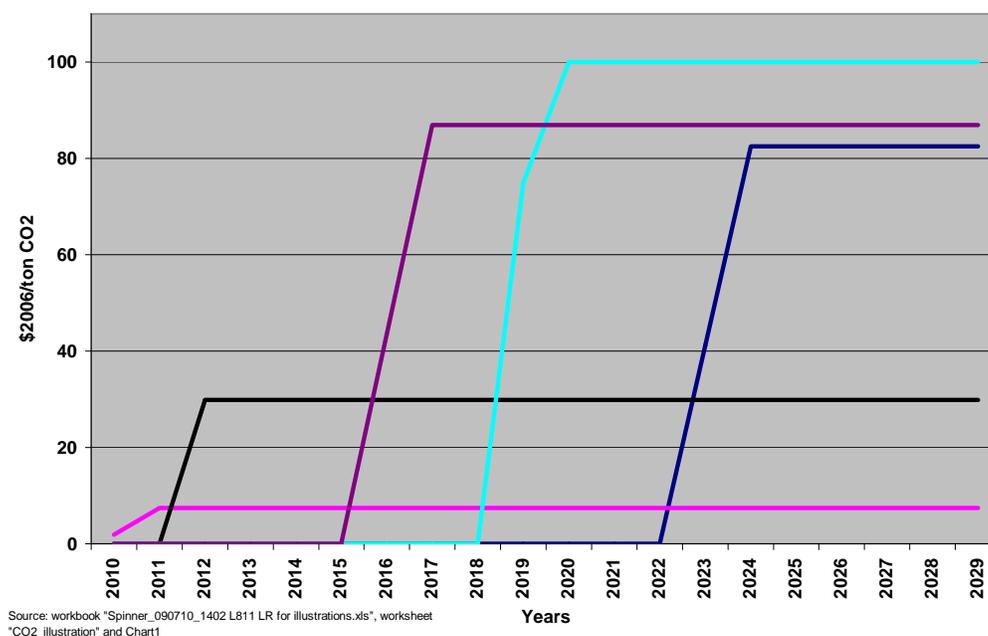
It is unlikely that reduction in carbon dioxide production can be achieved without cost. Consequently, future climate-control policy can be viewed as a cost risk to the power system of uncertain magnitude and timing. A cap and trade allowance system appears to have been a successful approach to controlling sulfur oxides and may be used again for CO₂ production control. Alternatively, a carbon tax has the benefit of simpler administration and perhaps fewer opportunities for manipulation. It is also unclear where in the carbon-production chain – the source, conversion, or use – a control policy would be implemented. It is unclear what share of total carbon production the power-generation sector would bear or what would be done with any revenues generated by a tax or trading system. It is unclear which ratepayer sector will pay for which portion of any costs associated with a control mechanism.

The Council's scenarios use a fuel carbon-content tax as a proxy for the cost of CO₂ control, whatever the means of implementation. When considered as an uncertainty, scenarios represent carbon-control policy as a penalty (dollars per ton CO₂) associated with burning natural gas, oil, and coal.

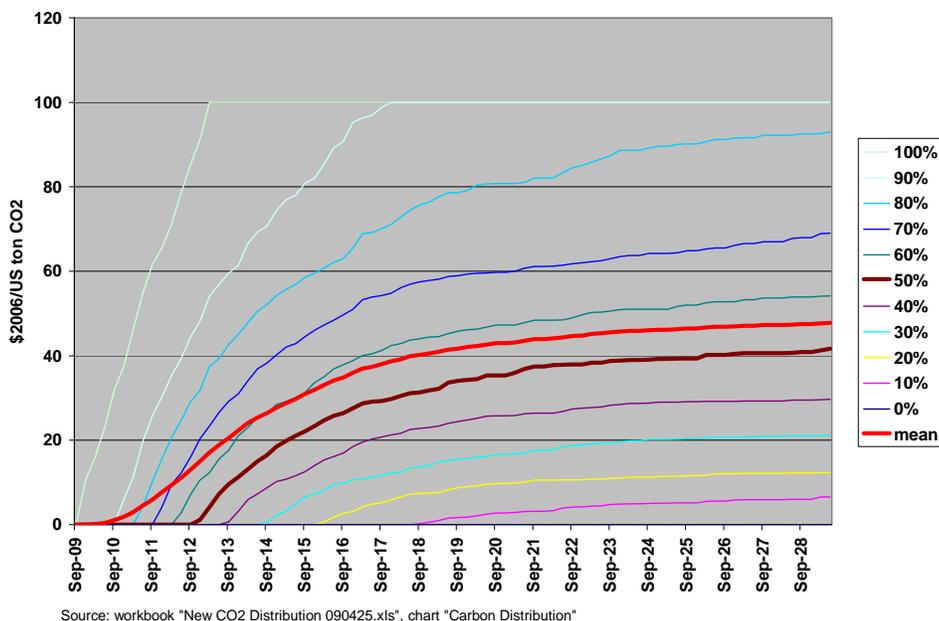
The model keeps track separately of the two costs that arise from a carbon tax. There is a cost associated with any revenues generated by the tax. There is also a cost associated with alternative dispatch of resources. Separate accounting facilitates evaluation of the effects of a tax independent of assumptions regarding the use of the tax revenues.

Each carbon-penalty future is a step up to a random value, selected by the model, where it remains until the end of the study period (Figure 9-8 illustrates the penalty in a small handful of futures). The progression of carbon penalty over time is unlikely to resemble any of these futures. Nevertheless, using a large number of futures should provide a fair idea of the risk associated with most paths.

Figure 9-8: Samples on Individual CO₂ Penalty Futures



In the Council's carbon-risk scenarios, a carbon penalty can arise at any time. The modeled probability of such a penalty being enacted at some time during the forecast period is 95 percent. If a penalty is enacted, its value is selected from a uniform distribution between zero and \$100 per ton (in 2006 dollars). The resulting probability of finding a carbon penalty at or below various levels in each period appears in Figure 9-9. The distribution indicates an even likelihood of seeing some positive carbon penalty around 2012. This assumption, recommended by the Council's Generation Resource Advisory Committee and adopted by the Council's Power Committee, is responsible for the shape of the distribution. The mean of the distribution over all futures rises gradually to about \$47.50/ton of CO₂ by the June – August 2029 quarter. As discussed in Chapter 11, the distribution corresponds to the range of outcomes that EcoSecurities, Ltd., estimated for the Council.

Figure 9-9: Deciles for Carbon Penalty

Preliminary analyses evaluated alternative carbon-penalty distributions. Reducing the penalty in each future by half results in substantially the same resource plan for the first decade of the scenario as does the zero to \$100 distribution.

There are mechanisms in addition to carbon penalties and trading programs to meet carbon-emission objectives. Scenarios considered displacement of existing resources with new renewables or more-efficient gas-fired plants. The Council also evaluated direct curtailment and retirement of existing coal-fired plants. The Council has not taken a position in favor of any particular approach to carbon reduction. Rather, the plan provides information and analysis on alternative approaches. Results of this analysis appear in Chapter 10.

Plant Availability

Power plants are not perfectly reliable, and forced outages are an important source of uncertainty. The analysis includes simulation of forced outages based on typical forced-outage rates for the generating technologies considered.

Renewable Energy Production Incentives

The production tax credit and its companion Renewable Energy Production Incentive were originally enacted as part of the 1992 Energy Policy Act. The intent was to commercialize wind and certain biomass technologies. Congress has repeatedly renewed and extended them.

The longer-term fate of these incentives is uncertain. The original legislation contains a provision for phasing out the credit as the costs of qualifying resources become competitive. Moreover, federal budget constraints eventually may force reduction or termination of the incentives.

In the model, two events influence the value of the production tax credit over the 20-year study period. The first event is termination due to cost-competitiveness. The likelihood of termination peaks in about five years in the Council's model. The model provides, however, for the possibility of the credit remaining indefinitely or expiring immediately. The second event that modifies the credit in the Council's model is the advent of a carbon penalty. The value of the credit following introduction of a carbon penalty depends on the magnitude of the carbon penalty⁵.

The Council did not want any reduction in the value of the production tax credit to exceed the advantage afforded renewables by a CO₂ penalty. Such an outcome would be contrary to the likely intent of a CO₂-control policy. This concern determines the value of the production tax credit in the model due to the magnitude of any carbon penalty that arises in a given future.

Production tax credits amounted to \$15 per megawatt hour when first adopted and have escalated with inflation. The current value for wind, closed-loop biomass, and geothermal is \$21 per megawatt hour. Investors receive credits only for the first 10 years of project operation. Council modeling scenarios use real, levelized values, however. The levelized value over a 20-year economic life would be about \$9.10 in 2006 dollars.

Renewable Energy Credits

Power from renewable-energy projects currently commands a market premium, which can be unbundled from the energy and traded separately as renewable energy credits (RECs). REC value varies by resource and over time, like most commodities. This value reduces the cost of the power source if sold. In the Council's model, REC value varies in a manner similar to other commodities and differs by future.

The Council models the Montana, Oregon, and Washington Renewable Portfolio Standards (RPS). The RPS regulations of these states require an obligated utility to retain the REC associated with the power produced by the utility's renewable resource. That is, the utility cannot buy or build qualifying renewable power and then sell or trade the REC separately. While obligated utilities may sell RECs associated with resource surplus to their requirements, they may also bank the energy to meet future RPS needs. If this makes economic sense, the utility would also not sell the REC.

OTHER ASSUMPTIONS

This section discusses assumptions that are not treated explicitly as uncertainties. These assumptions include those about the treatment of renewable portfolio standard (RPS) resources,

⁵ If the carbon penalty is below half the initial value of the PTC, the full value of the PTC remains. If the carbon penalty exceeds the value of the PTC by one-half, the PTC disappears. Between 50 percent and 150 percent of the PTC value, the remaining PTC falls dollar for dollar with the increase in carbon penalty. The sum of the competitive assistance from PTC and the carbon penalty is constant at 150 percent of the initial PTC value over that range. The conversion of carbon penalty (\$/US short ton of CO₂) to \$/MWh is achieved with a conversion ratio 1.28 #CO₂/kWh. This conversion ratio corresponds to a gas turbine with a heat rate of 9000 BTU/kWh. The Fifth Power Plan, which uses the same approach, has additional explanation and details.

conservation, independent power producers, recent resource additions to the existing system, and the treatment of flexibility and capacity requirements.

The plan discusses some assumptions thoroughly in other chapters or in the appendices. Consequently, their description does not appear in this chapter. In particular, Chapter 7 describes the treatment of transmission in Council analysis. Resources in the model include the cost of any incremental transmission required and the impact of transmission energy losses. Transmission constraints do not appear explicitly in the model. It is assumed that resources that do not have additional transmission cost can be located such that additional transmission is unnecessary. Finally, the model uses a 5-percent discount rate to equate costs occurring at different times, and this value is derived in Appendix N.

Existing Renewable Portfolio Standard Resources

Table 9-1 lists the 1,050 average megawatts of existing renewables. The table includes about 2,634 megawatts of wind that the region has completed or will soon complete. When evaluating the potential for wind generation in the region, this quantity – which is not included in any specification of new resource capability the model may select – must be considered.

Table 9-1: Base of RPS Resources

Project	Capacity (MW)	Service Year	Resource	Load	CA	MT	OR	WA
Biglow Canyon Ph I	125.4	2007	Wind	PGE			100%	
Biglow Canyon Ph II	149.5	2009	Wind	PGE			100%	
Broadwater	10.0	1989	Hydro	NWE		100%		
Clearwater Hatchery (Dworshak)	2.9	2000	Hydro	BPA			22%	78%
City of Albany (Vine St)	0.5	2009	Hydro	PAC	4%		74%	22%
Coffin Butte 1 - 5	5.2	1995	Biomass	Consumers			100%	
Combine Hills I	41.0	2003	Wind	PAC	4%		74%	22%
Condon	49.8	2002	Wind	BPA			22%	78%
DeRuyter Dairy	1.2	2007	Biomass	PAC	4%		74%	22%
Douglas County Forest Products	3.2	2006	Biomass	PAC	4%		74%	22%
Dry Creek Landfill	3.2	2007	Biomass	PAC	4%		74%	22%
Echo	44.6	2009	Wind	PAC	4%		74%	22%
Farm Power (Rexville)	0.8	2009	Biomass	PSE				100%
Foote Creek (BPA)	16.8	2000	Wind	BPA			22%	78%
Foote Creek (EWEB)	8.3	1999	Wind	EWEB			100%	
Foote Creek (PAC)	33.1	1999	Wind	PAC	4%		74%	22%
Freres Lumber	10.0	2007	Biomass	PAC	4%		74%	22%
Georgia-Pacific (Camas)	52.0	1995	Biomass	PAC	5%		95%	0%
Georgia-Pacific (Wauna)	27.0	1996	Biomass	BPA			100%	0%
Goodnoe Hills	94.0	2008	Wind	PAC	4%		74%	22%
H.W. Hill (Roosevelt Biogas) 1 - 5	10.5	1999	Biomass	Klickitat				100%
Hampton Lumber	7.2	2007	Biomass	Snohomish				49%
Harvest Wind	98.9	2009	Wind	Various			20%	80%
Hay Canyon	100.8	2008	Wind	Snohomish				100%
Hopkins Ridge	150.0	2005	Wind	PSE				100%
Judith Gap	135.0	2006	Wind	NWE		100%		
Klondike I	24.0	2001	Wind	BPA			22%	78%
Klondike II	75.0	2005	Wind	PGE			100%	
Klondike III (BPA)	50.0	2007	Wind	BPA			22%	78%
Klondike III (EWEB)	25.0	2007	Wind	EWEB			100%	
Klondike III (PSE)	50.0	2007	Wind	PSE				100%
Leaning Juniper	100.5	2006	Wind	PAC	4%		74%	22%
Marengo I	140.4	2007	Wind	PAC	4%		74%	22%
Marengo II	70.2	2008	Wind	PAC	4%		74%	22%
Martinsdale (Two Dot)	2.8	2004	Wind	NWE		100%		
McNary Dam Fish Attraction	7.0	1997	Hydro	N. Wasco			50%	
Nine Canyon	63.7	2002	Wind	COU				100%
Portland Habilitation	0.9	2008	PV	PGE			100%	
ProLogis	1.1	2008	PV	PGE			100%	
Puyallup Energy Recovery Company (PERC) 1 - 3	2.8	1999	Biomass	PSE				100%
Qualco	0.5	2008	Biomass	Snohomish				100%
Rock River I	50.0	2001	Wind	PAC	4%		74%	22%
Rough & Ready Lumber	1.2	2007	Biomass	PAC	4%		74%	22%
Round Butte	339.0	1964	Hydro	PGE			15%	
Short Mountain 1 - 4	2.5	1993	Biomass	Emerald			100%	
Sierra Pacific (Aberdeen)	10.0	2003	Biomass	Grays Harbor				56%
Sierra Pacific (Fredonia)	28.0	2007	Biomass	SMUD, SCL	82%			11%
South Dry Creek	1.8	1985	Hydro	NWE		100%		
Stahlbush Island Farms	1.6	2009	Biomass	PAC			100%	
Stateline (AVA)	35.0	2001	Wind	AVA				100%
Stateline (BPA)	90.0	2001	Wind	BPA			22%	78%
Stateline (SCL)	175.0	2001	Wind	SCL				100%
Tiber-Montana	6.0	2004	Hydro			100%		
Tieton	13.6	2006	Hydro	EWEB			100%	
Two Dot	0.9	2004	Wind	NWE		100%		
Vansycle Wind Energy Project	24.9	1998	Wind	PGE			100%	
Weyerhaeuser (Springfield) 4 (WEYCO)	25.0	1975	Biomass	EWEB			100%	
Wheat Field	96.6	2009	Wind	Snohomish				100%
White Creek (Benton PUD)	3.0	2007	Wind	Benton PUD				100%
White Creek (Cowlitz)	94.0	2007	Wind	Cowlitz				100%
White Creek (Emerald)	15.0	2007	Wind	Emerald			100%	
White Creek (Franklin)	10.0	2007	Wind	Franklin				100%
White Creek (Klickitat)	53.0	2007	Wind	Klickitat				100%
White Creek (Lakeview)	2.0	2007	Wind	Lakeview				100%
White Creek (Snohomish)	20.0	2007	Wind	Snohomish				100%
White Creek (Tanner)	4.0	2007	Wind	Tanner				100%
Wild Horse Wind	228.6	2006	Wind	PSE				100%
Wild Horse Expansion	44.0	2009	Wind	PSE				100%
Wolverine Creek	64.5	2005	Wind	PAC	4%		74%	22%

Source: "Plan 6\Power Plan Documents\Chapter 9 DevStrategy (previously chapter 8)\Renewables for the RPS.xls"

Forced-in Renewable Portfolio Standard (RPS) Requirements

Montana, Oregon, and Washington, like many other western states, have legislated goals that obligate utilities to meet a prescribed portion of their energy loads with renewable generation according to schedules that extend to 2025, in the case of Oregon. When modeled as an uncertainty related to regional load growth, the Council assumes obligated utilities meet 95 percent of their nominal RPS goals. This representation captures the possibility that utilities will face obstacles to meeting their nominal targets. One mechanism, for example, that might give rise to not meeting targets is the “opt-out” provision. This provision in legislation excuses utilities from meeting their targets when meeting the requirements would cause significant rate increases.

Adoption of RPS legislation by other states, in particular California, is expected to affect the region primarily through the expected price of wholesale power. The anticipated change in wholesale electricity prices due to this effect is incorporated in Council modeling, as is the uncertainty around such change.

Renewable resources constructed to meet RPS requirements do not receive a cost reduction due to the sale of renewable energy credits (RECs). When regional utilities acquire renewables to meet their state’s requirements, they must retain any RECs associated with the resource. This has the effect of increasing the cost of the resource relative to what renewable costs would have been had the utility been able to sell the RECs. Utilities, however, may bank RECs that are not used toward meeting RPS requirements. These credits may be applied toward future obligations. States differ in the policy regarding how long RECs may be banked and under what conditions.

Modeling does not include wind or geothermal explicitly when an RPS is assumed. Earlier studies suggest that renewables will not be constructed for economic reasons earlier than or in greater quantity than required by these standards. In scenarios that assume RPS requirements disappear, wind and geothermal are available for the model to select.

Figure 9-10 provides an example of how existing RPS resources, banked RECs, and new RPS resources play out for one state under a particular future. This particular example is for the state of Oregon. Obligated utilities’ target portions of energy sales, after conservation, comprise the heavy, dotted line at the top of the graph. Targets are specified only in a handful of years, so targets for other years are interpolated. Next, it is assumed that obligated utilities achieve only 95 percent of target amounts. The next line down reflects that assumption. Resources that currently qualify for renewable energy credits are illustrated in dark green.

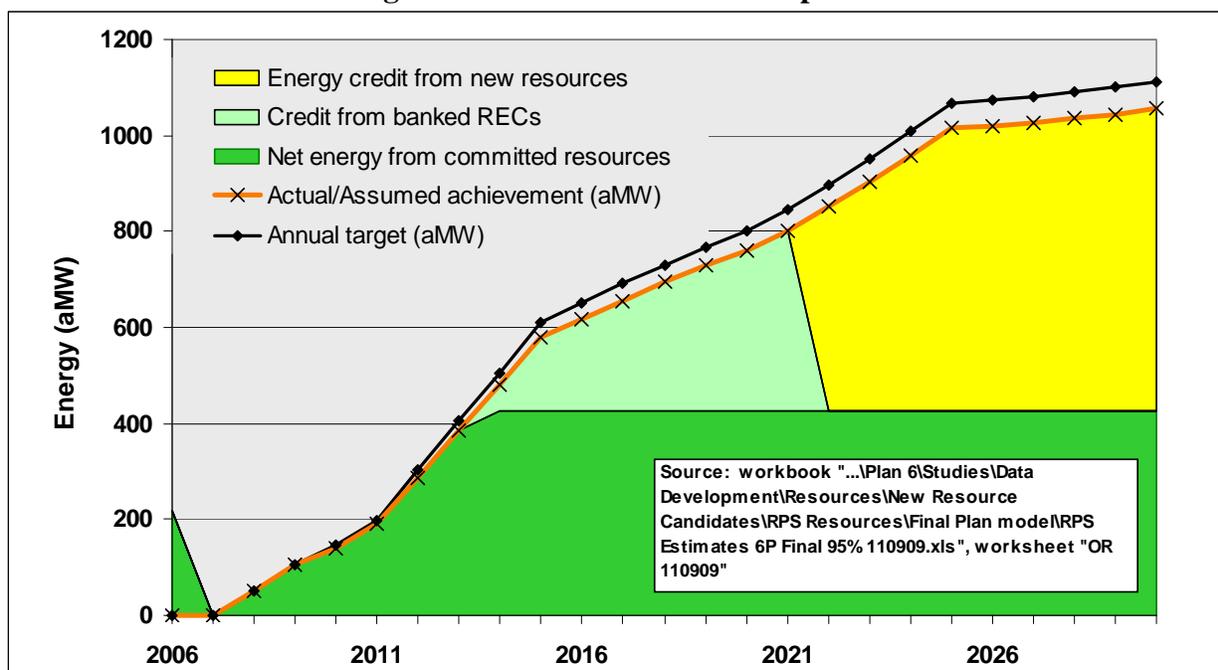
Based on the current level of RPS development and state policy, credit balances are calculated. In Oregon, credits do not expire. Renewable energy credit balances for Washington and Montana must be updated every year to account for expiring credits, and these two states have different requirements regarding the how soon credits expire. It is assumed that if credits would expire quickly and would not be used, they are sold to offset the cost of the resource.

The light green area corresponds to banked renewable energy credits. While RECs do not expire in the case of Oregon, they do get used. RECs are denominated in megawatt-hours. This means that once a REC is used to meet a megawatt-hour of customer energy load in some year, it goes away. Consequently, the light green area ends when energy produced by utility renewable

resources is insufficient to meet the RPS energy target and Oregon utilities have used up their banked credits.

The energy corresponding to this net requirement, after banked credits are used up, is illustrated in yellow. This energy is assumed to be largely wind but also geothermal, biomass, small hydro, and photovoltaic solar. Because the energy is dominated by wind, wind operating and construction costs are used for new renewables. These costs are subject to the same construction cost uncertainty as are wind generation resource modeled without RPS requirements. The new resources are also expected to have value derived from sale in the wholesale power market, whereas credits have no associated cost or value of this sort.

Figure 9-10: RPS Source Development



Conservation from New Programs, Codes, and Standards

Conservation due to existing codes and standards is incorporated in the Council's load forecast. An example of such a code is the mandated conversion to energy-efficient lighting throughout the nation beginning in 2012. Such conservation is excluded from programs that the model may select going forward. New conservation is subject to severe constraints on development in the model early in the scenario period. Full penetration of lost-opportunity conservation is assumed to develop slowly over the next decade.

A large amount of discretionary conservation, however, exists at prices far below the current wholesale power price. Left unconstrained, the model would add as much as 2,000 average megawatts of this conservation immediately. While difficult to quantify, utilities have budget constraints that, given no other consideration, would significantly limit how quickly the region can acquire this conservation. The Council, with the guidance of the Conservation Resource Advisory Committee and the Regional Technical Forum, chose a rate of acquisition that it

considers aggressive but achievable: development of discretionary conservation at the rate of 160-average-megawatts-per-year. These constraints are discussed in Chapter 4 and Appendix E.

Independent Power Producers' (IPP) Resources

Independent power producers provide depth to wholesale markets but do not mitigate regional ratepayer costs or risks. IPP plants not currently under contract provide energy for the regional wholesale market. The IPP owners, however, receive the benefits of any energy sold, not the region. There are about 3,335 megawatts of IPP generating capacity currently not under contract to regional utilities. This generation does not have firm transmission access to markets outside the region. The amount that is under contract declines over the next few years. A list of the IPP generation modeled in Council scenarios appears in Table 9-2.

Table 9-2: Independent Power Producers

Plant name	Uncommitted share	Project Owner	January Capacity (MW)
Big Hanaford CC1A-1E	100%	TransAlta	233.4
Centralia 1	85%	TransAlta	625.1
Centralia 2	100%	TransAlta	625.1
Grays Harbor Energy Facility (Satsop)	100%	Invenergy (dba Grays Harbor Energy)	611.7
Hermiston Power Project	100%	Calpine, dba Hermiston Power Partners	498.7
Klamath Cogeneration Project	100%	Iberdrola Renewables	451.7
Klamath Generation Peakers 1 & 2	100%	Iberdrola Renewables	47.5
Klamath Generation Peakers 3 & 4	100%	Iberdrola Renewables	47.5
Lancaster (Rathdrum CC)	100%	Cogentrix	264.4
Morrow Power	100%	Morrow Power (Subsidiary of Montsano Enviro Chem Systems)	23.7
Discounted total			3334.9

Source: workbook "Table of IPPs 100118.xls", worksheet Sheet2

New Generating Resource Options

Resources explicitly considered include natural gas combined-cycle gas turbines, natural gas simple-cycle gas turbines, wind-power plants, and gasified coal combined-cycle combustion turbines. A complete list appears in Table 9-3, below.

Table 9-3: New Resource Candidates

- Conservation
 - Discretionary conservation limited to 160 average megawatts per year
 - Phased in up to 85-percent penetration maximum
- CCCT (415 MW) available 2011-2012
- SCCT (85 MW Frame GT) available 2012
- Wind generation (100 MW blocks), 4800 MW available by end of study
 - No REC credit if RPS are assumed in force
 - Costs includes any production tax credit, transmission, and firming and integration costs
- Geothermal (14 MW blocks) available 2011, 424 MW (382 MWa) by end of study
- Woody biomass (25 MW), available 2014, 830 MW by end of study
- Advanced nuclear (1,100 MW), available 2023, 4,400 MW by end of study

- Supercritical pulverized coal-fired power plants (400 MW), available 2016
- Integrated Gasified Combined-Cycle combustion (518 MW) available 2023, with carbon capture and sequestration
- Wind imported from Montana, with new transmission, available 2011, 1,500 MW by end of study
- Five classes of demand response, 2,000 MW available by end of study, 1,300 MW of this limited to 100 or fewer hours per year of operation

As mentioned in the discussion of existing renewable portfolio standard resources, resources that have a very good chance of completion are included in the base level of resources. This includes certain other thermal resources having high probability of completion. They are not modeled explicitly as new resources.

Table 9-4 shows relatively new resources that are not listed in Table 9-1.

Table 9-4: Recent Construction

project	capacity (MW)	fuel type	in-service month
Arrowrock 1 - 2	15	Hydro	Jun 2010
Bettencourt Dry Creek Dairy	2.25	Biomass	Sep 2008
Big Sky Dairy	1.42	Biomass	2009
Cassia	29.4	Wind	Feb 2009
Danskin (Evander Andrews) CT1	170	Natural gas	Jun 2008
Double A Dairy	4.26	Biomass	2009
Flathead County Landfill	1.6	Biomass	April 2009
Grays Harbor Energy Facility (Satsop)	650	Natural gas	Jul 2008
Mill Creek Generating Station	150	Natural gas	Dec 2010
Mint Farm	319	Natural gas	Jan 2008
Mountain Home	42	Wind	Sep 2008
Raft River I	15.8	Geothermal	Jan 2008

In order to keep the analysis manageable, only new resources that are found to be cost-competitive and of significant potential⁶, or required by law, are considered in the model. The regional portfolio model evaluates large numbers of possible portfolios under many scenarios and requires several computers and significant time to develop a portfolio. The number of generation resources in the model affects the time required for a study. Consequently, small amounts of new micro-hydropower generation, solar thermal, and other smaller sources are assumed to be captured under renewable portfolio standards in the states.

System Flexibility and Capacity Requirements

Energy balance is central to economic risk and has been the focus of Council risk assessment. Regional power crises of the past were associated with energy shortages and surpluses. Examples include the hydropower generation insufficiency of the early 1970s and the 2000-2001 West Coast energy crisis. Overbuilding thermal power plants in the late 1970s and the unprecedented rate increases and financial failures that ensued illustrate the dangers of overbuilding.

⁶ The cutoff for consideration is around 300 MW of cost-effective potential by 2030.

The power system has other requirements, however. Power system balance on the sub-hourly level is critical to integration of wind and other variable resources. Without providing for system peaking and flexibility requirements, the region risks forgoing resources that can reduce energy risk. Chronic shortages in the special-purpose markets for resources that meet these requirements may result, or the power system otherwise may become inefficient.

In modeling wind power, an additional integration and firming cost is added to that of direct wind-turbine costs. The model does not include any additional resources that may be required to provide these services. Currently, it is unclear how much, or even whether, incremental generation resources may be required for this purpose. The action plan of this power plan supports work underway by the regional Wind Integration Forum to evaluate those requirements.

The model uses economics to evaluate peaking requirements and contribution. The model can discern economic value that arises from hourly events, such as forced outages. Economic value determines whether the model will build a power plant. Any value beyond that necessary to cover plant costs lowers the system cost, so the model would choose to add it. Traditional reliability and adequacy assessments of capacity requirements ignore fuel prices or operation costs. It is assumed that if the region needed capacity to meet an unforeseen circumstance, fuel price would not be an issue. If prices *were* considered, however, very high electricity prices would result. Of significance here is that the model would build more resources in this situation specifically to avoid exposure to these high prices.

Moreover, the Council relies on metrics that the regional adequacy forum has adopted. This forum, a consortium of utilities, regulators, and customers, has produced deterministic energy and capacity load-resource balance standards that incorporate much of what the region has learned about resource adequacy.

The model incorporates the forum's annual energy metric directly into resource-selection decisions. If a planned resource would not be constructed because the model forecasts that the resource would not be economic, the model forecasts the region's needs according to the forum's energy balance standard. If the calculation indicates the region is in danger of resource inadequacy, construction of the least-cost, planned resource continues.

Finally, any plans the model produces that the Council would recommend are compared to the forum's energy and capacity standards. Experience has shown, however, that economic adequacy produces plans that meet energy adequacy and peaking requirements. The plan addresses flexibility further in Chapter 12.

Chapter 10: Resource Strategy

Key Findings.....	1
A Resource Strategy for the Region	1
Summary	1
Planning Scenarios.....	2
Scenarios	3
Improved Efficiency	4
Renewable Generation	7
Natural Gas-Fired Generation.....	9
Improving, Expanding, and Preserving the Existing Power System	10
Develop Long-Term Resource Alternatives	11
Value of the resource strategy.....	11
Carbon Emissions	20
Response to Risk.....	20
Achieving Carbon-Reduction Targets	23
Value of the Hydroelectric System.....	27

KEY FINDINGS

The resource strategy for the Sixth Power Plan relies on conservation, renewable generation, and natural gas-fired generation. In addition, the region needs to better utilize, expand, and preserve its existing electric infrastructure and research and develop technologies for the long-term improvement of the region’s electricity supply. Scenario analysis showed that the electric power sector of the region could meet its share of carbon emission-reduction targets similar to those adopted by some states and proposed in national legislative initiatives through three primary actions: achieving the conservation targets in the Council’s plan, meeting existing renewable-energy portfolio standards, and reducing the use of the existing coal plants by about half.

A RESOURCE STRATEGY FOR THE REGION

The Council’s resource strategy for the Sixth Power Plan provides guidance for Bonneville and the region’s utilities on choices of resources that will supply the region’s growing electricity needs while reducing the risk associated with uncertain future conditions. The strategy minimizes the costs and risks of the future power system. The timing of specific resource acquisitions is not the essence of the strategy. The timing of resource needs will vary for every utility. The important message of the resource strategy is the nature of the resources and their priorities.

Summary

The resource strategy is summarized below in six elements. The first three are high-priority actions that should be pursued immediately and aggressively. The longer-term actions must be more responsive to changing conditions in order to provide an array of solutions to meet the long-term needs of the regional power system. The last element recognizes the adaptive nature of the power plan and commits the Council to regular monitoring of the regional power system to identify and adjust to changing conditions.

- **Efficiency:** The region should aggressively develop conservation with a goal of acquiring 1,200 average megawatts by 2014, and 5,900 average megawatts by 2030. Conservation is by far the least-expensive resource available to the region and it avoids risks of volatile fuel prices, financial risks associated with large-scale resources, and it mitigates the risk of potential carbon pricing policies to address climate-change concerns.
- **Renewables:** Increasing development of renewable generation is necessary to meet existing renewable portfolio standards. On average, the renewable resources developed to fulfill state RPS mandates will contribute 1,450 average megawatts of energy, or 4,500 megawatts of installed capacity. Most of the recent renewable development has been wind, and that is assumed to be the primary source of renewable energy in the immediate future. However, power production from wind projects creates little dependable peak capacity and increases the need for within-hour balancing reserves. The resource strategy encourages the development of other renewable alternatives that may be available at the local, small-scale level and are cost-effective now. The strategy also encourages research on and demonstration of different sources of renewable energy for the future.
- **Natural Gas:** Natural gas-fired generation is likely to be needed to supplement efficiency and renewable resources depending on load growth and the possible need to displace coal use to meet carbon-reduction goals. Even if the region has adequate resources, individual utilities or areas may need additional supply for capacity or wind integration. In these instances, the strategy relies on natural gas-fired generation to provide energy, capacity, and ancillary services.
- **Infrastructure Operation and Investment:** Strong emphasis should be placed on improving wind scheduling and system operating procedures as cost-effective and achievable initial steps for the purpose of wind integration. In addition, the region needs to invest in its transmission grid to improve market access for utilities and to facilitate development of more diverse cost-effective renewable generation.
- **Future Resources:** In the long term, the Council encourages the region to expand its resource alternatives. The region should explore additional sources of renewable energy, improved regional transmission capability, new conservation technologies, new energy-storage techniques, carbon capture and sequestration, smart-grid technologies and demand-response resources, and new or advanced low-carbon generating technologies, including advanced nuclear energy. Research, development, and demonstration funding should be prioritized in areas where the Northwest has a comparative advantage or unique opportunities.
- **Adapting to Change:** The Council will regularly assess the adequacy of the regional power system to guard against power shortages, identify departures from planning assumptions that could require adjustments to the plan, and help ensure the successful implementation of the Council's Columbia River Basin Fish and Wildlife Program.

Planning Scenarios

The resource strategy is based on analysis of several scenarios. The discussion of the elements of the resource strategy draws on those scenarios so some introduction to the scenarios and their

findings is needed. The bullets below summarize eight scenarios, or studies, that help determine the resource strategy.

Scenarios

- **Carbon Risk** - The carbon-risk scenario is intended to explore what resources result in the lowest expected cost and risk given current policy plus the risk that additional carbon reduction policies will be implemented. It includes a range of carbon prices from zero to \$100 per ton, which average to \$47 per ton by 2030. Specific numbers for average resource development in the resource strategy are taken from this scenario. It is designed to represent the current state of uncertainty about future carbon pricing policies and develop a responsive resource strategy.
- **Current Policy** - The current-policy scenario includes current policies such as renewable portfolio standards, new plants emissions standards, and renewable energy credits, but it does not assume any carbon pricing in the future. It helps identify the effect of carbon pricing risk when added to existing policies.
- **No Policy** - The no-policy scenario removes current policies from the analysis in addition to assuming no future carbon pricing risk. It does, however, assume that the renewable energy credit market will continue to operate. This scenario permits isolation of the effects of current policy.
- **No RPS** - This scenario includes future carbon-pricing risk, but the renewable portfolio standards are removed. Renewable energy credits are included. One can compare the cost-effectives of renewable generation to other responses to carbon emissions pricing risk by comparing this scenario to others.
- **\$45 Carbon** - The \$45-carbon price scenario is designed to achieve the carbon-emission reduction targets in proposed legislation. Instead of uncertain carbon prices from zero to \$100, a fixed price of \$45 is assumed starting in 2010.
- **Coal Retirement** - This scenario, like the \$45-carbon scenario, is designed to achieve a particular carbon-emissions reduction target. About half of the existing coal-fired generation in the region is phased out between 2012 and 2019. This scenario is done with and without carbon-pricing risk. In the without-carbon-pricing version, fewer coal plants are retired.
- **No Conservation** - This scenario assumes that no conservation is available to meet future electricity needs or reduce carbon emissions. Carbon pricing risk is included, as are current policies. This scenario allows estimation of the role of conservation in reducing carbon emissions and the effect of conservation on cost and risk in the face of carbon-pricing uncertainty.
- **Lower Snake Dam Removal** - This scenario explores the cost and carbon impacts that would occur if the four lower Snake River dams were no longer available to meet regional power needs. Carbon pricing risk is included as well as current policies.

Results of these studies are compared in the discussion of the elements of the resource strategy, and more detailed comparison of their results appears in the later in the chapter.

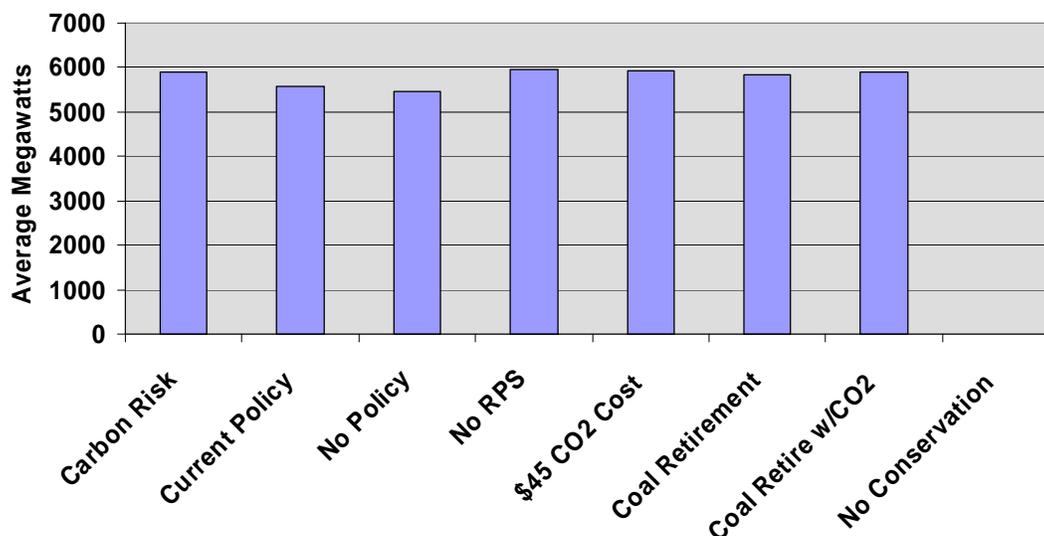
Improved Efficiency

The dominant new resource in the Sixth Power Plan resource strategy is improved efficiency of electricity use, or conservation. The attractiveness of improved efficiency is due to its relatively low cost and the absence of major sources of risk. Conservation costs half of alternative generating resources and lacks the risk associated with volatile fuel prices and potential carbon policies. It also has short lead time and is available in small increments, both of which reduce risk. Therefore, improved efficiency reduces both the cost and risk of the resource strategy.

Energy efficiency has been important in all previous Council power plans. The region now has a long history of experience improving efficiency. Since the Northwest Power Act passed, the region has developed nearly 4,000 average megawatts. That makes efficiency the fourth-largest source of electricity in the region following hydroelectricity, natural gas, and coal.

The average levelized cost of the efficiency developed in the resource strategy is \$36 per megawatt-hour. The comparable estimated cost of a natural gas-fired combined-cycle combustion turbine is \$92 per megawatt-hour, and Columbia Basin wind costs \$104 per megawatt-hour. Improved efficiency also costs less than the forecast market price of electricity. In the Council's analysis, extra resources are added to provide insurance against future uncertainties. Efficiency improvement provides attractive insurance for this purpose because of its low cost. In futures or time periods when the extra resources are not needed, the energy and capacity can be sold in the market and their cost more than recovered.

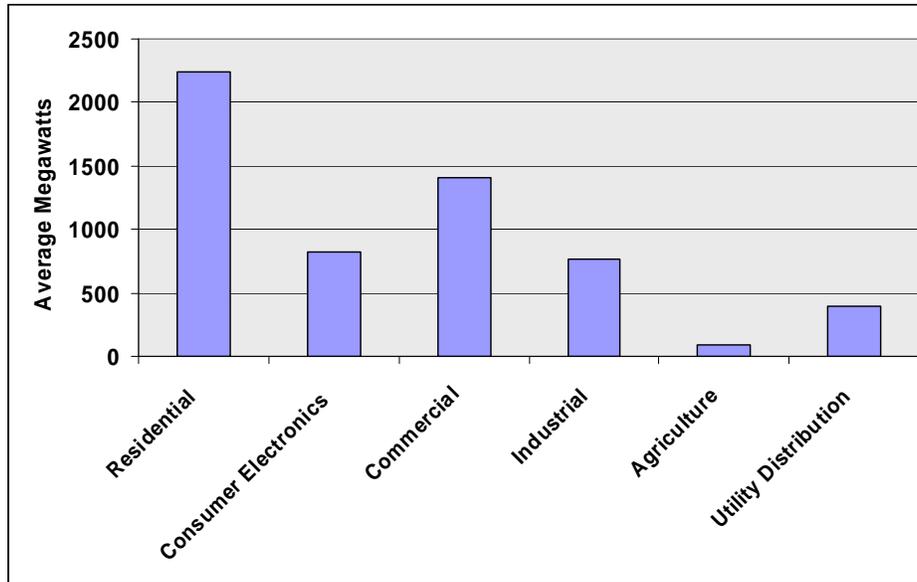
One result of these characteristics is that in all of the scenarios examined by the Council, both in the draft and the final power plan, similar amounts of improved efficiency are found to be cost-effective. Its role does not depend significantly on whether or not carbon policies are enacted. Figure 10-1 shows the amount of efficiency acquired in various scenarios considered by the Council in the power plan. In all scenarios except the no-conservation scenario, the amount of efficiency averages between 5,500 and 6,000 average megawatts. The amount of conservation developed varies in each future considered in the regional portfolio model. For example, in the carbon-risk scenario, while the average conservation development is 5,900 average megawatts, individual futures can vary from as low as 5,300 average megawatts to as high as 6,600 average megawatts.

Figure 10-1: Cost-Effective Conservation Resources

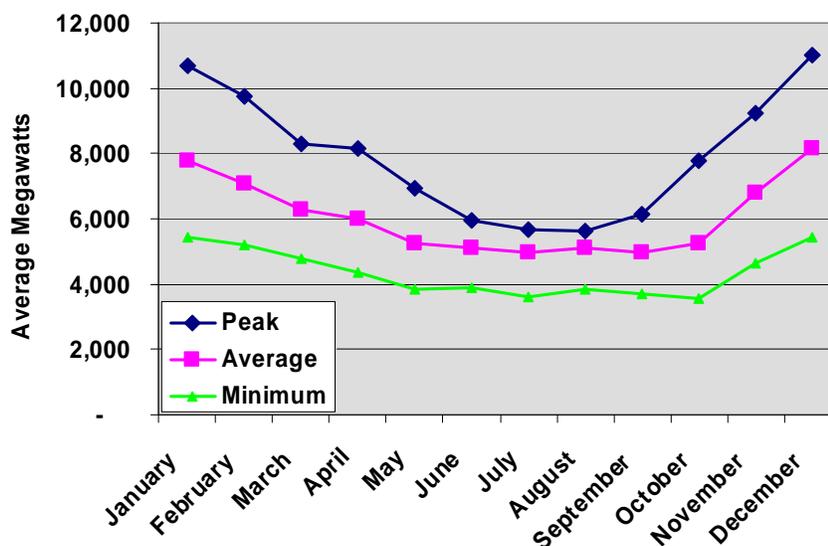
Developing the amount of efficiency included in the carbon-risk scenario is estimated to cost the regional power system \$15 billion over 20 years¹. The addition of a comparable amount of gas-fired generation would cost \$62 billion. The nature of efficiency improvement is that the total cost is recovered over a smaller number of sales. Average cost per kilowatt-hour sold will increase, but because total consumption is reduced, average consumer electricity bills will be smaller. Consumers who choose not to improve their efficiency of use could see their bills increase. However, if the region does not capture the efficiency, the higher cost of new generating resources will increase everyone's bills.

The amount of efficiency included in the Sixth Power Plan is significantly higher than in previous Council plans. For example, in the Fifth Power Plan cost-effective efficiency was 2,500 average megawatts compared to 5,900 megawatts in the sixth plan. To a large extent, this increase is the result of changing technology that has created new efficiency opportunities and reduced costs. The Council has identified significant new efficiency opportunities in all consuming sectors. Also important are the increased cost of generating alternatives and the risk of increased carbon regulations. Figure 10-2 shows how efficiency improvements are located in various consuming sectors. Additional information on the sources and costs of efficiency improvements is provided in Chapter 4 and Appendix E of this plan.

¹ About \$6 billion of this amount is already in utility costs as currently expensed conservation. The additional cost to be recovered is therefore \$9 billion over 20 years.

Figure 10-2: Cost-Effective Efficiency Potential by Sector

Improved efficiency contributes not only to meeting future energy requirements, but also provides capacity during peak load periods. The savings from conservation generally follow the hourly shape of energy use, saving more energy when more is being used. As a result, efficiency contributes more to load reduction during times of peak usage. Or in other words, efficiency improvements have capacity value, as well as energy value. The Council has built up the shape of efficiency savings from the hourly shape of individual end uses of electricity and the cost-effective efficiency improvements in those uses. Figure 10-3 shows the monthly savings of average energy, peak-hour capacity, and minimum-hour loads in 2030 based on 5,900 average annual megawatts of efficiency. The savings from efficiency actions in the Sixth Power Plan are highest in winter. For example, efficiency improvements that yield average annual savings of 5,900 average megawatts create 8,000 average megawatts of savings during December. The average capacity savings over the December 18-hour sustained peaking period is about 9,300 megawatts. Savings in the peak hour of December are 10,700 megawatts.

Figure 10-3: Monthly Shape of 2030 Efficiency Savings

As a comparison, the Council explored the effects of having no efficiency improvements available. A scenario was run based on the carbon-risk scenario but with no new efficiency improvements available. The resulting resource strategy was increased in cost, risk, and carbon emissions. Present value system cost increased 24 percent, from \$63.9 billion (2006\$) to \$87.8 billion. In addition, increased carbon taxes would be collected. The tax increase is due to an increase of carbon emissions from 39.7 million tons per year to 57 million tons per year. The efficiency gains are replaced by a combination of increased use of existing natural gas and coal-fired generation, new gas-fired generation, reduced net exports of electricity, and a substantial increase in renewable generation due to increased electricity sales. Another way of describing the effects of no efficiency improvements on carbon emissions is that even with carbon taxes averaging \$47 per ton by 2030 and current renewable portfolio standards, carbon emissions would not be reduced, on average, from 2005 levels. The efficiency improvements in the sixth plan resource strategy are a key to reducing carbon emissions.

Renewable Generation

Renewable generating resources are an important part of the resource strategy. Wind in particular has been a focus of recent generation development in the Pacific Northwest. Driven by financial incentives and renewable portfolio standards in three of the four states, the region has added over 3,400 megawatts of nameplate wind capacity since the Council's Fifth Power Plan. This existing wind is estimated to provide about 1,100 average megawatts of energy generation per year, but only provides about 170 megawatts of dependable peaking capability. Wind resources that have ready access to transmission are competitive with other generation alternatives.

Renewable resources currently are modeled as wind or geothermal in the regional portfolio model. The Council recognizes that additional small-scale renewable resources are likely available and cost-effective and the plan encourages their development as an important element of the resource strategy. In addition, there are many potential renewable resources that are

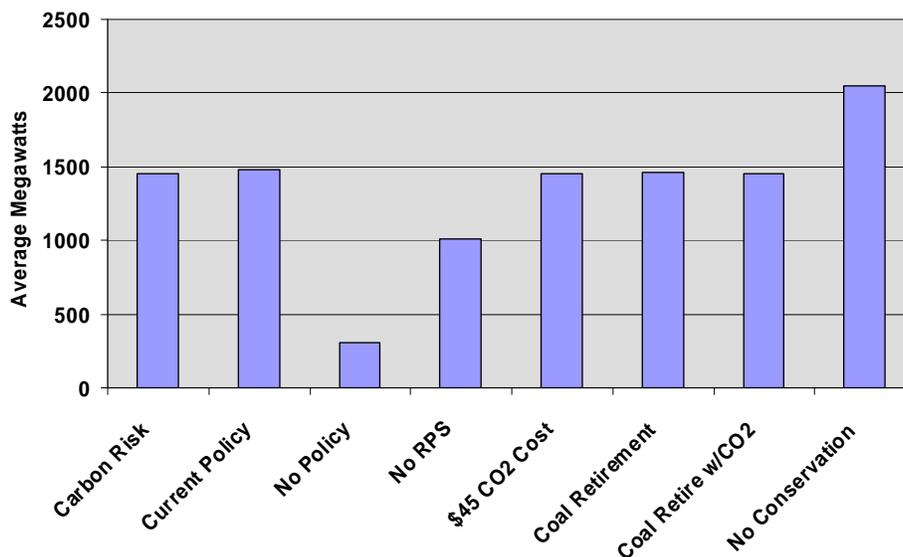
currently either too expensive or unproven technologies that may, with additional research and demonstration, prove to be valuable future resources.

Renewable generation development in the various scenarios is driven by state renewable portfolio standards. The amount of renewable energy acquired depends on the future demand for electricity because state requirements specify percentages of demand that have to be met with qualifying renewable sources of energy. Across the 750 futures of demand growth in the carbon-risk scenario, the amount of wind developed on average is 1,450 average megawatts. In terms of available capacity, that is 4,500 megawatts of installed wind capacity, but only about 225 megawatts of dependable peaking capacity.

Figure 10-4 shows the amount of additional renewable energy acquired on average in the various scenarios studied. The figure does not include the 1,100 average megawatts of existing and committed wind. In scenarios with renewable portfolio standards, the average development of additional wind is limited to 1,450 average megawatts, as required by the standards when the state’s goals are combined. The only exception to this is when no efficiency improvements are assumed. In that scenario, an additional 600 average megawatts of wind is developed to satisfy RPS requirements for the higher electricity sales.

In the two scenarios without renewable portfolio standards, no policy and no RPS, the results are different. In the no-policy scenario, only 311 average megawatts of additional renewable generation is developed. In the no-RPS scenario, which includes the risk of carbon prices between \$0 and \$100 per ton, 1,008 average megawatts of additional renewable generation is developed; about 70 percent of the amount developed in scenarios that include renewable portfolio standards and carbon pricing risk.

Figure 10-4: Renewable Resource Development



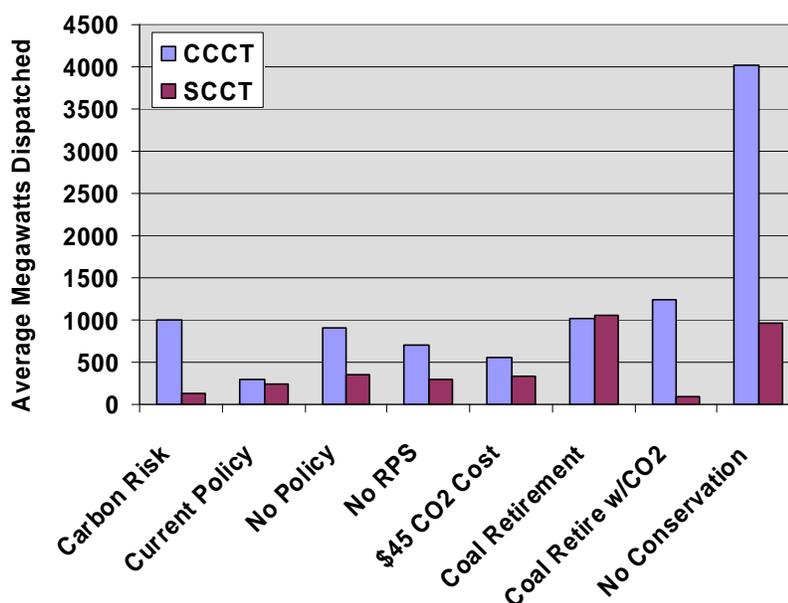
Natural Gas-Fired Generation

Natural gas is the third major resource in the Sixth Power Plan resource strategy. From an aggregate regional perspective, which is the plan's focus, the need for additional natural gas-fired generation is modest in the carbon-risk scenario. However, the role of natural gas may be larger than it appears in the Council's analysis for a number of reasons. The regional transmission system has not evolved as rapidly as the electricity market, resulting in limited access to market power for some utilities. In addition, some utilities have lost contract resources and have rapid load growth presenting them with significant near-term resource challenges. New gas-fired generation may be required in such instances even if the utilities meet their renewable portfolio requirements and develop conservation as rapidly as called for in the plan.

There are two types of natural gas-fired generation considered in the model: simple-cycle turbines (SCCT) that are most suitable for providing peaking capacity, and combined-cycle turbines (CCCT) that can provide base-load energy as well as peaking capacity. The gas-fired plants are optioned (sited and licensed) in the model so that they are available to develop if needed in each future. The resource strategy includes optioning 3,400 megawatts of CCCTs, and 650 megawatts of SCCTs. These options are developed in only a relatively small number of futures. The average build-out of natural-gas fired CCCTs over the 750 futures is 1,000 megawatts. For SCCTs the comparable number is 120 megawatts. In the carbon-risk scenario, the amount of energy actually generated from new CCCTs, when averaged across all 750 futures examined, is 400 average megawatts. For SCCTs the average energy provided is only 20 average megawatts. The contribution of these gas-fired resources would be largest during heavy- and peak-load hours, or in poor water years.

While the amounts of efficiency and renewables were fairly consistent across most scenarios examined, the future role of natural gas-fired generation is more variable and specific to the scenarios studied. Figure 10-5 shows the average amounts of SCCT and CCCT built among the 750 futures considered in each scenario. The actual amount of natural-gas fired generation constructed varies in each future.

The optioning of CCCTs is largest when there is a need for energy. This occurs, for example, in scenarios that feature energy lost from other resources as in the retirement, or decreased use, of existing coal plants or reduced conservation achievements. Among these scenarios not only does the amount of gas-fired resources optioned vary, but the likelihood of completing the plants also varies. The role of SCCT is greater when capacity needs to be replaced. This is prominent in the coal-retirement scenario where capacity from the retired coal plants is lost and in the no-conservation scenario where the capacity value of new conservation is eliminated.

Figure 10-5: Natural Gas-Fired Resource Options

The particular type of natural gas-fired generation built in the future depends significantly on anticipated future conditions. Specific utility needs drive resource choices. For example, individual utilities may find their circumstances include need for within-hour balancing reserves, a system with differing capacity requirements, or limited access to market resources. All of these factors limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas fired resources, or for the types of natural gas-fired generation.

Nevertheless, it is clear that after efficiency and renewables, natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Other resource alternatives may become available over time, and the Sixth Power Plan recommends actions to encourage expansion of the diversity of resources available.

Improving, Expanding, and Preserving the Existing Power System

The existing Northwest power system is a significant asset for the region. The FCRPS (Federal Columbia River Power System) provides low-cost and carbon-free energy, capacity, and flexibility. The network of transmission constructed by Bonneville and the region's utilities has supported an integrated regional power system. However, this regional infrastructure is in need of protection and expansion. In addition, the operation of the regional power system needs to evolve to better facilitate an efficient electricity market and help provide improved capacity and flexibility.

A key part of the Council's resource strategy is to improve the operation of the power system to better integrate variable wind generation and support growing capacity requirements. Improved wind forecasting, within-hour scheduling of resources, and increased use of dynamic scheduling among balancing authorities are likely to provide cost-effective and near-term solutions to

capacity and flexibility needs. The region has recently made significant progress through a joint initiative of Columbia Grid, Northern Tier Transmission Group, and WestConnect.

For many years the region has failed to make significant investments in its transmission infrastructure. As a result, transmission constraints have become significant, limiting access to regional electricity resources and reducing the efficiency of the power system. Recently, transmission investments have gained attention and important investments have been proposed or are underway. One area where added transmission may have value is in improving access to more diverse and cost-effective wind and other renewable resources. Investing in the regional transmission system is important to preserving an efficient and low-cost power system for the region.

Finally, preserving the capability of the existing hydroelectric system has significant value for the region. Mitigating damage to anadromous fish from development of the FCRPS has changed the operation of the hydroelectric system, reducing its energy capability and its flexibility. It is important to mitigate this damage, but also to do it in a way that best preserves the value of a low-cost and low-carbon electricity source. The Council attempts to ensure that its fish and wildlife program uses cost-effective strategies to improve salmon and steelhead survival. An analysis of the effects of a loss of hydropower capability was done to illustrate the value of the system. The example analyzed was the loss of the four lower Snake River dams. This example is provided to illustrate the significant economic and carbon-emission changes that resulted from the scenario. The last section of this chapter describes the results of this analysis.

Develop Long-Term Resource Alternatives

The fifth element of the Council's resource strategy recognizes that technologies will evolve significantly over the 20 years of the Sixth Power Plan. When the Council next develops a power plan, the cost-effective, available and reliable resources will be different from those considered in the Sixth Power Plan. But the Sixth Power Plan identifies areas where progress is likely to be valuable and includes actions to explore and develop such resources and technologies. In many instances the region can influence the development of technology and the pace of adoption.

Areas of focus in the long-term resource strategy include additional efficiency opportunities and the ability to acquire them, energy-storage technologies to provide capacity and flexibility, development of smart-grid technologies, expansion of demand response capability, and tracking the status and cost of potential no-carbon or low-carbon generation. The latter potentially includes renewable technologies, carbon sequestration, and advanced nuclear generation.

Research, development, and demonstration of these technologies is an important part of the Council's resource strategy. Tracking these developments, as well as plan implementation and changing assumptions, will identify needed changes in the power plan and near-term actions to implement it. These elements of the resource strategy are addressed primarily in the action plan.

VALUE OF THE RESOURCE STRATEGY

The resource strategy of the Sixth Power Plan is designed to provide a low-cost electricity supply to meet future load growth. But it is also designed to provide a low-risk electricity future for the

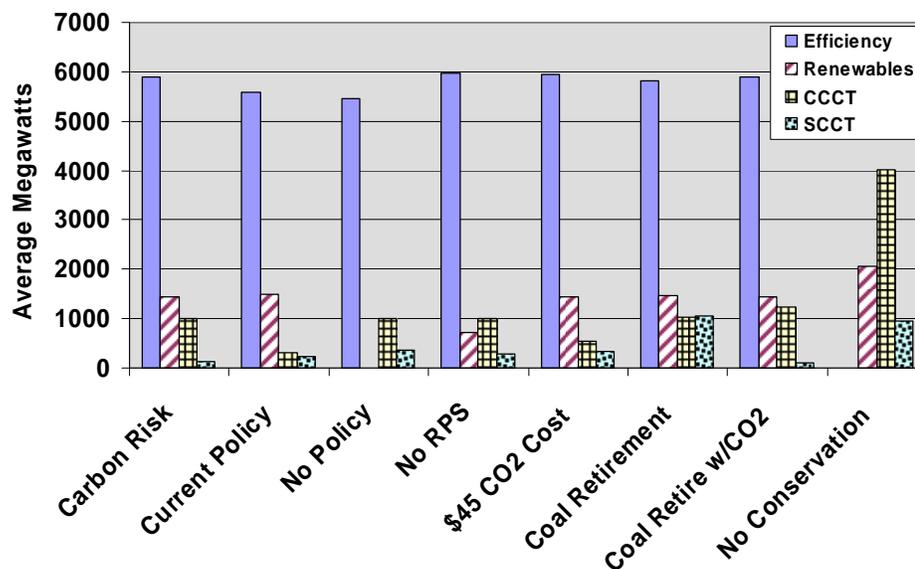
region. The Council choose to make risk reduction an important part of the resource strategy. Therefore the amount and type of resources included in the strategy are designed to meet loads, reduce costs, and help reduce the risks posed by uncertain future events.

All of the scenarios evaluated for the plan include the same uncertainty regarding fuel prices, hydropower conditions, electricity market prices, capital costs, and load growth. In addition, several scenarios include the risk of carbon pricing. The zero-to-\$100-per-ton carbon price risk is included in the carbon-risk, no-RPS, coal-retirement with CO₂ pricing, no-conservation, and Snake River Dam scenarios. Carbon prices are not included in the no-policy or current-policy scenarios, nor are they included in the coal-retirement scenario without carbon price risk. The \$45-carbon scenario assumes a fixed carbon price, instead of uncertain carbon prices. By comparing the results of these various scenarios, the effect of this significant uncertain future carbon-pricing policy on the resource strategy can be illustrated.

Figure 10-6 shows the resource development by resource type for each scenario. The resources are shown as average resource additions over 750 future scenarios. The high and consistent role of efficiency stands out. This is because of both its low cost and its role in mitigating risk from fuel price uncertainty and volatility. Efficiency acquisition is higher in scenarios with carbon prices reflecting its additional value for mitigating carbon price risk. Without conservation, renewable and gas-fired generation development is much greater. In the no-conservation scenario the net present value of future power system costs increases by \$24 billion, or 37 percent even without considering the additional carbon penalties that would have to be paid because carbon emissions increase from 40 million tons to 57 million tons per year. Without efficiency improvements, regional power costs would also increase by 37 percent excluding the cost of carbon and 47 percent including the cost of carbon

The role of renewable generation is driven by renewable portfolio standards and renewable energy credits. In the absence of both, little addition renewable development would take place. Assuming renewable energy credits continue, but without renewable portfolio standards, the amount of renewable generation developed is about 70 percent of what is required by the standards, even in the face of carbon price risk. The higher renewable generation in the no-conservation scenario reflects higher electricity consumption, which increases the amount of renewable energy needed to meet the standards.

The role of natural gas varies among the scenarios. It is greatest by far in the absence of efficiency. In scenarios with carbon prices or coal retirement it is similar because it is providing energy to reduce the use of coal. Because the coal-retirement and carbon-pricing scenarios have been designed to reduce carbon emissions to similar targets, the need for coal replacement is about the same in these scenarios. In the coal-retirement scenario without carbon pricing, simple-cycle combustion turbines play a larger role to replace the capacity of retired coal plants. If the plants aren't retired they continue to provide capacity under some future conditions.

Figure 10-6: Average Resource Development by Type in Alternative Studies

One of the key issues identified for the Sixth Power Plan was climate-change policy and the potential effects of proposed carbon-pricing policies. In addition, the Council was asked to address what changes would need to be made to the power system to reach a specific carbon reduction goal and what those changes would cost. The next section focuses on meeting carbon-reduction targets, but some more general carbon-emission results are addressed here. In providing analysis of carbon emissions and specific pricing or carbon-reduction targets, the Council is not taking a position on future climate-change policy. The Council's analysis is intended to provide useful information to policy-makers.

Figure 10-7 shows the costs and carbon emissions from all of the scenarios in the plan. The role of renewable portfolio standards in providing carbon reductions is one issue. This can be addressed by comparing results between two pairs of scenarios. The primary difference between the no-policy scenario and the current-policy scenario is renewable portfolio standards. In this comparison renewable portfolio standards reduce carbon emissions by 4 million tons per year, from 60.3 to 56.3 million tons per year. Conservation in the no-policy scenario slows the growth of carbon emissions, but emissions still increase above 2005 levels. The addition of renewable standards in the current-policy scenario reduces carbon emissions to 2005 levels by 2030. The renewable standards were estimated to increase the average cost of the power system by about 8 percent while reducing carbon emissions by about the same percentage.

The second comparison that shows the potential effects of renewable portfolio standards on carbon emission is the no-RPS scenario compared to the carbon-risk scenario. In these scenarios, which both include carbon-pricing risk, the presence of the standards reduced carbon emissions by 0.6 million tons per year, from 40.3 to 39.7 million tons per year. These results do not include, of course, the value of renewable portfolio standards in encouraging development of new carbon-free technologies for the future as encouraged in the Council's resource strategy.

The effects of carbon pricing risk on emissions can be seen by comparing the carbon-risk scenario to the current-policy scenario. The carbon-risk scenario adds to the expected cost of the

power system and reduces carbon emissions compared to the current-policy scenario. Expected power system cost increases about 14 percent, from \$56.1 billion (2006\$) to \$63.9 billion. Average carbon emissions decrease by 29 percent in 2030 reaching levels about 30 percent lower than 2005. By comparing emission levels and cost between the carbon-risk and the no-conservation scenarios, it becomes clear how important efficiency improvement is for reducing carbon at the least cost. Carbon emissions are not reduced from 2005 levels in the no-conservation scenario, but power system cost increases by \$24 billion, or 30 percent. If the carbon penalty is included in cost, the increase is even larger.

Figure 10-7: Costs and Carbon Emissions by Scenario in 2030

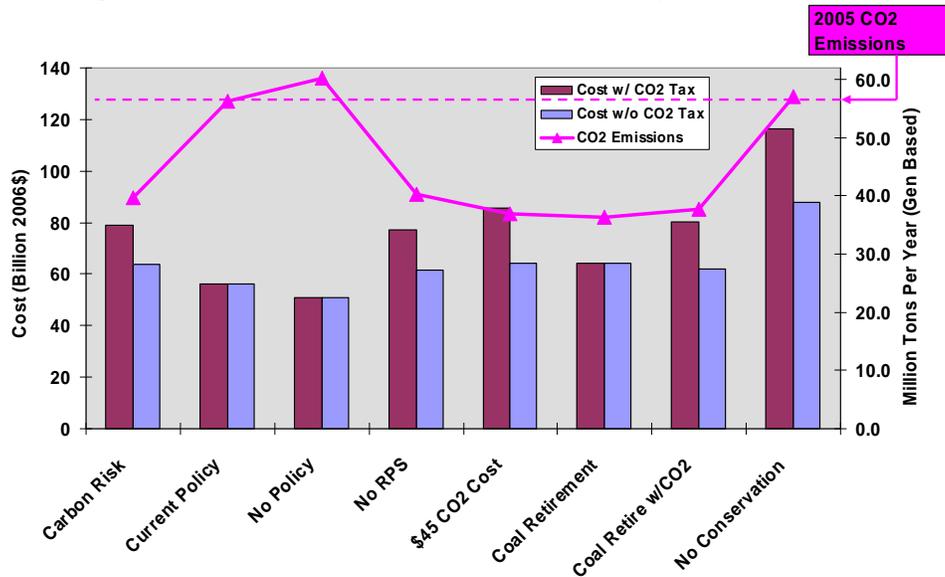
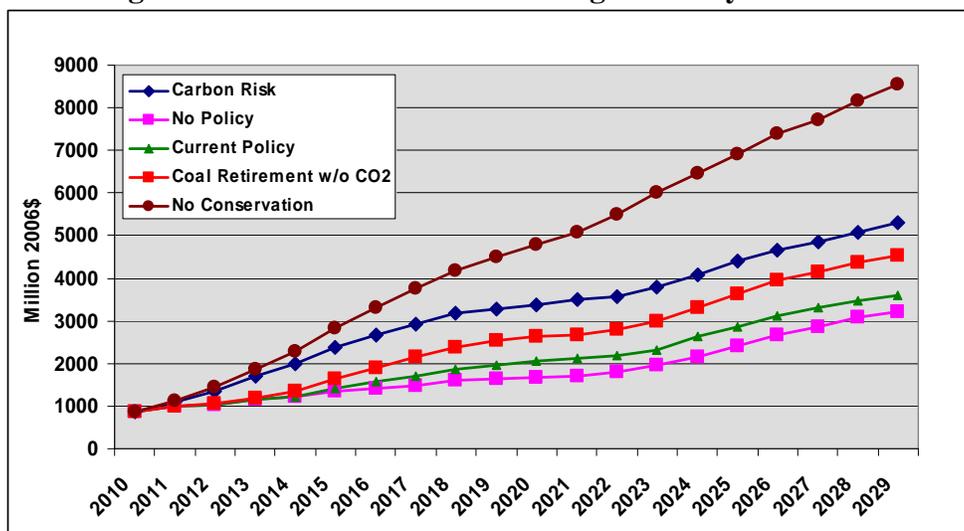


Figure 10-7 shows costs as the net present value of system costs, which is the measure of cost used for planning. It includes only the forward-going costs of the power system; that is, costs that can be affected by future conditions and resource decisions. Some have noted that reporting costs as net present values does not show patterns over time and obscures differences among individual utilities. The latter is unavoidable in regional planning and the Council has noted throughout the plan that different utilities will be affected differently by alternative policies. It is possible, however, to display the temporal patterns of costs among scenarios. Figure 10-8 shows forward-going power system costs for selected scenarios on an annual basis. Forward-going costs include only the future operating costs of existing resources and the capital and operating costs of new resources. The 2010 value in Figure 10-8 therefore includes mainly operating costs of the current power system, but not the sunk capital costs of the existing generation, transmission, and distribution system.

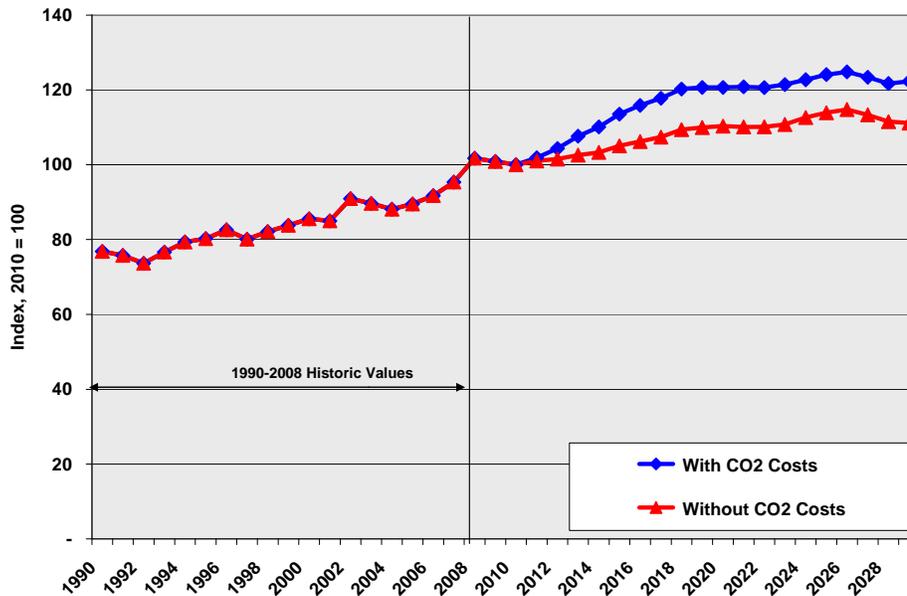
Figure 10-8: Annual Forward-Going Power System Costs

Power system costs increase over the forecast period even in the no-policy scenario. Renewable portfolio standards increase cost slightly in the current-policy scenario. The carbon-risk scenario, which best represents the resource strategy of the Sixth Power Plan, increases costs significantly, but not having conservation available in the future increases costs dramatically. The costs in Figure 10-8 all include the CO₂ penalty that would occur on average if carbon pricing were implemented, but three of the scenarios include no carbon-pricing policy: no policy, current policy, and coal retirement without carbon pricing. If carbon penalties were excluded from these costs, the cost of the carbon-risk and no-conservation scenarios would appear lower. The other scenarios analyzed in the plan all would appear about the same as the carbon-risk scenario if included in Figure 10-8.

To translate these planning costs to the changes that would likely be experienced by consumers in their rates and bills, existing power system costs need to be included and some costs that are not recovered through utility electric revenues need to be excluded. Figure 10-9 shows an index of forecast total utility revenue requirements for the carbon-risk scenario in the context of historical levels. The higher line of forecasts includes average carbon penalties as if they were entirely recovered through electricity revenues. Below, these revenue requirements are translated into electric rates and typical residential customer monthly electricity bills. The addition of existing system costs makes these impacts on consumers appear smaller than looking only at forward-going costs. The rate and bill effects are further dampened by the fact that conservation costs are not all recovered through utility rates. In fact, it becomes difficult to graphically distinguish among the effects some of the scenarios.

If the Council had developed a resource strategy based on current policies only, it would be lower cost as long as carbon pricing were not implemented in the future. It would be a strategy with fewer new resources and slightly lower rates and bills. However, if that resource strategy was followed and the future turned out to have significant carbon-pricing policy, costs could turn out to be substantially higher. Existing coal plants would have to be used to meet load and the carbon costs required by their emissions would be substantial. The extra cost of the resource strategy that considers carbon-pricing risk helps insure the region against future situations that could be expensive.

Figure 10-9: Index of Historical and Forecast Utility Revenue Requirements



The effects of the different scenarios on costs are translated into possible effects on electricity rates and residential consumer monthly electricity bills. The rate estimates are average revenue requirements per megawatt-hour. The residential bills are typical monthly bills. Both are expressed in constant 2006 dollars and have been levelized over the forecasting period. As can be seen in Figure 10-10, levelized rates and bills generally move in the same direction as the net present value of system cost that is reported as power system cost in this plan. The only exception to this relationship is in the no-conservation scenario. There, bills increase with system cost without conservation, but rates decrease because costs are spread over a larger number of megawatt-hours sold without conservation. Figure 10-11 illustrates how efficiency improvements lower electricity bills.

Figure 10-10: System Costs, Rates, and Monthly Bills

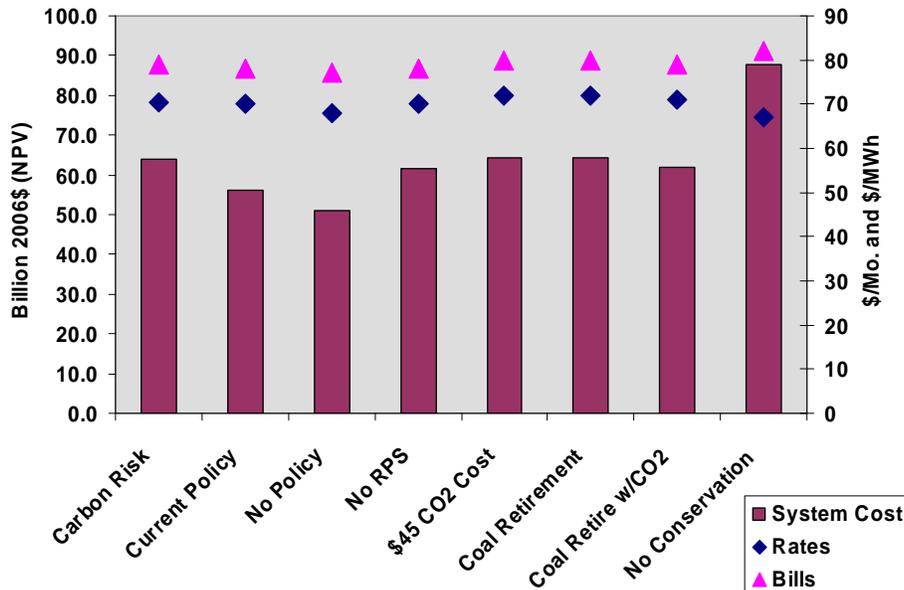
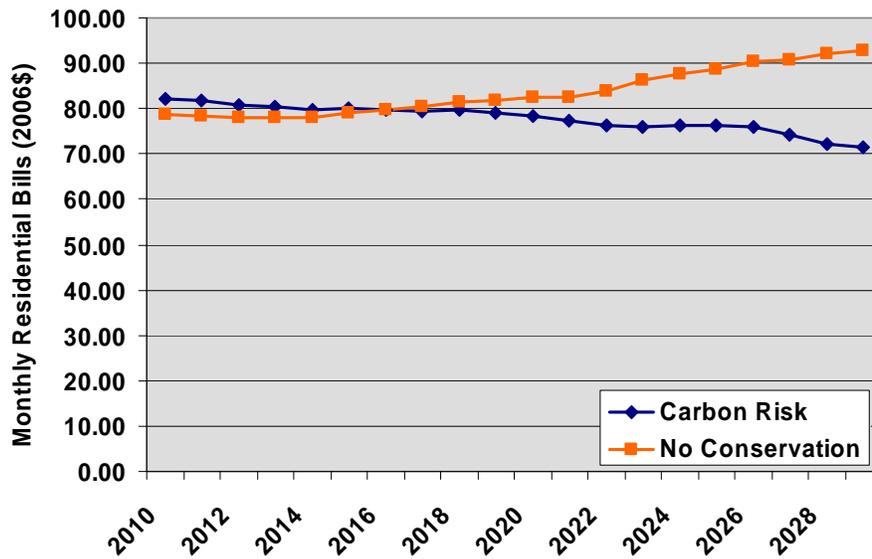


Figure 10-11: Residential Electricity Bills With and Without Conservation



The changes in rates and bills are small relative to system-cost changes. The primary reason is that revenue requirements contain a substantial amount of existing costs that do not change among the scenarios. The system costs used in planning exclude existing, or sunk costs and instead include only forward-going costs that could be affected by resource decisions. The effects of carbon reduction on rates and bills are smaller than some participants in the Council’s planning process expected. One reason is that conservation addresses much of the problem and it is cheap. A second reason is that the region is fortunate to have a low-carbon power system. Most of the carbon emissions come from a relatively small share of the generation that is fired by coal. This makes achieving substantial carbon reductions less costly than in many regions.

Figure 10-12 shows monthly residential bills in the current-policy, carbon-risk, and coal-retirement scenarios. Figure 10-13 shows electricity rates for the same scenarios. Neither figure includes carbon penalties in rates or bills. The coal-retirement scenario does not include carbon pricing policy, nor does the current-policy scenario. Therefore, the bills and rates of those scenarios do not change if carbon costs are included. The effects of including carbon costs in bills and rates are illustrated in Figures 10-12a and 10-13a, respectively. Including carbon cost in revenue requirements raises the bills and rates of the three scenarios that include carbon risk. If the carbon penalty is counted as a net cost to consumers, the carbon-risk scenario results in higher bills than the coal-retirement scenario. Coal retirement results in the highest rates if carbon costs are excluded, but when carbon costs are included rates in the carbon-risk and no-conservation scenarios are higher than in the coal-retirement scenario.

Figure 10-12: Monthly Residential Bills Excluding the Cost of Carbon Penalties

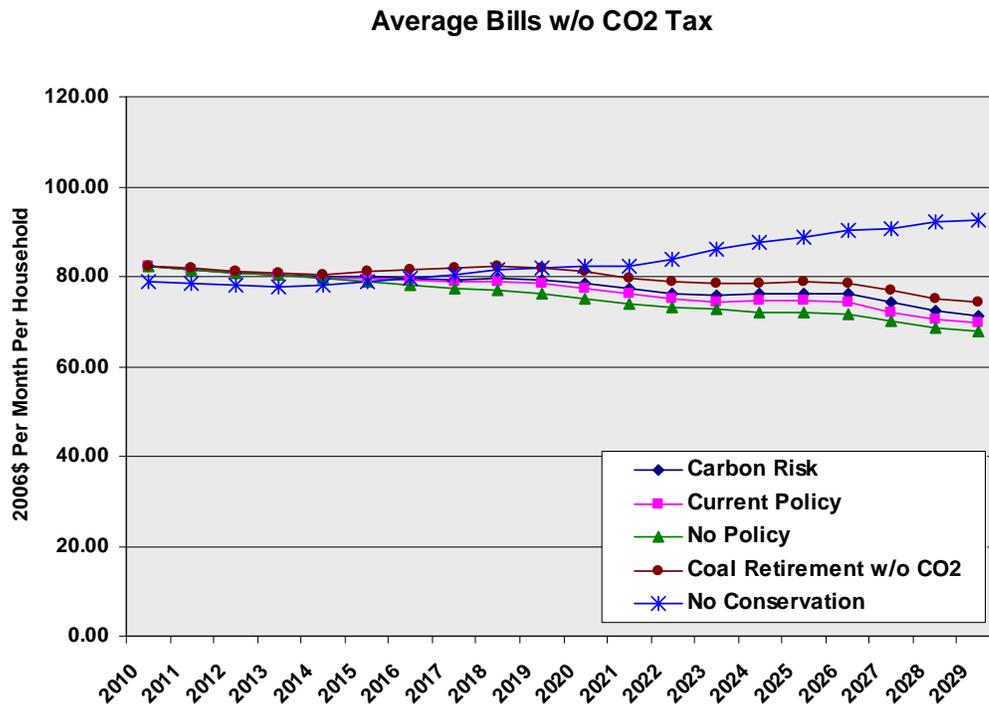


Figure 10-12a: Monthly Residential Bills Including the Cost of Carbon Penalties

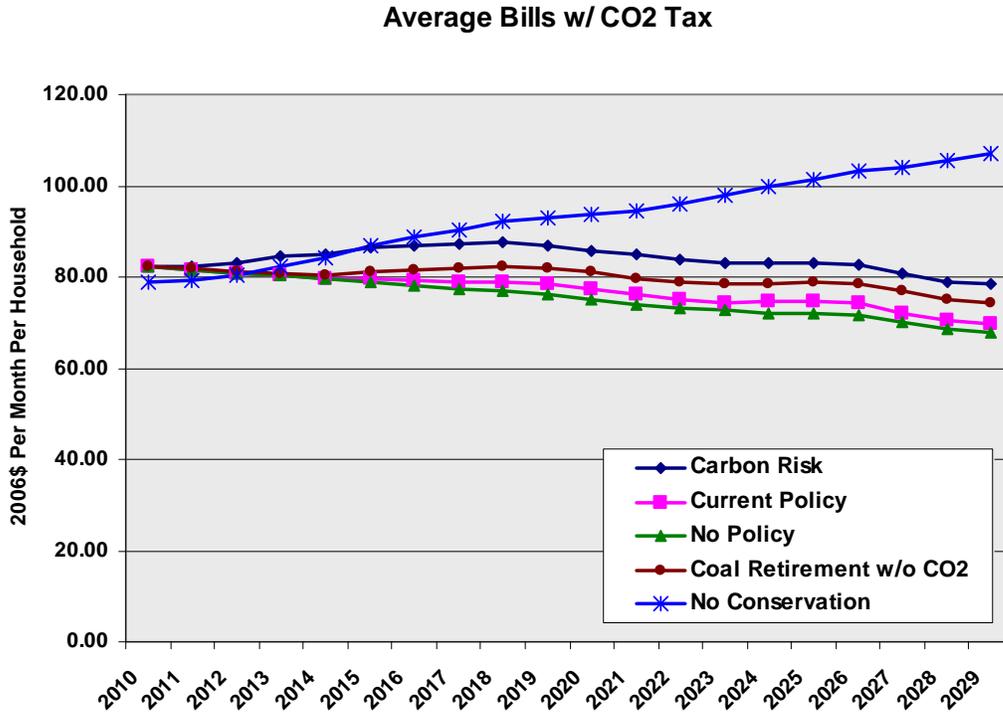


Figure 10-13: Electricity Rates Excluding the Cost of Carbon Penalties

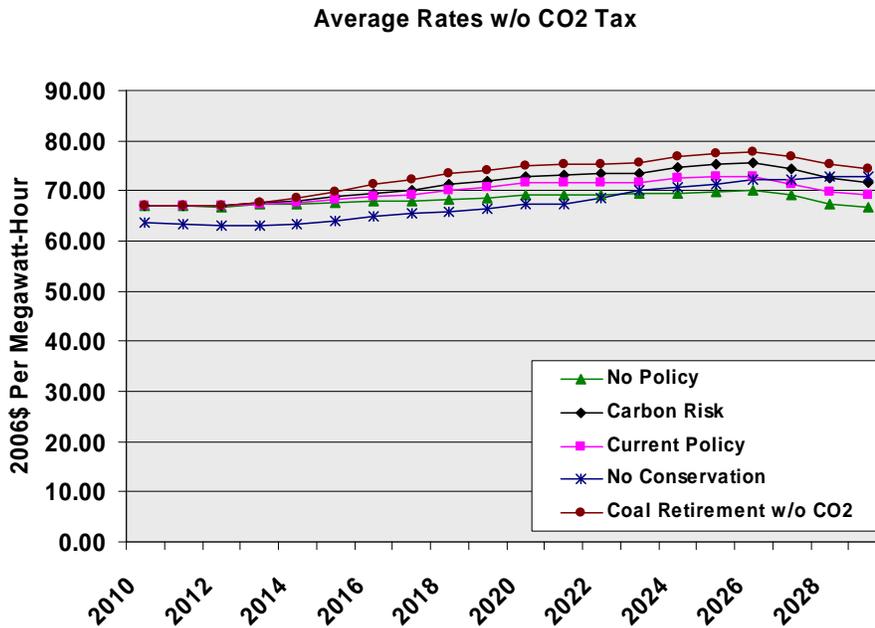
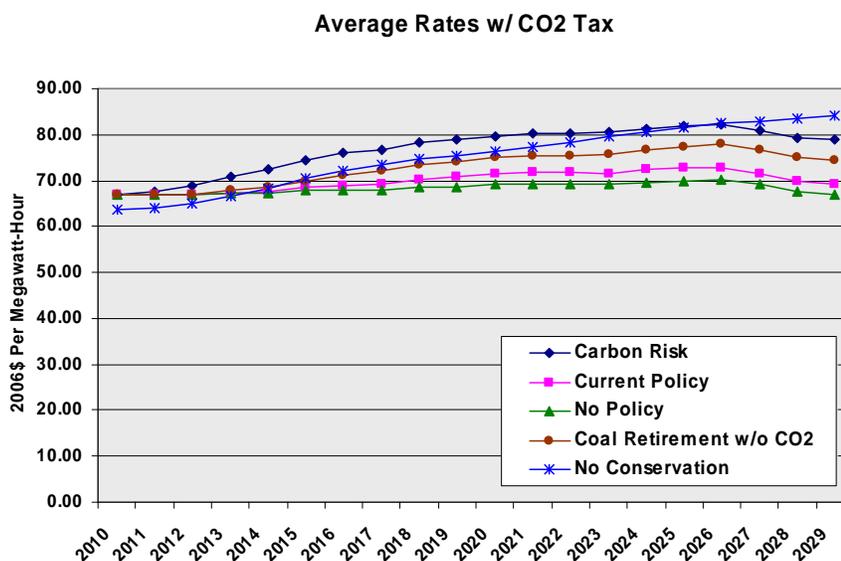


Figure 10-13a: Electricity Rates Including the Cost of Carbon Penalties

The pattern of change of rates and bills in other scenarios does not vary greatly from those shown in Figures 10-12 and 10-13. The trends in rates show a gradual increase, while the trends in bills show a gradual decrease. The one scenario that does have a significant effect on bills is the no-conservation scenario. Without the conservation available, the region, faced with carbon-price risk, would experience significantly higher electricity bills. This is apparent in Figures 10-11 and 10-12 compared to the carbon-risk Scenario. The no-conservation scenario results in about \$5 per megawatt-hour lower rates until near the end of the planning period when the two scenarios' rates converge (see Figure 10-13).

CARBON EMISSIONS

Response to Risk

One of the most important issues identified for this power plan is climate change and the possible effects that policies to reduce carbon emissions might have on the Northwest's power system. Current policies include renewable portfolio standards in three of the four Northwest states, limits on carbon emissions from new power plants, announced carbon-reduction goals, and numerous initiatives to reduce greenhouse-gas emissions from energy use. Additional policy discussions at the state, regional, and national levels have focused on some form of carbon pricing with most proposals focusing on a cap-and-trade system for carbon.

The uncertainty of future policies has been treated as one of the key risks facing the power system in the regional portfolio model. The carbon-risk scenario assumes that some form of price could be placed on carbon emissions, but the timing and level of the price are treated as uncertain. The intent of this scenario is to examine what actions should be taken by the power system in the face of likely but uncertain carbon-control policy. In this scenario, carbon pricing can be enacted at different times in the future, and when it is, the prices can be anywhere between \$0 and \$100 per ton of carbon dioxide emissions. One of the problems of unresolved policy direction is that utilities and business cannot anticipate what actions are going to be

required. Any decisions made today may turn out to be costly when policy is enacted some time in the future. This uncertainty can result in delayed decisions about additional resource investments. The carbon-risk scenario provides some guidance for current decisions, when future conditions are unknown.

The results of the carbon-risk scenario can be compared to a current-policy scenario that assumes current policies will continue into the future; that is, it includes no risk of carbon-pricing policy in the future. A comparison of these two scenarios is shown in Table 10-1. Analysis of the carbon-risk scenario indicates that the most cost-effective response to carbon-pricing risk is more efficiency and more natural gas-fired generation. The actual natural gas-fired generation built is much lower than the option amounts shown in Table 10-1, but the increased natural gas options indicates the strategy that makes sense in the face of significant carbon-pricing risk. The role of the increased natural gas-fired generation is to provide energy replacement for existing coal plants that would be used less when high carbon taxes are encountered.

Table 10-1: The Carbon-Risk Scenario versus the Current-Policy Scenario

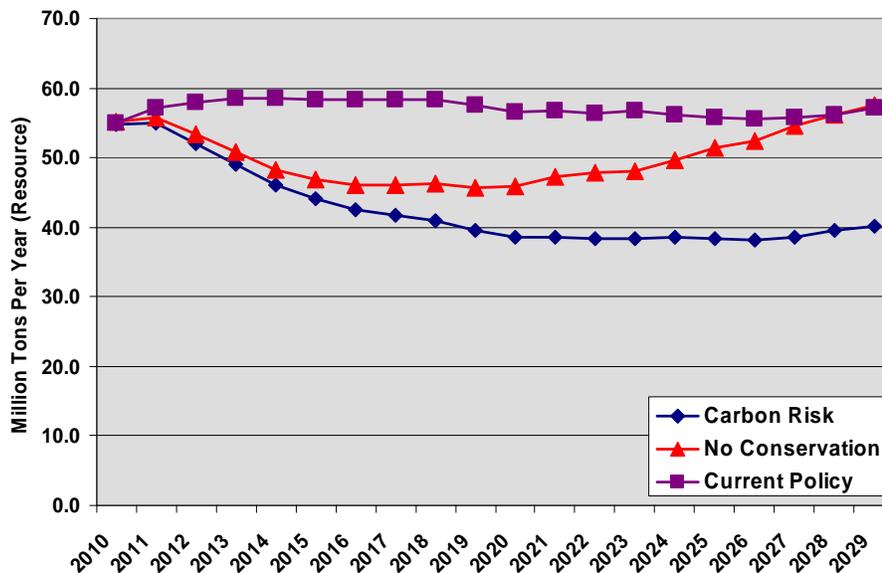
	Current Policy	Carbon Risk
Cost (billion 2006\$ NPV)		
With Carbon Penalty	\$56.10	\$123.5
Without Carbon Penalty	\$56.10	\$63.9
Change in Retail Rates from Current Policy (levelized 2006\$)		
Including Carbon Penalty		+ 8.6%
Without Carbon Penalty		+ 1.4%
Carbon Emissions (Gen) (Million Tons/Year in 2030)	56.3	39.7
Resources 2030		
Conservation (MWa)	5,572	5,895
Renewables (MWa)	1,480	1,453
CCCT Options 2030 (MWa)	1,512	3,402
SCCT Options 2030 (MWa)	1,620	648

Current (2005) carbon emissions from the Northwest power system are estimated to be 57 million tons per year (MMtpy) when adjusted to normal hydropower conditions. The comparable number for 1990 is estimated at 44 MMtpy. These are important numbers because proposed carbon-reduction targets usually are stated in terms of future emissions levels relative to either 2005 or 1990 levels. Based on simulations of the regional portfolio model, carbon emissions in the current-policy scenario are held fairly constant at 2005 levels through 2030. The commitment to aggressive efficiency improvement is largely responsible for limiting the growth of carbon emissions from the power system in the current-policy scenario. Actions taken in the carbon-risk scenario reduce carbon emissions by 30 percent from 2005 levels and by 10 percent from 1990 levels. The carbon reductions targeted by most stated or implied policy initiatives for 2020 are met in the carbon-risk scenario.² Continued reductions in carbon emissions would be required to meet long-term carbon reduction targets. Interpolation from 2020 targets to 2050 targets would place 2030 emissions targets between 35 and 40 MMtpy assuming the power sector is required to achieve carbon reductions in proportion to its share of total emissions.

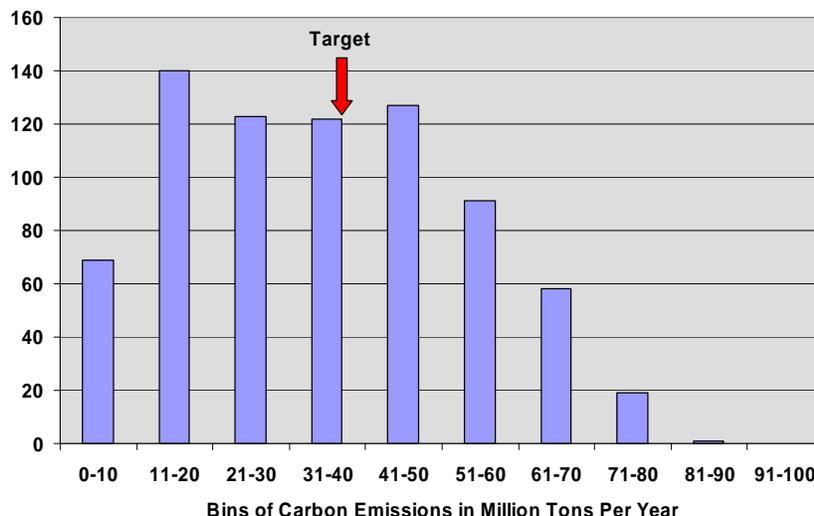
² See description of policies in Chapter 11.

Figure 10-14 shows the average annual carbon emissions for the carbon-risk scenario compared to the current-policy scenario and another scenario that includes carbon price risk but does not include conservation as a resource (the no-conservation scenario). The figure illustrates the importance of the two key actions that will be required to meet carbon reduction goals: reduced coal use and increased efficiency.

Figure 10-14: Average Annual Carbon Emissions for Current-Policy, Carbon-Risk, and No-Conservation Scenarios



It is important to recognize, however, that the average carbon emissions shown in Figure 10-14 hide a great variety of possible future carbon emissions over the 750 futures simulated by the regional portfolio model. To illustrate this, Figure 10-15 shows the frequency distribution of 2030 carbon emissions for all 750 futures. Across the simulated futures, which vary in loads, carbon prices, natural gas prices, electricity market prices, and other conditions, carbon emissions range from less than 10 MMtpy to over 80 MMtpy. This sensitivity of carbon emissions to hydroelectric and other conditions makes verification of emissions levels difficult. Further, there are many different approaches to measuring and counting a region’s carbon emissions. The measure that is shown in this plan is based on generation within, or committed on a long-term basis to, the region. An alternative approach is to base the carbon-emissions estimate on electricity consumption within the region. The Council calculates this concept as well, and because in most of the scenarios examined the Northwest is a net exporter of electricity, this measure of regional carbon emissions is lower. Because of all these factors, it would be inappropriate to make any definitive conclusions regarding carbon-emissions reduction targets and whether emission targets are achieved.

Figure 10-15: Frequency Distribution of Carbon Emissions in the Carbon-Risk Scenario

Reducing carbon emissions in the carbon-risk scenario is not free. The expected net present value of power system costs increases by \$7.8 billion, or 14 percent, if only changes in the cost of electricity generation are included. The cost is \$22.8 billion, or 40 percent greater, if the carbon price itself is included. The carbon price, perhaps a carbon tax, for example, may or may not be a net cost to the region depending on how the revenues from the tax are treated. Even for utilities the tax burden may be mitigated by other changes in taxation or credits. The structure of carbon-pricing policy is unknown at this time so both cost extremes are included in the plan.

Achieving Carbon-Reduction Targets

The carbon-risk scenario develops a resource strategy that addresses risk of future carbon costs. Another approach suggested in comments on the draft power plan is to design scenarios that are intended to achieve particular carbon-emission targets. As discussed above, 2030 carbon emissions targets fall into the 35-to-40-MMtpy range. Two scenarios examined alternative means to achieve carbon emissions levels that meet this target on average over the 750 futures simulated in the regional portfolio model.

The first scenario seeks a fixed carbon-emissions penalty that achieves the carbon-emissions target. Because the lowest penalty that achieves the target is \$45 per ton, it is called the \$45-carbon scenario. The tax is assumed to be implemented immediately in 2010. The level of this tax is similar to the average carbon tax in 2030 for the carbon-risk scenario, which assumed uncertain carbon taxes that, on average, increase over time.

Because it is clear that any significant carbon reduction requires reduced use of existing regional coal plants, the second scenario examined the retirement of enough coal-fired generation to meet the average emissions target. This is labeled the coal-retirement scenario. In the coal-retirement scenario, approximately half (54 percent or 2,700 average megawatts after planned and forced outages) of the region's coal-fired generation capability is phased out between 2012 and 2019. Because coal retirement is viewed as an alternative to carbon pricing in this scenario, there is no

carbon penalty in this study. An analysis of coal retirement with carbon pricing uncertainty has also been done and is discussed below.

Both of these scenarios meet the carbon emissions target of between 35 and 40 MMtpy by 2030, as did the carbon-risk scenario. However, the levels of carbon emissions, costs, and certainty of carbon reductions vary among them. Table 10-2 compares the results of the three scenarios. If the carbon penalties themselves are not included, the present value system costs of the three scenarios are very similar. If the carbon penalties are included (first row of Table 10-2) scenarios with carbon pricing are more costly. Because the carbon risk scenario includes many futures with prices well above the \$45-per-ton-level, its cost is even higher than the \$45 scenario.

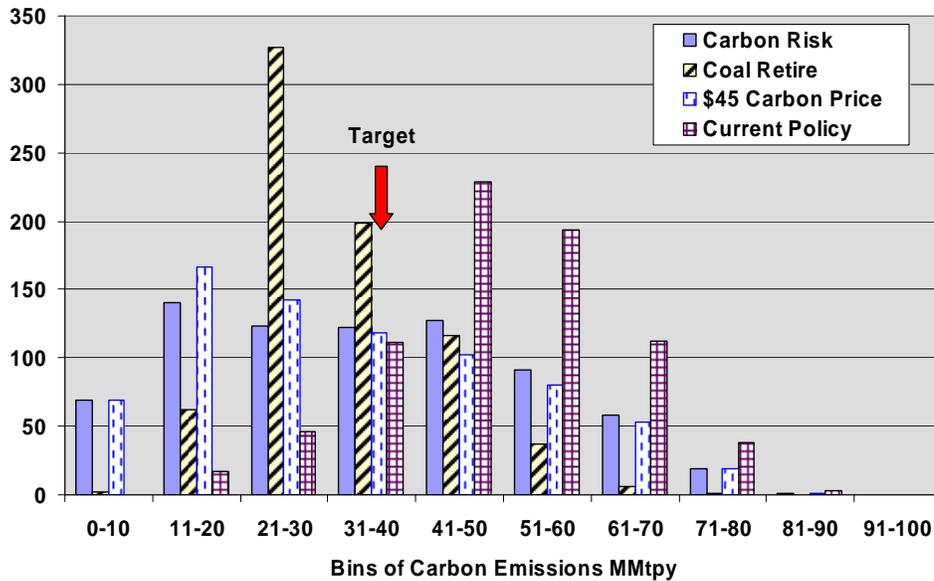
Table 10-2: The Carbon-Risk Scenario versus Current Policy

	Carbon Risk	\$45 Carbon	Coal Retirement
Cost (billion 2006\$ NPV)			
With Carbon Penalty	\$123.5	\$85.7	\$64.3
Without Carbon Penalty	\$63.9	\$64.2	\$64.3
Change in Retail Rates from Current Policy (levelized 2006\$)			
Including Carbon Penalty	+ 8.6%	+ 12.9%	+ 2.9%
Without Carbon Penalty	+ 1.4%	+ 2.9%	+ 2.9%
Carbon Emissions (Gen) (Million Tons/Year)	39.7	37.0	36.3
Resources 2030			
Conservation (MWa)	5,895	5,933	5,825
Renewables (MWa)	1,453	1,450	1,459
CCCT Options 2030 (MWa)	3,402	1,890	3,024
SCCT Options 2030 (MWa)	648	1,620	3,240

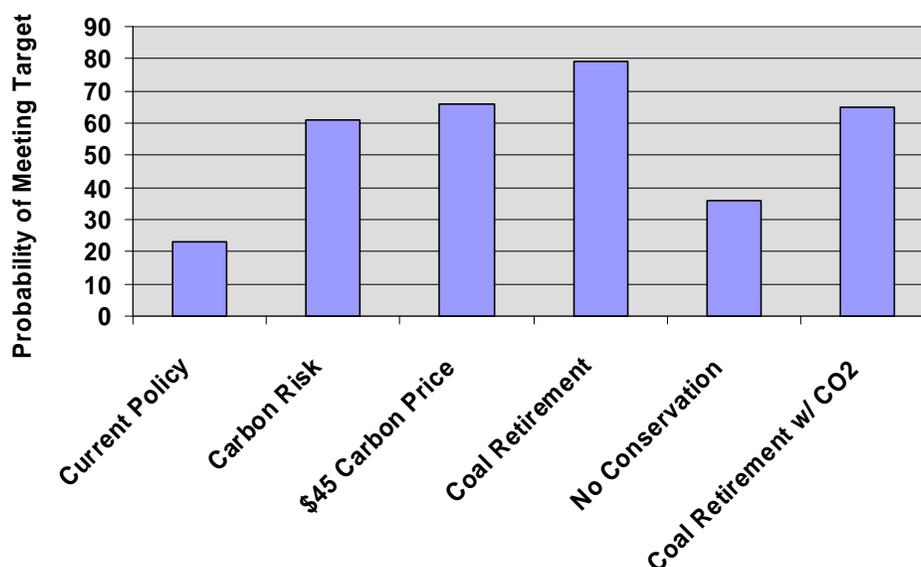
The role of conservation and the amount of renewables needed to meet renewable portfolio standards are very similar among the scenarios. The amount of natural gas-fired generation, however, does change. The role of natural gas-fired generation depends on how much energy and capacity needs to be replaced and how much risk needs to be insured against. In the \$45-carbon scenario, the cost of carbon is known as is the viability of existing coal plants. There is still variability based on uncertain natural gas prices, but on average less coal energy needs to be replaced than in the coal-retirement or carbon-risk scenarios. The coal-retirement scenario requires more natural gas-fired generation than the \$45-carbon scenario to replace the energy and capacity of retired coal plants. The carbon-risk scenario requires more natural gas-fired generation than the \$45-carbon scenario because of the risk of higher carbon penalties and the reduced cost-effective coal and inefficient gas-fired generation that ensues.

These three scenarios vary in their certainty of carbon reduction across the 750 futures that the regional portfolio model examines. Figure 10-16 shows a frequency distribution of carbon emissions, similar to Figure 10-15, for each of the three scenarios that, on average, meet the carbon-emissions target compared to the current-policy scenario. The carbon-risk frequency distribution is the same as shown in Figure 10-15. All of the three carbon scenarios shift the distribution of carbon emissions to the left. The distribution of the \$45-carbon and carbon-risk scenarios are generally similar to one another. The coal-retirement scenario, however, focuses the emissions much more into the 20- to 40-MMtpy area.

Figure 10-16: Carbon Emissions Frequency Distribution in Four Scenarios



Another way to summarize the differences among the carbon scenarios and the current-policy scenario is to calculate the probability that each scenario will result in carbon emissions below 40 MMtpy. Figure 10-17 shows these probabilities. With current policies, the likelihood of emissions falling below 40 MMtpy in 2030 is only 23 percent. Coal retirement is the most certain of the policies to achieve the target under the variety of future conditions examined by the model. It achieves less than 40 MMtpy in 79 percent of the 750 futures. Pursuing actions to mitigate the risk of uncertain carbon pricing, as in the carbon-risk scenario, will achieve success in 61 percent of the futures, while a fixed carbon tax of \$45 would achieve success in about 66 percent of the futures. Figure 10-17 includes the coal-retirement scenario combined with carbon pricing (coal retirement w/ CO₂). In this scenario carbon prices do most of the carbon-reduction work. Only about 13 percent of the existing coal-fired generation is retired in this scenario. Its certainty of carbon emissions below 40 million tons per year is only slightly higher than the carbon-risk scenario, and slightly lower than the \$45-carbon scenario.

Figure 10-17: Probability of Meeting Carbon Emissions Targets

The analysis of these scenarios indicates that in order to reduce carbon emissions from the Northwest power system to meet a pro-rata share of the current targets adopted by some Northwest states or being proposed in federal legislation, the region would have to acquire about 5,900 average megawatts of efficiency and significantly reduce the use of existing coal-fired power plants. If conservation were not available to the region in the face of carbon-pricing risk, the probability of meeting carbon reduction targets would only be 36 percent. Phasing out about half of the existing coal plants would provide a more assured reduction of carbon emissions at a comparable expected cost without the carbon penalty included. There is no guarantee that coal retirement would be a substitute for carbon pricing, however. Fewer coal plants would need to be retired if the region also faced the risk of carbon penalties. But relying on response to carbon risk does not provide the same assurance of carbon reductions.

The actual use of coal-fired generation, when averaged over the 750 futures in the three carbon scenarios, is fairly consistent. In 2030, the average dispatch of existing coal plants is 2,441 average megawatts in the carbon-risk scenario. The comparable numbers for the \$45-carbon and coal-retirement scenarios are 2,276 and 2,136, respectively. With current policy the average dispatch of coal is about double these levels at 4,157. When the frequency distribution of coal plant dispatch over the 750 futures is examined, patterns similar to the carbon emissions patterns in Figure 10-16 result. The conclusion is that whether through retirement or less dispatch, existing coal would only provide about half as much energy and capacity to the power system as is now the case. Coal retirement provides increased certainty of carbon emission reduction and also increased certainty about actions that need to be taken and their costs over time. In addition, it may be that dispatch of coal plants at half their current levels would be an uneconomic operation for these plants. If that is the case, the carbon-pricing scenarios would imply that coal plants likely would be retired based on economic considerations.

VALUE OF THE HYDROELECTRIC SYSTEM

The Pacific Northwest power system emits about half the carbon dioxide per kilowatt-hour of the nation or the rest of the western states. This is due to the large role played by the hydroelectric system of the region. To illustrate the value of the hydroelectric system, a scenario was run to examine the effects of removing the lower Snake River dams on power system costs and carbon emissions. The results of the scenario, however, could apply to other changes that reduce the capability of the hydroelectric system for any reason.

The lower Snake River dams provide 1,110 average megawatts of energy under average water conditions, about 5 percent of regional annual electric energy needs. In addition, the dams provide 3,500 megawatts of short-term capacity, a little more than 10 percent of the total hydroelectric system capacity, and as part of the Automated Generation Control (AGC) System, they provide system reserves to maintain the reliability of the power supply. They also provide reactive support for the stability of the transmission system.

The effects of removing the capability of the lower Snake River dams are mainly determined by the replacement resources that would be required for the power system to duplicate the energy, capacity, real-time load following, stability reserves and reactive support currently provided by the dams. To examine the effects on energy and capacity, the generating capability of the dams was removed from the carbon-risk scenario of the Sixth Power Plan. For this scenario, it was assumed that the power produced by the dams was removed in 2020 and the energy and capacity were replaced by other resources selected by the regional portfolio model. That is, given the reduced energy and capacity of the hydroelectric system a low-cost and low-risk portfolio of new and replacement resources is developed. The changes in cost, carbon emissions, risk, and average retail electricity rates are shown in Table 10-3. The effects analyzed include the replacement resources for the assumed loss to the power system of only the energy and capacity of the Snake River dams. No estimate was made of the cost of replacing the other services provided by the dams. There are many other implications and costs of dam removal including the cost of removing the dams, future operating cost and replacement savings, substitution of other transportation modes for barge transportation (including fish transportation), changes in irrigation sources, and other factors. These were addressed most completely in the Corps of Engineers EIS on the *Lower Snake River Juvenile Salmon Migration Feasibility Study*,³ and have not been included in this analysis.

³ U.S. Army Corps of Engineers. *Lower Snake River Juvenile Salmon Migration Feasibility Study* 2000. <http://www.nww.usace.army.mil/lsr/>

Table 10-3: The Effect of the Dam Removal Scenario

	Carbon Risk	Dam Removal	Change
Cost (billion 2006\$ NPV)			
With Carbon Penalty	78.9	85.8	+ \$6.9 (+8.7 %)
Without Carbon Penalty	63.9	68.1	+ \$4.2 (+6.5 %)
Risk (TailVar90 Billion 2006\$ NPV)			
With Carbon Penalty	123.5	135.6	+ \$12.1 (+ 9.8 %)
Retail Rates (levelized 2006\$ Per MWh)			
With Carbon Penalty	75.6	77.0	+ 1.4 (1.9%)
Without Carbon Penalty	70.5	71.3	+ 0.8 (1.1%)
Carbon Emissions (Gen) (Million Tons/Year)	39.7	42.7	+ 3.0 (+7.6 %)

Dam removal increases the carbon emissions, cost, and risk of the power system. The projected changes to the power system to accommodate the loss of hydroelectric capability are not a simple energy and capacity replacement. Small increases in conservation and renewable resources occur in this scenario, but the primary replacement of the dams is provided by changes in the construction of new gas-fired generating plants, changes in the operation of existing and new generating plants, and changes in net exports. Existing natural gas-fired and coal-fired generation is used more intensively. In addition, the region exports less energy and imports more. The combination of these changes makes up for the lost 1,100 average megawatts of energy. Table 10-4 summarizes the average replacement resources; however, the average hides a wide variation in responses depending on the future that is encountered.

Replacement of the lower Snake River dam energy and capacity results in increased carbon emissions of 3.0 million tons year, a 7.6 percent increase compared to emissions in the carbon-risk scenario. To place this number in context, it is an amount five times greater than the amount of carbon saved by renewable portfolio standards between the carbon-risk and the no-RPS scenarios. Increased carbon emissions result because without the dams the resource strategy includes more options of additional new gas-fired generation and builds the options more frequently. In addition, existing carbon-producing resources are dispatched more often. In total, Table 10-4 shows that 1,103 average megawatts would be required to replace the dams with 437 average megawatts coming from carbon-producing resources, not including increased imports that would also most likely come from carbon-producing resources

Table 10-4: Replacement of Lower Snake Dam Energy

Replacement Resource	Average Change in Energy
Existing Natural Gas	+ 91
Existing Coal	+ 149
New Natural Gas	+ 197
Conservation	+ 145
Renewables and Other	- 10
Net Imports (reduced exports and increased imports)	+ 531
Total Energy Replaced on Average	= 1,103

The changes in net present value system cost shown in Table 10-3, while appropriate for regional electricity planning comparisons, hide significant changes in costs and their allocation over time

and among utilities and consumers in the region. Figure 10-18 shows the annual pattern of cost changes for the dam-removal scenario. Annual cost of the power system increases in 2020 by over \$530 million and remains higher. Further, because the lower Snake River dams serve Bonneville public-utility customers, those utilities and their consumers would bear the cost increases. Using a rate-making rule of thumb that a \$65 million to \$80 million cost increase translates into a \$1 per megawatt-hour increase in Bonneville rates, a \$530 million increase in Bonneville costs would raise rates by between \$6.60 and \$8.15 per megawatt-hour. Based on Bonneville’s priority firm rate of \$28 per megawatt-hour, dam removal causes an increase of 24 percent to 29 percent.

Figure 10-18: Annual Cost Changes for the Dam-Removal Scenario

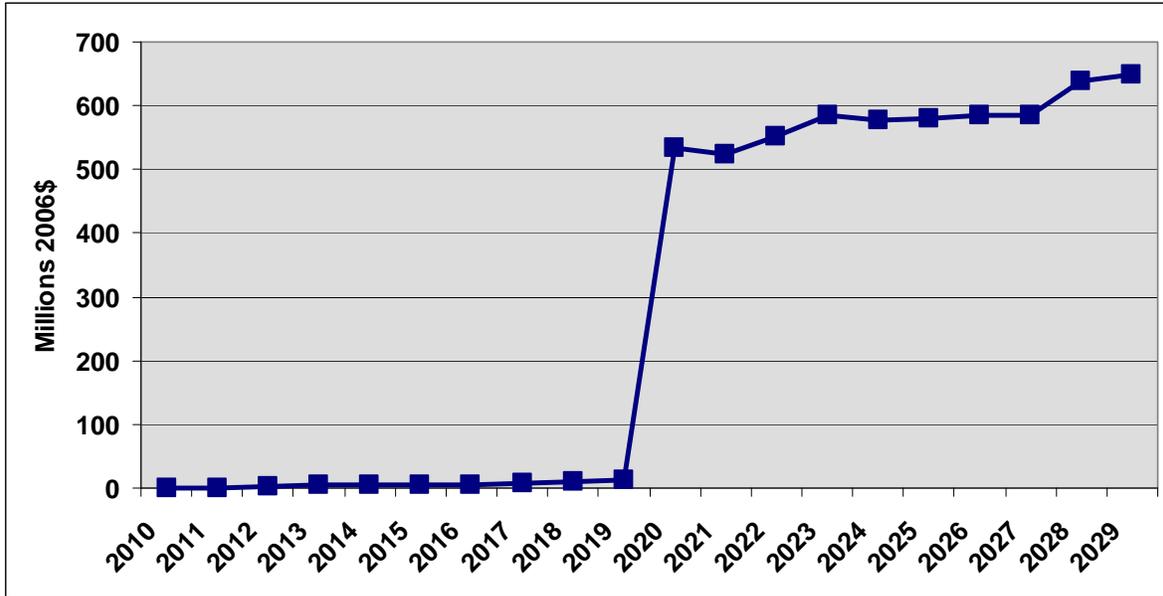


Figure 10-19: Summary of Scenario Results

Scenario	Least Risk →								
	Carbon Risk Least Risk L813LR	Current Policy Least Risk L813g	No Policy Least Risk L813i2	No RPS Least Risk L813h2	\$45 CO2 Cost Least Risk L813d	Coal Retirement Least Risk L813b	Coal Retire w/CO2 Least Risk L813j	No Conservation Least Risk L813a	Dam Removal Least Risk L813k
COST & RISK									
NPV Cost (Bil. 2006\$) (w/ carbon penalty)	78.9	56.1	51	77	85.7	64.3	80.3	116.2	85.8
NPV Risk (Bil. 2006\$)	123.5	83.4	82.6	123.3	121.1	96.4	125	185.7	135.6
NPV Cost (Bil. 2006\$) (w/o carbon penalty)	63.9	56.1	51	61.6	64.2	64.3	61.9	87.8	68.1
RATES (levelized 2006\$/Mwh)									
Retail Rates (w/o carbon penalty)	71	70	68	70	72	72	71	67	71
Retail Rates (w/ carbon penalty)	76	69	68	75	79	72	76	73	77
2010-29 Growth rate of rates (w/o carbon penalty)	0.4%	0.2%	0.0%	0.2%	0.2%	0.6%	0.4%	0.7%	0.5%
% change levelized from Carbon Risk scenario (w/o)		-1.0%	-3.0%	-1.0%	2.0%	2.0%	1.0%	-6.0%	1.0%
MONTHLY RESIDENTIAL BILLS (2006\$)									
Monthly Residential Bills (w/o carbon penalty)	79	78	77	78	80	80	79	82	79.00
Monthly Residential Bills (w/ carbon penalty)	84	78	77	84	88	80	84	91	85.00
2010-29 Growth rate of bills (w/o carbon penalty)	-0.70%	-0.9%	-1.0%	-0.9%	-0.9%	-0.5%	-0.7%	0.9%	-0.6%
% change levelized from Carbon Risk scenario (w/o)		-1.0%	-3.0%	-1.0%	2.0%	2.0%	-1.0%	5.0%	1.0%
CARBON									
2030 Emissions (Generation Based, MMtpy) adjusted	39.7	56.3	60.3	40.3	37.0	36.3	37.7	57.0	42.7
2030 Emissions (Use Based, MMtpy) adjusted	29.0	42.0	50.0	31.0	28.0	28.0	27.3	60.0	35.0
RESOURCES									
Total Conservation (Average Development)	5895	5572	5452	5966	5933	5825	5903	0	6040
Renewable Resources (Forced in if RPS)	1453	1480	311	1008	1450	1459	1452	2049	1443
CCCT (Amount Optioned)									
Earliest Option	3402	1512	3780	2268	1890	756	378	3780	378
Earliest Construction Date	2019	2019	2019	2019	2019	2015	2013	2013	2017
Maximum Optioned	3402	1512	3780	2268	1890	3024	4158	10962	4536
Average Built	991	299	909	704	551	1027	1243	4024	619
SCCT (Amount Optioned)									
Earliest Option	162	648	648	648	162	162	162	162	0
Earliest Construction Date	2015	2015	2017	2017	2017	2015	2021	2009	
Maximum Optioned	648	1620	1620	1458	1620	3240	489	2916	
Average Built	122	236	355	288	329	1062	93	961	
Demand Response	4	4	4	4	4	4	4	9	4
Average Market Purchases	-1977	-2751	-1990	-1784	-1772	-1648	-1893	344	-1446
Total New Energy	8465	7591	7031	7970	8267	9377	8695	7043	8106

Chapter 11: Climate Change Issues

Summary of Key Findings	1
Background	2
The National View	3
The Pacific Northwest Regional View	4
Actions to Reduce Greenhouse Gas Emissions	6
Policies to Reduce Greenhouse Gases	9
Mandates	9
Tax Incentives	10
Cap-and-Trade Programs	10
Carbon Taxes	11
Current Policies and Goals Affecting the Pacific Northwest.....	11
International Initiatives	12
Federal Policies	12
Environmental Protection Agency Role	12
Legislative Efforts.....	13
Regional Policies	13
State Policies	14
Greenhouse Gas Emission Reduction Goals.....	14
Renewable Portfolio Standards.....	14
Carbon Dioxide Emission Performance Standards.....	15
Evaluating Carbon Strategies.....	16

SUMMARY OF KEY FINDINGS

Climate change presents a daunting challenge for regional power planners. There are at least two ways in which climate can affect the power plan. First, warming trends will alter electricity demand and change precipitation patterns, river flows, and hydroelectric generation. Second, policies enacted to reduce green house gases will influence future resource choices. There remains a great deal of uncertainty surrounding both of these issues. This chapter describes how current and potential new policies affect the plan’s resource strategy and what actions will be needed to achieve greenhouse gas emission-reduction goals. The issue of potential changes to electricity demand and hydroelectric generation is discussed in Appendix L.

The focus of climate policy, especially for the power sector, will be on carbon dioxide emissions. Nationally, carbon dioxide accounts for 85 percent of greenhouse gas emissions, with about 38 percent originating from electricity generation. For the Pacific Northwest, the power generation share is only 23 percent because most of our electricity comes from hydroelectric generation. Analysis by others has shown that substantial and inexpensive reductions in carbon emissions can come from more efficient buildings and vehicles. More expensive reductions can come from substituting non- or reduced-carbon electricity generation such as renewable resources, natural gas, and nuclear, or from sequestering carbon.

Reductions in carbon emissions can be encouraged through various policy approaches such as regulatory mandates (e.g. renewable portfolio standard or emission standards), emissions cap-and-trade systems, emissions taxation, and efficiency-improvement programs. Climate change

policies enacted in the Northwest states have focused on renewable energy and new generation emission limits. National and Western proposals have focused on cap-and-trade systems, although none have been implemented successfully. Although carbon taxes are easier to implement than cap-and-trade systems, none have been proposed.

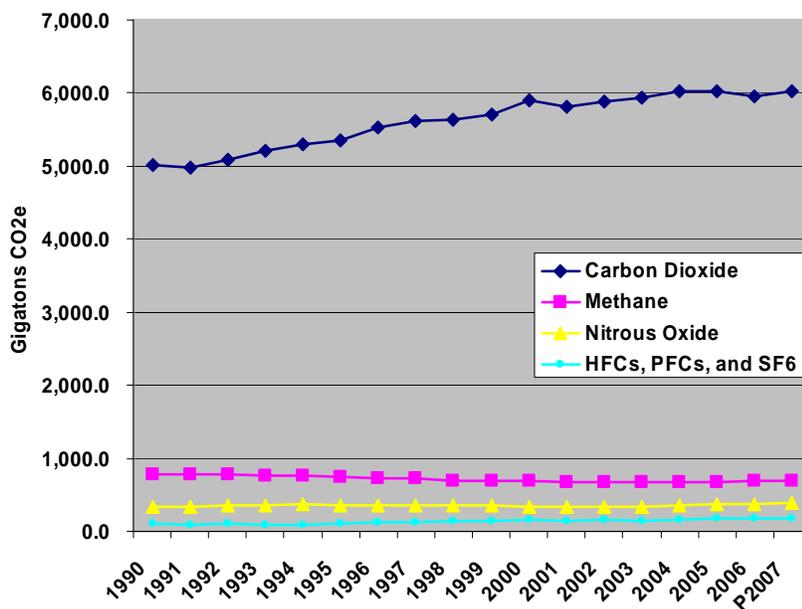
Washington and Oregon have adopted specific greenhouse gas reduction targets. Similar targets exist for the Western Climate Initiative and in proposed national legislation. These goals imply reductions of 30 to 40 percent from 2005 levels by 2030. The Council's plan explores, through various scenario analyses, what actions must be taken to meet these targets in the most cost-effective manner. There are four critical elements to those actions. First is acquiring all of the efficiency improvements (which are significant) identified in this plan's resource strategy. Second is reducing reliance on coal-fired generation to about half of current levels. Third is meeting renewable portfolio standards that already exist in three of the four Northwest states. Finally, the region needs to preserve the capability of the hydroelectric system to the greatest extent possible within the limits of fish and wildlife and other obligations.

BACKGROUND

Greenhouse gases include a family of gases that affect the ability of the Earth's atmosphere to absorb or reflect heat.¹ These include carbon dioxide, methane, nitrous oxide, and man-made chlorofluorocarbon refrigerants. Different gases have different effects on warming and are rated as to their global warming potential. Carbon dioxide, which has become almost synonymous with greenhouse gases, has the least global warming potential. Many other gases have global warming potential thousands of times greater than carbon dioxide. Nevertheless, carbon dioxide has become the primary focus of climate change policy since it accounts for more than three-quarters of the world's greenhouse gas emissions. In the U.S., carbon accounts for 85 percent of emissions, and it is a growing source. Figure 11-1 shows that it is the primary source of greenhouse gas emissions growth in the United States since 1990. Levels of emissions from most other greenhouse gases have been stable or declining. Even carbon dioxide emissions, although growing in total, have declined relative to population and gross domestic product growth in the United States.

Declining carbon dioxide emissions per dollar of gross domestic product have been due to a changing mix of economic activity and improved energy efficiency. Burning fossil fuel accounts for 94 percent of U.S. carbon dioxide emissions. Therefore, declining carbon dioxide emissions reflects a corresponding decline in energy use per dollar of gross domestic product.

¹ The source of information for much of the following discussion is from the Environmental Protection Administration. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006. April, 2008. USEPA #430-R-08-005. <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>

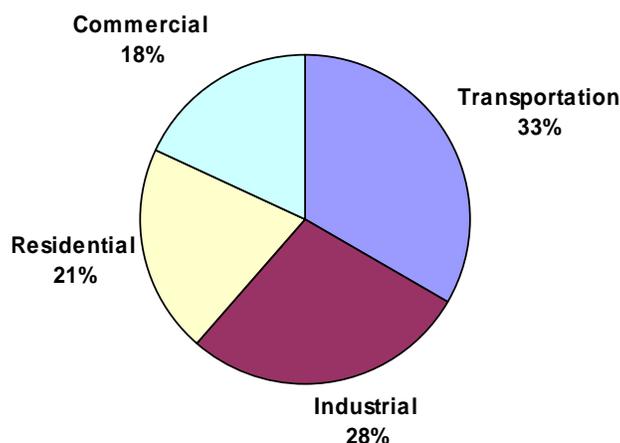
Figure 11-1: Sources of U.S. Greenhouse Gas Emissions, 1990 to 2007

Source: U.S. Energy Information Administration

The National View

Electricity generation is the largest source of carbon dioxide emissions in the U.S. Electricity generation accounted for 38 percent of carbon dioxide emissions in 2005 (Figure 11-3). The next largest sector was transportation at 28 percent, followed by the industrial sector at 20 percent. Other significant sectors include agriculture, residential, and commercial. However, electricity is generated for use in other sectors, too, and when emissions are added to those sectors, a different allocation results. When carbon emissions are connected to human activities, transportation becomes the largest carbon-emitting sector. Figure 11-2 shows the sources of carbon dioxide emission by end-use sector in the U.S.

This implies that to reduce carbon dioxide emissions from the electricity sector, policies should address both electricity generation and energy efficiency. Improved energy efficiency reduces the need to generate electricity in the first place. Improved efficiency of generation and transmission technologies, changing the mix of generation from coal to natural gas, substituting renewable non-carbon emitting sources of generation, or various strategies to sequester the carbon dioxide emissions are all options. Policies should target both sides of the electricity equation, with priority given to the lowest-cost approaches. Furthermore, policies should also address emissions from the direct use of fossil fuel in other sectors, including transportation.

Figure 11-2: Carbon Dioxide Emissions by Sector, 2006

*Note: Electricity generation emissions allocated to end use sectors
Source: U.S. Environmental Protection Agency*

The Pacific Northwest Regional View

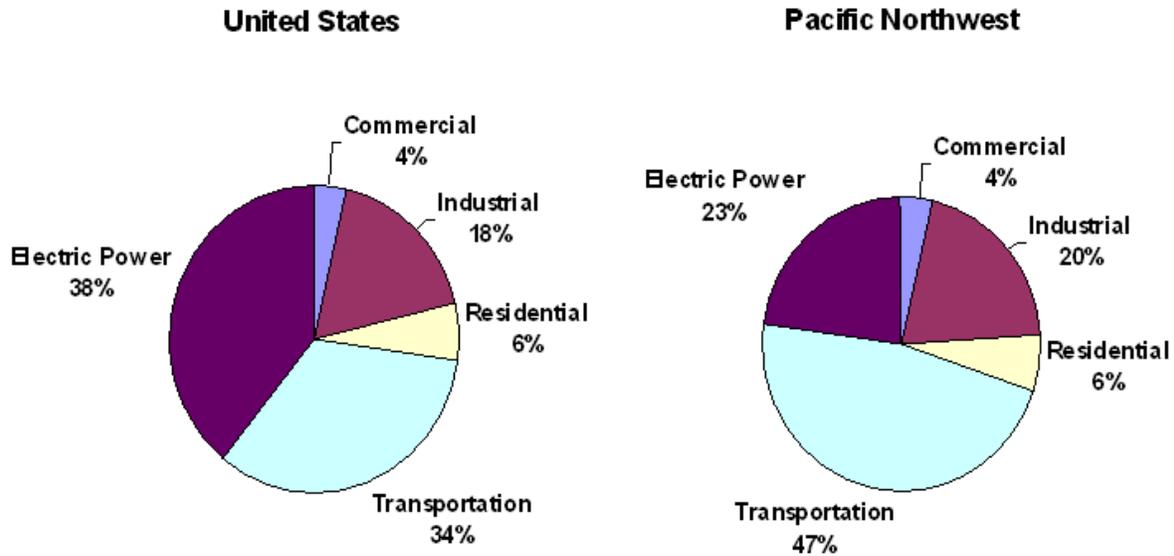
The sources of carbon emissions in the Pacific Northwest are not typical of the U.S. Figure 11-3 compares the shares of carbon dioxide emissions from economic sectors for the U.S. and the four Northwest states. Unlike Figure 11-2, emissions from electricity generation are included in the electric power sector in Figure 11-3. In the Pacific Northwest, the share of energy-related carbon dioxide emissions from electric power generation is much smaller than for the U.S. For the U.S., electricity generation is the largest source of carbon dioxide, but in the Pacific Northwest, transportation is the largest. The reason, of course, is the dominance of the hydroelectric system in Northwest's electricity supply.

The years 1990 and 2005 are frequently used as benchmarks in policies for the control of greenhouse gases.² The 1990 production of carbon dioxide from the Pacific Northwest power system is estimated to have been about 44 million tons, based on electricity production records of that year. Load growth, the addition of fossil fuel generating units, the loss of hydropower production capability, and the retirement of the Trojan nuclear plant resulted in growing carbon production over the next 15 years. By 2005, the most recent year for which electricity production or fuel consumption data are available, carbon production increased 52 percent to 67 million tons (Figure 11-4). This is approximately the carbon output of 23 400-megawatt

² For example, California Assembly Bill (AB) 32, passed by the legislature and signed by the governor in 2006, calls for enforceable emission limits to achieve a reduction in CO₂ emissions to the 1990 rate by 2020. Washington Governor Gregoire's climate-change executive order includes the same target for CO₂ reductions. Oregon House Bill 3543, passed by the legislature and signed by Governor Kulongoski in August, declares that it is state policy to stabilize CO₂ emissions by 2010, reduce them 10 percent below 1990 levels by 2020, and 75 percent below 1990 levels by 2050. The goal of the Western Climate Initiative is to reduce greenhouse gas emissions to 15 percent below 2005 levels by 2020.

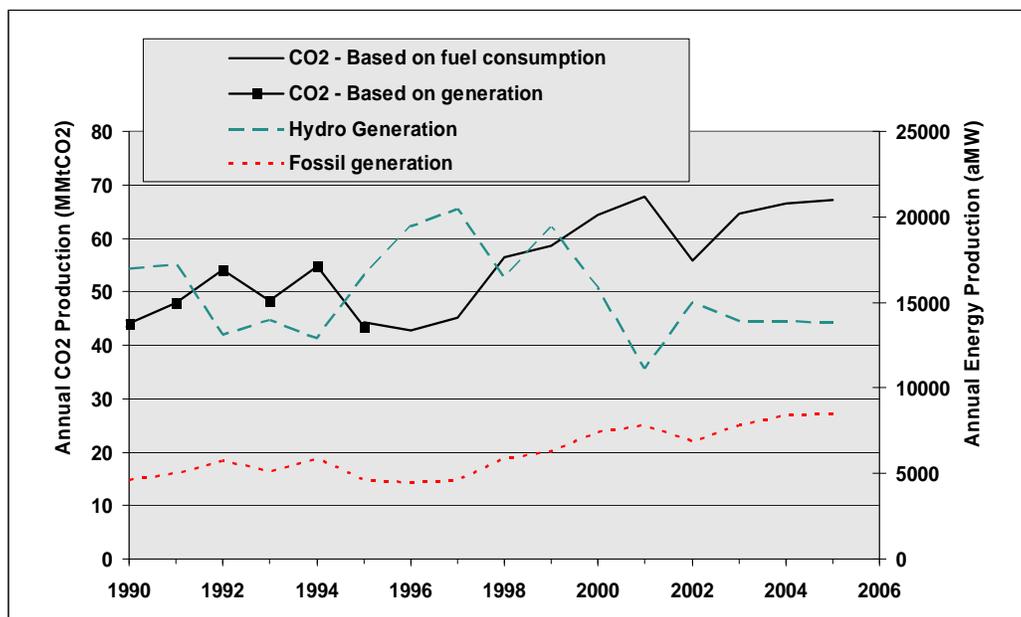
conventional coal-fired power plants, 56 400-megawatt gas-fired combined-cycle plants or about 11.7 million average U.S. passenger vehicles.

Figure 11-3: Energy Carbon Emissions by Sector, 2005



Regional carbon production estimates from 1995 through 2005, shown in Figure 11-4, are based on the fuel consumption of Northwest power plants as reported to the Energy Information Administration (EIA). Because fuel consumption data were not available before 1995, estimates for 1990 through 1995 are based on plant electrical output as reported to EIA and staff assumptions regarding plant heat rate and fuel type. Estimates based on plant electrical production are likely somewhat less accurate than estimates based on fuel consumption because of multi-fuel plants and uncertainties regarding plant heat rates. However, the two series of estimates are within 2 percent in the “overlap” year of 1995.

Figure 11-4: Growth of CO₂ Emissions from Electricity Generation in the Pacific Northwest



Annual hydropower conditions can greatly affect power system carbon production. Average hydropower production in the Northwest is about 16,000 average megawatts. As shown by the plot of Northwest hydropower production in Figure 11-4, the 1990 water year was nearly 17,000 average megawatts, slightly better than average. Other factors being equal, this would have slightly reduced carbon production that year because additional hydroelectric generation would have displaced thermal plant operation. Conversely, hydro production in 2005 was about 13,800 average megawatts, a poor water year. Other factors being equal, this would have increased thermal plant dispatch, raising carbon production. This effect of hydropower generation on thermal plant dispatch and carbon production is apparent in Figure 11-4.³

If the estimated CO₂ production in 2005 were normalized to average hydropower conditions, emissions would have been 57 million tons instead of 67 million tons, a 29 percent increase over the 1990 rate. Current targets have not been clear about this adjustment, but without adjustment, a goal based on 2005 emissions would be much easier to meet than one based on 1990. In the power plan, the Council has used the adjusted-to-normal hydro value for 2005 so that the number will be comparable to forecasts of average emissions in the plan's scenarios. It should be clear, however, from the discussion and Figure 11-4 that average carbon emissions will disguise significant carbon emissions sensitivity to hydro conditions in the region.

ACTIONS TO REDUCE GREENHOUSE GAS EMISSIONS

From a broad perspective, there are three things we can do to reduce carbon dioxide emissions: generate electricity from lower or zero carbon-emitting fuel, use less electricity, or sequester or

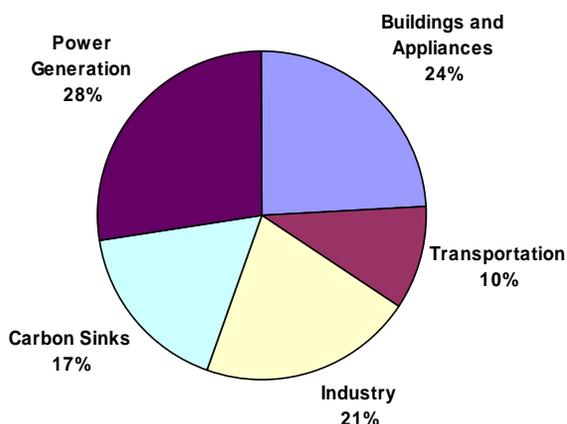
³ In Figure 11-4, it is evident that Northwest thermal generation does not decline as much as Northwest hydro generation increases in above average water years, e.g. 1994 - 1997. This is likely due to the fact that the abundant hydropower of good water years creates a regional energy surplus that can be sold out of the region where it displaces thermal generation, which often consists of older, less efficient gas-fired units.

offset carbon that is released. In 2007, McKinsey and Company studied how much greenhouse gas reduction was possible in the U.S. and what it might cost.⁴ The McKinsey report looked at alternative actions to reduce greenhouse emissions. They assumed that without actions, greenhouse gas emissions would grow from 7.2 billion metric tons to 9.7 billion metric tons by 2030. They then analyzed ways to reduce 2030 emissions by 3.0 billion metric tons, which was characterized as the mid-range of reductions sought in proposed legislation.

They estimated that about 40 percent of reductions could be done at no cost. Nearly all of this came from improved energy efficiency in buildings or vehicles. The remaining 60 percent of greenhouse gas reduction came from an array of actions that increased in cost as reductions grew. The most expensive option to achieve the 3.0 billion metric ton reduction of 2030 emissions was estimated to cost \$60 per ton.

All of the actions included in the McKinsey analysis were placed into five categories: buildings and appliances, transportation, industry, carbon sinks (or sequestration), and power generation. In the case where carbon emissions were reduced by 3.0 billion tons, the sources of reductions are shown in Figure 11-5. As with the case for Figure 11-2, emission reductions from energy efficiency are counted in the sector where electricity is consumed.

Figure 11-5: Estimated Sources for a 3 Billion Ton Reduction of GHG Emissions by 2030



There are some interesting observations to make about the McKinsey results. Although a great deal of the policy discussion on carbon reduction focuses on the electricity generation sector, only a quarter of the actions identified in the McKinsey report are electricity generation changes. Further, the electricity generation changes are among the more expensive actions, and they include actions such as renewable generation and carbon capture and sequestration, which cannot be implemented easily in the near term.

Another focus of policy speculation is hybrid vehicles. In the McKinsey analysis, it is the most expensive alternative shown (around \$90/ton) and it has relatively small potential for carbon

⁴ McKinsey & Company. Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost? U.S. Greenhouse Gas Abatement Mapping Initiative, Executive Report. December 2007.

reduction. The plug-in hybrid option was not needed to reach the 3.0 billion ton reduction case. However, improved efficiency of conventional vehicles has far more potential to lower carbon emissions in the short-term, and it is less expensive than PHEV.

If the goal is to stabilize greenhouse gas concentrations in the atmosphere, and if the climate change science is correct, policy decisions would not be a question of which mitigation strategies to pursue, but rather how to pursue all possible actions. The reductions in emissions that the McKinsey report addressed were for recent climate change policy proposals, but they do not reach the reduction levels needed to stabilize warming trends identified by climate scientists. For example, the Intergovernmental Panel on Climate Change estimated that greenhouse gas emissions would need to be reduced to about one-quarter of today's emissions by 2100 to stabilize their atmospheric concentrations.

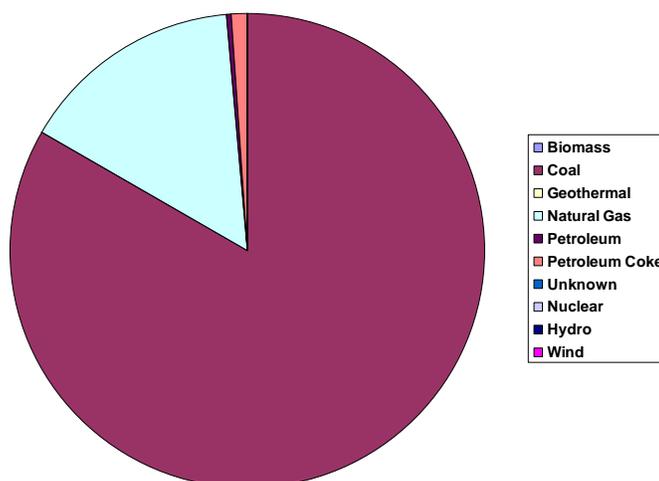
There have been many studies on the costs of particular climate change policies. The usual purpose has been to try to estimate the price of carbon that is likely to be associated with a policy. EcoSecurities Consulting Limited conducted a study for the Council to determine a range of likely carbon costs for the plan's analysis. EcoSecurities reviewed many studies and provided a set of alternative estimates based on their models of supply curves for carbon-mitigation actions. In addition, Point Carbon reviewed the results of seven studies of the Lieberman-Warner bill for the Bonneville Power Administration, and used the studies to estimate a reasonable range of expected carbon prices under the proposed cap-and-trade policy.

Carbon price estimates under cap-and-trade programs are very sensitive to different assumptions about such things as the level of the carbon emissions cap, the use of offsets, banking and borrowing provisions, and the geographic scope of trading. Price forecasts for the 2025 to 2030 time period varied from near zero to well over \$100 per ton of carbon emissions. However, the more plausible range of prices was from roughly \$10 to \$80. The EcoSecurities report estimated that carbon prices might need to reach about \$50 a ton by 2030 to move toward the Intergovernmental Panel on Climate Change goal of stabilizing emissions concentrations by 2100. Point Carbon's assessment suggested that prices would escalate rapidly in years beyond 2030, although they regard their forecasts that far into the future as highly speculative and unlikely to consider technological developments that may occur.

For the Sixth Power Plan, the Council considered a range of possible carbon costs between zero and about \$100 per ton, with an average cost of about \$47 per ton by the end of the study's horizon. This possible but uncertain cost of carbon has a significant influence on the plan's resource strategy. Energy efficiency, renewable generation, natural gas-fired generation, coal (with or without carbon sequestration), and advanced nuclear power all compete to provide the lowest-cost and least-risky resource portfolio. Even before accounting for the effects of uncertainty and risk on resource costs, it is clear that improved efficiency is available in significant amounts and at low cost without adding carbon or fuel price risks for the region. Natural gas, wind (that can be developed without significant transmission expansion), and possibly some small quantities of other currently available renewable technologies are more expensive. Many other renewable resources--coal with carbon separation and sequestration and advanced nuclear--may become available within the Council's planning horizon, but they are not currently available or are very expensive.

To achieve significant reductions in the regional power system's carbon emissions, simply reducing or stopping the growth of carbon emissions will not be enough. As shown in Figure 11-6, existing coal-fired power plants account for about 88 percent of the region's emissions. Therefore, the region could not reduce its power system emissions below 1990 levels, as some targets require, if the region's coal plants continue to operate as they do now. Part of the solution to aggressive carbon emission reductions would have to include changing the role of existing coal-fired generation. This would occur as a matter of economics if carbon penalties are high enough and natural gas prices low enough. Natural gas-fired generation would begin to displace coal-fired generation in the dispatch order. In addition, some older coal-fired plants that need additional investment to continue or meet more stringent environmental requirements may choose to close rather than face the uncertainty of unknown future carbon costs.

Figure 10-6: Sources of CO₂ Emissions from the Northwest Power System, 2005



POLICIES TO REDUCE GREENHOUSE GASES

There are many possible policy approaches to reduce carbon emissions: cap-and-trade programs, direct taxation of emissions, regulatory programs that limit emissions or require non-emitting resources to be developed, and efforts to improve energy efficiency. Most recently, proposed national legislation has focused on cap-and-trade programs, but none has been passed to date. At the regional and state level, renewable portfolio standards and limits on the emissions of new power plants have been the prevailing policies. The Council has primarily focused on energy efficiency, and states, utilities, and the federal government have initiatives to improve efficiency as well. Most of these efficiency programs existed well before the climate change issue was prominent, simply because improved efficiency was cheaper than building new electric generating plants and it contributed to reduced oil imports. Each approach has advantages and disadvantages.

Mandates

Mandates direct companies and individuals to acquire or produce equipment that meets an approved standard of energy efficiency or uses approved types of energy. One example is the

Corporate Average Fuel Efficiency standard for cars and light trucks. It has been in place since 1975 and imposes fines on car manufacturers whose products do not meet the standard. Other examples are appliance efficiency standards and the region's building codes, which have had an energy-efficiency component for more than 20 years.

More recently, Washington, Oregon, and Montana in the Pacific Northwest and a number of states elsewhere in the country have passed laws (renewable portfolio standards) that require utilities to increase generation from renewable resources. These or related laws have in some cases also required generators that use non-renewable fuel to keep their emissions below a maximum emissions per kilowatt-hour standard (e.g., Washington and California).

Mandates have the advantage of being simple and are fairly easy to enforce. They have the disadvantage that they are inflexible in the face of changing technology or other conditions. Unless made sufficiently flexible, a mandate would focus policy on only one approach to reducing carbon emissions and not consider other alternatives that might be more effective or less expensive.

Tax Incentives

Tax incentives will help by reducing the overall investment in preferred resources and equipment through accelerated depreciation, tax credits, or various forms of tax exemptions. Such tax incentives have been extended to hybrid cars, wind generators, energy-efficient equipment and structures, renewable energy equipment purchases, and renewable energy equipment manufacturing facilities.

Tax incentives can also increase the value of output from preferred equipment such as wind-driven generators by granting tax credits (e.g. the production tax credit) based on the amount of electricity produced by the generators. Compared to investment tax credits, production credits have the advantage in that the credit is based on the actual generation, so that producers are encouraged not only to invest in preferred equipment, but also to produce as much electricity as possible with it.

Cap-and-Trade Programs

A cap-and-trade policy sets a cap on the total amount of emissions allowed in the covered territory. The cap is enforced by issuing allowances in the amount of the cap and then requiring emitters to surrender allowances in the amount of their emissions. The strategy is to reduce the amount of the cap and the equivalent allowances over time to reduce emissions. Emitters are allowed to trade allowances to encourage those who can reduce emissions easily and cheaply to do so and profit by selling their surplus allowances to other emitters. Emitters may be allowed to "bank" or "borrow" allowances from year-to-year if they have a surplus or deficit of allowances in a given year. Cap-and-trade programs may include provisions for offset allowance credits resulting from taking certain emission reduction actions outside the scope of the regulated system.

A cap-and-trade policy to control emissions of sulfur dioxide and nitrogen oxide was established as part of the 1990 Clean Air Act. This policy is generally regarded as a success, resulting in faster reductions in sulfur dioxide emissions at lower costs than anticipated. Cap-and-trade

programs have been included in proposed federal legislation to control greenhouse gas emissions and are also included in Western Climate Initiative discussions. The European Union Emission Trading System has been in place since 2005, capping a substantial fraction of Europe's total greenhouse gas emissions and providing experience with this policy approach.

Compared to mandates and tax incentives, a cap-and-trade policy has the advantage of flexibility. Emitters can pursue a variety of strategies to reduce their own emissions or they can pay other emitters to reduce. They can choose the strategy that will minimize their cost (and the societal cost) of compliance. Another advantage of cap-and-trade policy compared to mandates and tax policies is that the cost of emission allowances is incorporated into the retail prices of energy, at least theoretically providing appropriate price signals to consumers.

As a policy with the goal of reducing emissions of greenhouse gases, cap-and-trade programs make the physical target for emissions explicit. As a result, the policy should meet the target reliably, but emission prices and total costs of emission reductions could be volatile and hard to predict. In contrast, carbon tax policy has a more predictable total cost, but a less predictable total reduction in emissions.

Finally, cap-and-trade programs need to develop a market to trade emission allowances. The market mechanism offers the potential for emission reductions at low costs. But developing a market to trade newly-created assets like emission allowances requires careful consideration to ensure that the market will function as expected.

Carbon Taxes

A carbon tax would likely apply not only to carbon, but to all greenhouse gases in proportion to their climate-changing effects, and would tax emissions at a level to control and mitigate climate change.

A carbon tax has the advantage of being easier to administer than a cap-and-trade system and the cost is predictable, but the carbon reductions are less certain. A cap-and-trade program makes carbon reductions more predictable, but it is complex to administer and the total cost is unpredictable.

As a practical matter, this distinction between a carbon tax and cap-and-trade program may be less than it seems. Given the current state of knowledge about the effects of climate change and the technological choices available for reducing emissions, it seems inevitable that whatever initial cap is chosen for the cap-and-trade program, or whatever initial level is chosen for a carbon tax, new information that becomes available over the next several decades will require adjustments in the national and global strategy to control greenhouse gases.

CURRENT POLICIES AND GOALS AFFECTING THE PACIFIC NORTHWEST

At present, carbon reduction policies regionally, nationally, and globally are still very much in a state of flux. Reduction goals range from stabilizing emissions at current levels to reducing emissions to 1990 levels or below.

International Initiatives

Significant international initiatives targeted at climate change can probably be dated from 1992, when the United Nation’s Framework on Climate Change was negotiated. Since then, there have been several significant milestones in international action, including the Berlin Mandate in 1995, calling for emission targets for developed countries, and the Kyoto Protocol in 1997, which set reduction targets for developed countries to meet by the 2008-2012 period. The Kyoto Protocol, in spite of the withdrawal of the U.S. in 2001, has been ratified by 182 countries, including 37 industrialized countries that account for over 60 percent of the emissions from developed countries.

The European Union’s Emissions Trading System has been functioning since 2005. It is a cap-and-trade system currently covering sources that are responsible for about half of the European Union’s total carbon dioxide emissions. The system’s first three years of operation (2005-2007) were intended to test the functioning of the market mechanism itself rather than to achieve significant reductions. The system has experienced episodes of price volatility, which has been attributed to imperfect data and the limited provision for banking emission allowances. Some electric power generators appear to have received windfall profits, which has focused attention on the regulatory treatment of those generators. The system will gradually expand to include emissions from more sources constituting a bigger share of total emissions over time.

The Intergovernmental Panel on Climate Change⁵ has identified a goal of limiting global warming to 2 degrees Celsius (3.6 degrees Fahrenheit) and has translated that goal into emission-reduction targets for developed countries. Those targets call for an 80 percent to 95 percent reduction relative to 1990 levels by 2050.

Federal Policies

Environmental Protection Agency Role

On April 2, 2007, in *Massachusetts v. EPA*, 549 U.S. 497 (2007), the Supreme Court found that greenhouse gases are air pollutants covered by the Clean Air Act. The Court held that the administrator must determine whether or not emissions of greenhouse gases from new motor vehicles cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare, or whether the science is too uncertain to make a reasoned decision.

On December 7, 2009, the Environmental Protection Agency administrator signed two distinct findings⁶ regarding greenhouse gases under section 202(a) of the Clean Air Act:

- that the current and projected concentrations of six key greenhouse gases, including carbon dioxide in the atmosphere threaten the public health and welfare of current and future generations and

⁵ Information on the Intergovernmental Panel on Climate Change (IPCC) can be found at <http://www.ipcc.ch/>.

⁶ The Environmental Protection Agency findings are found in “40 CFR Chapter I Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act; Final Rule” and were published on December 15, 2009 in the *Federal Register* under Docket ID No. EPA-HQ-OAR-2009-0171. The final rule will be effective January 14, 2010.

- that the combined emissions of these greenhouse gases from new motor vehicles and new motor vehicle engines contribute to the greenhouse gas pollution which threatens public health and welfare.

These findings currently do not impose any requirements on industry or other entities. However, they are a prerequisite to finalizing the EPA's proposed greenhouse gas emission standards for light-duty vehicles, which were jointly proposed by EPA and the Department of Transportation's National Highway Safety Administration on September 15, 2009.

These findings also are not likely to have a significant adverse effect on the supply, distribution, or use of energy because they do not impose any requirements at this time.⁷ There remains a possibility that the EPA could impose greenhouse gas emission limits on electricity generators at some time in the future; however, the current administration has indicated a preference to control greenhouse gases via legislation as opposed to EPA mandates.

Legislative Efforts

There have been a series of proposals for national legislation on climate change. The most recent serves as an example of the policy being discussed. The Waxman-Markey draft legislation, entitled "The American Clean Energy and Security Act of 2009," proposed a comprehensive strategy for energy planning and use. The legislation contained provisions to increase use of renewable energy and to improve efficiency. It would require electric utilities to meet 25 percent of their load with a combination of renewable energy and efficiency improvements by 2025. In addition, it proposes creation of a greenhouse gas tradable allowance system that would reduce emission allowances to 83 percent lower than 2005 levels by 2050. The bill also contained numerous other provisions providing assistance for reducing emissions and directing EPA to take specific actions.

Regional Policies

The Western Climate Initiative (WCI) is a broad regional effort to implement policies to reduce greenhouse gas emissions. The governors of Oregon, Washington, and Montana have joined five other Western state governors and the premiers of four Canadian provinces to implement policies that address climate change. The overall goal of the WCI is to reduce the region's greenhouse gas emissions to 15 percent below 2005 levels by 2020. The primary policy objective of the WCI is to implement an economy-wide regional cap-and-trade program.

The WCI Partners have promulgated specific design recommendations for the regional cap-and-trade program. In its first phase, beginning in 2012, the program would cover emissions from electricity production and from large industrial processes. The program would cover emissions of carbon dioxide and five other major greenhouse gases. In its second phase, beginning in 2015, the program would be expanded to cover emissions from the combustion of transportation fuel and fuel burned at industrial, commercial, and residential buildings.

The WCI's work has made it clear that a regional cap-and-trade program faces problems that a national or international program does not. For example, because individual states and provinces

⁷ See "H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use."

have significant flexibility to modify their jurisdiction's reduction targets, the allocations are a source of potential conflict. Another example is the potential for "leakage" that can result from shifting emissions from inside the WCI to the outside. Such a shift would allow WCI emission targets to be met, but with no net reduction in global emissions. Leakage becomes less likely as the geographic scope of the cap-and-trade program expands to the national or international level.

State Policies

Policy initiatives at the state level to address climate change are numerous, but three types of state policy predominate: greenhouse gas reduction goals; renewable portfolio standards; and emission performance standards. There is a great deal of policy work aimed at establishing renewable energy tax credits, renewable energy feed-in tariffs, renewable energy enterprise zones, funding mechanisms for energy-efficiency projects, improved commercial and residential building codes, and others that either directly or indirectly influence greenhouse gas production, but the focus here is on policies that have the greatest relevance to the Sixth Power Plan.

Greenhouse Gas Emission Reduction Goals

The 2007 Oregon Legislature set greenhouse gas emissions reduction goals for the state. The mid-term goal is to reduce emissions to 10 percent below 1990 levels by 2020. The long-term goal is a 75 percent reduction from 1990 levels by 2050. The 2009 Legislature is considering Senate Bill 80, which would authorize the state's participation in the WCI cap-and-trade program as a key means of reaching the future emission goals.

The 2009 Washington Legislature is also considering WCI cap-and-trade legislation. House Bill 1819 and Senate Bill 5735 would codify the state's goal of reducing greenhouse gas emissions to 1990 levels by 2020, achieving a 25 percent reduction by 2035, and a 50 percent reduction by 2050.

Renewable Portfolio Standards

Since the adoption of the Fifth Power Plan, renewable resource portfolio standards that mandate developing certain types and amounts of resources have been adopted by Oregon, Montana, and Washington. Similar standards have been adopted by Arizona, British Columbia, California, Colorado, New Mexico, and Nevada. The key characteristics of the Pacific Northwest states' renewable targets are summarized in Table 10-1. The targets are subject to adjustments if costs increase above certain limits.

Table 10-1: Renewable portfolio standard targets

	Basic Standard
Montana	15% of IOU sales by 2015
Oregon	25% of sales by 2025 (large utilities)
	10% of sales by 2025 (medium utilities)
	5% of sales by 2025 (small utilities)
Washington	15% of sales 2020 + cost-effective conservation (utilities w/25,000 or more customers)

Carbon Dioxide Emission Performance Standards

Carbon dioxide emission performance standards have been adopted by California, Montana, Oregon, and Washington. The Northwest state standards in effect at the time of this plan's release are as follows:

Montana: In May 2007, Governor Schweitzer of Montana signed into law HB 25, an electric power reregulation bill. Among various provisions, this bill prohibits the Public Service Commission from approving electric generating units constructed after January 1, 2007 and primarily fueled by coal unless a minimum of 50 percent of the carbon dioxide produced by the facility is captured and sequestered. The requirement remains in effect until such time that uniform state or federal standards are adopted for the capture and sequestration of carbon dioxide. The bill further provides that an entity acquiring an equity interest or lease in a facility fueled primarily by natural or synthetic gas is required to secure cost-effective carbon offsets where cost-effective is defined as actions to offset carbon dioxide that do not increase the cost of electricity produced by more than 2.5 percent.

Oregon: Since 1997, the developers of new power plants in Oregon have had to offset their carbon dioxide emissions to a level 17 percent below best commercial generating technology of equivalent type. In July 2009, Governor Kulongoski signed into law SB 101 to establish a new greenhouse gas emission performance standard for all long-term procurements of electricity by electricity providers. The standard will be established by the state's Department of Energy and will apply to all baseload electrical generating facilities. Baseload generating facilities are defined as facilities designed to produce electricity on a continuous basis at a 60% capacity factor or greater. The standard will require that the greenhouse gas emissions of new baseload facilities be no greater than the rate of greenhouse gas emissions of a combined-cycle power plant fueled by natural gas.

Washington: Since 2004, Washington has required fossil-fueled power plants of 25 megawatts or greater to offset or otherwise mitigate carbon dioxide emissions by 20 percent. In addition, RCW 80.80, signed into law by Governor Gregoire in May 2007 establishes a greenhouse gas performance standard for all "long-term financial commitments" for baseload generation used to serve load in Washington, entered into in July 2008, or later. The requirement applies whether the source is located within or outside the state. Modeled on California Senate Bill 1368, the law defines baseload electrical generating facilities as facilities designed to produce electricity at a 60 percent capacity factor or greater. The law adopts the initial California limit of 1,100 lbs/CO₂ per megawatt-hour, and requires that the limit be reviewed and adjusted every five years by the Department of Community Trade and Economic Development to match the average rate of emissions of new natural gas combined-cycle power generation turbines. The limit is likely to be reduced on review since current natural gas combined cycle plants produce about 830 lb/CO₂ per megawatt-hour (the California limit appears to have been based on the carbon dioxide output of an aeroderivative simple-cycle gas turbine operating on natural gas, not a combined-cycle turbine). The law allows up to five years to implement a carbon dioxide separation and sequestration regime (if the technology is available), as long as average lifetime emissions comply with the emissions performance standard.

EVALUATING CARBON STRATEGIES

Existing climate change policies, such as the Oregon and Washington emission reduction goals, as well as proposed future policies were factors in developing the Sixth Power Plan's resource strategy.

The recommended actions in the Sixth Power Plan reflect existing carbon emissions policies that are assumed to continue. That is, the renewable portfolio standards that have been adopted in three states, the new generation emissions standards adopted by three states, and renewable energy credits are included in the analysis and are assumed to be enforced. In addition, the plan recognizes that there are adopted goals for greenhouse gas emissions reductions for Oregon and Washington, as well as proposed federal legislation with similar goals. Most proposed policies to attain these goals rely on some system for putting a cost on carbon emissions. Whether these costs are the price of emission allowances under a cap-and-trade system or some form of carbon tax, the costs imposed on the power system are a risk that the plan addresses, along with other costs and risks faced by the regional power system.

The Council's assumptions on carbon price risk were based on consultations with a range of utility and other analysts and reviews of studies by others, including a report done for the Council by EcoSecurities Consulting Ltd. The assumptions are included in the regional portfolio model's carbon risk study as a distribution of 750 carbon-price trajectories that range from zero to \$100 per ton, with an expected value of about \$47/ton in 2030. A partial survey of regional utilities indicated that the range of prices the Council included in its analysis is generally consistent with assumptions used in their analyses.

Tracking power system emissions in the region requires a definition on how to treat emissions from electricity that is imported and exported. The emissions reported in this plan include those from generators located outside the region, but whose output is committed to serving regional load. These generators include parts of the Colstrip generation complex in eastern Montana, all of the Jim Bridger complex in Wyoming, and part of the Valmy generation complex in Nevada. This approach is referred to as "generation based." The regional portfolio model also reports another approach referred to as "load based" carbon emissions. This alternative approach counts emissions associated with imports and excludes emissions associated with the electricity exported from the region. For ease of exposition and comparability, most of the discussion in the plan refers to generation-based carbon counting. In addition, the generation-based carbon emissions are adjusted to be consistent with the accounting reflected in the Council's 2007 carbon footprint paper.⁸

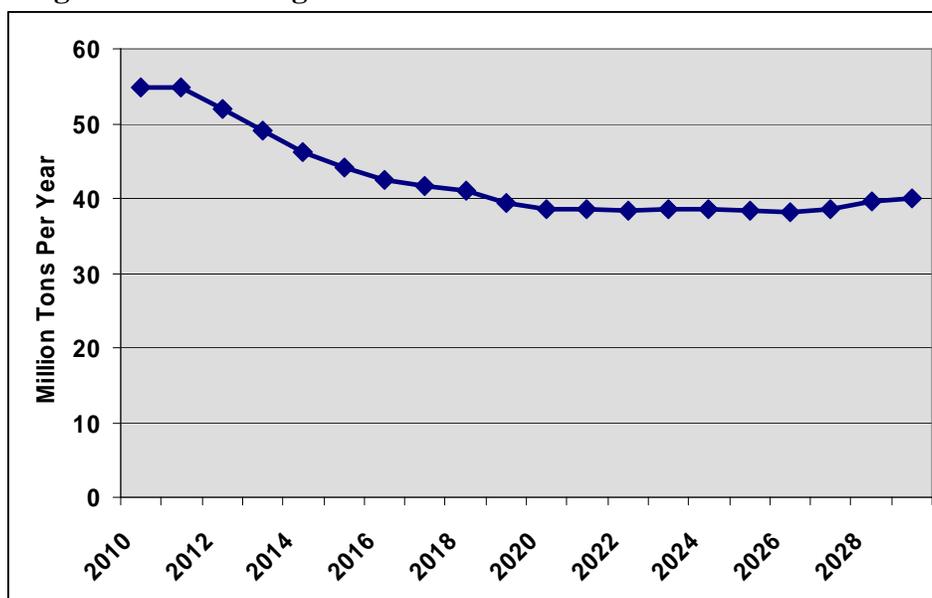
There are also some complications in how to account for the estimated cost of carbon-pricing policies to the regional power system. The default accounting of power system costs in the Council's models includes carbon penalties as though they were paid as a tax on every ton of carbon emitted. This approach is valid for modeling the penalties' effect on power system development and operating decisions. However, the default accounting can significantly overestimate the total costs that the power system would recover from ratepayers, depending on the kind of carbon penalty the system faces. In particular, the current language of the U.S.

⁸ Northwest Power and Conservation Council, *Carbon Dioxide Footprint of the Northwest Power System*, November 2007. (Council Document 2007-15)

House of Representatives proposal on climate policy includes a cap-and-trade system that grants free allowances to utilities that roughly offset their emissions until 2026. This approach would greatly reduce the cost to the power system, compared to a carbon tax on all emissions. To include the effect of different forms of carbon penalties, the regional portfolio model has an alternative accounting that excludes the amount of tax revenues. This alternative accounting provides a better cost estimate of a cap-and-trade, free-allowances mechanism to the power system.

The Council's plan provides a resource strategy that minimizes the cost of the future power system given the policy risks. A combination of aggressive development of energy efficiency, renewable resources, and in the longer-term, new gas-fired resources results in a reduction of power system carbon emissions from 57 million tons per year in 2005 to 40 million tons in 2030, which is below the 1990 emission level of 44 million tons. These reductions are generally consistent with the targets adopted by Northwest states. The reduced carbon emissions depend on efficiency improvements and other low-emission generation displacing the reliance on existing coal plants. Figure 11-7 shows the projected average carbon emissions over time in the carbon risk scenario. That scenario on average meets or exceeds the 2020 targets adopted by Washington, Oregon, the WCI, and the Waxman/Markey proposed legislation.

Figure 11-7: Average Sixth Power Plan Annual Carbon Emissions



The carbon-cost risk assumptions play an important role in these results. If only current policies are assumed in the future--and no carbon pricing policies are implemented or expected--a least-cost resource strategy would stabilize carbon emissions from the power system at around current levels. Current policies arrest the growth of carbon emissions because of aggressive efficiency improvements, which are cost-effective even without carbon penalties, and increased acquisition of renewable generation. But existing policies will not achieve the carbon emissions goals of the WCI or of some individual states in the region.

The cost of moving from current policy to the carbon risk scenario is significant. Responding to the risk of carbon penalties in the \$0 to \$100 per ton range increases power system costs by 14 percent. When the carbon penalty is included, the cost increase is estimated to be 41 percent.

The extent to which the carbon penalty is a net cost to the power system or region depends on how that policy is structured. Current proposed federal policy provides free emission allowances under a cap-and-trade system for many years, which would put the cost impact near the lower end of the range. If power system costs increase by 14 percent, average electricity revenue requirements would increase by about 2 percent compared to current policies. However, the cost increase would not be spread evenly among the regional utilities and consumers. Utilities that are more reliant on coal-fired generation would bear a larger part of the cost of carbon emission reduction.

To significantly lower carbon emissions from the power system, existing coal-fired generation would have to be reduced. This is not surprising since existing coal plants account for about 88 percent of the carbon emissions from the regional power system. In the carbon risk scenario, carbon reductions occur because these plants are used much less frequently. In doing so, however, maintaining the plants may not be economically feasible for utilities. In addition, while carbon emissions are reduced to target levels on average, the certainty of achieving targets is low. Depending on how some future uncertainties unfold, such as hydro conditions, carbon prices, and other factors, emissions can vary greatly and need not fall below the targets.

Two alternative scenarios were analyzed that provided more clarity with regard to what the region would need to do to meet a specific carbon reduction target in the 35 to 40 million tons per year range. One of those scenarios implemented a fixed \$45 per ton carbon penalty, which was sufficiently high to reach the emissions target. That scenario resulted in average 2030 carbon emissions of 37 million tons, 35 percent below 2005 levels. In addition, the likelihood of attaining the desired reductions is somewhat higher than in the \$0 to \$100 per ton scenario.

The second of these scenarios phased out existing coal generation until emission targets were met. This coal retirement scenario retired about half of the coal-fired generation serving the region. Average 2030 carbon emissions were reduced to 36 million tons. Importantly, the certainty of carbon reductions is much greater in the coal retirement scenario. Replacing the energy and capacity from coal plants would increase average power system costs by about 15 percent above the current policy scenario. While this is an alternative policy approach to consider, it would not have the broad effect on other sectors and resource decisions that a cap-and-trade or tax would have. If a coal retirement policy were implemented in combination with a carbon penalty, fewer coal plants would need to be retired, but the remaining plants would still be used less frequently in response to the carbon prices. These scenarios are discussed further in Chapter 10.

In summary, there are four things the region would have to do to meet existing 2030 carbon reduction targets. First, the efficiency of electricity use has to be improved to save nearly 6,000 average megawatts by 2030. These efficiency improvements are key to reducing carbon emissions. In the carbon risk scenario, efficiency improvements lower 2030 carbon emissions by 17 million tons per year. Without efficiency improvements, carbon prices modeled in the carbon risk scenario would only stabilize emissions at the 2005 level. Second, renewable portfolio standards adopted in three of the four Northwest states must be implemented. These resources play a significant role by reducing the amount of carbon-emitting generation. Third, the use of coal-fired generation must be further reduced either by policy or by carbon penalties. In all three of the scenarios that meet carbon reduction goals, coal-fired generation is reduced by about half

from current levels. Finally, the region needs to preserve the capability of the hydroelectric system to the greatest extent possible within the limits of fish and wildlife obligations.

Just as coal-fired generation is the source of most of the power system's carbon emissions, the regional hydroelectric system is the source of most of the region's energy, capacity, and flexibility supply. As a carbon-free resource, it is extremely valuable to the region. Because of the hydroelectric system, combined with the region's past accomplishments in energy efficiency, the region's carbon emissions are half the nation's in terms of carbon emission per kilowatt-hour of energy consumption. Meeting the region's responsibilities for mitigating the fish and wildlife losses caused by the dams has depleted the capabilities of the hydroelectric system over time. If the region needs to further reduce hydroelectric generation for fish and wildlife survival, it should do so with careful analysis of the costs, risks, and benefits of the proposed actions. The region needs to be sensitive to the fact that further reduction in hydroelectric generation will increase carbon emissions, which will also harm fish and wildlife in the long term through accelerated climate change. For example, an analysis in the draft plan showed that removing the lower Snake River dams would undo 40 percent of the carbon reductions expected to be accomplished through the existing carbon policies in the region, while also increasing the cost of the power system.

Chapter 12: Capacity and Flexibility Resources

Summary of Key Findings	1
Background	2
Power System Requirements: Capacity, Energy, and Flexibility	2
Capacity: Meeting Peak Demand.....	2
Energy: Meeting Average Demand	5
Flexibility: Providing Within-hour Balance	5
Power System Operations	5
Ancillary Services.....	6
Regulating and Balancing Reserves.....	6
Flexibility Issues Raised By Wind Generation.....	11
Response to Growing Need for Flexibility	12
Institutional Changes	13
Adding Flexible Capacity	14

SUMMARY OF KEY FINDINGS

Historically, Northwest power system planners have focused on providing sufficient energy to meet the annual energy load of the region. Largely because of the way the hydroelectric system developed, capacity, the ability to meet peak-hour load, and flexibility, the ability to rapidly increase or decrease generation output, were not significant problems.

Today, however, focusing regional power system planning solely on annual energy requirements is no longer adequate. Changes in the seasonal shape of Northwest load, increasing constraints on the operation of the hydrosystem to meet fish requirements, and rapidly increasing amounts of variable generation, especially wind, are making increased system capacity and flexibility a new priority.

Wind generation needs back-up, flexible resources to handle unexpected changes in its output. While the problems appear daunting, particularly in integrating new wind generation with a more constrained hydrosystem, there are solutions. The first step is to change system operating procedures and business practices to more fully utilize the inherent flexibility of the existing system. The Council believes these changes will be significantly cheaper to achieve, and can be implemented sooner than adding additional generating capacity solely to provide flexibility. It will also set the stage for determining how much flexibility will ultimately be needed from new generation.

Actions for these operating and business practice changes include: establishing metrics for measuring system flexibility; developing methods to quantify the flexibility of the region's existing resources; improving forecasting of the region's future demand for flexible capacity; improving wind forecasting and scheduling; transitioning from the current whole-hour scheduling framework to an intra-hour scheduling framework; and increasing the availability and use of dynamic scheduling. Fully implementing these improvements may also require physical upgrades to transmission, communication, and control facilities, though the cost of these upgrades is expected to be relatively small compared to the cost of adding new flexible capacity.

Because the reliable operation of the power system depends on agreement on these operating procedures, they cannot be changed overnight. However, significant studies and discussions are underway to achieve these changes and the Council urges they be supported by the region's utilities and power producers.

The next step is to ensure that resources added to meet peak-hour load are also flexible enough to respond to unexpected changes in wind plant output. These solutions should be sought in a sequence that makes economic sense. Actions include: considering rapid-response natural gas-fired generators, pumped-storage hydro plants and other storage resources, utility demand response programs and other potential smart grid applications, and geographic diversification of wind generation as options to meet the region's future demand for flexibility. Some balancing authorities, Bonneville especially, may need additional flexibility resources, either from better use of existing resources or from new resources, solely for integration of wind generation that meets load in other balancing authorities.

BACKGROUND

The fundamental objective of power system operations is to continuously match the supply of power from electric generators to the customers' load. Historically, for resource planners, the balancing problem was addressed in two ways. First, build enough generating capacity to meet peak-hour demand, plus a reasonable cushion to account for unexpected generator outages. Second, ensure an adequate fuel supply to operate electrical generators month-after-month and year-after-year to meet customers' energy demand. This was sufficient because traditional resources provided system operators with the means to deal with the fundamental requirements of power system operation. Because of the way the Northwest hydropower system was developed, over most of the past 40 years, the Northwest's resource planning has been more straightforward: to meet the annual energy needs of the system. The Northwest was able to focus on annual energy needs because the hydrosystem provided ample capacity and flexibility to balance generation and load at all times.

Today, power system operators and planners must again focus on ensuring that the installed generating capacity is flexible enough to rapidly increase or decrease output to maintain system balance second-to-second and minute-to-minute. This shift is a result of the dramatic increase in the region's use of wind generation, which creates unique challenges for system operators. Over the course of minutes and hours, the output of a wind generator can be extremely variable, ranging from zero to its maximum output. While power system operators try to predict changes in wind generation, they also need other capacity, sufficiently flexible, to offset unexpected changes in its output.

POWER SYSTEM REQUIREMENTS: CAPACITY, ENERGY, AND FLEXIBILITY

Capacity: Meeting Peak Demand

In previous plans, the Council focused primarily, like other regional resource planners, on the energy output of generators. Energy is the total output of a plant, typically measured over a year in megawatt hours or average megawatts. The touchstone for judging whether the region had

adequate resources has long been whether the power system could generate sufficient energy during adverse water conditions. This focus was largely due to the Northwest's hydrosystem, which had an excess of installed capacity. Because most traditional generating resources, like natural gas, coal, and nuclear plants, provide additional capacity at the same time they provide the ability to generate energy, most resource planning was carried out in an environment in which capacity could be taken for granted, as long as enough additional energy capability was provided to meet the total energy needs of the region.

Capacity is the maximum net output of a generator, measured in megawatts. For most generation, this is relatively straightforward: the plants can operate at their maximum output level (within certain predictable environmental, emission, and technical constraints) if called upon by the system operators, unless they have an unplanned, or forced, outage. Utilities account for the probability of forced outages by carrying contingency reserves, which are required by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) reliability standards. The required contingency reserves equal about 6 percent to 8 percent of demand for most utilities.

For hydroelectric generation, measuring capacity can be problematic. The total output of the hydrosystem is limited by its fuel supply, water, which is extremely variable from year-to-year. It is also limited by the fact that the reservoir system can only store about 30 percent of the annual runoff volume of water. Under some circumstances, there may not be enough stored water to run the generators at their maximum level to meet hourly load during peak conditions, like multi-day cold snaps in the winter or multi-day heat waves in the summer. While the machinery may be capable of reaching maximum output for short periods, it cannot sustain that level of output for longer periods. In fact, the maximum output a hydroelectric facility can provide depends on the duration of the output period--the longer the period, the lower the maximum sustainable output. This type of capacity is referred to as "sustainable capacity" and is a characteristic peculiar to hydroelectric systems.

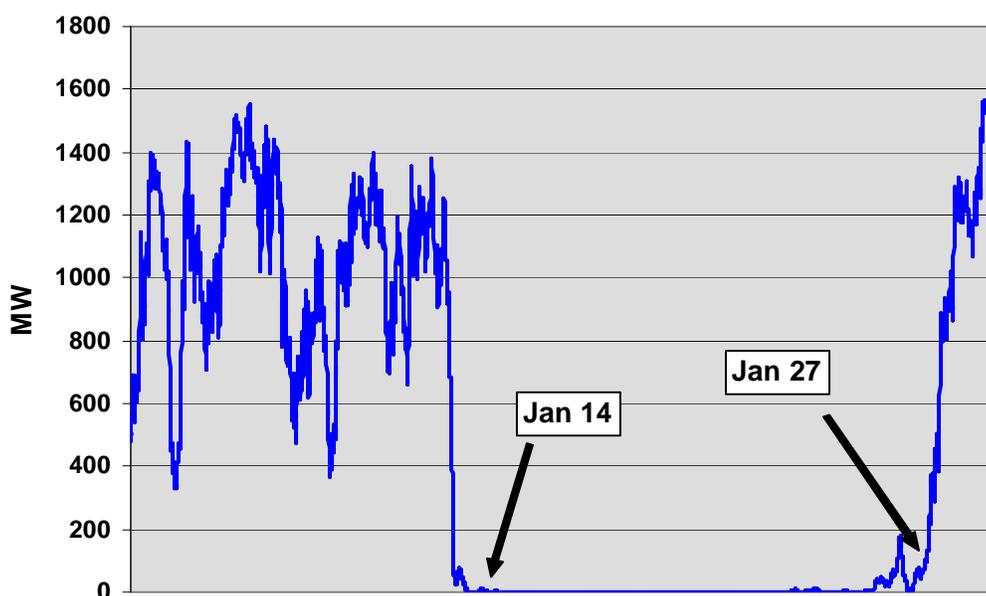
The Northwest Resource Adequacy Forum, jointly chaired by the Council and Bonneville, with participation by other regional utilities and interest groups, has devoted considerable effort over the past several years to reaching an understanding of the hydrosystem's sustainable capacity value. The work of the forum is described more fully in Chapter 14.

Wind generation capacity also raises capacity issues because it is not controllable. Wind generation is variable; operators can reduce generation when the wind is blowing, but they cannot make it produce more, even if the rated wind capacity is much higher. Furthermore, the output level is relatively unpredictable and, in the Northwest, is unlikely to be available at times of extreme peak load--for example when load is high because of a winter cold spell or a summer hot spell.

The amount of installed capacity expected to be available during peak-load hours is often called a generator's "peak contribution" or "reliable capacity." There is a body of technical literature on methods for the calculation of this value. Analysis done by Bonneville and the Resource Adequacy Forum suggests that, for the wind area at the east end of the Columbia River Gorge, where much of the region's current wind generation is located, there is an inverse relationship between wind generation and extreme temperatures, both in winter and summer. This is likely due to widespread high pressure zones covering the region's load centers (the biggest ones being

west of the Cascades) and the area of wind generation east of the Cascades during periods of extreme low and extreme high temperatures. Figure 12-1 illustrates the loss of wind generation during a recent winter period. While efforts to better define the reliable capacity of wind generators are ongoing, both in the Northwest and in NERC and WECC, the Resource Adequacy Forum has adopted a provisional peak contribution for wind of 5 percent of installed capacity. This work will need to address the impact of future wind development in other areas, such as Montana and Wyoming, that may have different weather patterns and could improve the overall capacity contribution of wind.

**Figure 12-1: Bonneville Wind Generation
January 5 - 29, 2009**



The current adequacy assessment (Chapter 14) indicates that the Northwest will probably encounter a summer-capacity problem before a winter-capacity problem, largely because of hydrosystem constraints and different expectations about the availability of power from plants owned by the region's independent power producers and from wider Western markets. Providing capacity to meet peak demand is only one part of balancing generation and load. Resources added to provide energy and flexibility will also help the region meet its developing summer-capacity deficit.

Before system planners and operators began to emphasize flexibility as part of the solution to the balancing problem, it was possible to talk about pure peaking resources. Peaking units were resources added to the system primarily to meet peak-hour demand, without having to generate large amounts of energy over the course of the year. Peaking units have been characterized as low-fixed cost and high-operating cost resources. These cost characteristics correspond to their intended infrequent use as peaking plants. To a certain extent, this characterization originated with the historical practice of demoting aging, less-efficient baseload units to infrequent peaking duty. In recent decades, however, specialized units capable of delivering a broad array of ancillary services as well as peak capacity at reasonable efficiency--such as aeroderivative and

intercooled gas turbines and gas-driven high-efficiency reciprocating engines--have appeared on the market. These units may have greater per-kilowatt capital costs than combined-cycle plants.

Resources in this category include simple-cycle gas turbine generators (both frame and aeroderivative), reciprocating engines, capacity augmentation features for combined-cycle gas turbines (including water or steam injection and fired heat-recovery steam generators), and utility demand response programs. Today, aeroderivative combustion turbines, reciprocating engines, and even some types of demand response, are often considered first for their flexibility and second for their ability to help meet peak demand. Demand response programs are described more fully in Chapter 5. These generating technologies are discussed later in this chapter and in Chapter 6.

Energy: Meeting Average Demand

Energy is the total output of a plant, typically over a year. For most plants, the maximum energy is simply the capacity times the number of hours per year that the plant runs, excluding forced or planned (maintenance) outages. For most types of generation, the energy output of the plant is not limited; the plant can run at its maximum level as long as desired, subject to forced or planned outages, and occasionally fuel supply and environmental constraints.

A fuller discussion of the regional portfolio results of the Council's analysis, as well as their implications for meeting capacity and energy requirements of the system, is in Chapter 10 of the plan.

Flexibility: Providing Within-hour Balance

The basic measures of a plant's flexibility are: its ramp rate, measured in megawatts-per-minute or some other short period; its minimum generation level; and its capacity. Minimum generation is most often defined by a combination of physical limits and economic limits, as when a plant's efficiency drops off dramatically below a certain point. Power system operators need to set aside a certain amount of flexible generation just to follow load, which varies. More flexibility is required if there is a significant amount of wind or other variable generation on the system.

The Northwest's hydroelectric generators are tremendously flexible resources. Physically, they have a wide operating range and very fast ramp rates. The inherent flexibility of the Northwest hydrosystem helps explain why flexibility has been taken for granted in previous Power Plans. This inherent flexibility is now partly limited by the challenges of salmon protection in Columbia and Snake rivers and the increasing amount of flexibility that is needed.

POWER SYSTEM OPERATIONS

The electric power system is organized into balancing authorities¹ for the purpose of operating the system reliably. Each generator (or fraction of a generator in specific circumstances) and load is in one, and only one, balancing authority. There are 17 balancing authorities in the Northwest Power Pool Area and 36 in the Western Interconnection.

¹ Balancing authority is NERC terminology for the entity that is responsible for the actions. Balancing area is sometimes used for the portion of the electrical system for which the balancing authority is responsible.

Each balancing authority is responsible for a number of things, including continuously balancing load and resources, contributing to maintaining the frequency of the interconnection at its required level, monitoring and managing transmission power flow on the lines in its own area so they stay below system reliability limits, maintaining system voltages within required limits, and dealing with generation or transmission outages as they occur. It does these things using what are called ancillary services, most of which are services provided by generation or, less commonly, demand response under the control of the balancing authority. The potential to expand demand response for ancillary services is addressed further in Chapter 5.

Ancillary Services

The NERC and WECC reliability standards, and prudent utility practice, require balancing authorities to hold operating reserves, first to maintain load and resource balance in case of an outage of a generator or transmission line, second to meet instantaneous variations in load, and in the case of wind generation, fluctuations in resource output.

The portion of operating reserve held ready in case of an outage is called contingency reserve, specified by NERC and WECC standards. The portion of operating reserve meeting the second requirement is called regulating reserve in the reliability standards. Additional reserves that are not explicitly required by NERC and WECC, but are prudent practice and assist in meeting the regulation requirement, are often called balancing reserves.

Regulating and Balancing Reserves

Operators must balance load and resources and keep track of imports and exports, all while load is continuously changing.

Balancing authorities do this by operating in a basic time frame of one hour, every hour of the day. The basic test of success in this balancing is called area control error (ACE). ACE is a measurement, calculated every four seconds, of the imbalance between load and generation within a balancing area, taking into account its previously planned imports and exports and the frequency of the interconnection. The NERC and WECC reliability standards govern the amount of allowable deviation of the balancing authority's ACE over various intervals, although the basic notion is that ACE should be approximately zero. The ACE is maintained through a combination of automatic and operator actions. The automatic part is done through a computer-controlled system called automatic generation control (AGC).

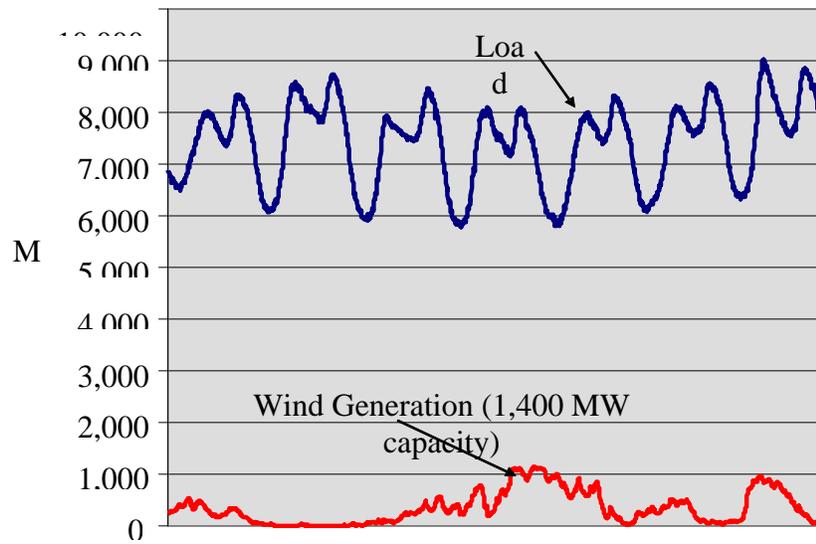
The basic regulation and balancing control challenge for the balancing authority is driven by load changes, both random, short-term fluctuations, and trends within the hour. It is exacerbated by the presence of large amounts of wind generation physically located in the balancing area, whether or not that wind is generating for the customers of the balancing area. There are specific exemptions from this requirement that in some cases require additional institutional or business practice changes, which are described later.

This is illustrated in several graphs based on five-minute interval data from the Bonneville balancing area in the first week of January 2008. The problems in this period are representative of the problems in other periods, although for Bonneville the problems are now magnified by the increase in installed wind capacity on its system. Bonneville now has approximately 2,800

megawatts of installed wind capacity. Figure 12-2 illustrates a typical weekly load pattern at five-minute intervals, with a sharp daily ramp in the morning as people rise, turn on electric heat, turn on lights, take showers, and as businesses begin the day.

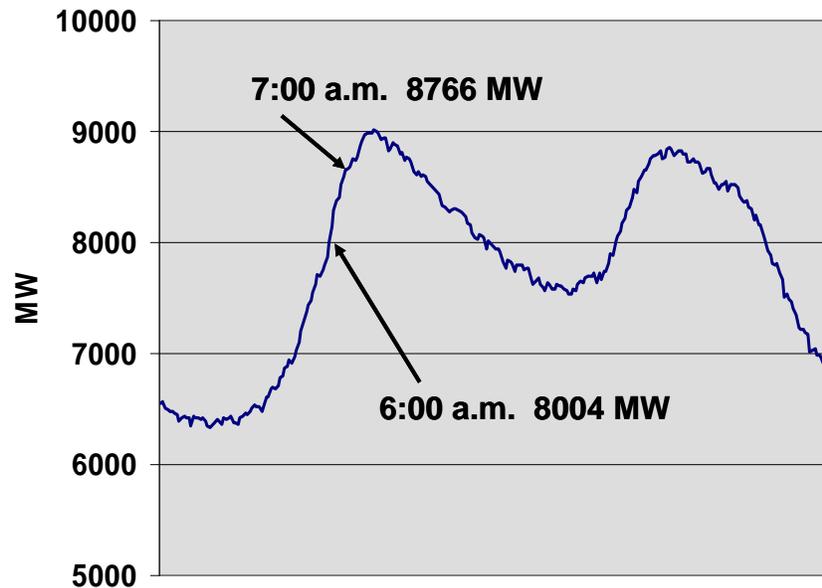
It also shows the Bonneville balancing area wind generation from the same period, illustrating the irregular pattern typical of wind generation. The data from this week will be used in several subsequent graphs, focusing on shorter time intervals and illustrating particular issues.

**Figure 12-2: Example Load and Wind Pattern
BPA January 1-7, 2008, Midnight to Midnight**



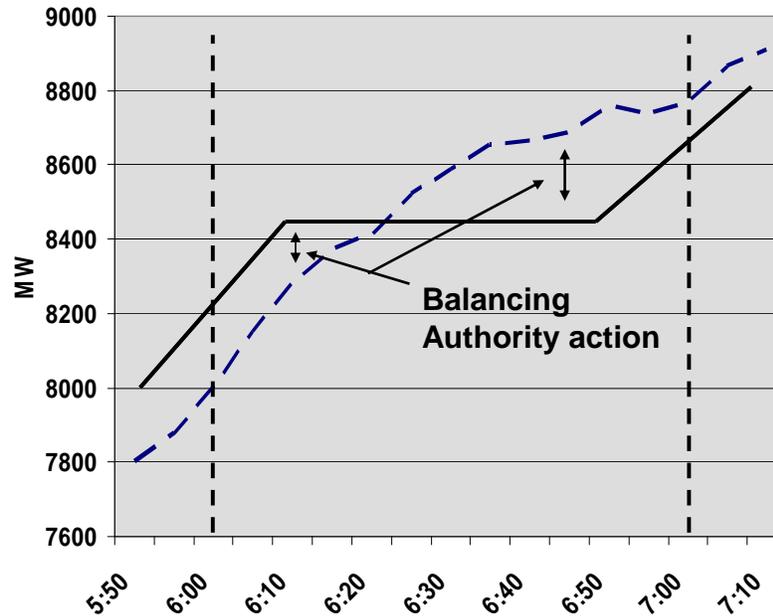
Focusing on a single day, January 7, 2008, Figure 12-3 highlights a single operating hour, from 6:00 a.m. to 7:00 a.m.

**Figure 12-3: Daily Load Curve - BPA January 7, 2008
Midnight to Midnight**



A balancing authority has to deal with a load ramp of, for example, 762 megawatts over the course of an hour, using the generation under its control in its own balancing area. At the same time, it must deal with any imports or exports that have their own time pattern for adjustment. Scheduling between balancing authorities in WECC is generally done in one-hour increments, with the schedules ramping in across the hour, from 10 minutes before the hour to 10 minutes after the hour.

Figure 12-4 focuses on the 6:00 a.m. to 7:00 a.m. load from the previous graph, while adding a hypothetical net schedule (including exports from and imports into the balancing area), and the generation scheduled to meet the average hourly load by any of its providers, including the transmission provider's merchant arm. The balancing authority must address the differences (both positive and negative) between the total scheduled generation and the net load in the balancing area by operating the generation in its control either up or down to match the load instantaneously, and to manage its ACE to acceptable levels. The graph points to the differences between scheduled generation and actual load that requires balancing authority action.

Figure 12-4: Example Hourly Scheduling

There are NERC and WECC reliability standards that govern how that action must be taken. In addition to contingency reserves, which must be available in case of a sudden forced outage, the standards require regulation reserves, which is generation connected to the balancing authority's AGC system. The standards do not require any specific megawatt or percentage level of regulation reserves. Rather, they require that the balancing authority hold a sufficient amount so that its ACE can be controlled within the required limits. How the balancing authority meets the requirements highlighted in Figure 12-4 involves some discretion on its part.

Most balancing authorities prefer to break the requirement into two parts: one meeting the pure regulation requirement, allowing AGC generation to respond every four seconds; the other adjusting generation output over a longer period, typically 10 minutes. The pure regulation requirement is illustrated by Figure 12-5, which shows a hypothetical, random pattern at four-second intervals (which is the kind of pattern the load actually exhibits) on top of a five-minute trend. This is the load that the generation on AGC actually follows.

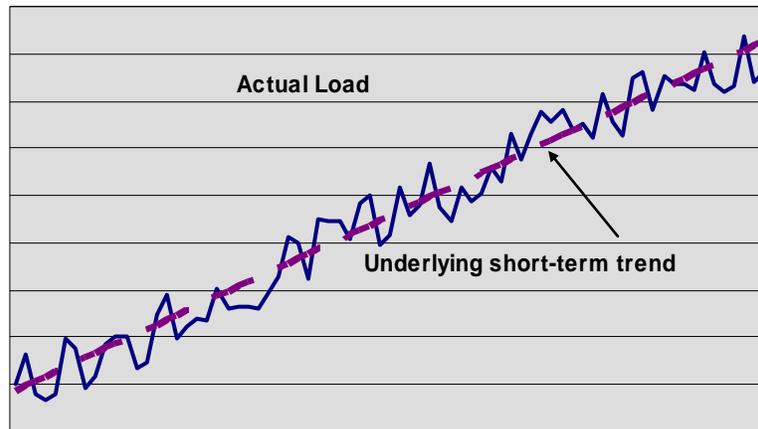
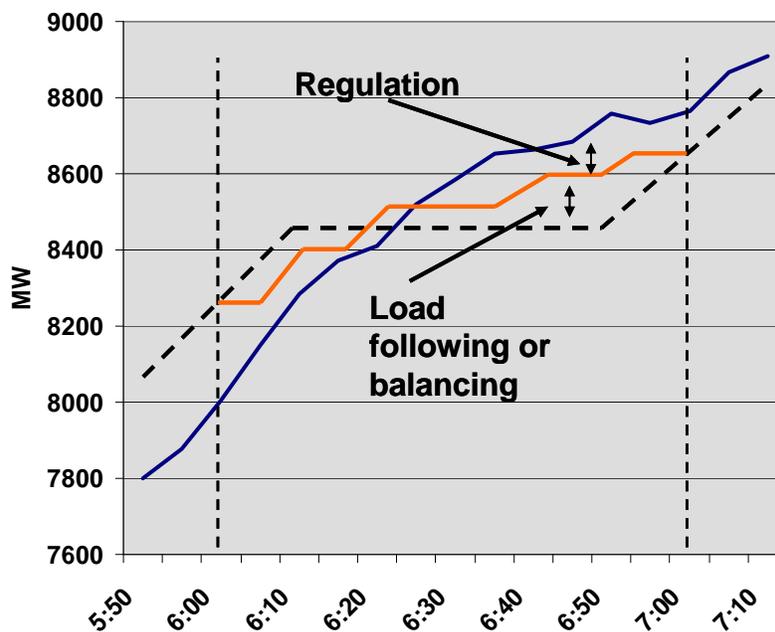
Figure 12-5: Example Load at Four-Second Intervals Over Five Minutes

Figure 12-6 illustrates one pattern of breaking that requirement up, separating the regulation requirement for generation on AGC from the remaining requirement, usually called load-following or balancing.²

Figure 12-6: Illustration of Hourly Scheduling with Load Following

Balancing authorities plan for regulation and balancing services before the need for them arises. They ensure that enough scheduled generation is on AGC to provide moment-to-moment regulation services. They also plan to operate some generators at levels lower than they otherwise would in order to have the ability to increase generation and provide incremental load-following. Conversely, they may also need to operate some generators at levels higher than they

² When the only remaining requirement is the variation in load, load-following is the most common term. When the requirement includes the effect of variable generation, like wind, the term balancing is often used instead.

otherwise would in order to have the ability to decrease generation and provide decremental load following.

By operating generators in this manner, a balancing authority can incur increased operation costs, increased maintenance costs, and foregone revenues. These are the opportunity costs of providing regulation and load-following or balancing services. Balancing authorities typically decide which generators to use for regulation and load-following based on the physical characteristics of their generators and the opportunity cost of operating specific generators in this manner. Much of the region's flexibility, and particularly for the large amount of wind generation in Bonneville's balancing area, has been provided by the hydrosystem. This description focuses on issues raised for the Northwest and its hydro system, but it needs to be recognized that there are other areas of the world or the U.S., like Texas, where integrating significant amounts of wind has taken place using non-hydro resources. Texas, for instance, currently integrates approximately 8,000 megawatts of wind primarily with combined-cycle gas generation.

Historically, the cost of operating the power system to provide regulation and load-following services received little attention. The effect of wind and other variable generation on the balancing authority's ability to balance generation and load has raised awareness of the cost of providing these services. Improving operating procedures and business practices should help to hold down integration costs, but they will likely increase over time as more variable generation is added to the system.

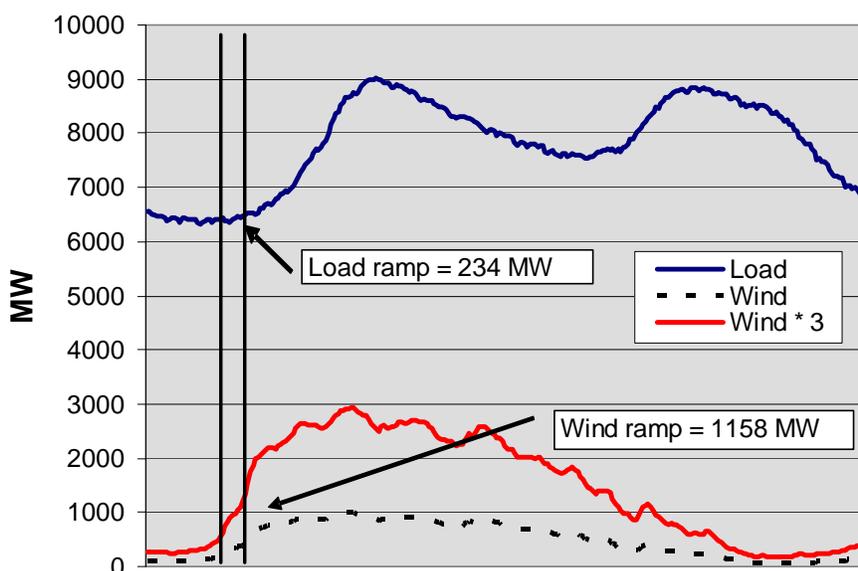
FLEXIBILITY ISSUES RAISED BY WIND GENERATION

Unpredictable and rapid swings in the output of wind generators have increased the need for power system flexibility. Load is typically much more predictable in the one-to-two hour time frame than wind generation. If load is relatively flat, and the wind unexpectedly drops off over the course of 10-20 minutes, then system operators must ramp up other generation at the same speed that the wind generation is ramping down in order to maintain load and resource balance and support the system frequency. Likewise, if the wind unexpectedly increases, then system operators must be able to ramp down other generators in order to maintain load and resource balance.

The possibilities become more complicated with changes in both wind generation and load over a given time period. But the result is still the need to be able to quickly adjust generation up or down.

Figure 12-7 illustrates a situation where both load and wind generation increased at the same time. It shows the load and wind pattern from the last day of Figure 12-1, and the effect of wind generation if its capacity were three times greater than what was operating on January 7, 2008, assuming for the sake of illustration that the additional wind generation did not bring any geographical diversity with it. Note that Bonneville already has about 2,800 megawatts of installed wind capacity, instead of the then 1,400 megawatts. Bonneville is concerned about the potential of over 6,000 megawatts by 2013.

**Figure 12-7: January 7, 2008 Load and Hypothetical Wind Data
Midnight to Midnight**



Looking at the early morning hours only, between 3:00 a.m. and 4:00 a.m. indicated by the vertical bars on the graph, we see an increase in load of 234 megawatts in that period. We also see an increase in the hypothetical wind generation of 1,158 megawatts. System operators would need to ramp down other generators by 924 megawatts to maintain system balance. Because Bonneville can face significant minimum generation requirements in the low-load night time hours, this pattern is a particular problem for them. Solutions to these issues, some of them under development already, are discussed in the following section.

For capacity and energy, it is possible to provide estimates of the timing and size of future deficits. At this time, we are unable to make a similar projection for flexibility. This is because the industry has not yet developed standard methodologies and metrics to make such an assessment. However, Bonneville has estimated in its recently concluded 2010 rate case that by the end of 2011 it might need to set aside up to about 750 megawatts of generation to respond to unexpected drops in wind generation, and about 975 megawatts of generation to respond to unexpected increases in wind generation. These amounts are based on a wind forecast of almost 3,845 megawatts of installed wind, a 30-minute persistence forecast and several mitigation measures for wind generation outside the level of the set-aside balancing reserves. For Bonneville's needs specifically, see also the discussion in Chapter 13.

Response to Growing Need for Flexibility

The response needs to be twofold. First, modify existing operating procedures and business practices to allow the maximum and most efficient use of the region's existing flexibility for those balancing authorities with large amounts of wind generation. Second, the new dispatchable generation needed for energy, or to meet the peak-hour capacity needs of the system (should that become the primary need in the future), should also be able to be adjusted up or

down to deal with changes in wind output, and to allow the region's balancing authorities to maintain their ACE measures within acceptable bounds.

Institutional Changes

There are several changes in operating procedures and business practices that would either reduce the burden on the balancing areas or substantially increase the available flexibility of the existing system.

Increasing the accuracy of short-term wind forecasting, either by wind generators or the balancing authorities themselves would reduce the amount of balancing reserve capacity needed to cover a forecast error. Bonneville has estimated, for example, that using the prior 30 minutes' generation level (rather than previous methods that looked further back) as the forecast for the next hour would substantially reduce the forecast error and the amount of needed balancing reserves. Bonneville has made this adjustment and adopted other methods to increase forecast accuracy. More sophisticated wind modeling is also being explored.

Going to a 10-minute scheduling window instead of the current whole-hour scheduling would also help maintain the host balancing authority's ACE by allowing it to bring in generation from other balancing authorities. This would require a more developed market (either bilateral or centralized) in these intra-hour, short-term generation deliveries to take advantage of the new framework. The joint initiative between ColumbiaGrid, Northern Tier Transmission Group, and WestConnect is taking steps in this direction by creating a tool to facilitate within-hour transactions on a bilateral basis.

Increasing the availability and ease of use of dynamic scheduling is another important change. This mechanism enables generation in one balancing authority to be transferred into another balancing authority for the ACE calculations of the two areas. This is helpful for several reasons. It allows available generation in one balancing authority to be used in another to meet the latter's regulation and balancing needs.

It also allows wind generation that is physically located in one balancing authority, but meeting load in another balancing authority, to be effectively transferred out of its area and into the second authority's area and ACE. Normally, while the FERC Open Access Transmission Tariff (OATT) allows the first balancing authority to charge some other party (the wind generators meeting external load or the external load) for the ancillary services, including regulation and balancing, NERC standards require that the host balancing authority provide the physical response. Dynamic scheduling allows both the physical response and cost of the wind generation to be the responsibility of the recipient load.

Dynamic scheduling is a long-established practice, but is typically done now on a case-by-case basis for relatively long periods, and it requires time-consuming, individual coordination between balancing authorities. Work is underway by the joint initiative to standardize the protocols and communication to make dynamic scheduling easily and quickly available--ideally so that dynamic schedules could be changed on an hour-to-hour or shorter basis.

There are some additional issues that need to be resolved regarding the limits on the amount of generation that can be dynamically scheduled over various transmission paths, particularly if the schedule involves long distances; for example, dynamic scheduling between Bonneville and the

California ISO. Among these issues is control of voltage levels in the system. Voltage levels on transmission lines are in part a function of the line loading, and dynamic scheduling tends to change line loadings rapidly, increasing the burden of controlling voltage levels within reliability limits. The Northern Tier Transmission Group and ColumbiaGrid have formed a group called the Wind Integration Study Team to examine these limits within the two entities.

Adding Flexible Capacity

System planners and operators are looking at resources that can be used to meet peak-hour demand and respond to variations in wind output. These flexible-duty resources do not necessarily need to generate large amounts of energy over the course of the year. Resources typically placed in this category include: rapid-response natural gas-fired generators; storage resources such as pumped-storage hydro plants; and utility demand response programs.

In the near term, natural gas-fired turbines and reciprocating engines appear to be good options for meeting the increased demand for flexibility. To offset unexpected changes in wind output, these resources need rapid-start capability and efficient operation at output levels less than full capacity.

The LM6000 Sprint (50-megawatt) and LMS100 (100-megawatt) aeroderivative turbines are two good candidates for flexibility augmentation. Starting cold, both turbines can be ramped to their maximum output within 10 minutes. These aeroderivative turbines are more efficient than comparable frame turbines, and therefore more cost-effective to operate at partial output levels. The LM6000 Sprint is a commercially mature technology with more than 200 units in operation. The first LMS100 unit went into commercial operation at the Groton Generating Station in South Dakota in 2006.

Gas-fired reciprocating engines are also a good flexibility option. The Plains End Generating Facility in Colorado is a 20-unit plant that has an output range of anywhere from 3 megawatts to 113 megawatts. The engines have a 10-minute quick start capability and can ramp up and down in response to an AGC signal. All of the above options can be constructed with short lead times, and therefore are good near-term flexibility options. A more complete description of these natural gas-fired generating technologies is provided in Chapter 6.

Pumped-storage hydro is a good mid-term option for meeting increased demand for flexibility since it can quickly change its operating level. These hydro plants operate in either a pumping mode or a generating mode. Traditional operation of pumped-storage hydro is based on the price of electric power. When the price of electric power is low, water is pumped from a source to a storage reservoir located at a higher elevation. When the price of electric power is high, the stored water is released and passed through a turbine to generate power.

As more wind power is added to the system, pumped-storage operation is likely to respond to the price of regulation and load-following services. For example, operators of pumped-storage plants can commit in advance to increase pumping when there are unexpected increases in wind output. Plants with variable-speed pumps are likely to be more responsive in these circumstances. Likewise, operators can also commit to increase generation when wind power output unexpectedly drops. Furthermore, operating the plant in this manner is not likely to result in dramatic operating cost increases or reduced revenue. However, with a 13-year construction

lead time, and high capital cost, risk is high. Other options may capture a large share of the ancillary services market before a new pumped-storage plant can be brought on-line.

The potential use of hot water heaters, plug-in hybrid vehicles, and other demand response options to provide regulation and load-following services is described in Chapter 5, Appendix H, and Appendix K.

Chapter 13: Bonneville’s Obligations

Summary of Key Findings 1
 Statutory Background 2
 Bonneville’s Evolving Role..... 3
 The Council’s Recommendations for Bonneville’s Future Role in Power Supply 3
 The Regional Dialogue 5
 Bonneville’s Posture Today; its Response to Regional Recommendations 6
 The Administrator’s Resource Requirements 7
 Conservation Resources..... 8
 Additional Resources 10
 Preliminary Conclusions Regarding Bonneville’s Draft Resource Program..... 13
 Major Resources 14
 Assessing Fish and Wildlife Costs and Accomodating Fish and Wildlife Operations..... 14

SUMMARY OF KEY FINDINGS

Bonneville engaged in an extensive, multi-year set of regional processes, culminating in the Regional Dialogue in 2007 and power-sales contracts in 2008, to define its future power supply role. The Council strongly supported and participated in these processes and offered a number of recommendations as part of the Fifth Power Plan, which were addressed in the Regional Dialogue.

Bonneville adopted a Regional Dialogue Policy, which defined its potential resource-acquisition obligations for power sales after 2011, whether at Tier 1 or Tier 2 rates. The administrator’s potential future obligations also include additional firm energy, capacity, and flexibility for integrating wind power into Bonneville’s balancing area. Its obligations to provide flexibility for wind-power balancing also are driven by its obligations under NERC standards as the host balancing authority for wind-power resources that are meeting load elsewhere, primarily in California.

The Council’s analysis, while it looks at regional capacity and energy requirements, does not break out utility-specific capacity and energy requirements and does not look at within-hour issues like flexibility. Thus there might be specific Bonneville obligations that are not addressed in detail in the Sixth Power Plan. The size of these obligations for Bonneville is, however, not well known at this time because it will be driven by choices of Bonneville’s customers and the amount of wind power that is located in Bonneville’s balancing area whether to serve its customers, other regional utilities, or for sale outside of the region. These will not be known until after the adoption of the plan. Moreover, the supply of resources available to meet these obligations, particularly for additional flexibility to deal with wind integration, is uncertain at this time. There are, for instance, a number of regional and West-wide discussions underway about institutional and business practice changes to help balancing authorities deal with these issues.

Because of these uncertainties, the Council has several general principles to guide Bonneville should it need to acquire resources to meet any of these several kinds of obligations. They are, briefly:

- Aggressively pursue the Council's conservation goals first
- Aggressively pursue the various institutional and business-practice changes to reduce the demand for flexibility and to use the existing system more fully
- Look broadly at the cost-effectiveness and reliability of possible sources of new capacity and flexibility, such as gas or other generation types, and take into account synergies in meeting several types of needs with single resources

STATUTORY BACKGROUND

The Northwest Power Act gave the Bonneville Power Administration new authorities and new responsibilities. It authorized the Bonneville administrator to acquire resources to meet the administrator's obligations. At the same time, it obligated the agency to serve the loads placed on the agency by preference customers and the investor-owned utilities (IOUs). The Act also authorized sales to federal agency customers and to the direct-service industries (DSIs). Sales to the DSIs must provide a portion of the reserves available for meeting the administrator load obligations.

The Act also gave new authority to the member states of the Pacific Northwest Electric Power and Conservation Planning Council (Council), the interstate compact authorized by the Act. Congress directed the members of the Council, appointed by the governors of the member states, to develop a 20-year regional power plan. One component of that plan is the Council's fish and wildlife program, intended to protect, mitigate, and enhance fish and wildlife, and related spawning grounds and habitat, that have been affected by the construction and operation of hydropower dams in the Columbia River Basin. The Council's power plan is meant to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply. Bonneville, with certain narrow exceptions, must act consistently with the power plan in its resource-acquisition activities. This consistency requirement is most prominent when Bonneville proposes to undertake a number of actions related to a major resource, that is, a resource that has a planned capability greater than 50 average megawatts and is acquired for a period of more than five years. Thus, Congress intended the four Northwest states to have some say in Bonneville's resource-acquisition activity.

Bonneville occupies a unique, dual role in the region's utility system. On one hand it functions as a utility business, supplying energy, load-following, reserves, and transmission. Indeed, the agency markets the output of the federal base system (FBS), which consists of 31 federal hydroelectric projects (29 in the Columbia River Basin and two outside the basin), one non-federal nuclear plant, and several other small non-federal power plants. As noted, Bonneville also acquires resources to meet customer loads. In acquiring resources, the Act directs Bonneville to make cost-effective conservation the resource of first choice. To carry out that function, Bonneville also manages programs that help utilities acquire conservation. Bonneville accounts for the amount of conservation acquired and verifies savings. These functions are important in assuring the region that ratepayer funds are being expended in a business-like fashion. To enhance the range of conservation resources that will be available in the future, Bonneville also funds research and development. The resource of second choice under the Act is renewables. Bonneville both acquires renewables, as it has added about 245 megawatts of wind power to its portfolio of resources, and provides integration services, both for its own renewable

resources and for wind located in its control area but owned by others. In acquiring renewable resources, Bonneville first adds to its power supply to meet its total contractual load obligation and secondarily assists its customers who are obligated to meet renewable portfolio standards (RPS) set by their respective states. Again, Bonneville also supports research and development in the realm of renewable resources, to expand the amounts and sorts of renewables that will be available in the future.

On the other hand, in addition to its utility business functions, Bonneville is also a federal agency, to which Congress entrusted defined public purposes. The Act gave Bonneville the responsibility of funding efforts to restore fish and wildlife affected by the hydroelectric dams on the mainstem Columbia River and its tributaries. Among other public purposes, the agency also funds low-income weatherization programs through local public utilities, at the administrator's discretion.

BONNEVILLE'S EVOLVING ROLE

Bonneville's evolving role in the changing electricity utility industry has been the subject of a number of public processes that have garnered widespread regional participation. These processes ultimately were reflected in recommendations from the Council in its Fifth Power Plan and decisions by Bonneville in its Regional Dialogue Policy.

The Comprehensive Review of the Northwest Energy System in 1996, the 1997 Cost Review, the Joint Customer Proposal in 2004, and the administrator's 2005 Power Supply Role for fiscal years 2007-2011 all examined the issue of Bonneville's role in the region's electricity system. Each step in this series of discussions contributed to or modified in some way the region's thinking about what role Bonneville should serve. Naturally, not every entity that took part in each process endorsed every recommendation.

Impetus for these various processes derived from the restructuring and deregulation of the nation's electricity industry following passage of the National Energy Policy Act of 1992. Bonneville, the marketer of nearly half the electricity consumed in the region, faced an unusual and troubling situation. The agency's longstanding customers suddenly sought to diversify their wholesale power sources away from Bonneville by purchasing from competitive, lower-cost providers of electricity. In the mid-1990s, there were concerns that Bonneville's high fixed costs, including the debt on the Federal Columbia River Power System (FCRPS) and its past investments in nuclear power plants, would make it uncompetitive in the wholesale power market. Against this background, the region determined it was time to give serious thought to Bonneville's role in the region's electricity system.

The Council's Recommendations for Bonneville's Future Role in Power Supply

The Council recognized that recommendations from these various regional processes had a number of principles in common. Three were particularly important. The first was preserving the region's low-cost hydroelectric resources through long-term contracts. Second was improving preference customer utilities' and federal agencies' incentives to meet their load growth with responsible resource choices by charging an individual utility that chooses to have Bonneville meet its needs beyond the capability of the existing FCRPS the cost of incremental

supplies. The third was providing equitable and predictable benefits to the residential and small-farm customers of the region's investor-owned utilities.

Based on these considerations, the Council developed its own set of recommendations regarding Bonneville's future role in power supply for the Fifth Power Plan. As summarized here, these remain the Council's recommendations regarding Bonneville's role:

- Bonneville should market the output of the existing FCRPS to eligible customers at cost. Customers that request more power than Bonneville can provide from the existing federal system should pay the additional cost of providing that service. This change in role should be implemented through 20-year contracts that should be offered as soon as possible, and compatible rate structures.
- Bonneville should develop a clear and durable policy regarding the agency's future role in resource acquisition, to guide contract negotiations and future rate cases.
- To implement its new role, Bonneville should allocate the power from the existing FBS among eligible customers through a process that minimizes opportunities for gaming the process.
- Bonneville should move to implement tiered rates as soon as practicable; if they cannot be offered in new contracts by October 2007, the Council would consider recommending their implementation under the existing contracts.
- Bonneville should offer the full range of products currently available, such as requirements, block, and slice products. The costs of each product should be confined to the purchasers of that product, avoiding cross-subsidies.
- If Bonneville offers service to the DSIs, the amount of power and term should be limited, the cost impact on other customers should be minimized, and Bonneville should have the right to interrupt service to maintain system stability and cover any temporary power supply inadequacy.
- Bonneville should find a stable and equitable approach to offer benefits of low-cost federal power to the residential and small-farm customers of the IOUs for a significant period.
- 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's role could be reduced to the extent customers can meet these objectives. But, if necessary, Bonneville must use the full extent of its authorities to ensure that the cost-effective conservation and renewables identified in the Council's power plan are achieved on all its customers' loads. The Council committed to working with Bonneville, utilities, the states, regulatory commissions, and other regional and West-wide organizations to ensure that appropriate adequacy policies are in place and that the data and other tools to implement the policies are available.
- Bonneville should continue to carry out its fish and wildlife obligations, allocating its mitigation costs to the existing FCRPS.

The Regional Dialogue

The concepts that emerged from the Comprehensive Review and the Joint Customer Proposal, as well as the Fifth Power Plan, have been addressed in subsequent discussions among Bonneville, its customers, state agencies, regulatory bodies, the Council, and public interest groups in a process called the "Regional Dialogue." The Regional Dialogue concluded in 2007 with a set of policy decisions by Bonneville to guide development of tiered rates and new power-sales contracts to replace the contracts that expire in 2011. The highlights of the Regional Dialogue Policy, as expressed when the policy was adopted, follow.

- Bonneville will offer contracts to all its customers, public utilities, IOUs, and DSIs; at the same time. For public utilities, Bonneville will develop new 20-year contracts accompanied by a long-term Tiered Rate Methodology (TRM). Through the contracts and TRM, each public utility will get a High-Water Mark (HWM) that defines the amount of a customer's load that can be served with Federal power at BPA's lowest cost-based Tier 1 rate. To meet load above the HWM customers can choose to purchase power from either non-federal resources or from Bonneville at rates reflecting Bonneville's marginal cost of acquiring the additional power, or through a mix of Bonneville Tier 2 priced power and non-federal resources.
- Bonneville will acquire resources, if necessary, to supply up to 250 megawatts at the Tier 1 rate to new public utilities (including new and existing public body tribal utilities).
- Bonneville will acquire resources to augment the existing system by the lesser of 300 megawatts or the amount needed to meet utilities' HWMs based on their Fiscal Year 2010 loads. At the 300-megawatt cap, this would be roughly a 4-percent increment to the existing system and is in addition to any acquisitions to serve new public utilities.
- Bonneville will offer three product choices: load-following, block, and slice. The load-following product will include services to follow the actual loads a customer experiences. Slice and block products do not include load-following service.
- Bonneville will increase the amount of power sold under the slice product from the current 22.6 percent to as much as 25 percent of the power available from the FBS resources.
- Bonneville acknowledged that service to the DSIs had not been resolved and so that issue was not decided in this policy.
- Bonneville omitted a section on the residential exchange, due to then-recent decisions from the Ninth Circuit. Nonetheless, Bonneville's goal is to ensure that the residential and small-farm customers of the IOUs receive a fair and reasonably stable share of the benefits from the federal system over the long term, consistent with law, that will parallel the certainty obtained by public utilities.
- Bonneville will institute a regional cost review to give customers and other stakeholders opportunities to comment on Bonneville's costs.

- Bonneville established guidelines for dispute resolution, in response to customer requests, but noted that final decisions in this arena likely will be taken in conjunction with development of the TRM and power sales contracts.
- Bonneville will pursue the development of all cost-effective conservation in the service territories of public utilities served by Bonneville and of renewable resources based on its share of regional load growth. Bonneville expects these goals to be met to a significant extent through programs initiated and funded by its public utility customers. Bonneville will supplement and facilitate utility initiatives. Bonneville will provide the necessary integration services to customers that wish to acquire non-federal renewable resources to meet their load growth and enhanced incentives for conservation development.
- Bonneville will require its customers to provide their load and resource data and resource development plans necessary to track regional implementation of the voluntary resource adequacy standards adopted by the Council. Bonneville did not make compliance with the standards a contractual requirement.
- Bonneville will propose stable and predictable low density discount (LDD) and irrigation rate mitigation (IRM) programs in future rate proceedings. Bonneville will ensure that the LDD approach will not bias customers' choices between taking power at a Tier 2 rate from Bonneville or from non-federal resources.

These policy choices did not conclude the Regional Dialogue process. Negotiation and drafting of new contracts, their release for public comment, and eventual execution were to follow. Bonneville also committed to a review of its Northwest Power Act sections 5(b)/9(c) policy. The TRM was to be developed in a separate Northwest Power Act Section 7(i) process, as were rates to be effective for power sales under the Regional Dialogue contracts in Fiscal Year 2012. The Regional Dialogue policy decisions were meant to inform those subsequent processes, but it did not decide them.

Bonneville's Posture Today; its Response to Regional Recommendations

Late last year Bonneville signed 20-year contracts with all its public utility customers. This was the culmination of a lengthy public process in which all parties had the opportunity to address the terms and conditions under which Bonneville would offer power to its customers. The fact that these contracts are long-term should help ensure the stability of the relationship between Bonneville and its customers. Knowing that Bonneville will have this long-term, stable financial relationship with its customers should also bolster confidence that Bonneville will be able to meet its annual payment to the U.S. Treasury. The contracts also support Bonneville's commitment to conservation and renewables, as well as to meeting its fish and wildlife costs.

Bonneville has also developed and is preparing to implement a Tiered Rate Methodology. Bonneville will sell electricity from the existing FCRPS to eligible customers at cost. To ensure that it has sufficient resources to meet the initial demand, Bonneville will augment the federal base by acquiring a limited amount of additional resources, the cost of which it will meld with the cost of the existing system. This initial demand will be sold at priority firm (PF) Tier 1 rates. Customers that place more demand on Bonneville, that is, load above their individual high-water

mark, will pay PF Tier 2 rates for that service, which will recover the costs of additional power needed to meet this demand. Note that Bonneville has reached an accommodation with a number of small customers that do not view themselves as well-situated to acquire new resources on their own. Participants in this Shared Rate Plan will not face Tier 2 rates for individual growth, but if Bonneville has to acquire resources to meet the overall growth of the pool, costs will be shared among all participants in this subset of customers.

This tiered rate structure should meet several goals in the recommendations the region has offered. First, tiered rates will make clear who has responsibility for resource development. This structure should result in customers seeing the true cost of adding resources, which will provide better incentives for resource choices. It will also prevent the dilution of the value of the existing federal system that results from melding the costs of new and more expensive resources.

Bonneville also has responded to direction from the Ninth Circuit and reworked its Residential Exchange Program (REP). To accomplish this, the agency revised and implemented a new average-system-cost methodology, the result of a lengthy and comprehensive consultation process with customers, interested parties, and the Council. Bonneville aimed at sharing with the residential and small farm customers of the IOUs the benefits of the generally lower cost FCRPS, both over the time when payments were made under settlements struck down by the Ninth Circuit, the look-back period, and going forward. The issues are again being litigated, and the customers are now discussing a negotiated settlement to try to resolve the uncertainty in the REP methodology under the Act.

These changes in Bonneville's future role do not change Bonneville's fundamental responsibility to serve the loads of qualifying customers that choose to place load on Bonneville; it does not change Bonneville's responsibility for ensuring the acquisition of Bonneville's share of all cost-effective conservation and renewable resources identified in the Council's plan; and it does not change Bonneville's responsibility to fulfill its fish and wildlife obligations under the Act and the Council's fish and wildlife program. It does represent a change in the way Bonneville traditionally has carried out those responsibilities.

Some important policies Bonneville has adopted to implement the recommendations of these public processes and the Regional Dialogue Policy have recently been challenged in the Ninth Circuit. As of the date of the release of this draft plan, more than 40 petitions have been filed that could result in the invalidation of how Bonneville has responded to earlier judicial decisions directing the agency to implement the REP in line with the directives of the Northwest Power Act, its determination of how to make the preference customers whole, and its adoption and implementation of the tiered rates concept. Depending on the outcome of these challenges, the region may need to undertake a variety of efforts to enable Bonneville to serve the roles identified in the long series of public processes outlined above and in the Regional Dialogue Policy.

THE ADMINISTRATOR'S RESOURCE REQUIREMENTS

The Northwest Power Act requires that the Council's power plan "shall set forth a general scheme for implementing conservation measures and developing resources pursuant to section 6 of this Act to reduce or meet the Administrator's obligations." The Act requires the plan to give "priority to resources which the Council determines to be cost-effective," and also ranks types of

resources by priority: "Priority shall be given: first, to conservation; second, to renewable resources; third, to generating resources utilizing waste heat or generating resources of high fuel-conversion efficiency; and fourth, to all other resources."

When Bonneville acquires resources, the Power Act then requires that, with certain narrow exceptions, all of Bonneville's resource actions be consistent with the Council's power plan. The Council engages in an extended planning process for developing and amending the power plan. It gathers experts in advisory committees on important subjects the plan treats: generating resources, conservation, and natural gas, for several examples. These committees both contribute technical information for use in the plan and evaluate analysis done by Council staff and others. It is the staff's analysis and synthesis, combined with public input and comment, that form the basis for the Council members' decisions when they adopt a plan or a plan amendment. Bonneville participates in the Council's process, sometimes as a member of an advisory committee, sometimes as a contributor to studies or analyses, and sometimes as a commenter on draft Council positions. Being fully apprised of the thinking that underlies a final Council plan should enable Bonneville to ensure that its own resource assessments and acquisitions build on the Council's planning process and are consistent with the plan.

The Council's power plan is first developed from a regional perspective. Much of the technical analysis for the plan assumes that the electrical loads in the region are served by all of the electric generation and conservation resources available in the region, without respect to specific utility loads and resources. The result is a regional resource strategy that minimizes costs and risks as if the entire region were served by all the resources and transmission in the region. The Power Act also requires, however, that the Council's power plan specifically include a resource plan for Bonneville to act consistent with as it works to meet its current and future obligations. For this plan, the Council has examined Bonneville's particular power system needs as described in this chapter. The Council did not develop its own quantitative forecast of Bonneville's loads and resources, concluding that analyses by Bonneville of its projected loads and resources will be more than sufficient for the Council to rely on here for planning purposes, with an understanding of further work to come as described below. The Council has distilled the plan's regional resource strategies into a set of resource-acquisition strategies specifically related to Bonneville and described in this chapter.

The Council expects Bonneville to acquire resources consistent with the power plan. Bonneville recently released a Draft Resource Program, intended when final to guide the agency's resource-acquisition choices for the next 10 years. As noted below, the Draft Resource Program describes Bonneville's expected loads and resources in much finer detail than is possible in this plan, yet appears to be appropriately based in the power planning efforts of the Council and reflects the resource strategies in this plan. The Council expects Bonneville's final Resource Program to do the same.

Conservation Resources

Section 6(a)(1) of the Northwest Power Act obligates Bonneville to "acquire such resources through conservation . . . as the Administrator determines are consistent with the [Council's power] plan." And as noted, the Act further requires the Council to give first priority in the plan to cost-effective conservation resources. The power plan's conservation measures thus have real legal meaning for Bonneville and real effects on Bonneville's utility customers in terms of

conservation's ability to reduce the need for Bonneville or the utilities to acquire lower-priority or higher-cost resources and in terms of the costs of conservation acquired by Bonneville and its customers.

The acquisition of cost-effective conservation by Bonneville through an ongoing program is not conditioned in the Power Act on whether Bonneville is or soon will be out of load-resource balance and therefore in need of additional resources. Rather, the point of this provision and of the structure of the Power Act as a whole is that conservation is a resource used to serve firm power loads by reducing consumer demand for electricity. As such, conservation lessens the need for Bonneville to acquire power generated by conventional generating resources that are more expensive than the costs of the hydrosystem. The Regional Dialogue's new power supply paradigm for Bonneville does not alter the legal or practical framework for Bonneville's ongoing conservation program. Bonneville's customers are still placing load on the agency and Bonneville is planning to acquire resources to serve its contractual load obligations, including potential loads above customer high-water marks and possibly direct-service industrial loads. Bonneville thus will need to continue to acquire cost-effective conservation to reduce loads and stretch the Federal Base System, consistent with the conservation provisions of this plan.

For this reason, the principal recommendation regarding Bonneville in the Sixth Plan, as in past plans, is that Bonneville aggressively pursue its share of the Council's regional conservation goals. This is to ensure that Bonneville meet whatever load it faces, whether served at Tier 1 or Tier 2 rates, efficiently and as cost-effectively as possible.

Bonneville and its customers understand the basic principle and through their actions have sustained the conservation program for decades. However, they have expressed concerns about the particulars here, that is, about the greater number of conservation measures, about the expanded conservation goals, and about what mechanisms might ensure that Bonneville achieves its share of the regional conservation goals. Even as concerns over the near-term targets are being worked out in collaborative discussions, the utility customers have remained generally concerned about having goals, methods, measures, and costs imposed on them by Bonneville to satisfy the plan. Under Bonneville's new resource policy, utility customers are responsible for the marginal costs of new resources acquired to meet their load growth, whether acquired by themselves or from Bonneville at Tier 2 rates. For this reason, the utilities believe it is in their interest to implement conservation programs tailored to their particular needs, programs that can serve to satisfy the plan's conservation goals, without mandates from Bonneville and with measures and costs the utilities themselves control.

In response, the Council believes Bonneville has the discretion to tailor its conservation program to match this new power supply paradigm and to assuage the utility customers' concerns, in a way consistent with the principles the Council recently outlined:

1. Conservation targets. Bonneville should continue to commit that its public utility customers will meet Bonneville's share of the Council's conservation targets. Bonneville should ensure that public utilities have the incentives and the support to pursue sustained conservation development. Active utility commitment to conservation should continue to be a condition for access to Bonneville power at Tier 1 rates.

2. Utility reporting. Bonneville has included in its power sales contracts requirements for utility reporting and verification of conservation savings so that Bonneville and the Council can track whether conservation targets are being achieved.
3. Implementation mechanism. Bonneville should offer flexible and workable programs to assist utilities in meeting conservation goals, including a backstop plan, should Bonneville and utility programs be found insufficient.
4. Regional conservation programs. Bonneville should continue to be active in funding and implementing conservation programs and activities that are inherently regional in scope, such as NEEA.

It should be emphasized that the Council's conservation methodology calculates conservation potentials for certain measures that might, at some point, be covered by building or energy codes, and then assumes that the savings will be accomplished over time by *either* utility programs or codes. The utilities should include these cost-effective, available conservation measures in their own plans and programs. However, *if* codes are adopted that ensure the capture of the potential savings, then the utilities may count the resulting savings in their service territories against the regional target. The Council in return expects the utilities to join with the Council, the governor's offices, and other relevant state and local agencies in their support of the necessary state and national improvements in codes and standards.

Additional Resources

Along with the conservation program, the power plan is to set forth a general scheme for developing other resources if needed to meet the administrator's obligations. Bonneville may need additional resources for a number of reasons. These include Bonneville's proposal to acquire resources to augment the existing system to serve the "high-water mark" load of its preference customers at Tier 1 rates; additional energy resources if needed because one or more customers call on Bonneville to meet their load growth, at Tier 2 rates reflecting the costs of the additional resources; additional resources to serve DSI loads, if Bonneville decides to offer such service; additional resources that may be necessary for capacity and within-hour flexibility purposes, such as to support the integration of intermittent renewable resources like wind; additional resources as may be necessary for system reserves, system reliability, and transmission support; and additional resources if necessary to assist the administrator in meeting Bonneville's fish and wildlife obligations under Section 4(h) of the Northwest Power Act. Conservation resources will help reduce the need for additional resources but are unlikely to address all of these needs. The Council is not undertaking at this time a detailed, quantitative assessment of Bonneville's need for additional resources, given the extent to which the overarching decisions and information that will affect this assessment are uncertain or in development. Instead, the Council is setting forth further information and a set of principles in this section (and linked to other chapters in the plan) to help guide any decisions by Bonneville to acquire additional resources consistent with the plan and the provisions of the Power Act:

Bonneville anticipates acquiring resources on a long-term basis to meet its obligations under the new Regional Dialogue power sales contracts. In the Long-Term Regional Dialogue Final Policy, Bonneville said it would acquire up to 300 average megawatts of power to augment the existing system to meet the "high-water mark" load of its preference customers at Tier 1 rates.

In addition to augmenting energy to meet preference customer high-water-mark demand, the Regional Dialogue Policy also provides that over the 20-year contract period, Bonneville may augment its energy supplies by up to 250 average megawatts of power to be sold at the Tier 1 rate to serve any newly created public utilities. Additional high-water marks for new publics will be limited to 50 average megawatts in each rate period, that is, in any two year period. Of the 250 average megawatts, Bonneville has designated 40 average megawatts for service, on a first-come, first-served basis, at Tier 1 rates for recently created or future tribal utilities that experience load growth beyond their high-water marks. Bonneville also committed to augmenting its energy supplies by up to 70 average megawatts to meet possible expansions of the Department of Energy's Richland facilities.

Beyond the Regional Dialogue provision to augment energy supplies by up to 620 average megawatts to be sold at Tier-1 rates, as described above, Bonneville may also be required to acquire resources to meet loads that are beyond a customer's high-water mark if the customer calls on Bonneville to meet its load growth. The amount of power sold to supply a customer's above-high-water-mark load will be subject to a Tier 2 rate. This service is by definition flat, so if Bonneville acquires resources to meet these loads, it will offer power in flat blocks. Further, Bonneville's service to direct-service industrial (DSI) customers has not been determined and could require additional resource acquisitions in the future. As of the time of this draft, Bonneville and the DSI customers have not reached an agreement regarding service of those industries.

Historically, Bonneville has purchased resources to serve the average annual energy needs of its customers. Given the reductions in the ability of the hydropower system to support the integration of intermittent resources like wind, it is more likely that Bonneville will focus on acquiring resources that offer both added capacity and flexibility that cannot be provided by conservation. Bonneville is designing such products in its Resource Support Services (RSS). For example, if a customer decides to meet its own load growth with new resources that have little or no firm capacity and operate intermittently, Bonneville will not require that utility to convert such resources into resources that can be used to meet firm loads by acquiring capacity, firming up the energy, and reshaping the output. Instead, Bonneville will do this for the customer and charge a resource-shaping charge, one of the RSS. Because many of Bonneville's customers are acquiring wind to meet state-imposed Renewable Portfolio Standards, this may prove to be an important Bonneville service.

Bonneville also will acquire resources to offer ancillary services to its utility and transmission service customers. These are flexibility services such as regulation, load-following and balancing services, spinning reserves, non-spinning reserves, supplemental reserves, and voltage control. Bonneville will need to provide some of these services to support resources, such as a good portion of the wind generation physically located in Bonneville's balancing authority area, that serve load outside the agency's balancing area. Resources needed for this service will be chiefly those that offer added capacity and flexibility. The resource strategy laid out in this plan acknowledges Bonneville's potential need to acquire capacity resources to meet heavy-load-hour demand and provide the flexibility needed to integrate intermittent resources.

Bonneville recently completed its 2009 Draft Resource Program, designed to assess its potential resource needs as of 2013 and 2019. Significant uncertainties remain at this time, though some will be resolved by the time of the final Sixth Plan. Bonneville's customers will have made their

resource choices for at least the 2012-2014 period by November 1, 2009, which will have established the amount of Bonneville's requirement for this period to serve above-high-water-mark load. The other uncertainties described above (e.g., augmentation for new public loads) will not have been resolved at this time. In its Draft Resource Program, Bonneville looked at the effect of all of the potential above-high-water-mark loads being placed on the agency.

The effect of potential RSS requirements would be no bigger than the effect of the potential above-high-water-mark loads themselves, so the potential effect of RSS on Bonneville requirements is covered by Bonneville's discussion of the potential effect of above-high-water-mark load placement in the Draft Resource Program.

Not only will the magnitudes of some of the requirements be unknown, but the availabilities of potential solutions, are, in some cases, not known either, because they will depend on ongoing regional and West-wide efforts. This is the case for solutions to the balancing problems Bonneville faces in integrating the large amounts of wind generation that appear likely to be developed in its balancing authority. Several institutional solutions that would relieve or mitigate the burden facing Bonneville's balancing authority are being discussed and developed by Bonneville's Wind Integration Team, which recently released a two-year work plan, and by the ColumbiaGrid/NTTG/WestConnect Joint Initiative, in which Bonneville, as a member of ColumbiaGrid, is participating.

These different kinds of needs can interact with each other. For instance, some kinds of resources that might be valuable for meeting capacity needs also could provide flexibility for managing wind fluctuations, or, alternatively, resources that might be required to meet flexibility needs, if institutional changes in business practices prove insufficient, also could provide resources to meet capacity requirements. However, the generating resources that might be best at providing flexibility, because they have wide operating ranges, might not be optimized to provide the cheapest energy.

The Council's analysis, while it looks at regional capacity and energy requirements, does not break out utility-specific capacity and energy requirements and does not look at within-hour issues like flexibility. Thus there might be specific Bonneville needs that are not explicitly addressed in detail in the plan.

First, there are some kinds of resources that the Council considers in its analysis, both for the plan specifically and for its annual adequacy assessments, that specific utilities may or may not want to purchase or acquire. Specifically these are out-of-region purchases and in-region uncontracted IPP generation. The Council considers these as available to meet regional loads, but they are not owned or contracted for by any in-region load-serving entity. (For more on this distinction, see Chapter 14.) For any in-region utility, they are potential resources, like others, that would need to be evaluated based on cost and risk.

Second, Chapter 12 of the plan describes various ways of meeting flexibility needs (both business practice changes and types of new generation). It suggests that the institutional and business practice changes are likely to be the easiest and cheapest. It does not, however, describe the total amounts of flexibility that would be available through all the various business practice changes, or the time frame within which they would all be available, because those issues are still being examined by various regional and WECC entities.

Because of this, the plan's recommendations for Bonneville's response to Bonneville's needs described above cannot be precise with regard to specific resources or strategies to meet those needs nor to their timing. Here is a set of general principles Bonneville should follow, with corresponding provisions in the Action Plan:

The first, and major principle, is that Bonneville aggressively pursue the Council's conservation goals. This will ensure that the customer load that remains, whether at Tier 1 or Tier 2 rates, is as efficient as is cost effective.

A second principle is that Bonneville should aggressively pursue the various institutional solutions to its balancing needs that are currently being discussed before acquiring power produced by new generation. These institutional changes, better forecasting, shorter scheduling windows, markets for the exchange of balancing services among balancing authorities, generation owners and operators, and demand-response providers, as well as other actions have the potential to be significantly more efficient and faster to develop than new generation to provide these services.

A third principle is that Bonneville should take a broad look at possible resource acquisitions for additional capacity and flexibility, if it turns out that resources are needed to meet its obligations. While Chapter 12 gives an overview of the business practice changes and generating technologies that are available to meet these needs, the possible synergies in simultaneously meeting both capacity and flexibility requirements need to be taken into account, and the possibility of newly developed technologies, including a smart grid and storage, should also be considered. Bonneville should take a similarly careful look at possible resource strategies and resources choices, if needed to meet its obligations in the other areas listed at the beginning of this section, including for reserve and reliability requirements and for transmission support.

Preliminary Conclusions Regarding Bonneville's Draft Resource Program

Despite the remaining uncertainties, the Draft Resource Program characterizes Bonneville's expectations and intentions sufficiently to be able to judge their alignment with the Council's principles and recommendations. Bonneville has committed to "ensuring achievement" of the public-power share of the conservation identified in the Council's plan. The Draft Resource Program says that, depending on the amount of load it must serve, Bonneville will meet most of the load that remains after conservation with short- to medium-term market purchases. Bonneville also says it intends to investigate other resources, as described in the Council's draft Sixth Plan.

It also describes its efforts to develop new institutional mechanisms and business practices as first approaches to its unmet balancing-resource needs, with investigation of other resources, such as those described in the plan, to meet any remaining flexibility requirements.

Bonneville's assessment of its potential needs and description of proposed actions for meeting those needs in its Draft Resource Program reflect the principles expressed above.

Major Resources

If Bonneville proposes to undertake a suite of activities related to the acquisition of a *major* resource, Section 6(c) of the Act requires the Administrator to conduct a public review of the proposal and make findings, taking into account the public comment. A major resource under the Act is one that is greater than 50 average megawatts and is acquired by the Administrator for a period of more than five years. This review provision applies to any proposal: (1) to acquire a major generating resource, (2) to implement an equivalent conservation measure, (3) to pay or reimburse investigation and preconstruction expenses for a major resource, or (4) to grant billing credits or services involving a major resource.

One of the findings Bonneville must make is whether a proposed action is consistent with the Council's plan. After Bonneville has made its finding, the Council has an opportunity to undertake its own review of the proposal to determine consistency with the plan. If either agency finds the proposal inconsistent, Bonneville must get specific authorization from Congress to proceed.

ASSESSING FISH AND WILDLIFE COSTS AND ACCOMODATING FISH AND WILDLIFE OPERATIONS

The cost of managing the hydroelectric system to improve conditions for fish and wildlife is largely assigned to the power system, which must not only absorb the financial effects of that operation but also of other expenditures required to fully implement the fish and wildlife program. In order to do so, the power system must generate sufficient revenue to cover all of these financial requirements. The critical elements of the fish and wildlife program that must be integrated with power plan development are projected changes to hydroelectric system energy and peaking capacity capability.

Bonneville uses a well defined method for calculating the cost of fish and wildlife operations, or in other words, the additional revenue requirement relative to an operation without fish and wildlife measures. Using this method, Bonneville estimates its total financial obligation for the fish and wildlife program to be \$750 to \$900 million per year, which includes ordinary and capital expenditures, and power purchases and foregone revenue associated with fish and wildlife operations. Bonneville implements these operations and funds these measures to fulfill its obligations under the Endangered Species Act and the Power Act consistent with the Council's fish and wildlife program.

Specific cost considerations for fish and wildlife are identified in the Northwest Power Act. The language describing the fish and wildlife program amendment process [Section 4(h)(6)(C)] directs the Council to utilize fish and wildlife measures with the minimum economic cost as long as they achieve the same sound biological objectives. To the extent that Bonneville funds fish and wildlife measures with the minimum economic cost, the expenditures are efficient.

Another section of the Northwest Power Act [4h(10)(C)] allows Bonneville a credit from the U.S. Treasury for that part of its actual fish and wildlife expenditures that can be allocated to non-power purposes of dam operations. The credit includes a percentage of Bonneville's power purchases (at market rates) made specifically because of fish and wildlife operations. Forgone revenues, due to bypass spill, are not included in the credit but are counted in Bonneville's

assessment of total fish and wildlife costs. Bonneville has the responsibility to calculate these costs and the Council reports them to the governors, Congress, and the region. The Council also independently reviews these cost estimates on occasion, and will continue to do so in the future.

The Northwest Power Act recognizes that the federal Columbia River power system has an adverse effect on fish and wildlife in the Columbia and Snake River basins but it also recognizes that the power system has an obligation to mitigate for these impacts by funding additional measures and modifying the operation of the hydroelectric system as directed by the Endangered Species Act and the Power Act consistent with the Council's fish and wildlife program. The Council's program ensures that fish and wildlife affected by the federal hydropower system are protected, enhanced, and mitigated and the Council recognizes that actions to do so impose an economic cost on the region's ratepayers. Despite these costs, however they are assessed, the power system remains economical in the broad sense that power rates remain affordable.

See Appendix M for a description of what the Northwest Power Act requires in terms of the integration of the Council's fish and wildlife program into the power plan and the power system, how the power system and resource planning accommodates the operations for fish and wildlife purposes over time, and certain opportunities and uncertainties with regard to the continued integration of fish and wildlife and power purposes in the future.

Chapter 14: Regional Adequacy Standards

Summary of Key Findings 1

Background 2

 Motivation for Developing a New Standard 2

 Historical Approach 3

 Adequacy Assessment Efforts Outside of the Northwest 3

 Assessing the Adequacy of a Resource Strategy 4

The Pacific Northwest Adequacy Standard 5

 Physical Adequacy, Economic Adequacy, or Both 5

 Defining the Resource Adequacy Standard 6

 Annual Needs (Energy Standard) 7

 Peak Hourly Needs (Capacity Standard) 7

 Implementing the Standard 7

 Working with Other Entities 7

The Adequacy of the Northwest Power Supply 8

Utility Perspective on Resource Adequacy 11

Methodology 14

 Analytical Tools 14

 Reliance on Market Resources 16

 Translating the Adequacy Standard into a Simpler Measure 17

SUMMARY OF KEY FINDINGS

The 1990s saw little new resource development in the Northwest due, in part, to the emergence of an electricity market and the anticipation of deregulation. As load continued to grow, supply remained stagnant, and utility planners became concerned about the adequacy of the power system. 2001 was the second-driest year on record in the Northwest. This, coupled with a failed wholesale power market in California meant the region faced a serious threat of blackouts. Actions were taken to avoid forced curtailments, but those actions were costly and resulted in soaring electricity prices.

It was becoming obvious that a new method of assessing resource adequacy was necessary. The power system was becoming more complex, with greater constraints placed on the operation of the hydroelectric system, increasing development of variable and dispersed resources, and the growth of a Westwide electricity market. The Council recognized this need, and in its Fifth Power Plan recommended developing a resource adequacy standard. Supporting this decision was federal legislation, passed in 2005, requiring an Electric Reliability Organization (the role now filled by the North American Electric Reliability Corporation, or NERC) to assess the adequacy of the North American bulk power supply.

In 2005, the Council and the Bonneville Power Administration created the Northwest Resource Adequacy Forum to aid the Council in developing a standard, and to annually assess the adequacy of the power supply. The forum, which is open to the public, includes utility planners, state utility commission staff, and other interested parties. After nearly three years of coordinated effort, it reached consensus on a proposed resource adequacy standard, which the Council subsequently adopted in April 2008.

The standard helps to assess whether the electricity supply is sufficient to meet the region's needs now and in the near future. It provides a minimum threshold that serves as an early warning should resource development fall dangerously short. It also suggests a higher threshold that encourages greater resource development to offset electricity price volatility. It does not mandate compliance or enforcement. It does not directly apply to individual utilities – because every utility's circumstances differ. Individual utilities must assess their own needs and risks to determine their own planning targets, which are screened by public utility commissions or by their boards of directors. It would be a misapplication of the adequacy standard to infer that utilities should slow their resource acquisition activity simply because the adequacy standard for the region is being met. The Pacific Northwest resource adequacy standard can be found at: <http://www.nwcouncil.org/library/2008/2008-07.pdf>.

Over the next five-year period, the region's existing resources, in aggregate, exceed the standard's minimum threshold for annual energy needs and for winter hourly needs. However, existing resources appear to just barely fall short of meeting the summer hourly adequacy requirement by 2015, which places the region in a yellow-alert status. Under the implementation plan agreed to by forum members, a yellow-alert status calls for an adequacy report to be released and for the forum to convene to discuss appropriate actions to take. The forum has met and decided that because the summer capacity shortfall is minimal and because regional utilities are already in a resource-acquisition mode, no additional resource actions should be recommended. However, the forum did recommend that all load and resource data be reevaluated and that the methodology used to define the adequacy standard be peer-reviewed. These actions are currently under way.

BACKGROUND

Motivation for Developing a New Standard

Economic growth depends on an adequate electricity supply, and the resource adequacy standard was developed to ensure that the region's energy needs will be met well into the future. In the worst-case scenario, an inadequate electricity supply can affect public health and safety, as in a blackout. Fortunately, such events are rare, and when they do happen, they are most often caused by a disruption in the delivery of electricity, not the supply. However, there have been times – during extreme cold spells or heat waves – when supply has been tenuous. The fact that most of the region's electricity comes from the hydroelectric system presents unique challenges to the energy supply, too, since periods of drought that limit hydroelectric power production are unpredictable.

While most disruptions in supply have been short-term, the Western United States did experience an extended energy crisis in 2000-01. At its root, the crisis was precipitated by an imbalance of electricity supply and demand centered in California and the Pacific Northwest, where for years development of new energy resources had lagged behind energy demand. Ripple effects from that crisis were felt throughout the West as electricity prices and consumer rates soared to historic highs.

In addition, changes in the energy environment have made ensuring the adequacy of the region's power supply more challenging. Greater constraints on the operation of the hydroelectric system, increasing development of variable and dispersed resources, and the growth of a

Westwide electricity market have all contributed to creating a much more complex and interconnected power system. Changes in the Bonneville Power Administration's role as a power provider also mean that load-serving entities will bear more responsibility for their load growth, making regional coordination to ensure adequacy especially important.

Historical Approach

Historically, the Northwest has planned to a critical-water standard, which implies that Northwest resources, including hydroelectric generation produced under the driest water condition, should at least match the forecast load on an annual basis. This standard originated when the region was essentially isolated from the rest of the Western system by limited transmission links. Even after cross-regional interties were built, this policy continued because high oil and gas prices dominated generation markets in the rest of the West.

However, since the collapse of oil and gas prices in the mid-1980s, the region has not had to balance in-region resources and demand under critical-water conditions in order to maintain a physically adequate power supply. The reasons for this are twofold. In almost all years, hydroelectric generation will exceed production under critical-water conditions; and the Southwest should always have surplus winter energy to export (the Southwest is a summer-peaking region and the Northwest is a winter-peaking region). Thus, the region has strayed from strict critical-period planning.

Generally, reservoirs behind the dams have been drafted in the fall and early winter under the assumption that the region would realize better-than-critical water conditions. Should a dry year ensue, the region could import surplus energy from the Southwest or interrupt a portion of the direct-service industry load. These kinds of contractual agreements with the remaining direct-service industries no longer exist, but the Northwest is still connected to the Southwest. Both regions should be able to benefit from the diversity in the timing of their peak loads. A strict assessment of adequacy, therefore, should consider the ability to import power from outside the region. For resource acquisition purposes, however, reliance on market resources will depend on impacts to overall cost and customer rates.

Adequacy Assessment Efforts Outside of the Northwest

In order for a regional adequacy standard to be effective, it must be compatible with actions in the rest of the West. Therefore, working with the Western Electricity Coordinating Council (WECC) and other Westwide organizations is necessary. Most of the discussions in the region and the rest of the West have been directed toward developing some sort of adequacy standard that would apply to load-serving entities. The Federal Energy Regulatory Commission (FERC) proposed an adequacy standard as part of its standard market design. However, that standard was inappropriate for an energy-constrained, hydropower-dominated system like the Northwest's. The FERC has subsequently deferred to the states, but in the absence of state or regional action, it might attempt to reassert authority in this area. In addition, the North American Electric Reliability Corporation (NERC) has begun developing a power supply adequacy assessment standard that would apply to the WECC.

The NERC Resource and Transmission Adequacy Task Force prepared a report with recommendations for both resource and transmission adequacy. The NERC adopted the report in

2004, and subsequently drafted a standard authorization request for a resource adequacy assessment incorporating the task force's recommendations. This proposed new standard requires regional reliability councils, such as the WECC, to establish resource adequacy assessment frameworks that the NERC will review to ensure compliance.

The WECC has since established a new framework that has been implemented in its annual power supply assessments for the last three years. Northwest planners continue to refine the characterization of the Columbia River hydroelectric system, both for the regional assessment and to improve the accuracy of its adequacy assessment for the Western Interconnection.

Some states, through their public utility commissions, have the ability to implement adequacy standards for the utilities they regulate. For example, the California commission adopted an adequacy standard requiring investor-owned utilities to have a 15-17 percent reserve margin over their peak load. This planning reserve includes the approximately 7-percent operating reserves required by the WECC. The California commission's order also requires load-serving entities to establish forward contracts to cover 90 percent of their summer (May through September) requirements, which would include their peak load plus the 15-percent reserve one year in advance. Some believe this standard goes beyond what is required to assure adequacy in a purely physical sense, as it is intended to limit California's exposure to the risk of extreme prices.

Assessing the Adequacy of a Resource Strategy

Assessing the adequacy of the Council's long-term resource strategy, as outlined in this power plan, is a separate issue from assessing the adequacy of the existing power system through the next five years. This section describes how those assessments differ and how the Council's resource adequacy standard is incorporated into its planning models to ensure that the resulting long-term strategy will provide an adequate supply.

The Northwest resource adequacy standard is based on a probabilistic metric defined by the resource adequacy forum that assesses whether existing resource capability is sufficient to meet firm loads through the next five years. That assessment takes into account only existing resources and new resources that are expected to be completed and operational during that time period. If a deficiency is identified, then specific actions are initiated. Those actions include reporting the problem, validating load and resource data used in the assessment and identifying potential solutions.

The process described above is intended to be an early-warning system for the region to indicate when the capability of the *existing power system* does not sufficiently keep up with demand. Although similar, an assessment of a resource **strategy** differs in significant ways. First, a resource strategy spans a much longer time period, namely 20 years for the Council's power plan. Second, a strategy implies that resource development will be dynamic, in other words, it provides a supply of cost-effective resources that the region can draw from depending on future conditions. The adequacy of a single resource plan (i.e. the resource-construction dates for a specific future simulated by the Council's regional portfolio model) can be assessed, but that is not the same as assessing the adequacy of the strategy itself.

What does it mean, then, to assess the adequacy of a resource strategy? In particular, how can we ensure that this power plan will provide an adequate supply? One approach is to assess the adequacy of each resource plan associated with each future simulated by the portfolio model (750 futures). But how many of those plans must pass the adequacy test in order for the strategy itself to be deemed adequate? If every plan is adequate, then we can be reasonably sure that the strategy is adequate. Unfortunately, that outcome is unlikely because of the number and range of uncertain variables used in the model. So, what percentage of possible future plans (derived from the resource strategy) must pass the test in order for the strategy to be deemed adequate?

The adequacy forum has not addressed this specific issue because it is somewhat outside the scope of its tasks. However, there is an alternative approach that provides a viable solution. Rather than assessing the adequacy of specific resource plans as a post process, the adequacy standard can be incorporated directly into the portfolio model. The standard is based on a probabilistic analysis that assesses the likelihood of curtailment to service (further defined in the next section). The result of that probabilistic analysis is translated into a minimum load/resource balance threshold. When a resource plan meets or exceeds this threshold, it satisfies the adequacy requirement. To ensure that the power plan's resource strategy is adequate, this minimum threshold has been added to the portfolio model as a requirement for resource acquisition. In other words, if the model's resource acquisitions (based on economic considerations) do not measure up to this threshold, it will add resources until that condition is satisfied.

THE PACIFIC NORTHWEST ADEQUACY STANDARD

The adequacy forum includes representatives from the region's electric utilities and utility organizations, public utility commissions and public interest groups, as well as from Bonneville and the Council. It is made up of a steering committee and a technical committee.

The forum's overarching goal is to *“establish a resource adequacy framework for the Pacific Northwest to provide a clear, consistent, and unambiguous means of answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework.”*

To that end, the forum has forged a voluntary, consensus-based standard for the region to address both energy (annual) and capacity (hourly) needs. This standard has been designed to assess whether the region has sufficient resources to meet growing demand for electricity well into the future. This is important, because it takes time – usually years – to acquire or construct the necessary infrastructure for an adequate electricity supply.

While some interests may wish to see an enforceable adequacy standard, currently, there are no institutions in the Northwest that could enforce such a standard for all the region's load-serving entities.

Physical Adequacy, Economic Adequacy, or Both

Is the purpose of an adequacy standard to ensure that the “lights stay on” with an acceptably high probability (physical adequacy); or is it to protect against the economic and social costs of an energy shortage (economic adequacy)? The adequacy standard addresses the first level by

providing a minimum threshold that serves as an early warning should resource development fall dangerously short. The standard also suggests a higher threshold that encourages greater resource development to offset electricity price volatility -- or economic adequacy. The economic threshold is tied to the resource strategy defined in the Council's power plan. The forum has not yet fully explored this interpretation of the economic threshold nor has it made any recommendations regarding failure to meet that threshold.

Different adequacy standards could be applied at different levels. For instance, a physical standard might be most appropriately applied at the WECC level. At this level, it would provide a baseline for physical reliability and actions by load-serving entities and their regulators to address. Economic adequacy might be better addressed at the individual (or perhaps state policy) level, where different mechanisms for mitigating price risk could be put in place.

Unlike past adequacy assessments, this assessment considers the question of reliance on market supply. Physical adequacy is determined by forecast load, existing firm resources, and assessing available market supply, cost notwithstanding. Economic adequacy is determined in a similar manner, except that the region (or utility) uses an economic analysis or makes a policy decision to determine how much power to buy from the market. Utilities may want to limit their exposure to market resources for a number of reasons, price volatility being only one.

The Council's portfolio analysis results suggest maintaining a higher level of in-region resources than the adequacy standard's minimum threshold. These additional resources reduce the likelihood of having to purchase high-priced electricity. At the same time, however, the analysis also indicates that if the overall level of regional resources is sufficient, overbuilding is a riskier and more expensive alternative than some level of reliance on the market. This is true regardless of the ownership of the resources.¹ The challenge is to find the right balance.

Defining the Resource Adequacy Standard

The Northwest resource adequacy standard² is based on a sophisticated hourly assessment of load and resources and how they might be affected by temperature (load deviations), precipitation (water supply), forced outages to generating resources, and other factors.

Historically, the region's tolerance for a significant power supply shortage has been assumed to be 5 percent – that is, the region would tolerate a significant power shortage no more than once in 20 years. This type of metric is commonly referred to as a loss-of-load probability (LOLP) and requires a complicated computer model to assess. However, not all utilities or other planning entities are willing or able to use such a tool. Therefore, the LOLP threshold is translated into a simpler and more familiar load/resource balance measurement that regional planners can use more easily. These simpler measurements are provided both for annual energy needs and peak hourly capacity needs.

¹ Ownership refers to either utility ownership or ownership by independent power producers.

² The Northwest resource adequacy standard can be found at:
<http://www.nwcouncil.org/energy/resource/Default.asp>.

Annual Needs (Energy Standard)

Energy in this context refers to the annual electricity needs of the region. The measure for this is the annual average load/resource balance in units of average megawatts. The threshold for this measure is set so that the resulting LOLP assessment yields a 5-percent value. In determining resource generating capability, the standard includes hydroelectric generation available under critical-water conditions, available annual output of regionally committed thermal generators and renewable resources, and a portion of the uncommitted independent power producer generation. The standard also includes a small amount of non-firm resources such as out-of-region market supplies and non-firm hydroelectric generation. The amount of non-firm resources the region should rely on is determined by the 5-percent LOLP analysis. In determining load, the standard uses the region's average annual firm load based on normal temperatures, and adjusted for firm out-of-region energy contract sales and purchases and savings from conservation programs.

Peak Hourly Needs (Capacity Standard)

Capacity in this context refers to the peak hourly electricity needs of the region. The measure for this is the planning reserve margin, or the surplus sustained-peak capacity, in units of percent. It represents the surplus generating capability above the sustained-peak period demand. In determining the planning reserve margin, the standard includes the same firm and non-firm resources used to assess the energy standard for the region. The planning reserve margin is assessed over the six highest load hours of the day for three consecutive days (sustained-peak period). This is intended to simulate a cold snap or heat wave – periods of the year when the Northwest requires the most capacity. The planning reserve margin is computed relative to normal-weather sustained-peak load. The threshold for this measure is determined by the 5-percent LOLP analysis and should be sufficient to cover load deviations due to extreme temperatures and the loss of some generating capability.

Implementing the Standard

The forum wanted to ensure it did not overstep the jurisdiction of states or the prerogatives of individual utilities in planning and acquiring resources to meet load. Because each utility's circumstances differ, it is difficult to translate a regional standard into a utility-specific standard. The forum has provided some guidance for utilities, but ultimately, they and their regulators are the decision-makers for resource acquisition. The implementation plan depends on regional sharing of information, transparency of assessment methodologies, and regional coordination. The forum believes that a voluntary approach will work because utilities and their governing bodies have a strong incentive to develop adequate resources to meet retail load.

Working with Other Entities

The Council, in conjunction with the forum, will assess the adequacy of the region's power supply on an annual basis. Demand forecast and resource assumptions will be compared to those in other regional reports, such as Bonneville's White Book and the Pacific Northwest Utilities Conference Committee's Northwest Regional Forecast. This sharing of information in a public forum should provide a favorable environment for addressing inconsistencies in data and reporting standards.

The Northwest is not alone in focusing on ensuring an adequate power supply. The NERC was expected to pick up its previously delayed work on the development of a resource adequacy assessment standard in 2009, which is expected to require the WECC to develop an adequacy assessment framework, but the standard development has since slipped. The WECC has spent the past several years developing a framework for the West's power supply, which is currently in place. The WECC's framework is not intended to override any state or regional assessments, including regional adequacy measures or their thresholds. In fact, the WECC has solicited help from regional entities to aid in its assessment of Westwide resource adequacy. The Council and the forum will continue to participate in the WECC's efforts.

THE ADEQUACY OF THE NORTHWEST POWER SUPPLY

The adequacy standard calls for the average annual energy capability to at least equal the average annual demand. It also calls for the system's peaking capability to be able to meet expected peak-hour demand and to have sufficient surplus to cover operating reserves,³ prolonged generator forced outages, and demand deviations due to extreme temperatures. Key findings of the current assessment are:

- Based only on existing resources (and those under construction), the region's power supply may fail to provide sufficient summer peaking capability by 2015 although not by much.
- This puts the region in a "yellow alert" situation, which triggers specific actions that require a review of all load and resource data and a review of the methodology used to assess adequacy. This work is underway.
- The Council and regional utilities are actively developing resource-acquisition strategies, which take economic risk, carbon-emission policies and other factors into account.
- Adding expected resource additions derived from the Council's power plan keeps the power supply adequate nearly through the entire study horizon period.

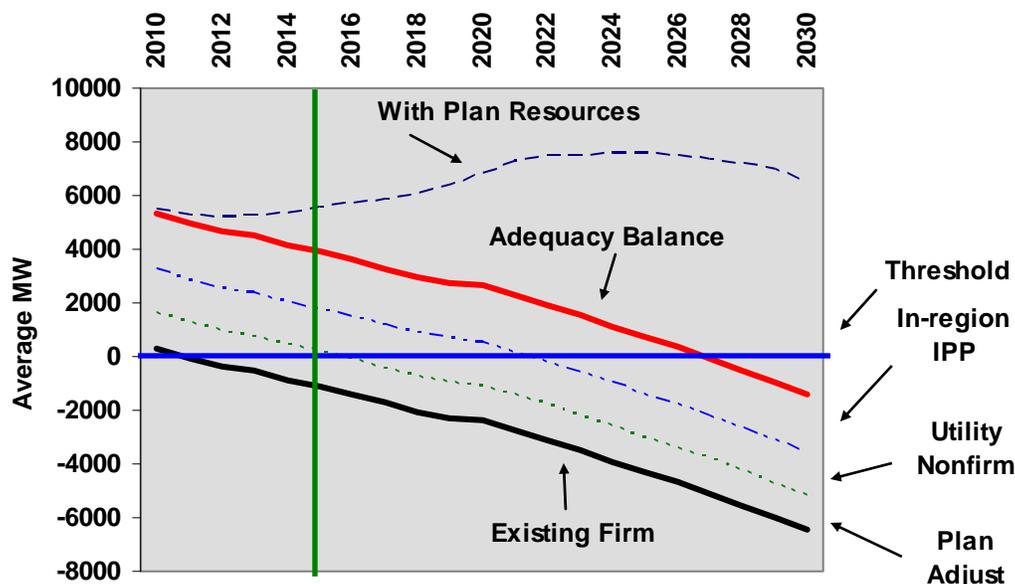
The Northwest adequacy standard, developed by the forum and adopted by the Council in 2008, specifies minimum thresholds for annual energy load/resource balance and for winter and summer surplus capacity margins. Normally the adequacy assessment is targeted for three and five years out, but in this instance the assessment is for the 20-year horizon of the power plan. Figures 14-1 through 14-3 show the assessed annual load/resource balance and capacity-reserve margins through the year 2030.

As apparent in Figure 14-1, only counting existing firm resources, the region is in about load/resource balance today, which (without any new resources) grows to a large deficit by 2030 (black line). The standard, however, includes some non-firm resources in its definition of the load/resource balance for adequacy purposes. A planning adjustment of 1,300 average megawatts is included to account for out-of-region market supplies and some amount of non-

³ Operating reserves currently do not include additional regulating or load-following reserves anticipated to be needed to integrate large amounts of new wind generation into the regional power grid, primarily because these reserves have not yet been quantified. In addition, this assessment only includes existing wind facilities and those currently under construction.

firm hydroelectric generation. The assessment also includes the full annual availability of regionally owned resources. This value is estimated to be about 1,600 average megawatts greater than the aggregate total of utility-declared firm non-hydro resources. Finally, there is a substantial amount of within-region but uncommitted generation, namely the independent power producer resources, which add about 2,150 average megawatts to the balance. Adding the non-firm resources to the calculation yields the solid red line in Figure 14-1, which shows the region well above the adequacy threshold until about 2027 (red line). Adding new resources suggested by the power plan (averaged over all futures) increases the surplus relative to a physical adequacy need (but are needed for economic and risk-aversion purposes).

Figure 14-1: Energy Adequacy Assessment



In a similar fashion, the winter and summer surplus sustained-peaking reserve margins can be calculated and compared to their adequacy thresholds. Figures 14-2 and 14-3 show those assessments for January and July, respectively. The sustained-peak reserve margin represents the amount of surplus generating capacity over the expected demand averaged over the sustained peak period, in terms of percent. The sustained peak period is defined to be the six highest load hours per day over three consecutive days (to reflect the duration of a typical cold snap or heat wave). As with the energy assessment, counting only existing firm resources shows the region below the January minimum capacity threshold for the entire planning horizon (black line). Adding non-firm resources, as defined in the standard (and described below), raises the reserve margin above the threshold until about 2030. Again, adding the expected generation from power plan resources makes the reserve margin even higher.

For these capacity adequacy assessments, the following non-firm resources were assumed to be available during emergency conditions. For winter months, in-region IPP generation is assumed to be fully available at 3,550 megawatts but for summer months that availability is reduced to 1,000 megawatts. Additional hydroelectric generation, in excess of critical-period generation, is assumed to be 2,000 megawatts in winter and 1,000 megawatts in summer. Finally, a maximum of 3,000 megawatts of out-of-region supply is assumed for winter but none for summer.

The story is a little different for July. Looking at Figure 14-3, the reserve margin, including defined non-firm resources, only keeps the region above the minimum threshold through about 2015. According to the standard, this puts the region in a “yellow-alert” situation, triggering specific regional actions, which currently are underway. First, regional planners are reviewing all load and resource data. Second, the methodology used to assess the minimum thresholds is being reviewed. Third, the Council and regional utilities are actively developing resource-acquisition strategies.

Adding expected new resource capability, based on the Council’s plan, to the reserve margin calculation in Figure 14-3 (topmost dashed line) indicates that the power supply should remain above the minimum adequacy threshold throughout nearly the entire study horizon. However, it should again be emphasized (see the above section entitled “Assessing the Adequacy of a Resource Strategy”) that using this type of static diagram (as in Figure 14-3) to assess the adequacy of the power plan’s strategy is inappropriate. Future resource acquisitions based on the plan’s strategy will vary depending on forecasts of future conditions. The dashed line in Figure 14-3 reflects new resource capability averaged across all futures analyzed by the portfolio model. The fact that it dips below the minimum adequacy threshold in 2029 provides no indication of the adequacy of the plan’s resource strategy. The proper use of Figures 14-1 through 14-3 is to compare the adequacy metrics (red lines), as defined by the standard, to their minimum thresholds (blue lines) over the next five-year period only. The reason the curves in these charts were extended to a 20-year period was only to indicate generally how the plan’s average resource build-out compares to the minimum thresholds -- not to assess the adequacy of the plan’s resource strategy.

Figure 14-2: January Capacity Adequacy Assessment

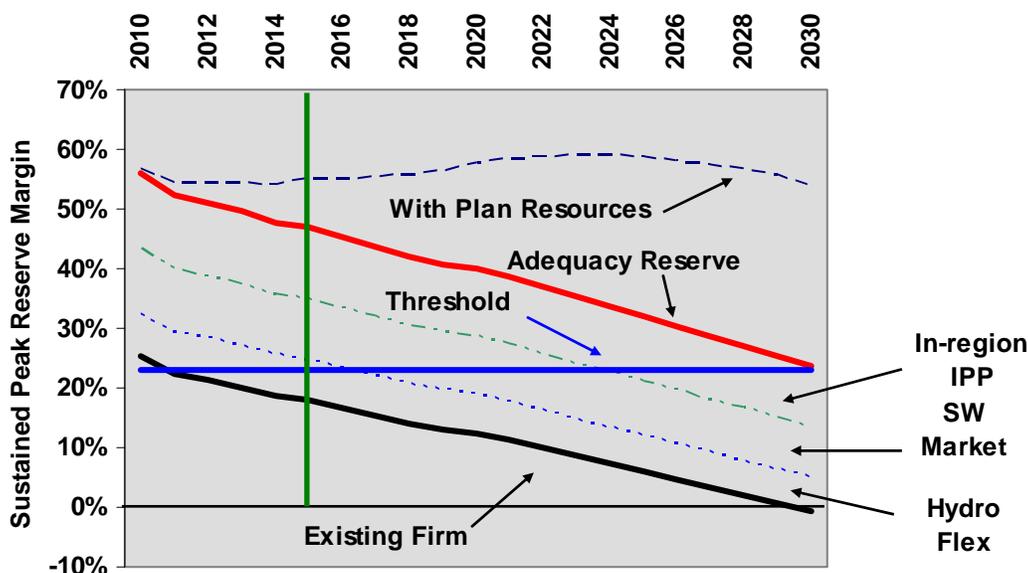
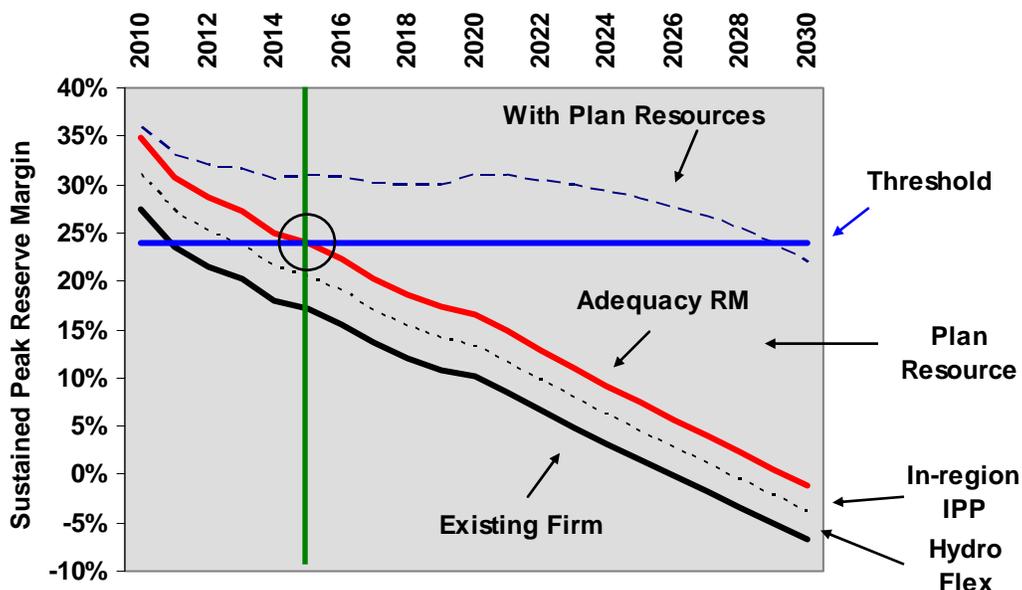


Figure 14-3: July Capacity Adequacy Assessment



UTILITY PERSPECTIVE ON RESOURCE ADEQUACY

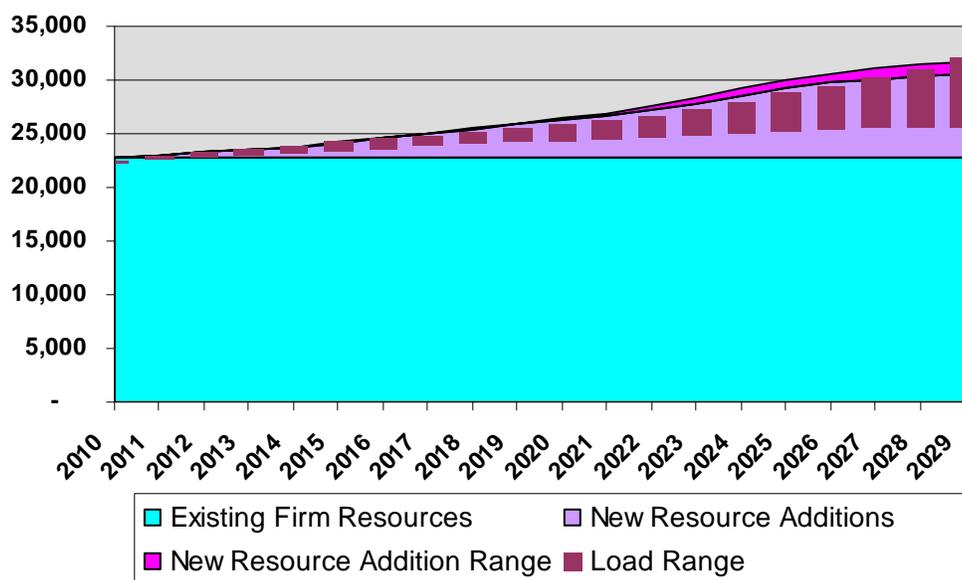
As discussed in Chapter 3, regional utilities historically have used the annual average load/resource balance as a simple metric to get an indication of their resource needs. This utility perspective compares only firm loads to firm resources (which include critical-period hydroelectric generation). The general conclusions that can be drawn from this simple metric is that when the average annual load is greater than the firm supply, additional resources likely are needed. And, as illustrated in Figures 3-13 through 3-15 in Chapter 3, the region's firm resources fall short of forecasted demand within the next five-year period, both for annual energy and hourly capacity needs. Utilities understand, however, that this is only a rough estimate at best and decisions regarding new resource acquisition must be made using more sophisticated analysis.

Nonetheless, the firm load/resource balance metric still provides a useful guide in assessing future power supply needs. Figures 14-4 through 14-6 show the balance between firm resources and load for annual energy and hourly capacity needs. These figures are identical to Figures 3-13 through 3-15 except for the addition of planned resources derived from the Council's resource strategy. Figure 14-4 indicates that on a firm basis only, existing resources combined with the expected resource development from this power plan will be sufficient to cover the entire range of load uncertainty. It should be noted that these results reflect the status of the region, in aggregate. Individual utility plans will differ based on their specific conditions and needs.

Another interesting result is reflected in the range of new resource additions. The purple area in Figure 14-4 reflects resources acquired in response to the low end of the load forecast range. The small pink area in this figure represents the additional resources acquired in response to the high end of the load forecast range. (The high end values are averaged over the top 100 futures analyzed by the portfolio model and the low end values are averaged over the bottom 100 futures). The interesting thing about this result is that almost regardless of load, the model suggests a high level of resource energy development. Most of the new resources (on the order

of 85 percent) are made up of conservation measures. Based on these results, we can infer that the model is acquiring this level of resource because it is economic to do so and because it minimizes exposure to other risks, such as carbon penalties -- not necessarily because of adequacy needs.

Figure 14-4: Energy Firm Loads and Resources



Figures 14-5 and 14-6 provide similar load and resource information for the region's winter and summer hourly needs. As in Figure 14-4, the resources depicted in these figures include only firm resources and planned resources derived from the portfolio model analysis. The generating capability of resources shown in these figures reflect their sustained-peak capability, that is, what these resources reliably can generate on average over the six highest load hours of the day for three consecutive days. The load forecasts in these figures do not include any amount of sustained-peak reserve margin requirement.

For both January and July, existing firm and portfolio-model planned resources are sufficient to cover the entire sustained-peak load forecast range throughout the study horizon. However it is not clear whether those resources would be sufficient to satisfy reserve-margin requirements throughout the study horizon. Figures 14-7 and 14-8 chart the resulting sustained-peak reserve margin ranges for January and July, respectively. Unfortunately, no utility-perspective (firm only) sustained-peak reserve-margin requirements have been established for the Northwest. If these requirements were known, Figures 14-7 and 14-8 could be used to identify years when the power supply fails to meet its hourly needs.

For January, in Figure 14-7, the entire range of sustained-peak reserve margin stays above the 20-percent level throughout the study horizon. If the utility-perspective sustained-peak reserve margin threshold were 17 percent (see Chapter 3), for example, then January would show no capacity deficiency, on average. Keep in mind that plan resources added to existing resources in these figures are averaged over all simulated futures, thus this conclusion cannot be made for each future condition.

For July, in Figure 14-8, the bottom end of the reserve-margin range drops below 17 percent by about 2024, which implies that existing resources plus plan resources would not be sufficient to cover loads plus reserve requirements by that year. However, these results do not provide an accurate assessment of hourly needs.

Figure 14-5: January Sustained-Peak Period (SPP) Loads and Resources

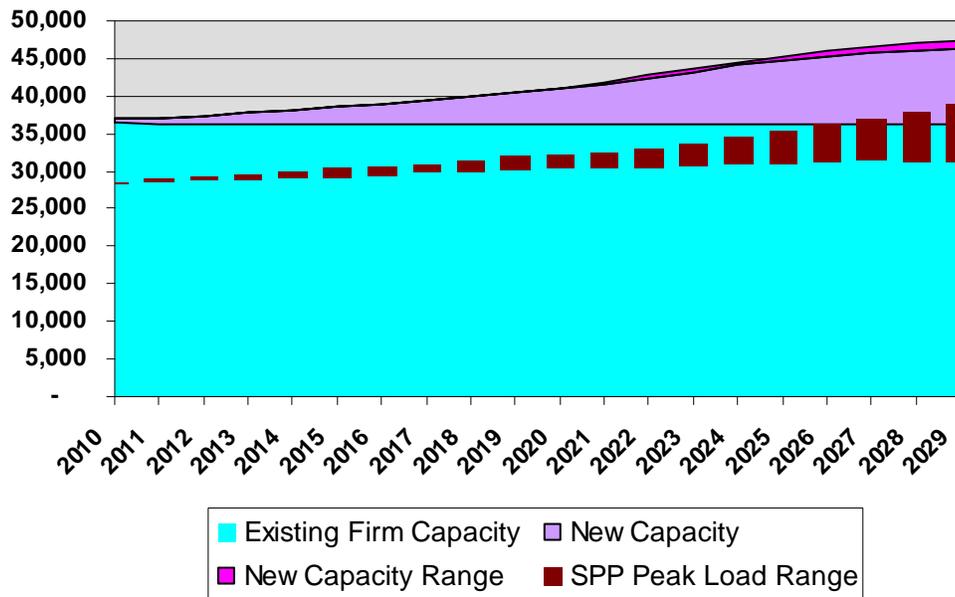


Figure 14-6: July Sustained-Peak Period (SPP) Loads and Resources

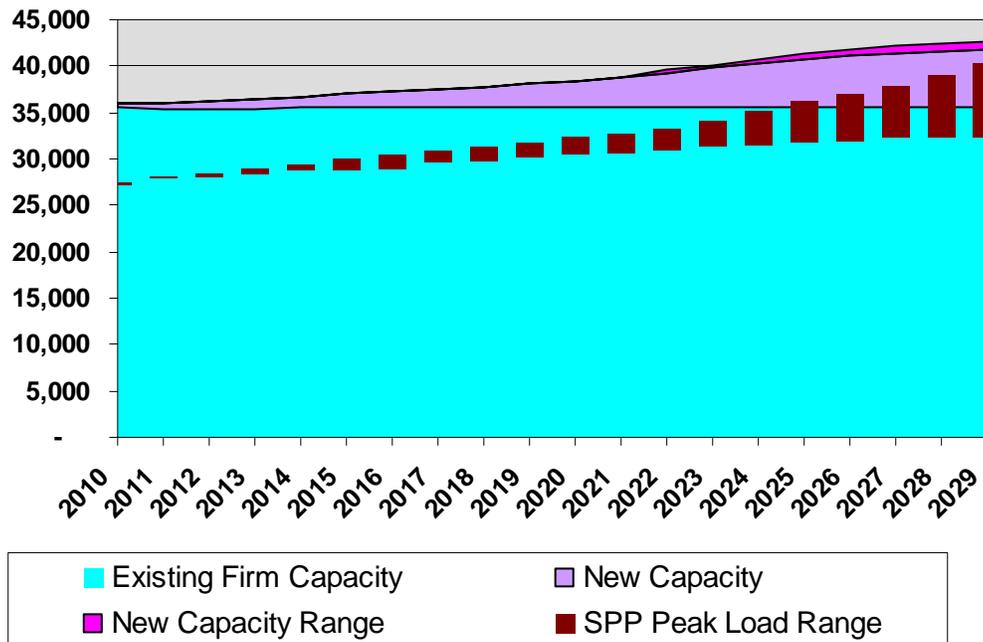


Figure 14-7: January Sustained-Peak Period Reserve Margins

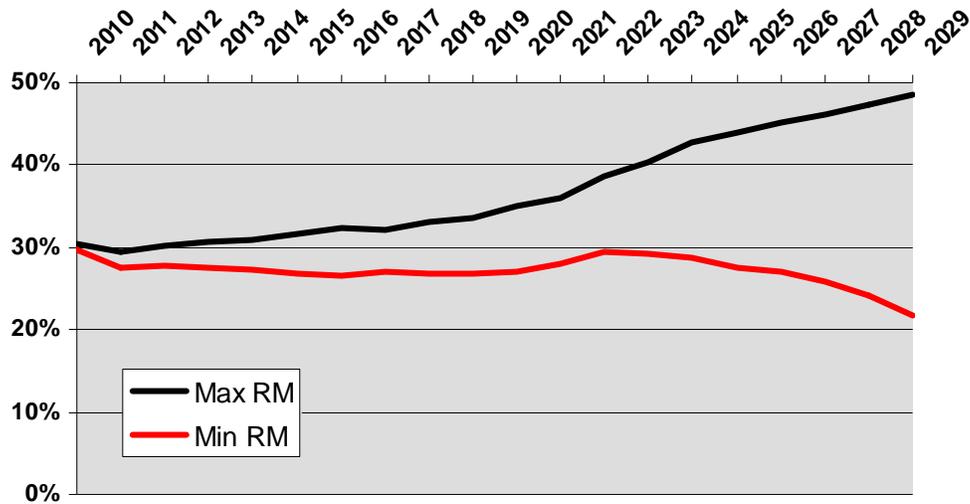
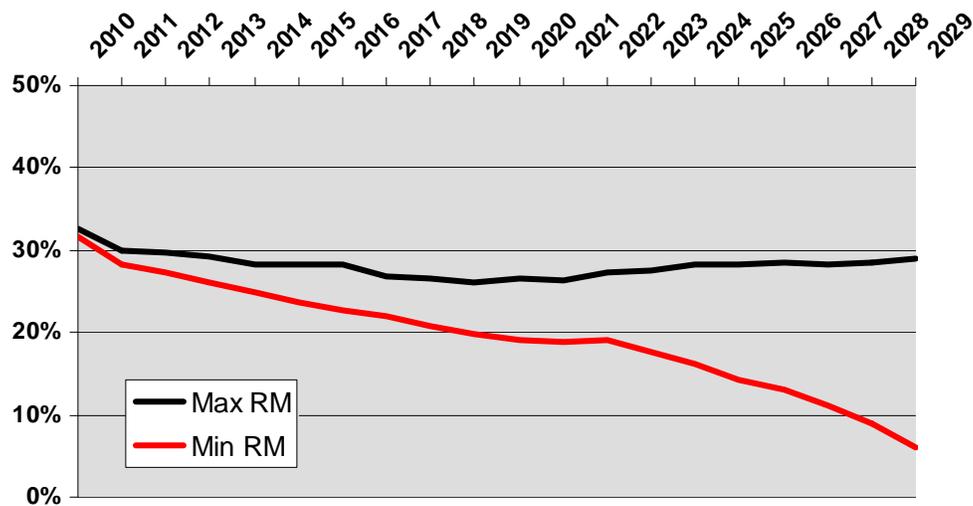


Figure 14-8: July Sustained-Peak Period Reserve Margins



METHODOLOGY

Analytical Tools

The Council used two complementary analyses to develop the adequacy standard. One addresses physical adequacy – the ability to meet load. The other addresses economic adequacy – avoiding extremely high costs that can result from tight supply conditions. The first analysis uses the GENESYS model, which performs a detailed simulation of the Northwest power system to

assess the ability of the system to meet load with variations in future conditions. The second analysis uses the portfolio model, described in Chapter 9, to explore the cost/risk tradeoff over a large number of possible futures.

The GENESYS model was developed in 1999 to assess the adequacy of the regional power supply.⁴ One of its most important features is that it is a probabilistic model, that is, it incorporates future uncertainties into its analysis. Each GENESYS study involves hundreds of simulations of the operation of the power system. Each simulation is performed using different values for uncertain future variables, such as precipitation (which affects the amount of water for hydroelectric generation) and temperature (which affects the demand for electricity).

More precisely, the random (or uncertain) variables modeled in GENESYS are Pacific Northwest streamflows, Pacific Northwest demand, generating-unit forced outages, and variability in wind generation. The variation in streamflow is captured by incorporating the 70-year (1929–1998) Pacific Northwest streamflow record. Uncertainty in demand is captured by using the Council’s short-term (temperature-driven) demand model.

GENESYS does not model long-term demand uncertainty (unrelated to temperature variations in demand) nor does it incorporate any mechanism to add new resources should demand grow more rapidly than expected. It performs its calculations for a known system configuration and a known long-term demand forecast, which can change over time. In order to assess the physical adequacy of the system over different long-term demand scenarios, the model must be rerun using the new demand and the corresponding new resource additions. The portfolio model deals with long-term demand uncertainty explicitly, as well as with other long-term uncertainties.

Another important feature of GENESYS is that it captures the effects of hydropower flexibility, that is, the ability to draft reservoirs below normal drafting limits during emergencies. Hydropower flexibility can be particularly important in helping address potential supply problems during extended periods of high demand from extreme cold events (or heat waves). In order for GENESYS to properly assess the use of this emergency generation, a very detailed hydroelectric-operation simulation algorithm was incorporated into the model. This logic simulates the operation of the hydroelectric system on an hourly basis. The portfolio model has a much more simplistic representation of the hydroelectric system and simulates resource dispatch on a seasonal basis.

The probabilistic assessment of adequacy in GENESYS provides much more useful information to decision-makers than a simple deterministic (static) comparison between resources and demand. Besides the expected values for hydroelectric generation and dispatched hours for thermal resources, the model also provides the distribution (or range) of operations for each resource. It also includes situations when the power supply is not able to meet all of its obligations. These situations are informative because they identify the conditions under which the power supply is inadequate. The frequency, duration, and magnitude of these curtailment events are recorded so that the overall probability of not being able to fully serve load is calculated. This probability, commonly referred to as the loss-of-load probability (LOLP), is the figure of merit provided by GENESYS.

⁴ *Northwest Power Supply Adequacy/Reliability Study Phase 1 Report*, Council Document 2000-4, March, 2000. <http://www.nwcouncil.org/library/2000/2000-4.pdf>

It should be noted that in determining the LOLP, an assumption is made in GENESYS that all available resources will be dispatched in economic order to “keep the lights on,” no matter what the cost. As such, the LOLP is a physical, rather than an economic, metric.

For the Northwest, the Council has defined an adequate system to have an LOLP no greater than 5 percent. This means that of all the simulations run, with uncertain water conditions, temperatures, forced outages, and variable wind, no more than 5 percent had significant curtailments. Such a system faces a maximum 5-percent likelihood that some demand will not be served due to inadequacies in the generation system (not counting potential problems in the transmission network).

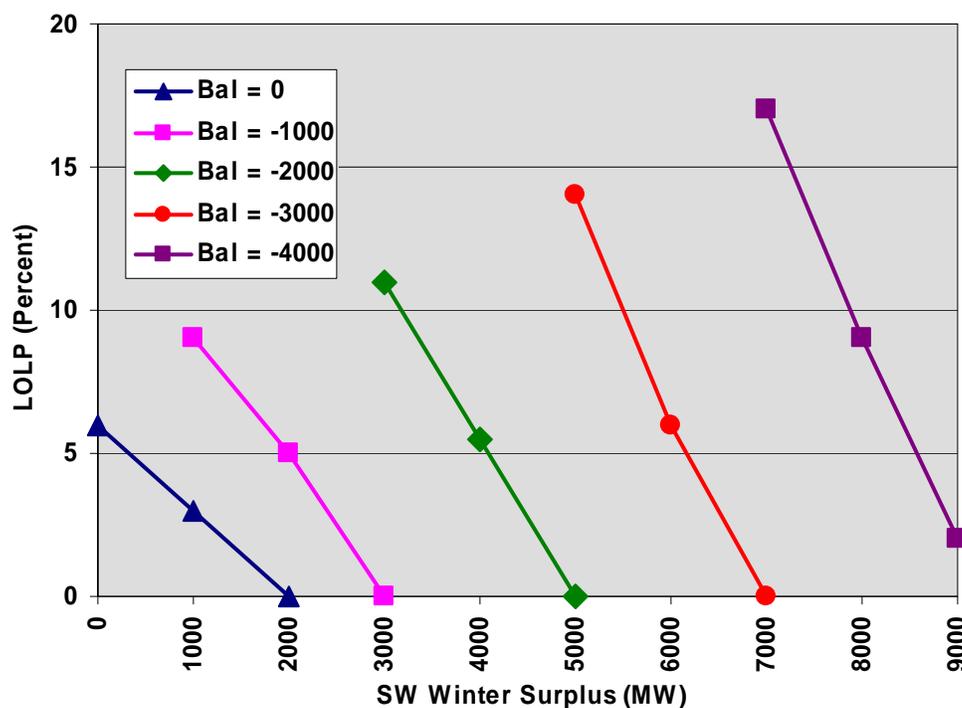
But what constitutes a significant curtailment event? Because the GENESYS model cannot possibly simulate all potentially varying parameters or know precisely every single resource that is available, a threshold is used to screen out inconsequential curtailment events. This threshold is commonly referred to as a “contingency” resource and depicts the amount and characteristics of additional generation available to utilities during emergencies.

Reliance on Market Resources

Assessing power supply adequacy is very sensitive to assumptions regarding market supplies, whether they come from within or outside the region. But how much of the market supply should the region rely on for adequacy? Assuming that no supply is available is probably too conservative, as it will result in greater resource acquisition and be more costly in the long run. And although relying more on market supplies could lower long-term costs, year-to-year price volatility could be extreme. Therefore, some level in between, calculated with the tradeoff between risk and cost in mind, is used for planning purposes.

Figure 14-9 illustrates the relationship between the LOLP and available market supply (presented in units of capacity), for different levels of Northwest firm load/resource balance. Generally speaking, the more the market supply, the lower the LOLP will be. For example, consider the case where the region is 2,000 average megawatts deficit on a firm basis (the curve with the diamond-shaped points in Figure 14-9). Assuming that a 5-percent LOLP represents an adequate power supply, the Northwest would be adequate (even though the load/resource balance is negative) if at least 4,000 megawatts of market supply were available. If no market supply were available, the projected LOLP would be on the order of 25 percent -- well over the minimum threshold of 5 percent. Even if the Northwest were in load/resource balance (the far left curve with the triangular points), the LOLP would be slightly over 5 percent with no available market supply.

Figure 14-9: Illustrative Example: LOLP as a Function of Available Southwest Capacity for Different Load/Resource Balance Conditions

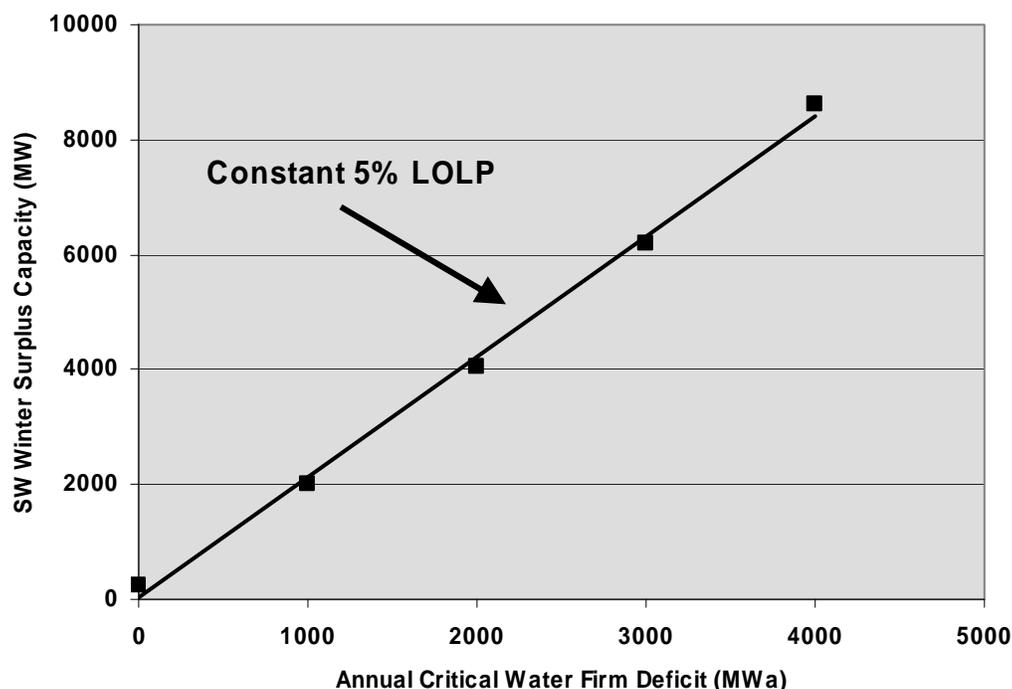


Translating the Adequacy Standard into a Simpler Measure

To make the relationship between the LOLP and market supply a little easier to see, the values in Figure 14-9 for all the points that cross the 5-percent LOLP level are plotted in Figure 14-10. In that figure, every point on the plotted curve represents the same adequacy, namely a 5-percent LOLP. Given a particular load/resource balance in the Northwest (horizontal axis), this graph shows how much market supply (vertical axis) is required to maintain an adequate system.

Again, using the same example, if the region was deficit by 2,000 average megawatts (on a firm basis), it would require about 4,000 megawatts of market supply from the Southwest surplus in order for the Northwest to maintain a 5-percent LOLP. This does not mean that the region would import 4,000 megawatts, but it does mean that in some hours the full 4,000 megawatts could be imported.

Figure 14-10: Illustrative Example Relationship between SW Surplus Capacity and Load/Resource Balance



The question of how much out-of-region surplus the Northwest should rely on for planning purposes, however, ends up being a policy question. If California goes forward with aggressive adequacy standards, it should mean that California will have ample winter surplus for years to come. However, current and potentially new air quality concerns may limit the operation of surplus resources in California. In addition, the potential of a future carbon tax may diminish their availability to the Northwest. Based on recent analysis, the current (arguably conservative) analysis assumes a 3,000-megawatt supply of out-of-region surplus capacity during winter months and no surplus capacity during summer months.

The in-region market supply is composed of independent power producer (IPP) resources, which are sold to the highest bidder, whether inside or outside the region. Current estimates show about 3,500 megawatts of such resources in the Northwest. During winter months, assuming that the Southwest is surplus, all of the IPP market supply should be available for Northwest use. However, during summer months, when Northwest utilities must compete with Southwest utilities for access to IPP generation, only a portion of their generation is assumed to be available for adequacy assessments. An estimate of available summer IPP generation for Northwest use is determined by their access to interregional transmission. IPP resources that have no direct access to interregional transmission are assumed to be available for Northwest use. Current adequacy assessments assume that 1,000 megawatts of IPP generation is available for summer use. Thus, for capacity assessments, 3,500 megawatts of IPP generation is assumed for winter and 1,000 megawatts are assumed for summer. For energy assessments, about 2,100 average megawatts of IPP annual average generation is assumed.

By using the relationship in Figure 14-10 and assuming that 3,000 megawatts of out-of-region surplus capacity is available, regional planners can assess the minimum balance between resources and loads that will yield an adequate supply (5 percent LOLP). Based on current analysis, that minimum for annual energy needs is a 1,300-average-megawatt deficit. In other words, counting only Northwest firm and IPP resources, the region's power supply can be no lower than 1,300 average megawatts less than firm loads in order to maintain an adequate supply. This means that, on average, the region can depend on 1,300 average megawatts from non-firm hydroelectric power and out-of-region supplies. A similar analysis and relationship is used to assess the minimum threshold for hourly needs.