NORTHWEST 6th POWER PLAN

DRAFT

9/3/09

Sixth Power Plan Overview

SUMMARY

The Pacific Northwest power system is faced with huge uncertainties about the direction and form of climate change policy, future fuel prices, salmon recovery actions, economic growth, and integration of 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 that these uncertainties and others pose for the region's electricity future and seeks an electrical resource strategy that minimizes the expected cost of the regional power system over the next 20 years. Across hundreds of possible futures considered in the development of the Sixth Power 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 many forms of additional electric-generating capability. In this Sixth Power Plan, because of 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 the load growth of the region for the next 20 years. If developed aggressively, this conservation, combined with the region's past successful development of energy efficiency could constitute the future equivalent of the regional hydroelectric system; a river of energy efficiency that will complement and protect the regional heritage of a clean and affordable power supply.

Aggressive pursuit of this conservation in the near-term is the primary focus of actions for the next five years. Combined with investments in renewable generation as required by state renewable portfolio standards, this holds the potential for delaying investments in more expensive and uncertain forms of electricity supply until the direction and form of future environmental legislation becomes clearer, and availability of alternative low-carbon technologies has matured in both technology and cost.

At the same time, the region cannot stand still in maintaining and improving the reliability of its power system. Investments in additional transmission capability and improved 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 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 also recognizes that meeting capacity needs and providing the flexibility reserves necessary to successfully integrate growing variable generation sources may require shorter-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 Plan is not a plan for every individual utility in the region, but rather is intended to provide guidance 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 the consideration of longer-term needs. The Plan encourages research on, and exploration of, advanced technologies for the long-term development of the power system. Advancing technologies that facilitate consumers' participation in their own efficiency improvements and their provision of capacity and flexibility services to the power system offer great potential for a transformed power system that is more diverse in its supplies and more efficient in its operation. Such "smart grid" development may facilitate the deployment of plug-in electric hybrid 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. This is a long-term process that will require many years to reach its full potential, but the region can facilitate progress through research, development, and demonstration of the technologies.

Along with a smarter grid, other technologies may be able to provide power when it is needed with low cost, low risk, and low emissions. In the future we may find greater value in power generated by geothermal resources, ocean waves, tides, gasified coal with carbon sequestration, or currently unknown technologies. New methods to store electric power, such as pumped storage or advanced battery technologies may enhance the value of existing generators like wind. Given the uncertainties of the future, the region should not concentrate on any one potential future solution to its power supply, and should diversify its exploration 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 16.3 million by 2030. This 3.6 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 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 size 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, current price levels, especially natural gas, are depressed by the effects of the recession. The production of nonconventional natural gas supplies has increased dramatically in the last few years, encouraged by higher prices. The technology to retrieve these supplies cost-effectively has only developed recently and this has made expectations for adequate future supplies more certain. 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.

Carbon emissions taxes or cap-and-trade policies are likely to further raise these energy costs. Some of the planning scenarios used to develop this Plan include a wide range of possible carbon mitigation costs from $0 to $100 per ton. The expected average prices in this range start at zero and increase over time to $47 per ton of CO_2 emissions by 2030. Carbon costs can have a significant impact on electricity costs and prices to consumers. While higher prices reduce demand, they also bring forward new sources of supply and efficiency, and make more efficiency measures cost-effective.

Electricity use before accounting for new conservation is expected to grow by about 5,500 average megawatts by 2030, growing at about 273 average megawatts, or 1.3 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 loads and the flexibility to provide within-hour load following and regulation. The requirements for within-hour flexibility reserves have been increased by the growing amount of variable wind generation located in the region.

CONSERVATION POTENTIAL

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, development of estimates in new areas such as efficiency in electricity distribution systems, consumer electronics, and street, parking and exterior building lighting. The estimated achievable potential conservation is nearly 6,000 average megawatts for measures costing under $100 per megawatt-hour. Over 4,000 average megawatts is available at a cost of less than $40 per megawatt-hour. These increased opportunities excluded savings from efficiencies that have already been secured through building codes, appliance efficiency standards, and utility programs. However, the amount of achievable technical conservation that is found to be cost-effective still has increased significantly because avoided costs have doubled and carbon cost risk is several times higher than in the Fifth Power Plan.

The Plan shows that a substantial amount of the growth in demand for electricity could be met by conservation. Portfolio model analysis shows that over 5,800 average megawatts of conservation are cost-effective in the draft plan, 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 considered possible, and an ultimate penetration rate limit of 85 percent. However, the amount of conservation that was found to be cost-effective changed very little in response to changing assumptions about carbon costs and policies. In general, failure to achieve the conservation included in the plan will increase both the cost and risk of the power system.

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, and 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. There are likely some 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. Longer-term alternatives that may develop include carbon separation and sequestration, maturing renewable technologies, advanced nuclear generation, demand response, smart grid, and storage technologies 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 $75 and $105 (levelized 2006$) per megawatt-hour.

RESOURCE STRATEGY

In addition to efficiency improvements, 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 readily accessible wind potential (5,300 MW) in the region. In addition to the wind, some geothermal resources enter the plan. However, the amount of geothermal potential is considered quite limited. Given risk of some form of carbon pricing strategy in the future, additional renewable generation is cost effective. Natural gas-fired generation is optioned toward the middle of the planning period. It is attractive for energy and capacity needs and provides an ability to displace coal plants in futures with high carbon costs, or assumed coal plant closures. Both combined-cycle turbines and simple-cycle turbines are included in most scenarios. Although these natural gas plants are optioned in the plan, they are not optioned until after the 5-year action plan period, and although the options protect against the risk of uncertain future conditions, they are not actually constructed in many of the simulated futures during the entire 20 year period.

Due to slower growth of electricity demand, the large conservation potential, and required RPS resources, there is no apparent need for these other generating resources in the Plan’s first five years from a regional planning perspective. The Council recognizes that individual utilities’ needs and access to market resources will vary. Some utilities will need additional resources in the next few years even if they acquire all conservation available to their service territory and meet their renewable portfolio standards.

During the last 10 years of the Power Plan the non-conservation resource priorities become less clear. Given current climate change policies and concerns, new coal without carbon sequestration is unlikely, and any significant reduction in carbon will require reduced operations of existing coal plants. Alternatives beyond more 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, use of 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.

CLIMATE CHANGE POLICY

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 and nuclear, or from sequestering carbon.

Reductions in carbon emissions can be encouraged through various policy approaches including, regulatory mandates (e.g. 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. National and regional proposals have focused on cap-and-trade systems, although none have been adopted successfully nationally or in the region. Although carbon taxes are easier to implement than cap-and-trade systems, none have been proposed. The Council's Sixth Power Plan reflects the likely, but uncertain, costs of potential carbon pricing policies by assuming a possible range of carbon costs between $0 and $100 per ton. The average of these uncertain future costs increases over time and reaches about $47 per ton by 2030. These potential costs play an important role in the proposed resource portfolio, 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 5 percent over 2005 levels by 2030.

- Without additional carbon pricing policies, current policies would stabilize carbon emissions from the Northwest power system.

- Assuming higher carbon prices, the Sixth Plan resource strategy has the potential to reduce regional power system carbon emissions to 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 over 85 percent of the carbon dioxide from the regional power system. A carefully coordinated retirement and replacement of coal-fired generation with conservation, renewable generation, and lower-carbon-emission resources could reduce carbon emissions to 35 percent of 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 variety of different scenarios are considered in Chapter 9.

- Protecting the capability of the existing regional hydroelectric generation through conservation and preservation of its generating capability keeps 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.

CAPACITY, FLEXIBILITY, AND WIND INTEGRATION

Reliable operation of a power system requires minute to minute matching of electricity generation to varying electricity demands. 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 the hydroelectric system historically 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 loads have 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 loads 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 be lower cost than adding peaking generation, demand response, or flexibility storage, and can be implemented more quickly.

FISH AND WILDLIFE PROGRAM AND THE POWER PLAN

The Fish and Wildlife Program is part of the Council's Power Plan. It is intended to guide Bonneville's efforts to mitigate for the adverse effect on fish and wildlife that resulted from construction and operation of the Columbia River hydroelectric system. One of the roles of power plan is to help assure reliable implementation of fish and wildlife operations. The power system, guided by the power plan, has done this in the past and will continue to do this in the future. It has done so by acquiring conservation and generating resources to make up for 1,170 average megawatts of lost hydroelectric generation stemming from actions to aid fish migration, by developing resource adequacy standards, and by implementing strategies to minimize power system emergencies and events that might compromise fish operations. Power system adaptations have taken place in such a way not only to accommodate fish operations but also to leave the power system adequate and reliable.

In addition to operational changes, the direct cost and capital costs of fish and wildlife programs have been recovered through Bonneville revenues, resulting in higher electricity prices. Bonneville estimates that replacing lost hydropower capability and funding direct fish and wildlife program expenditures has increased its costs from $750 to $900 million per year. This amount represents approximately 20 percent of Bonneville's annual net revenue requirement. The power system is less economical as a result of fish and wildlife program costs, but still economical in a broad affordability sense.

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 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 both improve electricity reliability and help insure reliable fish operations.

Sixth Power Plan Action Plan

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 green house gas emissions. With green house 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 efficiency potential that has been identified (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, to track and verify achievements, and adaptively manage regional efficiency acquisition strategies.

The Council target for regional acquisition of conservation over the first 5 years of the Plan is 1200 MWa. However, the conservation target relies on forecasts of underlying load and economic conditions, such as the rate of economic recovery and the construction rate of new *buildings, that may turn out to be different in the next five years than forecast. The uncertainties of the underlying assumptions thus create uncertainty about the total amount of the targeted conservation that will be available to acquire in the first five years. For this reason, the Council also developed a range of likely conservation savings over the first 5 years of 1100 to 1400 MWa. 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 6th Power Plan. The Council may choose to adjust the conservation target following a mid-term review to reflect actual achievements or conditions different than forecast that have effected the total amount of conservation available. These periodic evaluations will help the Council to monitor actual conservation savings and help prepare for the next major power plan in 5 years.*

Conservation: Deployment

CONS-1. **Achieve the level of conservation resource acquisition identified in the Sixth 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 believes that the region should be able to achieve at least 1,200 average megawatts of cost-effective conservation savings under the majority of future conditions. 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. Therefore, the Sixth Plan's likely range of conservation savings is from a low of 1100 average megawatts of savings to a high of 1,400 average megawatts over the next five years. Since the future is uncertain, Action Item CONS-16, calls for a mid-term review of regional progress towards the regional conservation target and to consider any adjustment to that target during the remainder of the period covered by the Action Plan. In addition the mid-term review will assess the potential impacts on other resource actions if there is significant difference, either up or down, in conservation acquisitions from the targets.

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 Sixth Plan identified nearly 6,000 average megawatts of cost-effective conservation realistically achievable over twenty years. Of that, approximately 2,500 average megawatts will require new initiatives, programs, market transformation efforts or progress towards 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 that the

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

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 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 program 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 Program 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 polices 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.** [To State Utility Regulatory Commissions, Investor-Owned and Publicly Owned Utilities, States, BPA and Others]

Conservation: 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 Plan's regional conservation target and accomplish the other actions set forth in the Sixth Plan 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 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 towards 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 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 decision makers 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 towards 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 towards meeting 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 others issues.** [Council] Guidance is needed to ensure that the Sixth 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 and implement effective and administratively-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.

Conservation: Development and Confirmation

The Sixth 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 Sixth 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 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 energy perspective, new generating capacity in excess of that needed to meet state renewable portfolio standards is unlikely to be needed in the near-term[2] for the purpose of maintaining energy adequacy. Additional energy acquisitions for the purpose of risk or cost reduction also appear not to be cost-effective. Although the region as a whole does not appear to be short of energy, this may not be true for individual utilities, some of which may be surplus while others may need to acquire additional energy generation capacity because of transmission or other limitations that constrain access to energy markets and surplus generation. This action plan includes guidelines for energy acquisitions in these circumstances.

Though the summertime surplus of firm capacity is declining, additional firm capacity is not needed on a region-wide basis in the near-term for the purpose of maintaining adequate winter or summer peaking reserves. However, continued development of wind power to meet regional renewable portfolio standards and for export[3] will continue to increase the demand for balancing capacity[4]. This action plan includes actions to reduce the demand for system flexibility, to more fully access the latent flexibility of the existing system and to better understand the interactions between provision of balancing, capacity and energy services. These actions are consistent with the current recommendations of the Northwest Wind Integration Action Plan.

Even with implementation of measures to more effectively use existing system flexibility, continued development of variable-output resources may eventually lead to the need to augment capacity and flexibility. Though the timing of this need on a regional basis is poorly understood,

[2] First five years of the 20-year period of the plan.
[3] Balancing authorities are obligated to provide interconnection and integration services for generators irrespective of local need.
[4] Balancing capability (often referred to as system flexibility or regulation and load-following) refers to the ability to balance generation and loads on seconds to minutes (regulation) and within-hour (load-following) bases.

Bonneville has asserted that it may confront this need in the near-term because of the geographic concentration of wind development within the Bonneville balancing area. This action plan includes guidelines for capacity acquisitions in these circumstances. As the region considers the cost effectiveness of new low or non-carbon emitting resource options, it will need to explicitly consider the costs that may be associated with the potential need to develop complementary carbon fueled resources to firm and shape variable-output non-carbon fueled generation, as well as the costs to the environment and region to develop necessary transmission facilities to integrate such resources. The region should also consider the carbon reduction attributes associated with using other technologies to integrate wind, such as smart grid and storage.

Over the longer-term it is expected that additional sources of low-carbon energy will be needed to reduce carbon dioxide production to sustainable levels. Cost-effective near-term low-carbon options include wind, limited quantities of geothermal, biogas and biomass residues, new hydropower and hydropower upgrades, and high-efficiency natural gas generation and cogeneration. Expanding the suite of available cost-effective low-carbon resource choices would be beneficial. 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 for the capture, storage or recycling of carbon from existing and new fossil-fueled power plants. This action plan includes actions to promote the cost-effectiveness and availability of additional low-carbon generating resources with a focus on options of special relevance to the Northwest.

Sound power system planning and decisions require capable analysis tools and reliable supporting data. In particular, techniques and data for assessing the most cost-effective approaches for long-term development and integration of variable-output resources are inadequate or lacking. This action plan contains actions to support improved planning and decision-making.

Generating Resource Acquisition

GEN-1. **Acquisitions to meet capacity, energy and ancillary service needs.** Bonneville, other balancing authorities and utilities needing to acquire resources to serve capacity, energy and ancillary service needs 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). Resource cost-effectiveness evaluations should recognize the net value of services provided (e.g., energy, capacity, ancillary services, avoided transmission and distribution costs, cogeneration load) and services needed to support (e.g., transmission, balancing services, supplemental firm capacity) the available alternatives. Resource-related risks including investment, performance and environmental 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, it is evident that certain 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 tend to be challenging to develop because of the complexity of business arrangements, engineering, fuel supply and interconnection, proportionally high transaction costs and long lead times, coupled with relatively small size. Design and engineering is often highly site-specific, as are costs and business arrangements. If successful, however, these projects can provide baseload energy, avoided transmission and distribution costs, residue disposal solutions, local economic development, 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 undertaking activities such as the following:

- Surveys of resource development potential
- Requests for proposals structured to accommodate small and diverse projects
- “Open window” application and evaluation process for unsolicited proposals
- Standard power purchase offers for qualifying projects
- Standard interconnection provisions
- Consideration of all project attributes in proposal evaluations
- Provision of financial, engineering and other development assistance
- Support for demonstration and pilot projects for developing, testing and demonstrating technology and business practices

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 ACE[5] diversity sharing among balancing areas. The Northwest Wind Integration Forum, working with Bonneville, regional utilities and grid entities should assess the feasibility, cost and benefits of these and other possible measures that would reduce the demand for balancing reserves and implement promising measures. ***This action is of high priority.***

GEN-4. **Expand access to existing system flexibility.** Some of the latent balancing capability of the existing power system cannot be used because of operating protocols, transmission and communication limitations, absence of equipment allowing plants to be operated for balancing purposes and environmental constraints. The 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 necessary to provide balancing capability. The Northwest Wind Integration Forum, working with regional balancing authorities and grid entities should assess the feasibility, cost and benefits of expanded dynamic scheduling within region and across the Northern and Southern interties. Attractive opportunities for expansion should be

[5] 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.

developed. This working group should also work with plant owners to establish balancing capability for generating units theoretically, but not currently practically capable of providing balancing services. ***This action is of high priority.***

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 and implement a methodology for evaluating the adequacy of fast-response balancing capability.

GEN-6. **Evaluate flexibility augmentation options.** This plan recommends development of wind and other renewable resources to offset carbon control cost and natural gas price risks. Addition of wind and other variable-output resources will continue to expand the need for balancing capability. In response to this need, the highest 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 meet the needs of an expanding inventory of variable-output resources. The Council, working with the Wind Integration Forum will undertake an effort to 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 include, but not be limited to, consideration of combined-cycle plants, gas turbine generators and reciprocating engines, compressed air energy storage, pumped storage hydro, battery storage, smart grid and demand-side options. Metrics should be developed to measure and compare the various options. The completed assessment should include a plan of development, consisting of research, development and demonstration activities, needed to ensure that the most promising options are available for operation when required. ***Because of the early commercial status or long development lead time of several of these options, this action is of high priority.***

Expanding the Menu of Cost-effective Low Carbon Resources

GEN-7. **Commercialize and confirm promising low-carbon resources.** Wave energy, deep-water wind power and enhanced geothermal 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 and to establish the body of knowledge and legal framework to support commercial development of the resources when available and needed. These efforts would include: 1) energy resource measurements of sufficient geographic scope, frequency and duration to support assessment of resource economics, identification of promising resource areas and assessment of resource integration needs; 2) technology assessment; 3) identification and resolution of potential environmental, economic and other development conflicts; 4) demonstration projects to test and evaluate technology; 5) assessment of system integration needs; and, 6) pilot projects to serve as the basis for commercial development. The initiatives of the Oregon Wave Energy Trust provides a model of a comprehensive resource confirmation agenda.

GEN-8. **Resource development mandates and incentives.** A diverse collection of federal and state resource development mandates and incentives has developed over time. The underlying public interest goals of mandates and incentives include commercialization of immature but promising technologies, developing the power system and social “infrastructure” for accommodating commercial-scale development of promising resources and promoting the 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 impact efficient system operation. The Council will undertake a review of the impacts and effectiveness of mandates and incentives including consideration of the following:

a. **Impact of production tax credits on optimal dispatch.** The federal production tax credit lowers the effective variable cost of generation, in some cases 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.** A renewable energy credit (REC) generally represents the environmental and renewable attributes of renewable energy production as a separate commodity from the associated energy. RECs can be transacted as “bundled” (i.e., with the associated energy) or “unbundled” (separate from the associated energy. Some states credit unbundled RECs (also called “tradable RECs”) to meeting a portion of renewable portfolio standards. Unbundled sale of RECs allows utilities to acquire the attributes of renewable power without securing transmission from the renewable energy plant to the utility’s service territory. To the extent that the renewable energy benefits are not location-specific (e.g., avoided carbon dioxide production), tradable RECs can reduce the cost to utilities of securing these attributes by allowing a utility to avoid transmission wheeling charges and to purchase from a higher quality, lower cost renewable resource than might otherwise be available. Tradable RECs can also provide a revenue stream to utilities choosing to develop renewable resources in advance of need without having to establish transmission to the customer utility, and can foster the non-power economic benefits of renewable energy resource development. Stimulating additional development of variable-output resources in the Pacific Northwest without corresponding inter-regional transmission connections may, however, create challenges for the region. The residual (“null”) power will be marketed locally and may depress the value of competing, non-RPS-qualifying energy. Integrating the additional variable-output resources that may be developed to export unbundled RECs will increase the demand for integration services, thus possibly increasing the costs of such services. This could have the effect of driving up costs of integrating variable-output resources needed to comply with RPS requirements within the region, even for variable-output resources where RECs will not be unbundled, but consumed in the region. The purpose of this review will be to identify and articulate the costs and benefits of the unbundled REC market and to suggest modifications, if any, needed to remedy significant inequities or perverse incentives.

c. **Geothermal development risk reduction.** Geothermal is a very 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, directed to offsetting 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 reduction in greenhouse gasses, 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 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 conservation in the design of renewable portfolio standards and other low-carbon resource incentives.

GEN-9. **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 longer-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-10. **Monitoring development of other promising resources and technologies.** Certain emerging resources and technologies have potential though not exclusive application in the Northwest. These include technologies for post-combustion carbon dioxide capture from conventional fossil-fuel power plants, carbon dioxide “recycling” technologies such as algae-derived biofuel production, 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. The commercial development of these technologies will be promoted by policies, incentives and other technological development drivers enacted at the global or federal level, or within regions where the technology might play a particularly vital role. While active participation of Northwest entities in the development of these technologies is not necessary, development of these technologies should be closely monitored. Moreover consideration might be given to joint participate in demonstration projects and other resource development efforts.

Information to Support Sound Planning and Decision Making

GEN-11. **Resource Assessment.** Bonneville, working with the Council should reestablish 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, working with the Wind Integration Forum, should undertake an effort 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 possible 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 upon the results of the flexibility augmentation assessment for estimates of 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 development of 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 tradeoffs between hydrosystem operational constraints and the availability of flexibility.

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 the 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. I**mplementation 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 new generation to provide these services.

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, which 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 that 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 flexibilty 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 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 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 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 the 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, acquired conservation resources and, if necessary, additional generating resources that Bonneville acquires 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, 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 consider service to the DSIs, such service should:

- have the lowest impact possible on other customers' rates;
- provide, so far as possible, ancillary services;
- provide the reserves required under the Northwest Power Act; and
- be offered at rates that will allow the DSIs a reasonable opportunity for operations in the region.

ENSURING ADEQUACY

Development and adoption of 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, complete 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 loads 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. An alternative growing in potential is demand response, which allows voluntary reductions in load during extreme loads 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 further 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 have little or no history but that have promise (e.g. use of demand response for load following).

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 its 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 these loads to provide reserves as required in the Power Act. In particular the potential for these loads to provide ancillary services should be examined for its cost effectiveness.

DR-7. **Complete the work of the PNDRP.** Council staff should continue the coordination, with the Regulatory Assistance Project, of the Pacific Northwest Demand Response Project (PNDRP). In particular, PNDRP should complete the 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 consideration of 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 as to 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

The development of smart-grid technologies has 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 understand better 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

SG-2. **Smart grid demonstration.** Develop smart grid demonstration projects.

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 / 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, and can be assisted by, actions at WECC.

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 that need to take place 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 the Northwest. Examples are 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 on 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: first, sub regional planning groups (SPGs) like Northern Tier Transmission Group and ColumbiaGrid and second, interconnection-wide, through TEPPC. TEPPC acts as a data provider and provider of 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 to create a public forum which brings together power planners and 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, demand, fuel prices, policies involving resource operation, and treaties affecting the hydroelectric system. Forum members will assist in developing ways to integrate these uncertainties into the Council's planning models.

The forum will also provide an opportunity to identify synergies that may exist between power and fish operations and to explore ways of taking advantage of those situations. For example, the acquisition of fish and wildlife habitat may also an opportunity to mitigate the effects of carbon emissions. The forum will also be expected to examine the impacts of fish and wildlife operations on the flexibility and capacity of the hydroelectric system and explore ways to minimize those impacts. These and other issues that may come up in the future need to be discussed in an open forum with both fish and power planners involved.

F&W-1. **Long-term planning forum.** The Council will work with federal, state, tribal and other entities in a public forum to improve the integration of long-term fish and wildlife operations and power planning.

F&W-2. **Contingency plans.** The Council will work with fish and wildlife managers and regional power planners to; 1) develop a curtailment plan for fish and wildlife operations in the event of a power emergency, 2) prepare a contingency power operation in the event of a fish and wildlife emergency, and 3) develop a plan for continued improvement in our ability to forecast and operate the 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 treaty expires during this plan's study horizon and modifications to the treaty are very likely to affect both power and fish and wildlife. The Council should be proactive in addressing this issue.

F&W-5. **Climate change.** The Council will work with Bonneville, 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 for these impacts and encourage others to improve runoff volume forecasting methods, especially for the fall.

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 Plan and report on progress biennially.

MON-1 **Assess changing conditions affecting the plan.** Council will monitor how developing electricity loads, fuel price, electricity prices, conservation technologies, resource costs, and other planning forecasts and assumptions compare to assumptions included in the Sixth Plan.

MON-1 **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-1 **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 development of 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 collection of data relating to 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 on the Council's ability to analyze major changes in regional and Bonneville Power systems and make recommendations on how best for the BPA Administrator to meet BPA's obligations and for the region as a whole to achieve as low cost and low risk in future power plans as possible. This review will focus on changing regional power system conditions such as capacity constraints, integration of 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 meeting 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 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 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 putting substantial amount of work by staff 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 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. Example 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 in use 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 Council's ability to see 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. **Evaluation of 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.

Chapter 1: Introduction

PURPOSE OF THE POWER PLAN

The Northwest Power and Conservation Council (Council) was formed by the Northwest states in 1981 in accordance with the Northwest Electric Power Planning and Conservation Act (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 system for the Pacific Northwest[1].

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 December of 1980. In each plan, costs and technologies have changed resulting in subtle changes in the plans. Alternative 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 has also 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 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 7,831 average megawatts between 1980 and 2007. During that time the region acquired 3,645 average megawatts of conservation, so that actual loads to be met by electricity generation only increased by 4,186 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 Bonneville, 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 polices 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.

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 Montana, 25 percent in Oregon, and 20 percent in Washington. The timing to reach these levels varies by state. Many other states in the West have similar renewable requirements.

Some policies are in already 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 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 raise 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 federal base resources to protect its low cost and ensure regional commitment to repaying debt to the U.S. Treasury.[3] 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 and its customers have been working toward new long-term contracts that would protect the cost-based federal system while providing better incentives for utility resource decisions. Bonneville adopted its Regional Dialogue Policy in July 2007. Since then, Bonneville and its customer utilities have been developing the policies and contracts needed to implement the policy.

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.

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

- How will the region implement the Council's power plan?

[3] Comprehensive Review of the Northwest Energy System: Final Report. December 12, 1996.

- 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, we can have much more confidence in our estimates of savings, and in our evaluations of conservation acquisition alternatives. As better information about the value of electricity savings in particular locations and at particular times is made available to consumers, efficiency improvements will increasingly 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.

- 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 electricity generation 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 predict we are facing 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.

- 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?

BACKGROUND

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 were already incurred and still affect electricity prices today.

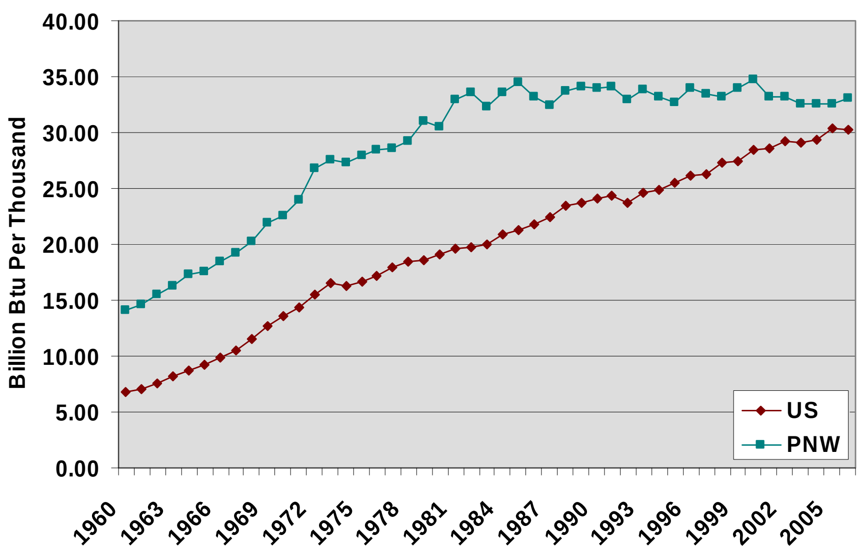
In 2000 and 2001, the region experienced a second large electricity price increase. Unlike the 1980 price increase, this one was a result of too little investment in electricity generation, combined with a poor water year, and a flawed power market design in California. This price increase confirmed 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 were first 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 here 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 has also historically 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

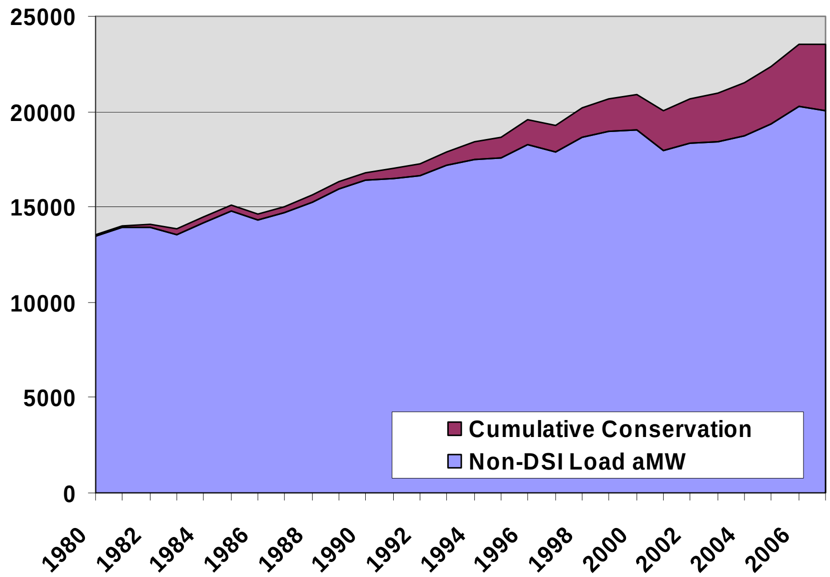


Both regional and national electricity prices have increased over the last 35 years. National prices increased following the oil embargo in 1973, but the region's prices, which were less influenced by changes in oil and natural gas prices, did not escalate rapidly until 1980. During the 1980s and 1990s 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. In 2007, the region saved 3,700 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 46 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 1.4 percent per year from 1980 to 2007 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 decreased 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.[4] 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 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.

[4] Figure X-3 shows average annual energy capability. The hydro numbers are critical water, and wind assumes a 30 percent capacity factor.

Conservation is the fourth largest resource meeting the Northwest's electric energy needs, exceeded only by hydro, coal, and natural gas.

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

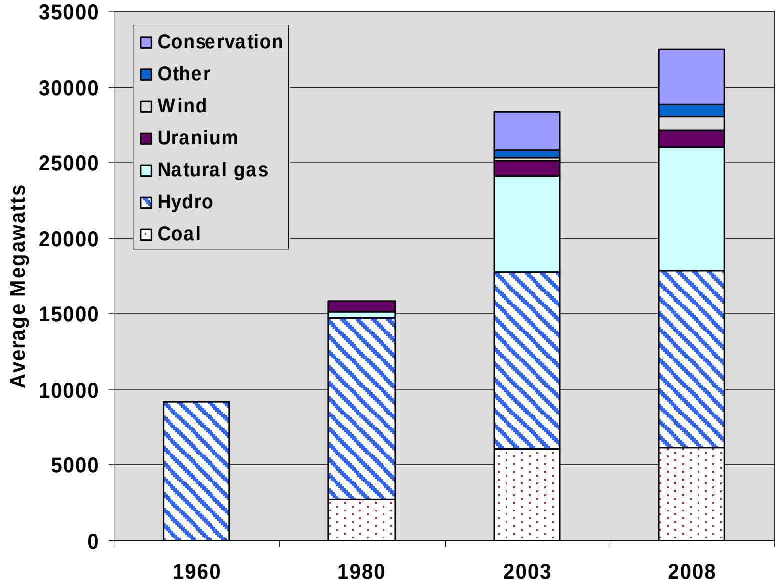
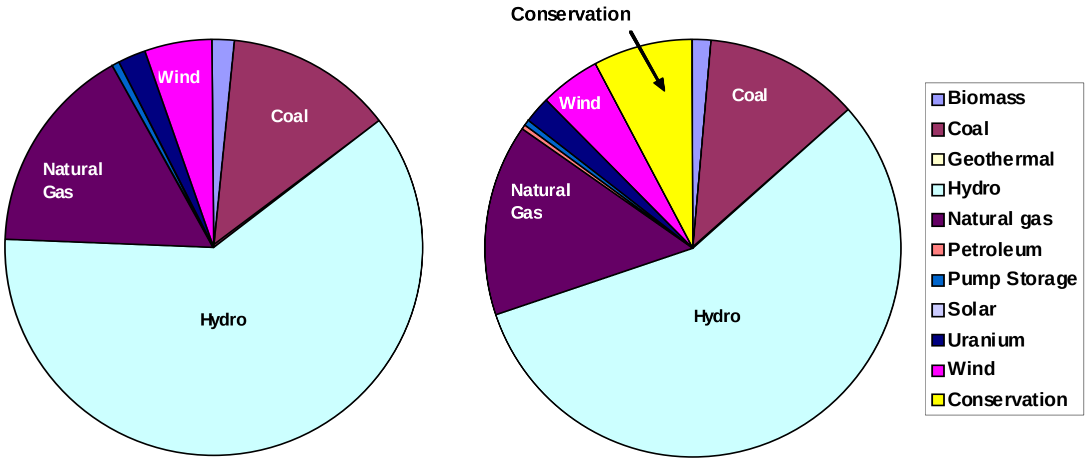


Figure 1-4 shows the mix of electricity capacity in the region.[5] Capacity refers to the ability to produce energy during peak demand hours. Figure 1-3 showed contributions to "energy," which refers to the sources of electricity used to meet average annual demand over a year typically. Compared to the energy mix, installed capacity shows much higher hydro 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 of 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.

[5] 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 Resource in the Pacific Northwest

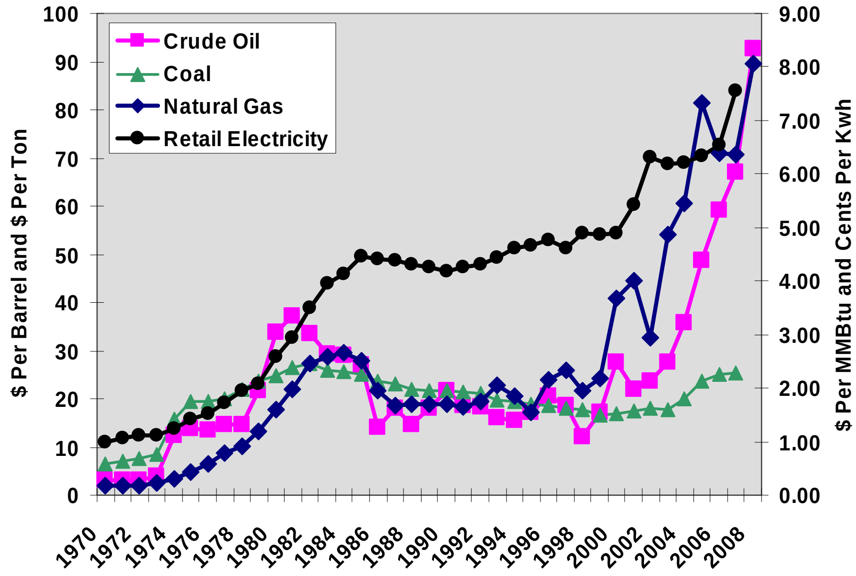


Energy Cost Trends

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.

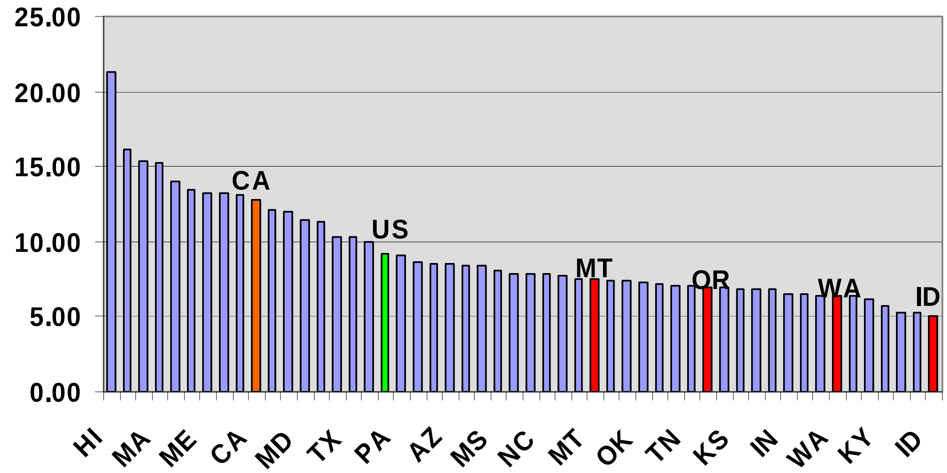
In the mid-1980s fuel prices fell, but electricity prices in the region remained high. The new millennium brought another commodity price cycle for oil, natural gas, and coal, which is now collapsing due to the economic recession and the price response of supply and demand to high prices. Electricity prices are more likely to follow this downward cycle in fuel prices because more generation is based on natural gas and coal now, and the stranded capital cost of over-investment is not as big a factor as it was in 1980. 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 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 their 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 hydro system's use as a base resource and its inexpensive flexibility together keep Northwest electricity prices low. As the region outgrows the hydro system's capability to provide peaking and flexibility, other resources will be necessary and the cost of electricity will likely grow. Preservation of the hydro 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 can also 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.

- Nearly 6,000 average megawatts of achievable energy efficiency will greatly reduce the Northwest's electricity demand and carbon-dioxide production over the next 20 years.

- Improved operation of the regional power system will help accommodate diverse and variable-output renewable generation and promote the efficient use and expansion of the regional transmission system.

- Conventional coal plants will operate with effective carbon-reducing technologies or be displaced by resources that emit less or no carbon.

- Smart grid and other technologies will make the energy system more efficient and decentralized, maintaining its reliability and safety, and potentially transforming power system operations. It could facilitate instant notification and location of outages, control the timing of water heater use to help meet peak loads, provide flexibility and energy storage, and help integrate variable-output wind power and plug-in hybrid cars into the regional power system.

- The region will preserve and improve the capability of the hydroelectric system 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.

- Citizens of the Pacific Northwest will have access to better information about their electricity supply and 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 Drivers of Demand

SUMMARY OF KEY FINDINGS

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 16.3 million by 2030. This 3.6 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 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, electricity) is expected to be significantly higher than during the 1980s and 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 only developed recently, making expectations for adequate future supplies more certain. Nevertheless, the cost of finding and producing it 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 further raise energy costs. Wholesale electricity prices are expected to increase from about $45 per megawatt-hour in 2010 to $85 by 2030 (2006$). These electricity prices reflect preliminary carbon costs that start at zero and increase to $47 per ton of CO_2 emissions by 2030. Residential consumer retail electricity prices are also expected to increase, growing 1.8 percent faster per year than general inflation for residential consumers, for example. Higher prices reduce demand, advance new sources of supply and efficiency, and make more efficiency measures cost-effective.

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 done 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 1.3 percent annually, resulting in a total regional population of 16 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 1.3 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.

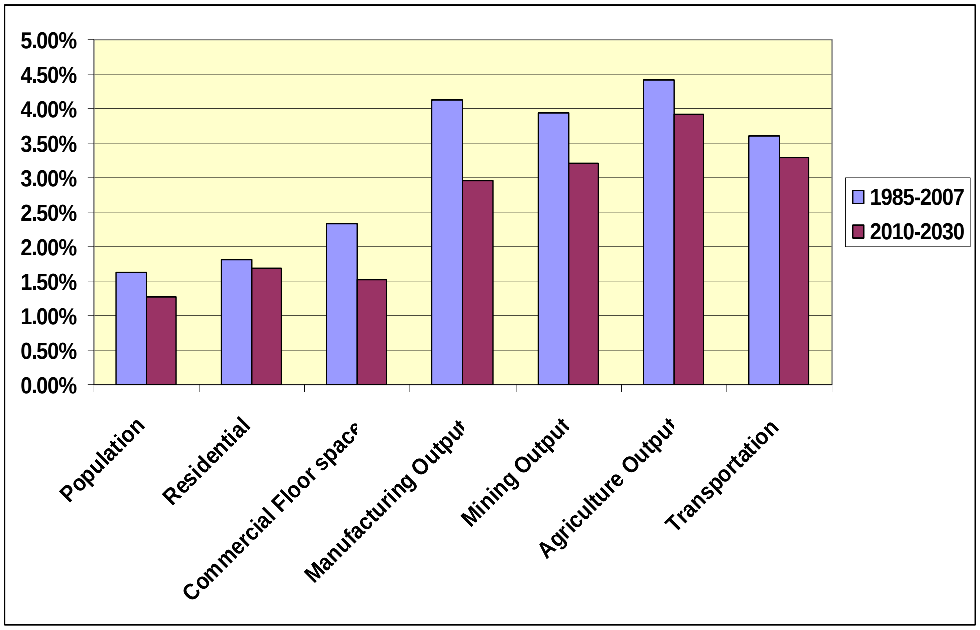
Commercial Square Footage. Demand for electricity in the commercial sector is driven by demand for commercial floor space that requires lighting, air conditioning, and services to make occupants comfortable and productive. The square footage of commercial buildings is forecast to grow at 1.5 percent 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 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 $95 billion (2006 constant dollars) in 2007 to $193 billion by 2030. Agricultural output, which drives irrigation electricity use, is projected to grow at 3.2 percent per year, from $14 billion (2006 constant dollars) in 2007 to $29 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 818 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. Second quarter 2008 data was used in developing the Council's draft 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 draft 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 draft plan using Global Insight's short-term March 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 path 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 low 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 higher 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 Growth Rates

Key Economic Drivers	1985-2007 (Actual)	2010-2030 (Low)	2010-2030 (Medium)	2010-2030 (High)
Population	1.6%	0.6%	1.1%	2.2%
Residential Units	1.9%	0.6%	1.3%	2.2%
Commercial Floor Space	2.3%	0.9%	1.5%	1.9%
Manufacturing Output $	4.1%	2.3%	3.0%	3.9%
Agriculture Output $	4.4%	3.0%	3.9%	5.0%
Light Vehicle Sales	-	0.5%	1.4%	2.2%
Inflation Rate	2.2%	3.5%	1.9%	1.7%
Average Annual Growth Rate in Price (2008-2030)*				
Oil Prices	1.7%	-1.0%	1.0%	2.0%
Natural Gas Prices	1.8%	-1.3%	0.9%	1.7%
Coal Prices	-4.8%	-0.5%	0.5%	1.2%

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

PRICE FORECASTS

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 source of 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 price, 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 developed in 2004. In most scenarios, fuel prices are assumed to decline from recent very high levels. This reduction in price is partly due to natural supply and demand responses to a period of high prices, but also is greatly increased by the current recession and financial crisis.[1]

Long-term fuel price trends are uncertain, as reflected in a wide range of assumptions. The 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.

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 $10 by 2025 and increases to nearly $12 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 very limited.

The low case assumes slow world economic growth which 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 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 basin 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.

Most of the cases show fuel prices declining from their most recent high levels in the early years of the forecast. This decline does not completely reflect very recent price changes and the likely

[1] The fuel price forecast used for the draft 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.

effects of what is becoming a severe recession. 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 portfolio analysis tools.

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

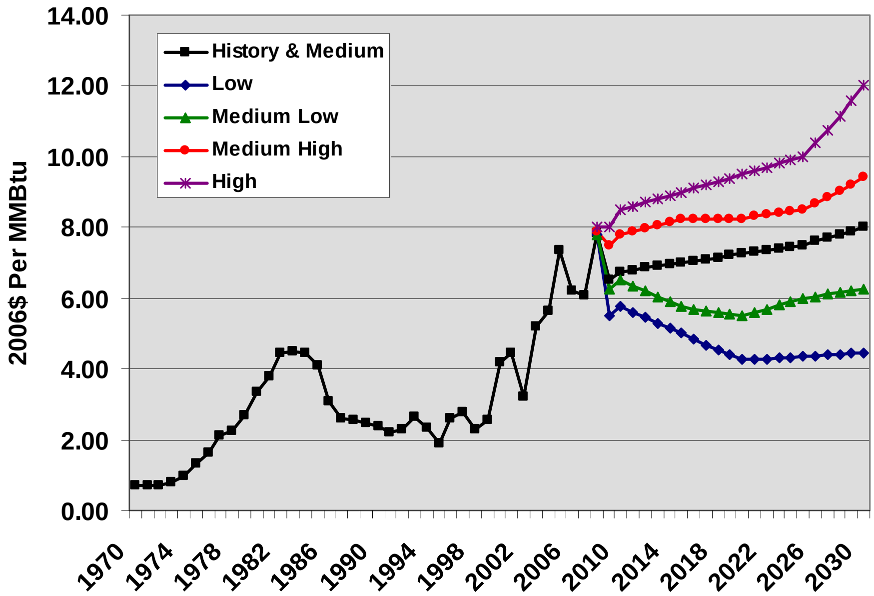


Table 2-2: U.S. Wellhead Natural Gas Price Forecast Range (2006$ per MMBtu)

	Low	Medium Low	Medium	Medium High	High
2007			6.06		
2010	5.75	6.50	6.75	7.80	8.50
2015	5.00	5.75	7.00	8.25	9.00
2020	4.25	5.50	7.25	8.25	9.50
2025	4.35	6.00	7.50	8.50	10.00
2030	4.45	6.25	8.00	9.40	12.00
Growth Rates					
2007-2015	-2.36%	-0.64%	1.83%	3.94%	5.08%
2007-2030	-1.33%	0.14%	1.22%	1.93%	2.89%

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

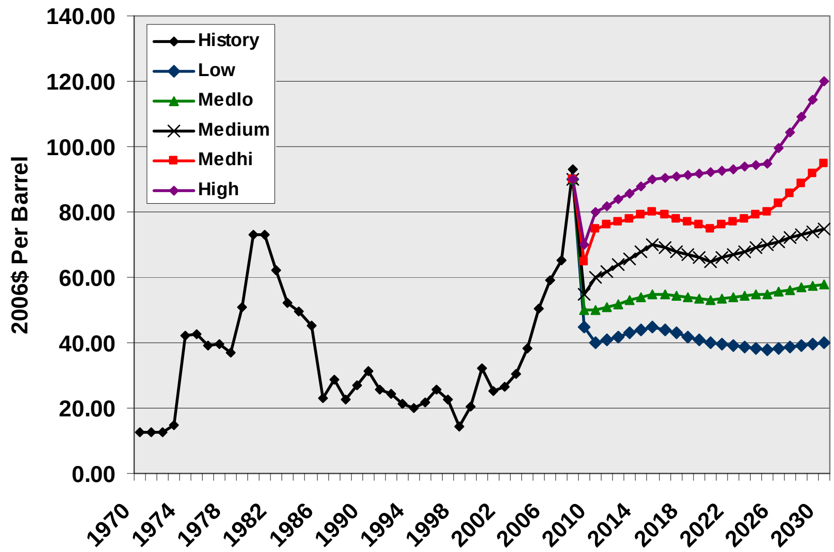


Table 2-3: World Oil Price Forecast Range (2006$ per Barrel)

	Low	Medium Low	Medium	Medium High	High
2007	-	-	65.29	-	-
2008	-	-	90.00	-	-
2010	40.00	50.00	60.00	75.00	80.00
2015	45.00	55.00	70.00	80.00	90.00
2020	40.00	53.00	65.00	75.00	92.00
2025	38.00	55.00	70.00	80.00	95.00
2030	40.00	58.00	75.00	95.00	120.00
Growth Rates					
2007-2015	-4.54%	-2.12%	0.88%	2.57%	4.09%
2007-2030	-2.11%	-0.51%	0.60%	1.64%	2.68%

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

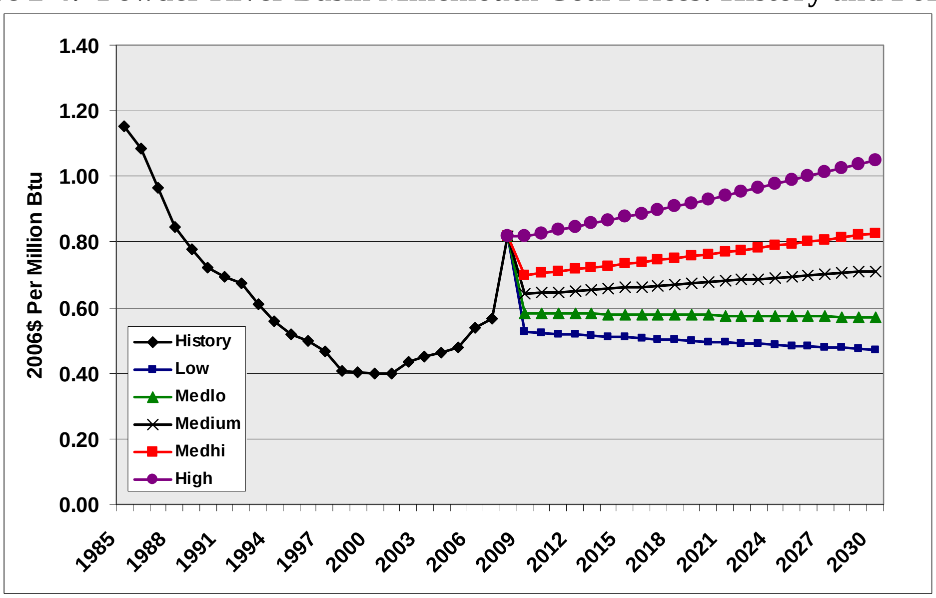


Table 2-4: Powder River Basin Minemouth Coal Price Forecasts (2006$ per MMBtu)

	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%

Wholesale Electricity Prices

Load-serving entities in the Pacific Northwest depend on the wholesale marketplace to match their customers' ever-changing demand for electricity with an economical supply. The wholesale power market promotes the efficient use of the region's generating resources by assuring that resources with the lowest operating cost are serving demand in the region. In the long run, the performance of the wholesale power market, and the prices determined in the marketplace, largely depend on the balance between generating resources and demand in the region and connected areas. Uncertainty regarding future demand in the region is discussed in Chapter 3. On the supply side, there are three primary factors that are likely to influence the wholesale power market during the current planning period: (1) the future price of natural gas; (2) the future cost of carbon dioxide (CO_2) emissions associated with climate control regulation; and (3) the future path of renewable resource development associated with the region's renewable portfolio standards (RPS).

The Council uses the AURORA$^{xmp®}$ Electric Market Model to forecast wholesale power prices for the Pacific Northwest. With AURORA$^{xmp®}$, the Council has the ability to build assumptions regarding future climate control regulation and RPS resource development into its forecasts of future wholesale power prices.

For the purpose of forecasting the long-term trend of future wholesale power prices, the Council developed a preliminary medium CO_2 emissions price forecast. The forecast begins in 2012 at a price of $8 per short ton of CO_2, increases to $27 per ton in 2020, and to $47 per ton in 2030.[2] Uncertainties regarding future climate control regulation and its impact on future resource development in the region are discussed more fully in Chapter 10.

There has been a rapid pace of renewable resource development in the Pacific Northwest in recent years, and the region's utilities appear to be well positioned to meet their future RPS targets. The Council has developed an expected build-out of renewable resources associated with state RPS in the western U.S. By 2030, the cumulative capacity of the RPS build-out includes: 17,000 megawatts from wind plants; 4,000 megawatts from concentrating solar plants; 3,000 megawatts from solar photovoltaic plants; and roughly 1,000 megawatts each from

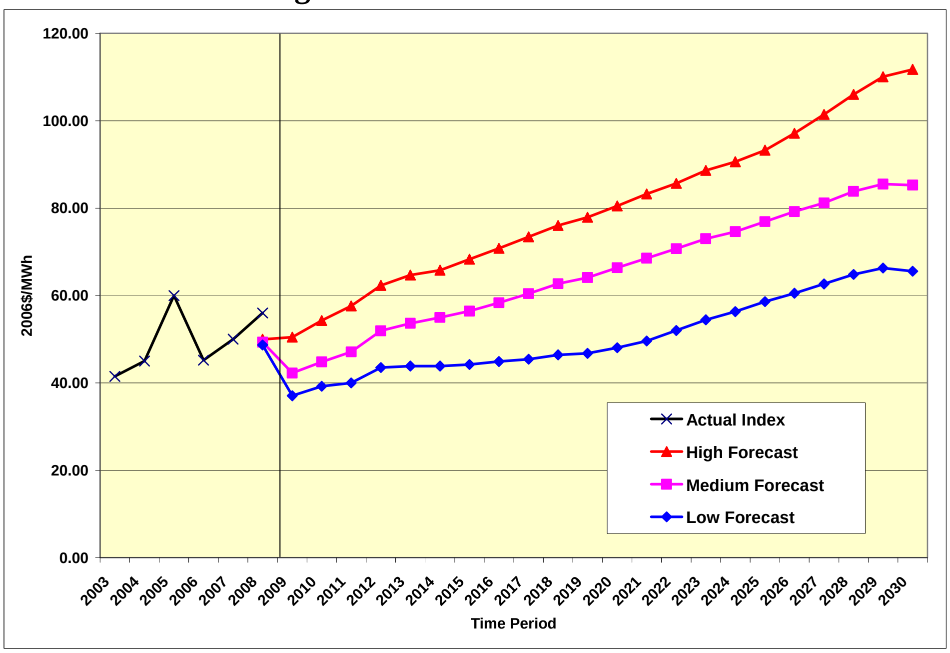
[2] These prices are not exactly the same as assumptions adopted later for the Regional Portfolio Model analysis. They will be revised when the Council's wholesale electricity prices, demand forecast, and other projections are revised in the process moving from the Draft Power Plan to the Final Plan.

geothermal, biomass, and small hydro plants. This mandated RPS resource development is reflected in the Council's wholesale power price forecasts.

The price of natural gas is an important factor in determining the future wholesale price of electricity. Natural gas-fired generating units are often the marginal generating unit, and therefore determine the wholesale price of electricity during most hours of the year. To establish a wide range for the future long-term trend of wholesale power prices in the Pacific Northwest, the Council has forecast wholesale power prices using its low, medium, and high forecasts of fuel prices described in the previous section, and more fully in Appendix A.

Under medium fuel price and CO_2 emission price assumptions, wholesale power prices at the Mid-Columbia trading hub are projected to increase from $45 per megawatt-hour in 2010 to $85 per megawatt-hour in 2030. For comparison, Mid-Columbia wholesale power prices averaged $56 per megawatt-hour in 2008 (in real 2006 dollars). Figure 2-5 compares the forecast range of Mid-Columbia wholesale power prices to actual prices during the 2003 through 2008 period.

Figure 2-5: Forecast Range of Annual Mid-Columbia Wholesale Power Prices



The Council's wholesale power price forecasts are projections of the long-term trend of future wholesale power prices. Short-term electricity price risk due to such factors as disequilibrium of supply and demand and seasonal volatility due to hydro conditions are not reflected in the long-term trend forecasts. This short-term price volatility is modeled in the Regional Portfolio Model (RPM) that the Council uses to inform its development of the Power Plan.

Pacific Northwest electricity prices tend to exhibit a seasonal pattern associated with spring runoff in the Columbia River Basin. The Council's forecast of monthly on-peak and off-peak wholesale power prices exhibits an average seasonal hydroelectric trend during each year of the planning period. Figure 2-6 shows the medium forecast of Mid-Columbia monthly on-peak and off-peak power prices. The forecast shows a narrowing of the difference between on-peak and off-peak power prices during the planning period. Table 2-5 shows the forecast values for selected years. Appendix D provides a detailed description of the wholesale power price forecasts.

Figure 2-6: Medium Forecast of Mid-Columbia Wholesale Power Prices

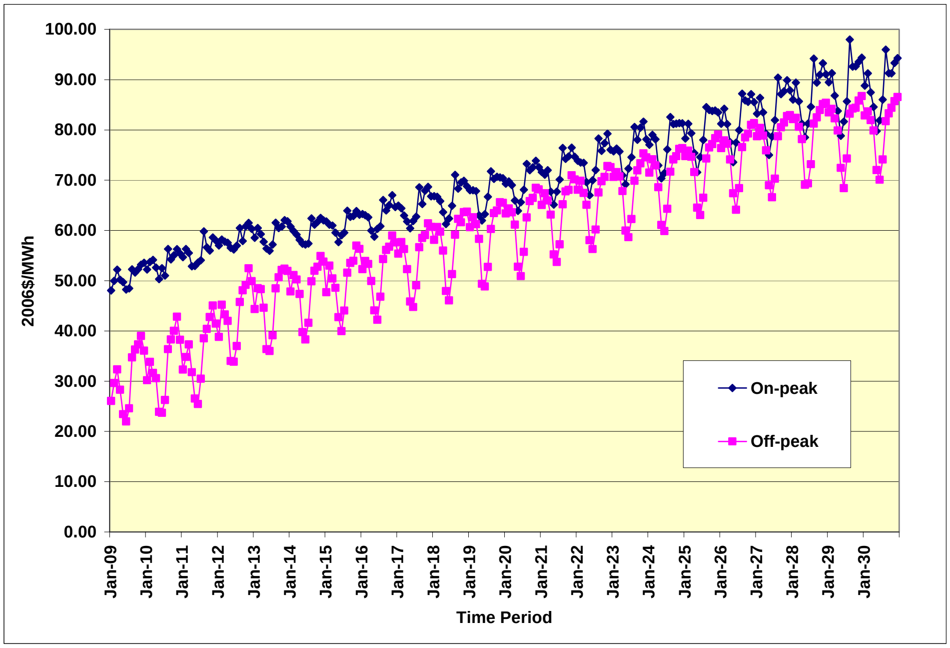


Table 2-5: Forecast of Mid-Columbia Wholesale Power Prices (2006$/MWh)

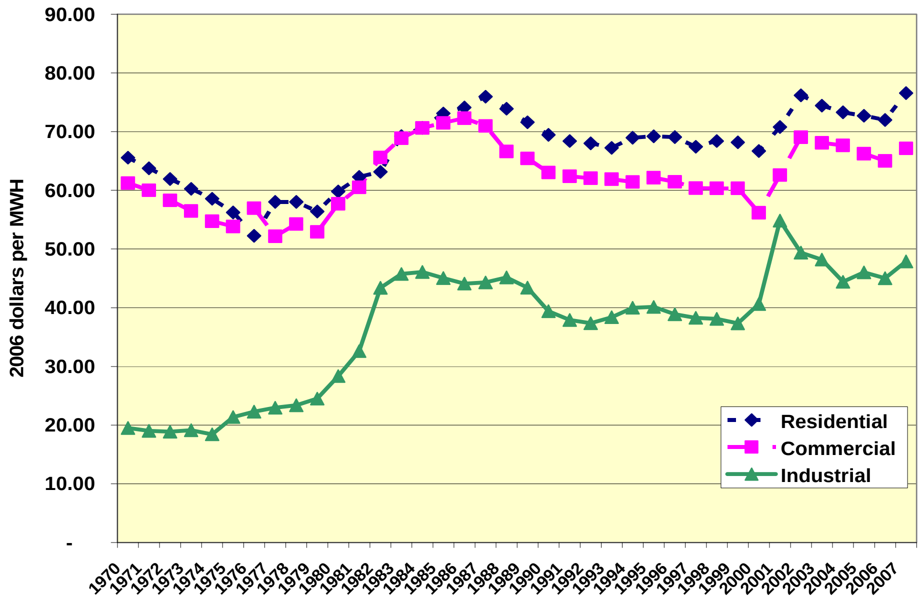
	On-Peak	Off-Peak	Average
Actual 2008	62.00	49.00	56.00
2010	54.00	33.00	45.00
2015	61.00	50.00	56.00
2020	70.00	62.00	66.00
2025	80.00	73.00	77.00
2030	89.00	81.00	85.00
Growth Rates			
2010-2020	2.61%	6.30%	3.93%
2020-2030	2.43%	2.62%	2.51%

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 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 2-7 illustrates this price history.[3]

Figure 2-7: Average Retail Electricity Price by Sector (2006$/MWh)



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 body 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, similar to the methodology used for forecasting other fuel prices such as gas, oil, and coal. A fuel price forecast starts with a national or regional base price, and then modifies the base price through the addition of delivery charges to calculate regional prices. In forecasting retail electricity prices, a similar approach is used. Starting with a forecast of the wholesale price at Mid-Columbia, transmission and delivery charges, along with other incremental fixed costs like conservation investments or meeting regional portfolio standards, are added in.

Sector Retail Prices

The estimated price of electricity by sector and state is presented in Tables 2-6 through 2-8. For the residential sector, the annual real growth rate of electricity prices is expected to be in the 1.5-1.9 percent per year range 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

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

the figures presented here. Also, individual utilities may have significantly higher or lower rate increases than these average state-wide figures would indicate.

Table 2-6: Price of Electricity for Residential Customers (2006$/MWh)

	Oregon	Washington	Idaho	Montana
1985	74	60	68	74
2005	75	68	65	84
2010	79	70	61	85
2015	85	76	66	92
2020	93	83	71	96
2030	114	101	88	114
Annual Growth				
1985-2000	-0.3%	0.0%	-0.3%	0.1%
2000-2007	2.9%	3.9%	0.3%	2.7%
2010-2030	1.8%	1.8%	1.9%	1.5%

Table 2-7: Price of Electricity for Commercial Customers (2006$/MWh)

	Oregon	Washington	Idaho	Montana
1985	81	57	65	67
2005	67	65	56	77
2010	70	63	49	77
2015	76	69	54	84
2020	84	76	58	88
2030	105	94	76	106
Annual Growth				
1985-2000	-1.3%	-0.2%	-1.2%	-0.4%
2000-2007	3.2%	3.6%	-0.3%	3.5%
2010-2030	2.0%	2.0%	2.2%	1.6%

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

	Oregon	Washington	Idaho	Montana
1985	56	34	42	40
2005	50	44	40	50
2010	47	45	36	55
2015	53	51	41	61
2020	61	57	46	66
2030	82	75	63	83
Annual Growth				
1985-2000	-1.3%	0.6%	-0.6%	0.7%
2000-2007	4.8%	3.2%	-0.1%	8.1%
2010-2030	2.8%	2.6%	2.8%	2.1%

Chapter 3: Electricity Demand Forecast

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 2007 and 2030, demand is expected to increase by a total of 6,500 average megawatts, growing on average by 270 average megawatts, or 1.2 percent, per year. This forecast has been influenced by expected higher electricity prices that reflect a rapid rise in fuel prices and emerging carbon emission penalties. At the same time, the impact of cost-effective efficiency improvements identified in the Sixth Power Plan should help to meet that demand growth.

This 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, resulting in their surge. 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 42,000 megawatts by 2030, an average annual growth rate of 1 percent. Summer-peak demand is forecast to grow from 28,000 megawatts in 2010 to 39,000 megawatts by 2030, an annual growth rate of 1.4 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-CO_2 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 range 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.

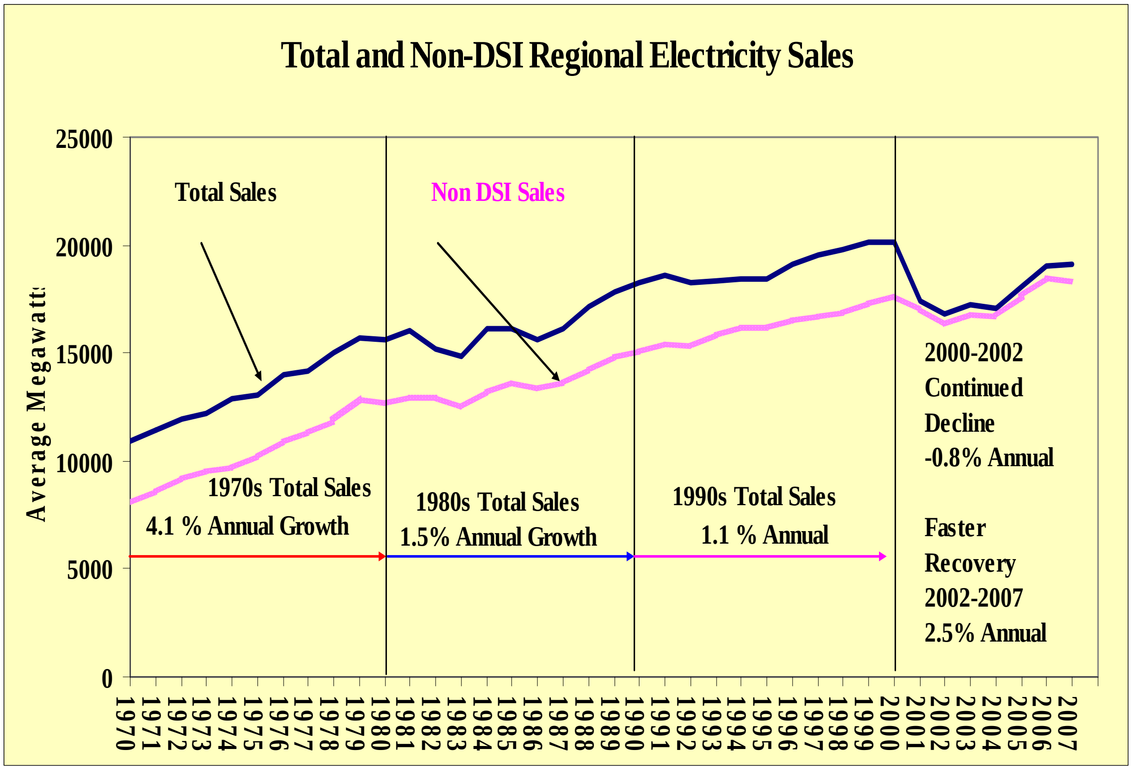
Historic Demand Growth

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, eliminating 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 Sales

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 Intensity of the Regional Economy

Year	Non-DSI Electricity Use Per Capita (MWa / Thousand Persons)
1980	1.64
1990	1.71
2000	1.61
2006	1.51

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.

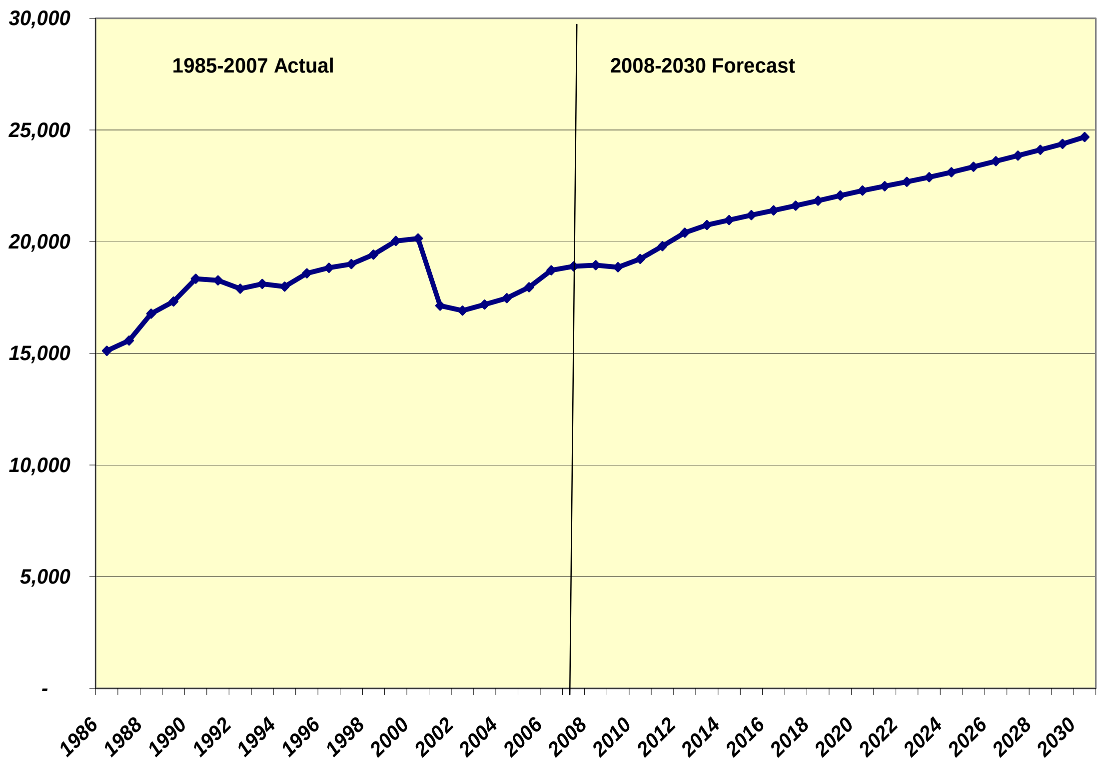
Sixth Power Plan Demand Forecast

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. This growth rate is similar to the Council's Fifth Power Plan forecast, which projected growth of 1.4 percent per year from 2000 to 2025.

Assuming normal weather conditions, the winter-peak demand for power is projected to grow from about 34,000 megawatts in 2010 to around 42,000 megawatts by 2030 at an average annual growth rate of 1 percent. Summer-peak demand is projected to grow from 28,000 megawatts in 2010 to 39,000 megawatts by 2030, an annual growth rate of 1.4 percent.

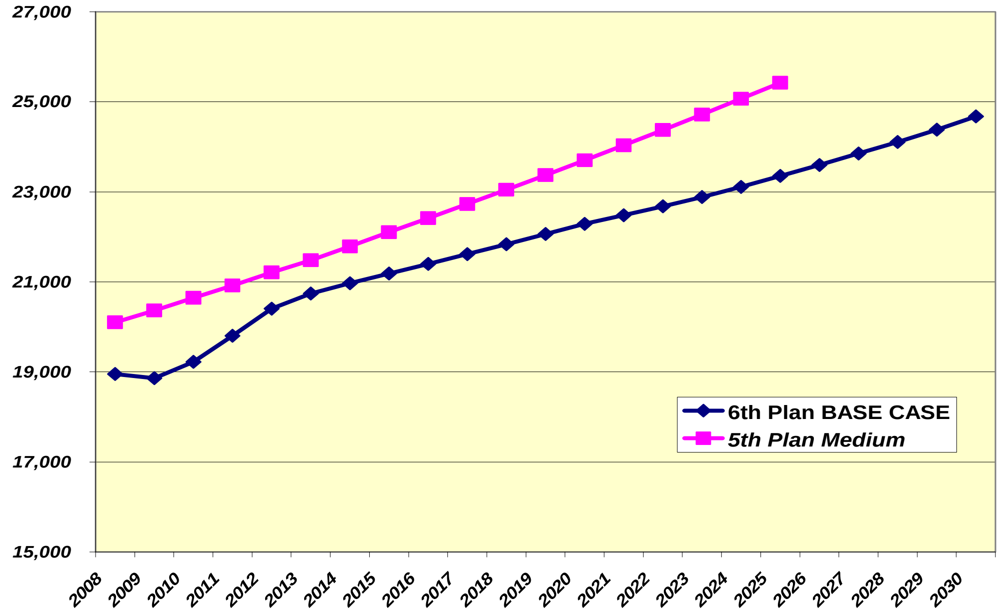
The medium demand forecast means that the region's electricity needs would grow by about 6,000 average megawatts by 2030, absent any conservation, an average annual increase of 260 average megawatts. Most of the growth is from increased electricity use by the residential and commercial sectors, with 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 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 2008-9 recession may prolong this recovery. Figure 3-2 illustrates the demand forecast for the medium case. Table 3-3 shows the sectoral demand forecast for selected years.

Figure 3-2: Sixth Plan Medium Demand Forecast (MWa)



Comparing the Fifth Power Plan projections with actual consumption, regional demand was in the range of the plan's medium to medium-high forecast. The Sixth Power Plan forecasts are lower than the Fifth Power Plan as illustrated in Figure 3-3. By 2025, the two forecasts differ by about 2,000 average megawatts.

Figure 3-3: Sixth Plan Demand Forecast Comparison to Fifth Plan (MWa)



Sectoral Demand

The draft Sixth Power Plan forecasts demand to grow at an average annual rate of 1.3 percent in the 2010 through 2030 period. The residential sector is expected to grow at 1.3 percent per year which, on average, translates to about 100 megawatts each year. Increased growth in the residential sector is from a substantial increase in demand for home electronics, categorized as information, communication, and entertainment (ICE,) and the increased use of air conditioning.

Table 3-3 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.

Table 3-3: 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	7,432	7,554	8,452	9,765	1.1%	1.5%	1.3%
Commercial	6,106	6,537	8,201	8,767	2.3%	0.7%	1.5%
Industrial Non-DSI	3,725	3,648	3,952	4,277	0.8%	0.8%	0.8%
DSI	764	693	818	818	1.7%	0.0%	0.8%
Irrigation	802	728	781	958	0.7%	2.1%	1.4%
Transportation	64	65	83	94	2.5%	1.3%	1.9%
Total	18,893	19,224	22,288	24,678	1.5%	1.0%	1.3%

Commercial sector electricity consumption is forecast to grow by 1.5 percent per year between 2010 and 2030. During this period, commercial sector demand is expected to increase from

6,500 average megawatts to 8,800 average megawatts. This increase is higher than the 1.2 percent per year that was forecast in the Fifth Power Plan. Compared to the Fifth Power Plan's forecast of commercial electricity use, 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 1,600 average megawatts higher than the 2025 medium forecast in the Fifth Power Plan. On average, this sector adds about 120 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.

In the last plan, Bonneville's direct service industries were treated separately because this assortment of plants (mainly aluminum smelters) accounted for nearly 40 percent of industrial electricity use. In addition, the future of these plants was highly uncertain. 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 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.

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 3,700 average megawatts in 2007 to 4,300 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.

Demand Forecast Range

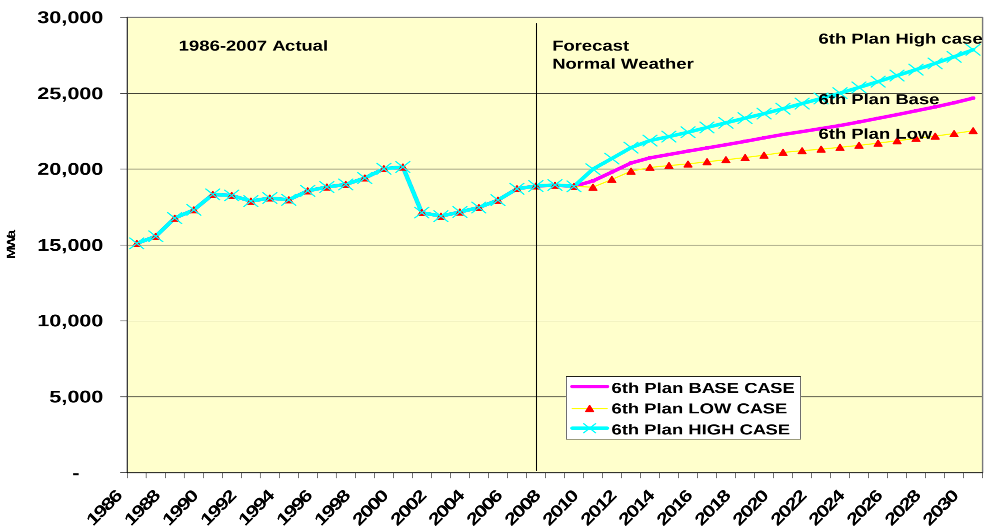
Uncertainty about economic and demographic variables, along with uncertainty about fuel prices, adds to uncertainty about demand. To evaluate the impact of these economic and fuel price uncertainties in the Sixth Power Plan, two alternative demand forecasts were produced. To forecast demand under each 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 3-4 and Figure 3-4, and is compared to the Fifth Power Plan in Figure 3-5.

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 0.9 and 1.7 percent per year. Figure 3-4 summarizes the forecast range. In all three scenarios demand growth in the first 10 years of the forecast is faster than the second 10 years, reflecting a recovery from the current recession in the 2010-2020 period followed by a return to the long term growth trend from 2020-2030.

Table 3-4: Sixth Plan Electricity Demand Forecast Range (MWa)[1]

	Actual 2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2020-2030	Growth Rate 2010-2030
Low	18,893	18,815	21,103	22,538	1.2%	0.7%	0.9%
Medium	18,893	19,224	22,288	24,678	1.5%	1.0%	1.3%
High	18,893	20,006	23,982	27,876	1.8%	1.5%	1.7%

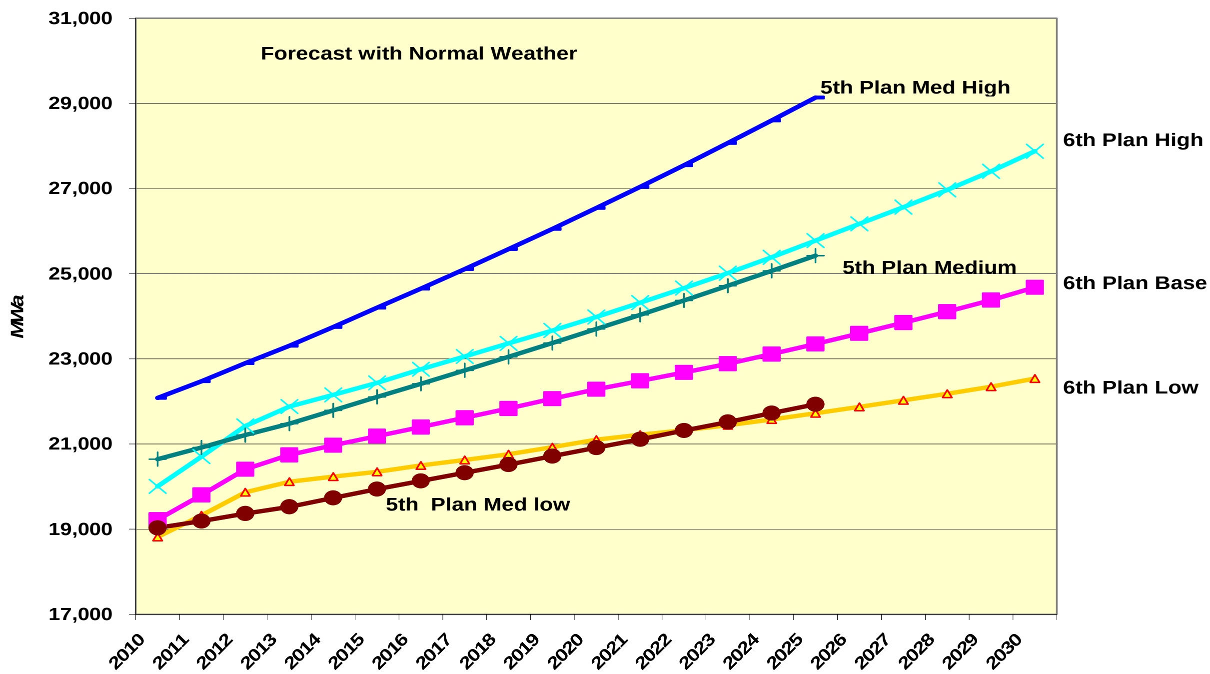
Figure 3-4: Historical Sixth Plan Sales Forecast



A comparison of the range of forecasts in the Fifth and Sixth Power Plans shows that the range is narrower in the Sixth Power Plan. As indicated in Figure 3-5, the medium cases for the two plans are very close. The low case in the Sixth Power Plan is comparable to the medium-low case of the Fifth Power Plan. The Sixth Power Plan medium case is about 2,000 average megawatts lower than the medium case in the Fifth Power Plan. The high case in the Sixth Power Plan is also lower than the medium-high case in the Fifth Power Plan. The main reason for this smaller difference between the high and low case in the Sixth Plan is the narrower range in the economic drivers. The low to high range in the Fifth Plan was intended to cover 95 percent of future demand growth possibilities. The Sixth Power Plan's low to high range is based on Global Insight's range of forecasts, which stays closer to its most likely forecast. The Sixth Plan's low to high range is more comparable to the medium-low to medium-high range in previous Council plans, and both are considered reasonably likely to occur. However, additional uncertainty is addressed in the Regional Portfolio Model (RPM).

[1] Sales figures are electricity use by consumers and exclude transmission and distribution losses.

Figure 3-5: Comparison of Fifth and Sixth Plan Demand Forecasts (MWa)



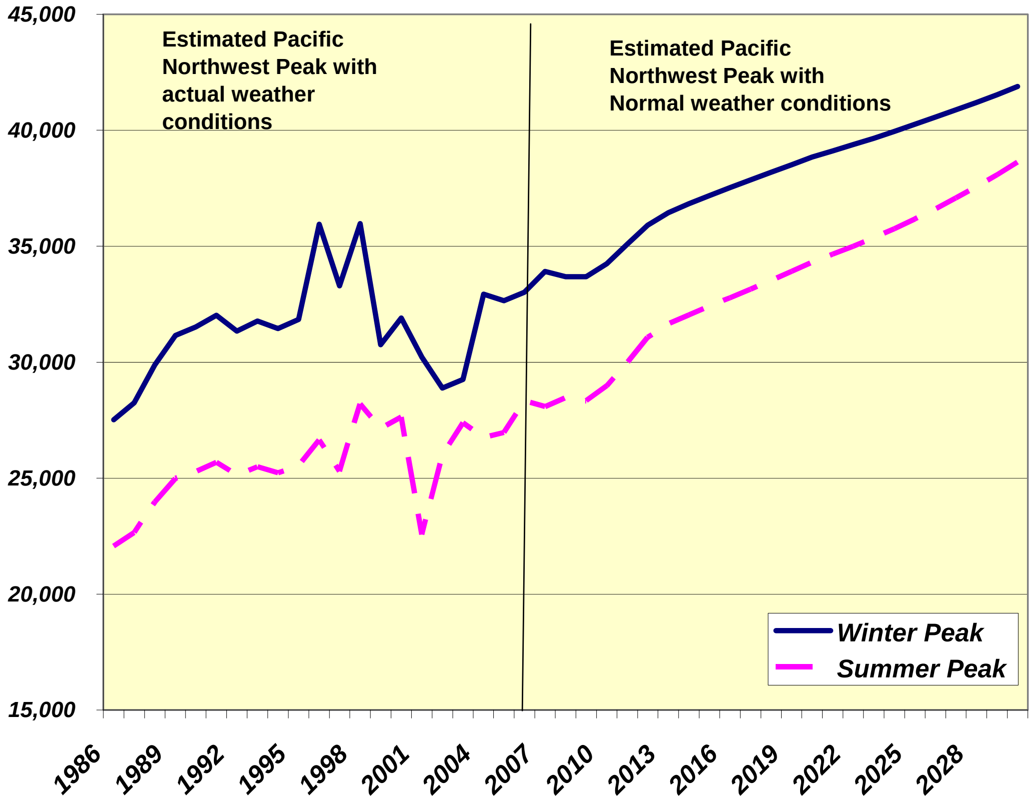
LOAD FORECAST AND PEAK LOAD

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 42,000 megawatts by 2030 at an average annual growth rate of 1.0 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 3-6 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 3-6: Historical and Forecast Regional Peak Load (MW)



Load Forecast Range

Figure 3-7 shows forecast winter and summer month 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 1.8 percent per year, about 0.1 percent higher than the growth rate in the high case average annual demand. 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 overtime.

Figure 3-7: 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	33,795	37,109	39,060	0.9%	0.5%	0.7%
Low - Summer	28,084	28,229	32,462	35,357	1.4%	0.9%	1.1%
Medium - Winter	33,908	34,243	38,842	41,885	1.3%	0.8%	1.0%
Medium - Summer	28,084	28,976	34,313	38,630	1.7%	1.2%	1.4%
High - Winter	33,908	35,416	41,481	46,552	1.6%	1.2%	1.4%
High - Summer	28,084	30,232	36,876	43,413	2.0%	1.7%	1.8%

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 39,000 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.

Plug-in Hybrid Electric Vehicles

A study of the potential impacts of plug-in hybrid electric vehicles (PHEVs) assumed a range of penetration of these cars into the market, with the result that regional electricity use increases by 100 to 550 average megawatts. The power system's emissions of greenhouse gasses increases slightly as a result of PHEVs, but that effect is more than offset by the decrease in emissions by vehicles. The estimated effects on electricity bills and rates were small; these estimates "conservative" since they did not include an estimate of the reduction in cost of gasoline purchases due to PHEVs.

Chapter 4: Conservation Supply Assumptions

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 just under 7,000 average megawatts of technically achievable conservation potential in the medium demand forecast by the end of the forecast period, at a levelized (net) life-cycle cost of up to $200 per megawatt-hour (2006 dollars). Sources of potential savings are about 50 percent higher than in the Fifth Power Plan. 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. Not all of the 7,000 average megawatts identified will prove to be cost-effective to develop. The Council uses its portfolio model to identify the amount of conservation that can be economically developed.

The savings break down as follows:

- About 3,300 average megawatts of conservation are technically achievable in the residential buildings and appliances. Most of the savings come from improvements in water-heating efficiency and heating, ventilating, and air conditioning efficiency.

- Nearly 1,000 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 is available in the agriculture sector through irrigation system efficiency improvements, improved water management practices, and dairy milk processing.

- The commercial sector offers about the same amount of savings as the Fifth Power Plan, about 1,400 average megawatts. 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 about 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 over 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 are likely to achieve a total savings of at least 875 average megawatts by 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. While the EISA standard does not cover all incandescent bulbs (bulbs over 100 watts and 3-way light bulbs are exempt), it does cover 70-80 percent of residential sector applications. Consequently, roughly 75 percent of savings from CFL contributes to a lower load forecast, leaving approximately 150 average megawatts of residential lighting potential.

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 - ≥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 over 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.[1] 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.[2] 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.

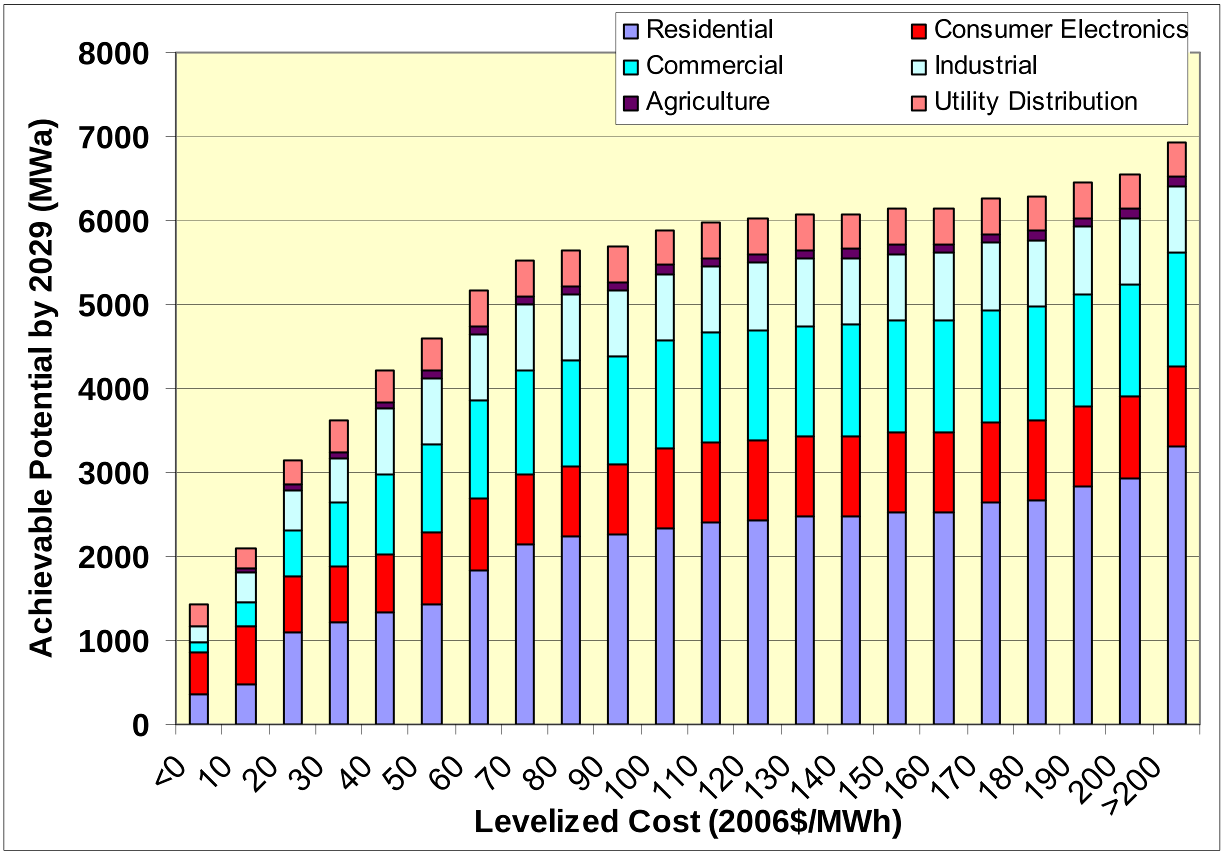
Figure 4-1 shows the Sixth Power Plan's estimate of the amount of conservation available by sector and levelized life-cycle cost. The Council identified just under 7,000 average megawatts of technically achievable conservation potential in the medium demand forecast by the end of the forecast period 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 technical potential compared to the Fifth Power Plan.[3] Slightly less than half of the potential is from lost-opportunity measures.

[1] Energy-efficient clothes washers use less water and require less detergent.

[2] 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.

[3] For purposes of comparison, the Council's Fifth Power Plan estimated that the technically achievable conservation was approximately 4,600 average megawatts at $120 per megawatt-hour. This plan's estimate is just over 5,100 average megawatts at an equivalent levelized life-cycle cost.

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 2,400 average megawatts at an equivalent cost.

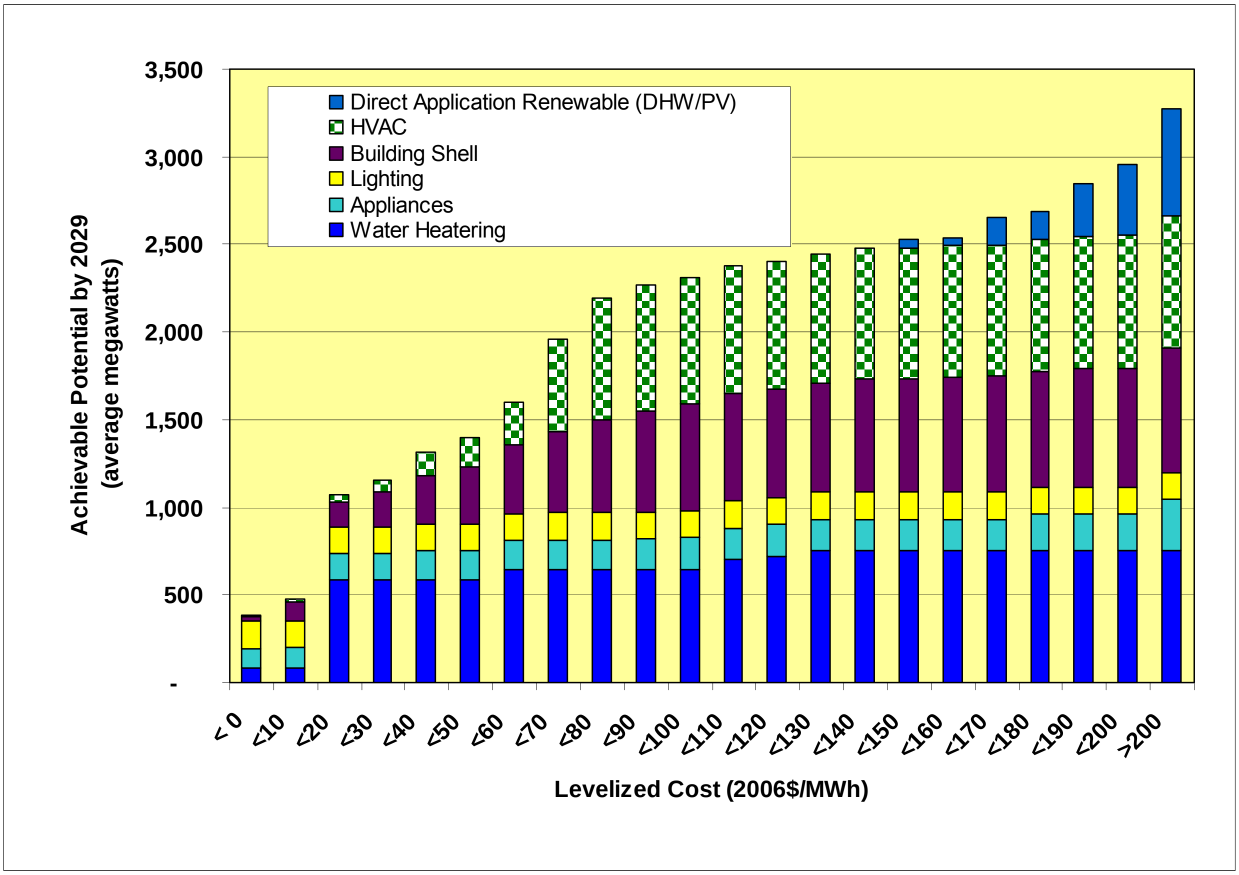
The largest decrease (475 average megawatts) in residential-sector potential came from the new federal efficiency standards for lighting. Figure 4-2 shows the residential resource potential by major category and cost. The figure shows that the largest remaining savings come from improvements in water-heating 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 250 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.

[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.

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



In the past year, three major U.S. water heater manufacturers have announced that they will begin producing heat pump water heaters by the end of 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 will be just over 1 percent. However, by 2030 heat pump water heaters could reduce regional electric water heating use by over 600 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. 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 $60 per megawatt-hour, there are almost 120 average megawatts of savings available from converting existing single family and manufactured homes with electric forced-air furnaces to high-performance heat pumps. At less than $70 per megawatt-hour, the potential savings increase to over 340 average megawatts.

Agriculture Sector

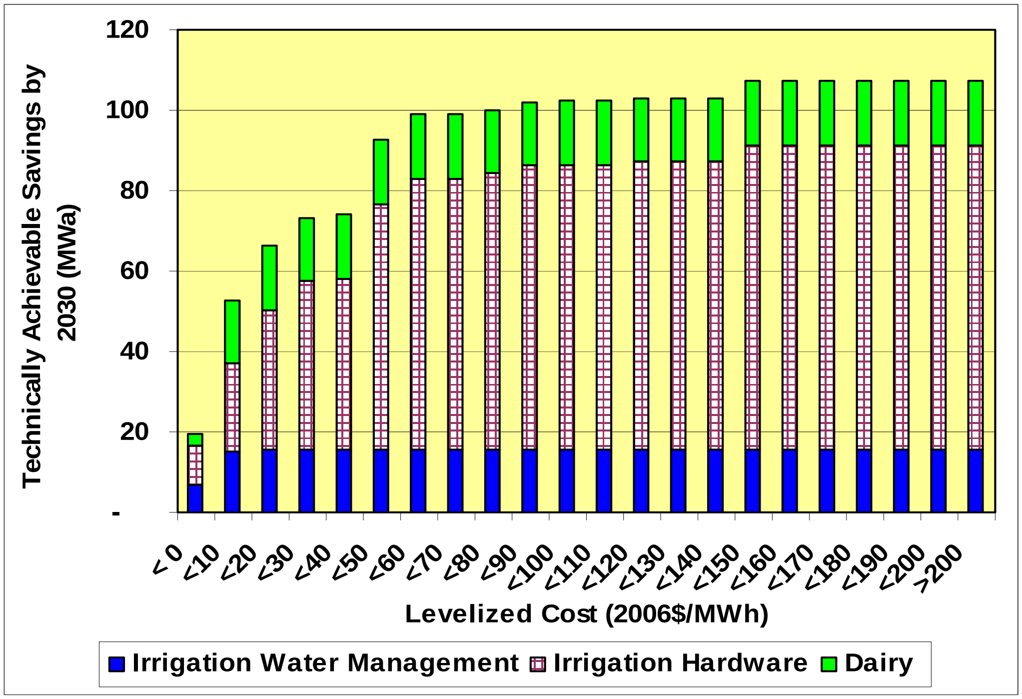
The Fifth Power Plan identified approximately 100 average megawatts of conservation potential available in the region through efficiency improvements in irrigation system hardware. Since the Fifth Power Plan, almost 685,000 acres have been added as land irrigated by pressurized sprinkler systems. However, 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 15 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



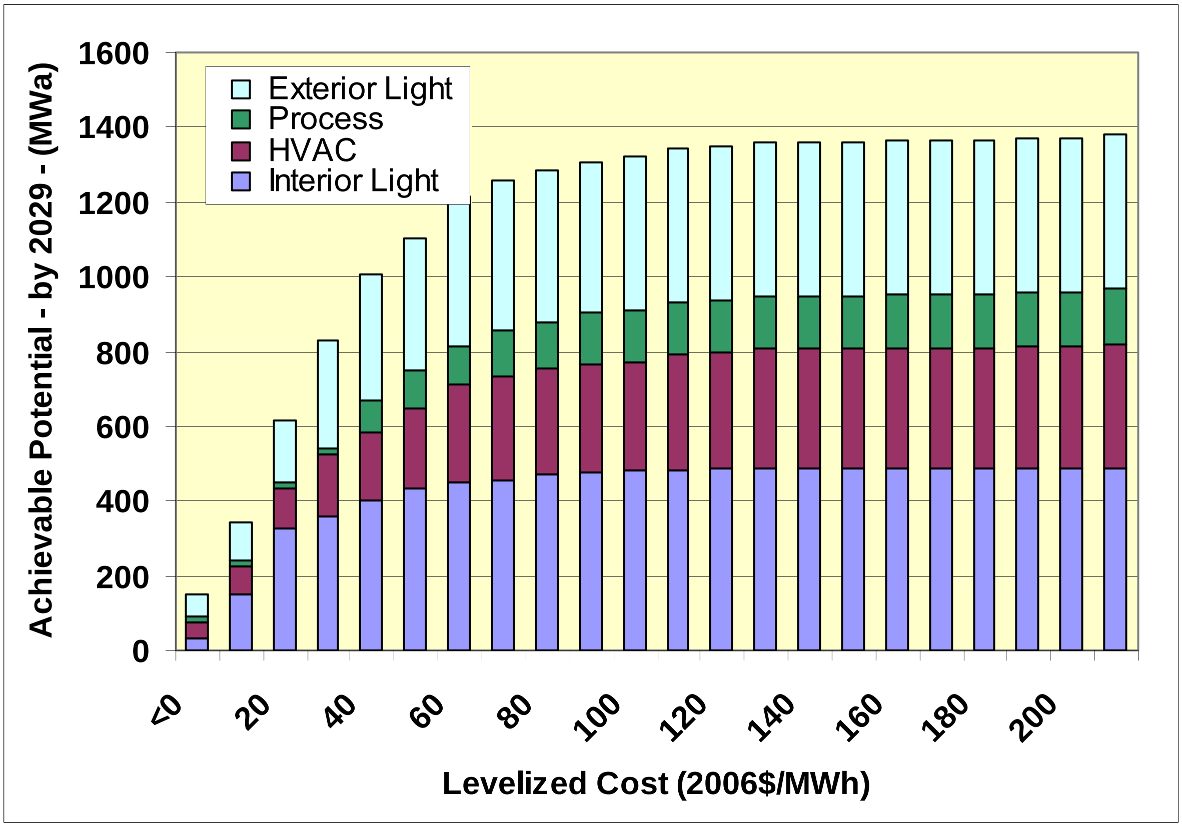
Commercial Sector

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, about 1,400 average megawatts. However, the allocations 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



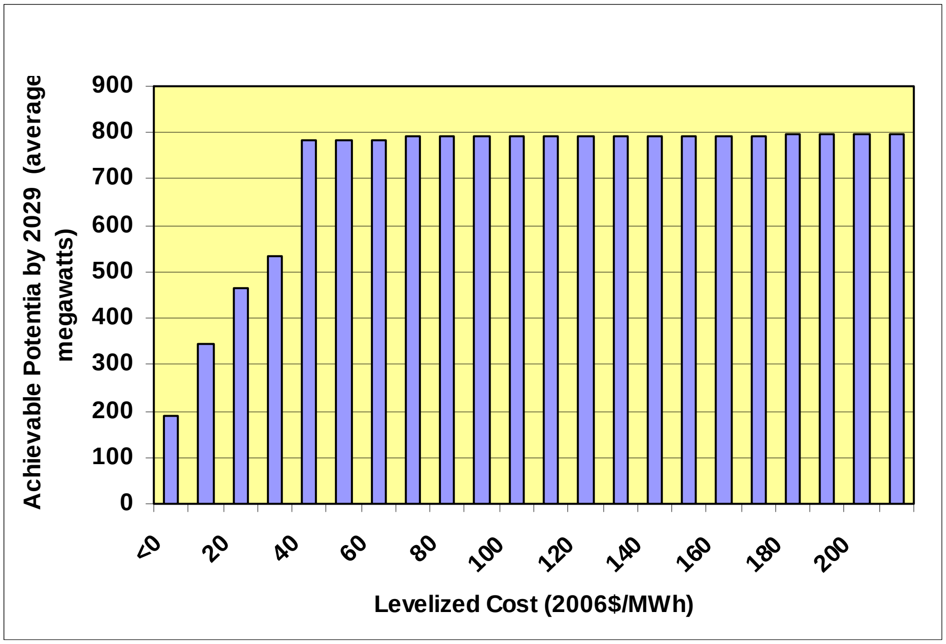
Nearly two-thirds of commercial-sector conservation potential identified in the Sixth Power Plan is lost-opportunity conservation. The increase in lost-opportunity conservation compared to the Fifth Power Plan is primarily due to a revised approach to modeling natural lighting stock turnover as a lost-opportunity 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 decisionmakers 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

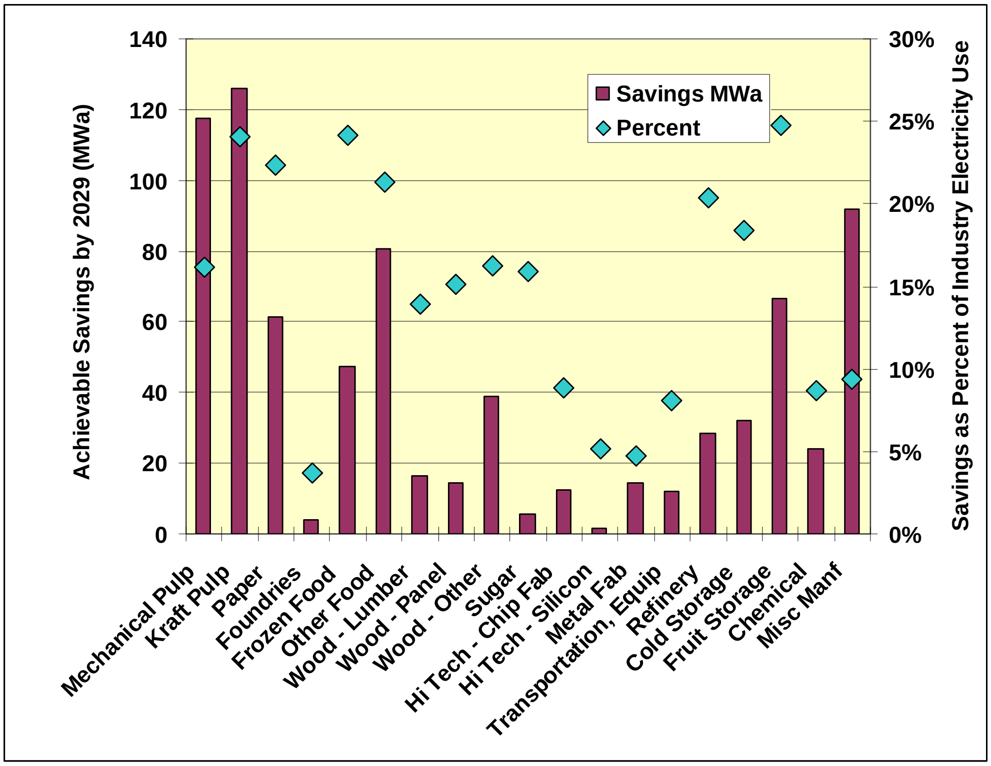
In the Fifth Power Plan, the industrial sector's potential was estimated to be 5 percent of 2025 sales, or 350 average megawatts. For the Sixth Power Plan, the Council, with financial support from the Bonneville Power Administration, contracted an in-depth study of industrial-sector potential. The industrial-sector conservation assessment evaluates 60 conservation measures and practices as they apply to 19 Northwest industries. This research indicates potential savings of about 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 over 230 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 60 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

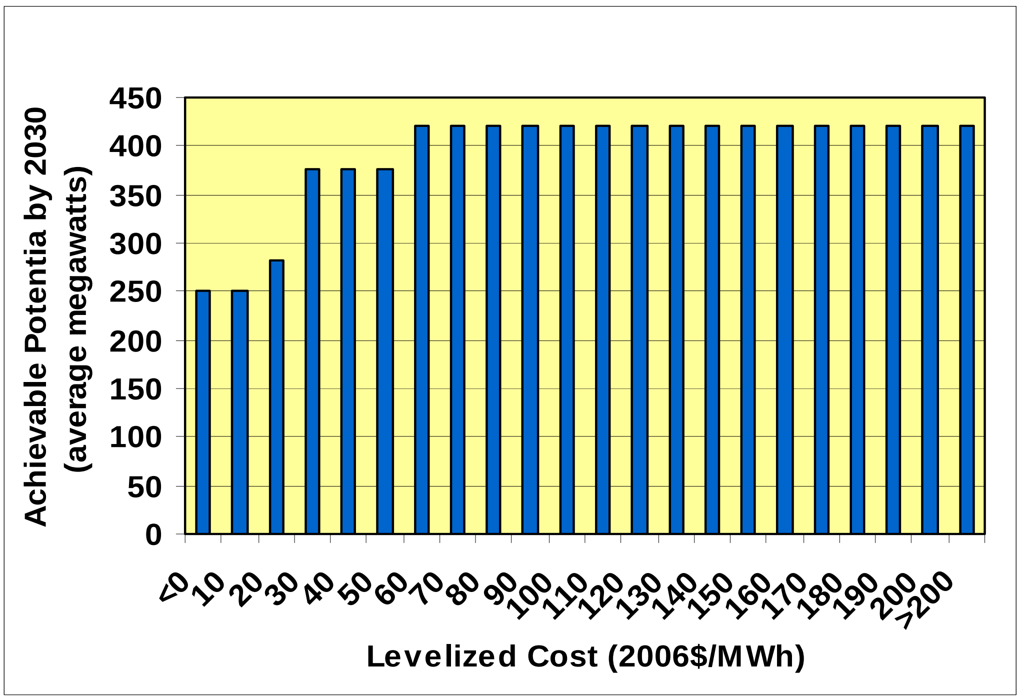
Potential savings from utility distribution systems come from a NEEA project to improve the efficiency of utility distribution systems. Based on the results of a pilot program in six utilities across the region, the study demonstrated that operating a utility distribution system in the lower portion 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 over 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



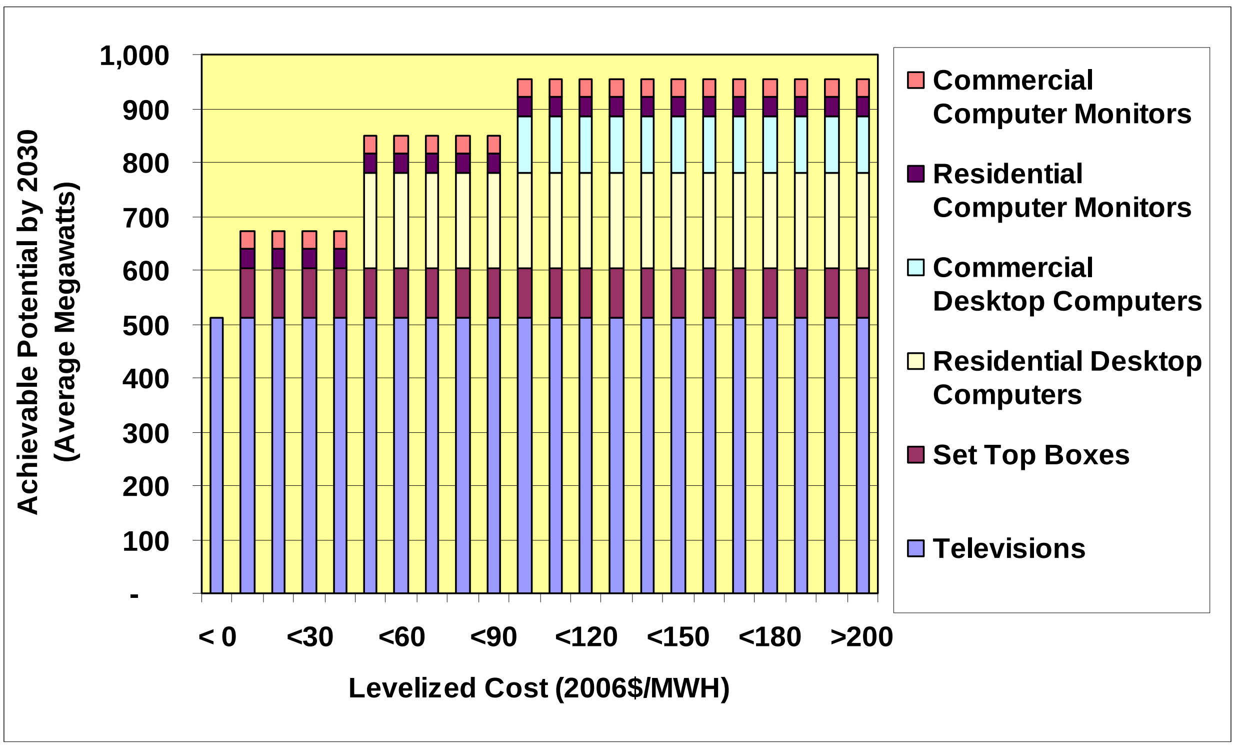
Consumer Electronics

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 nearly 1,000 average megawatts by the year 2029. Most of the savings potential, over 800 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.

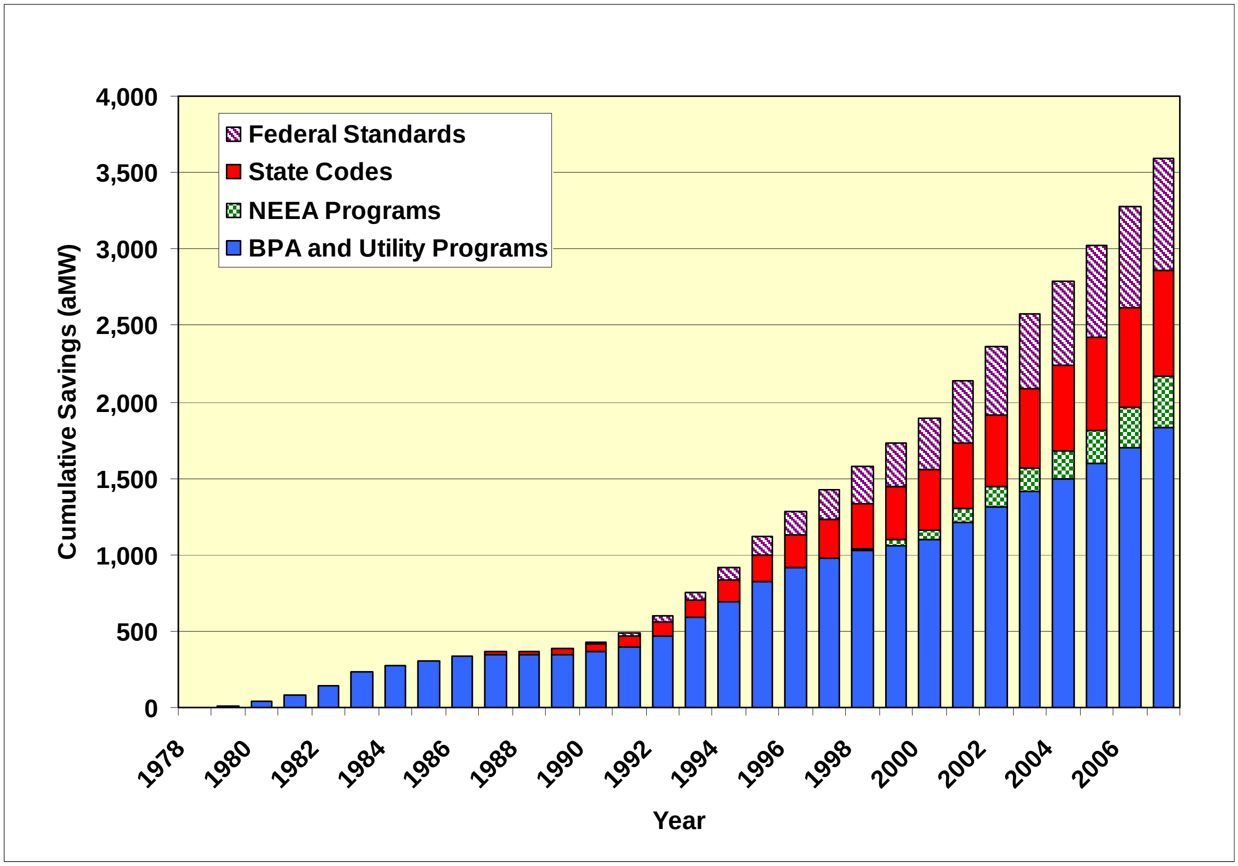
The upper limit of annual conservation resource development reflects the Council's estimate of the maximum that is realistically achievable. Since there is no perfect way to know this limit, the Council used several approaches to develop estimates of annual achievable conservation limits. First, the 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 more than 3,500 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 1978-2007 (MWa)

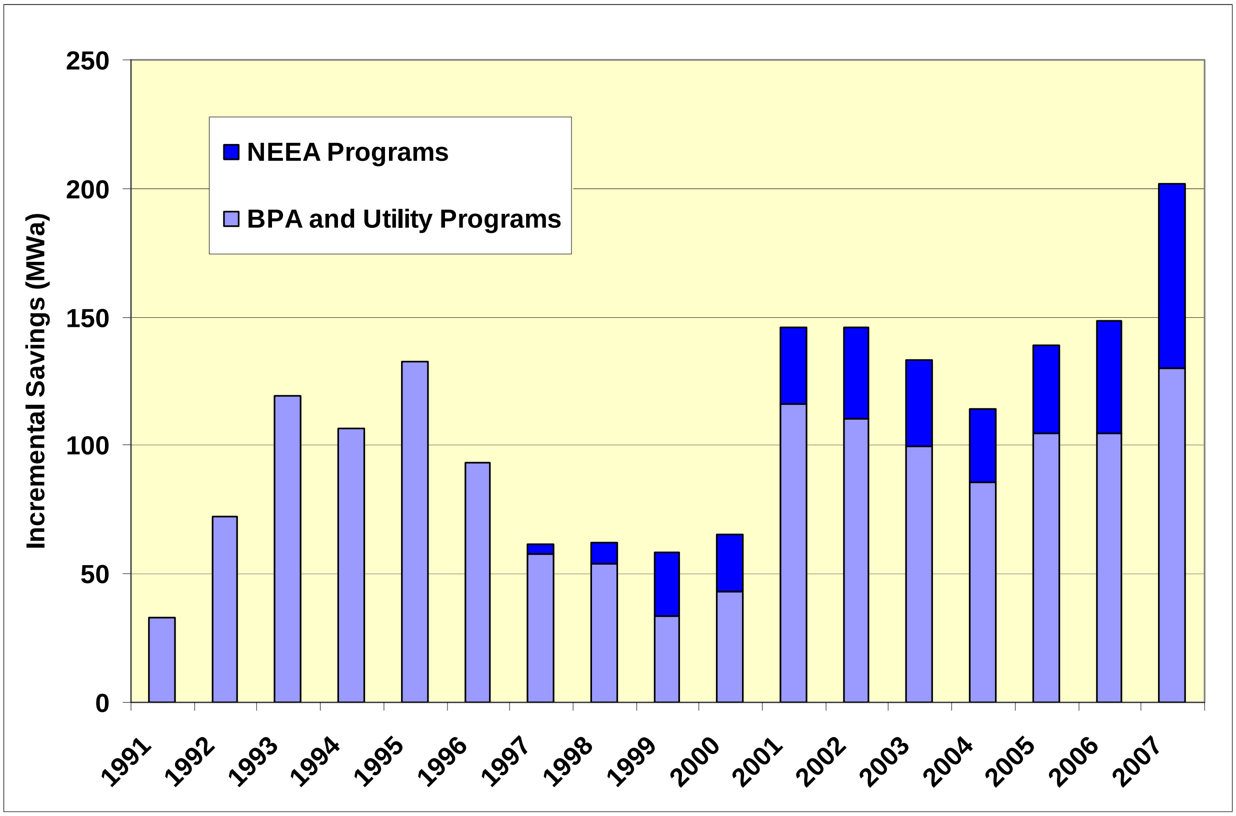


Over this 30-year period, the mix of measures has changed significantly. Early years were dominated by residential programs. In the 1990s commercial and industrial programs were added. Starting in the mid-1980s, state building codes began to capture significant savings. About five years later, federal 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 200 average megawatts per year in 2007, 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 200 average megawatts per year, which is consistently higher than long-term annual rates for program delivery.

Figure 4-10: Annual Conservation Achievements from Programs 1991-2007 (MWa)



There were three historic periods when program savings showed fast acceleration. The 1991-1993 period, the 2000-2001 period, and more recently the 2005-2007 period. During these periods, regional program activities increased by over 40 average megawatts year-to-year, not counting codes and standards.

While complete data are not available for 2008, preliminary surveys indicate that regional program savings alone will be in the range of 220 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. Early indications are the region will capture about 1000 average megawatts, exceeding the targets by about 40 percent. A large part of that success is due to higher penetration of compact fluorescent lamps, than anticipated in the 5th Power Plan.

Regional savings in 2007 and 2008 include about 75 average megawatts from the sale of compact fluorescent light bulbs (CFL), a substantial portion of which are not in the conservation assessment going forward since they are covered by the federal standards. The 2007 suite of programs (without CFLs) has achieved about 140 average megawatts per year in 2007 and 2008. The Council believes that non-CFL program accomplishments have been on the increase since 2007 based on preliminary reports from large utilities and system benefits administrators. Furthermore, non-CFL acquisitions would likely have been higher if the region had not been so successful at deploying residential CFLs to exceed near-term conservation targets. Summing up, it appears that at a minimum the region can achieve about 150 average megawatts per year of non-CFL savings based on the current pace of activity and the suite of existing programs and measures.

New measures identified in the Sixth Power Plan and increased penetration rates for existing programs could add significantly to future annual acquisition rates. For example, the Council estimates that 150 average megawatts of potential residential retrofit lighting savings are available by replacing incandescent lamps not covered by recently enacted federal standards with compact fluorescent lamps or lamps of similar efficacy. An additional 85 average megawatts of potential savings are available from the replacement of residential showerheads with more efficient fixtures. Since utility programs and infrastructure already are in place, these savings could be captured over a five to seven year period. Thus, by ramping in these two measures alone, utilities could immediately add 50 to 65 average megawatts of savings to the 150 average megawatts savings they are currently acquiring from measures other than CFLs covered by federal standards.

Estimating the Annual Achievable Pace 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.

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

	Lost Opp	Non-Lost Opp	Total
20-Yr Cumulative	3,200	2,600	5,800
5-Yr Cumulative (2010-2014)	370	900	1,270
5-Yr Annual Average	70	180	250
5-Yr Ramp Up	30 to 110	160 to 200	190 to 310
10-Yr Cumulative (2010-2019)	1,200	1,700	2,900
10-Yr Annual Average	120	170	290
10-Yr Ramp Up	30 to 200	160 to 160	190 to 370

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 overall ramp-up increases from about 160 average megawatts in 2010 to 200 average megawatts per year by 2014, averaging about 160 average megawatts per year over the five-year period. In aggregate, this results in nearly 900 average megawatts of retrofit conservation viewed as achievable. This is only about one-third of the over 2,400 average megawatts of retrofit conservation available at an average cost of $30 per megawatt-hour in the Council's supply curve. At an average pace of 160 average megawatts per year, it would take about 15 years to acquire all 2,400 average megawatts of this potential.

It was assumed that the maximum achievable pace of acquisition for lost-opportunity resources 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 new lost-opportunity resources because acquiring these measures is slower given the relative difficulty of deploying them. For lost-opportunity measures where the region has experience and 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 370 average megawatts of savings 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 30 average megawatts per year in 2010 to 110 average megawatts per year five years out, and to 200 average megawatts per year 10 years out.

In combination, this analysis indicates that nearly 1300 average megawatts of lost-opportunity and retrofit conservation are achievable over the 2010-2014 action plan period. Maximum annual average acquisitions increase from nearly 200 average megawatts per year in 2010 to about 350 average megawatts per year within 10 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 9.

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

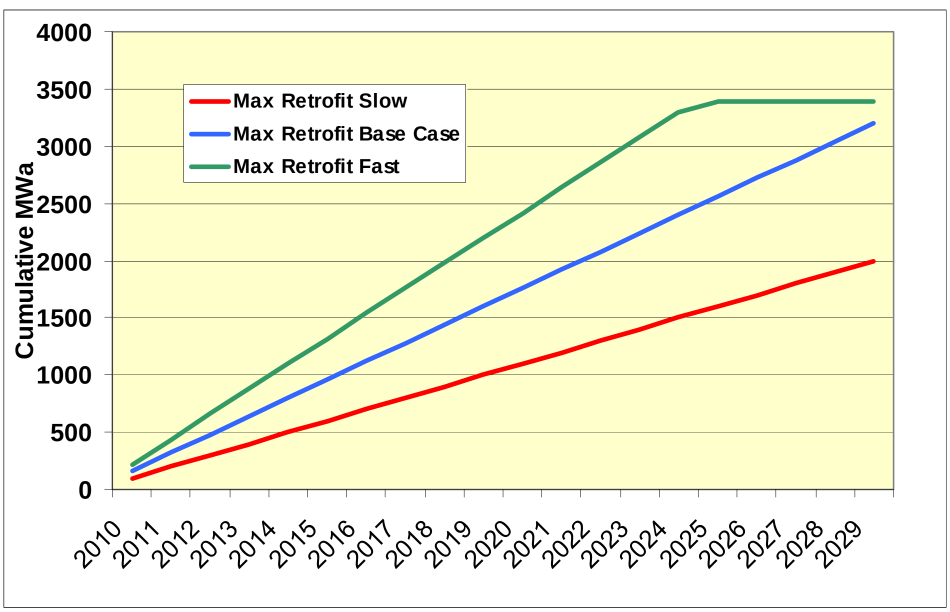
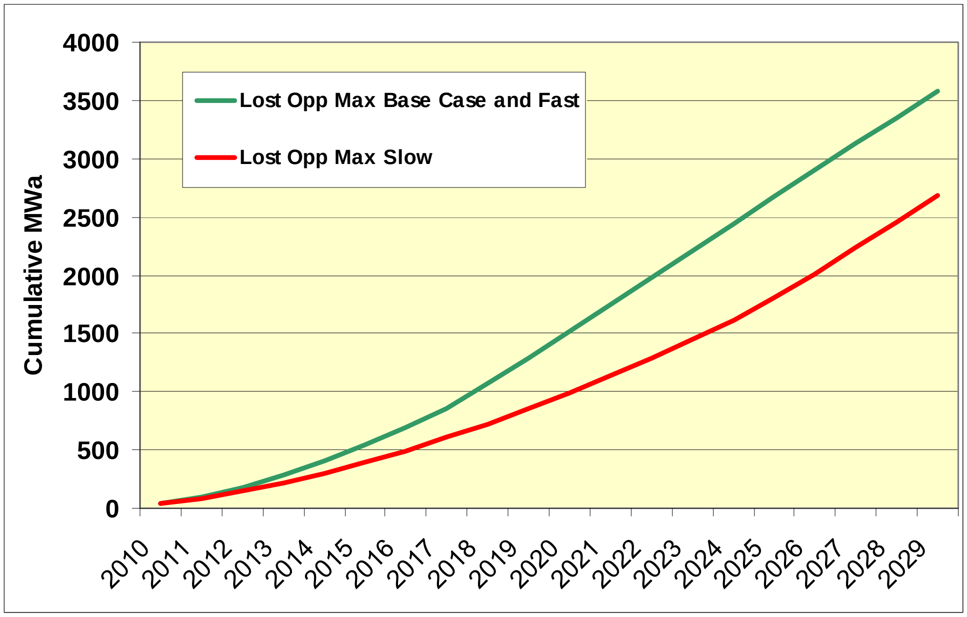


Figure 4-12: Maximum Conservation Acquisition Rates Tested for Lost-Opportunity Conservation



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

[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)

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.

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 seventeen utilities that serve 88% of the retail load in that state to "pursue all available conservation that is cost-effective, reliable, and feasible." By January 2010, each utility to which the law applies must develop a conservation plan that identifies its "achievable cost-effective potential" for the next ten 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 ten-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 or apply or implement I-937 for the utilities and regulators in the State of Washington. But because of the intersection between the two mandates -- 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 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 Council staff and others, adopted rules in 2008 that outline the methodology that 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 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 the 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, growth rates) and their own determination of avoided cost and the measures available to them.

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 ten-year life of the utility's conservation plan for I-937, but also to identity 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 ten-year period." Having to acquire 20 percent of any ten-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

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

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

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 of load reductions together with dispatchable standby generation. This achievable technical potential was included in analysis by the Council's regional portfolio model[1] 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 resource[2] in its Fifth Power Plan.[3] The Fifth 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 Plan described pricing and program options to encourage demand response, made a very rough estimate of 2,000 MW 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 and Appendix H on DR at 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 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 are now 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 Appendices H-1 and H-2. 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 have also 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 have usually 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% of peak load in the winter and 2.2% 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 are actually called to reduce load.

Puget Sound Energy (PSE) commissioned a study by Cadmus in 2009 that is still being revised. Preliminary results indicate that about 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 Draft Sixth Power Plan was released, but are expected soon. Their results may be available in time to include in the final version of 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 Utility Commission. This level of demand response would be accomplished by converting much of their irrigation demand response to dispatchable[9] 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 MW 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

[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.

number of hours per year. PGE also has received responses from a Request for Proposals (RFP) asking for proposals 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 4500 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 their programs. About 2,000 megawatts of that total are subject to significant penalties if they don't deliver promised reductions when called upon, 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) cites 1,678 megawatts of demand response without dispatchable standby generation and 2278 megawatts of demand response with dispatchable standby generation in 2007. These figures are 6.1 and 8.3 percent of the ISO's average weather summer peak load of 27,400 megawatts, (winter 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 estimates 4460 megawatts of demand response in its control area in 2008 compared to a forecasted peak load of 137,950 megawatts[11] 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 MW of interruptible load on July 13, 2006 to help meet a record peak load of 50,270 MW. California had 1,200 megawatts more of DR 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]

---

[10] http://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 pg 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 ten years, so that accomplishing a similar level of total demand response over 20 years in our region 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 has already been achieved, amounting to more than 160 MW by 2009. Second, they include announced plans to acquire demand response by regional utilities amounting to more than 350 MW. 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 Items of this chapter, the Implementation Plan and in Chapter 9.

[14] For more information about the working of the portfolio model, see Chapter 8.

Table 5-2: Demand Response Assumptions

Program	MW	Fixed Cost	Variable Cost (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 DR 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 are currently reducing irrigation load by nearly 100 megawatts by 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 DR 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. Experience this summer should support the revision of this assumption before the release of the final version of the Sixth Plan.

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 are usually 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 can also 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 has 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

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

facilities with emergency generation are built and existing facilities are brought into the program. 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 based[16] 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 that could provide from about 15 MW to over 300 MW 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 MWa 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 MW of AC and irrigation were assumed adopted in all portfolios to reflect the level of program already adopted by PacifiCorp and Idaho Power, and the 400 MW demand buyback resource was assumed adopted in all portfolios based on its very low fixed costs. The remaining resources were modeled as "optional" i.e. 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 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 is also 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 the spring of 2009. 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 the region as a whole.

Providing Ancillary Services with Demand Response

Demand response has usually been regarded as an alternative to generation at peak load (or at least near peak load), which occur a few hours per year. Because demand response for this purpose is only needed a few hours a year, customers need to reduce their usage for only a few hours a year. The load whose reduction provides such 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 11). Not all demand response can provide such services, since 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 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 DR and wind machines.

requirement is satisfied. Presently, 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 cars (PHEVs). Many parties have suggested this possibility, and the general outline of these cars' potential interaction with the power system is common to most proposals -- the PHEVs' individual 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 coordinate[20] 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 megawatt. 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 to about 5,300 megawatts, depending on when it is needed.

But to provide regulation or load following, reductions aren't sufficient -- loads need also to be increased when the power system needs it. 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-hydro generation is operating, and winds are increasing. System operators have too much energy and few good options – they can cut hydro 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 rise in water temperature above its normal setting that we allow. If, for example, we allow the temperature to rise from 120 degrees F to 135 degrees F, 3.4 million 50 gallon water heaters can accept 6,198 megawatt hours of energy, store it (at the cost

[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] A more detailed description of how PHEVs could contribute to the power system is at Appendix K-1

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

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 his 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 unlikely that many other plants could provide regulation to the power system.

[23] This rise could result from an increase in load of 6198 MW for an hour, or an increase in load of 3099 MW for two hours, etc.

Chapter 6: Generating Resources and Energy Storage Technologies

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 balancing reserves to complement variable-output energy resources.*

- *Economic and reliable low carbon energy 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 alternatives ranges from about $80 to $100/MWh.*

- *Other low-to-moderate carbon resources available in the near-term, but in limited quantities include bioresidue energy recovery projects, natural gas and bioresidue cogeneration, conventional geothermal and new and upgraded hydropower projects. These resources are commercially mature and in many cases economically competitive. They are, however, typically small and often challenging to develop. Solar photovoltaics, while commercially mature, low carbon, easy to develop and available in large quantity, is very expensive.*

- *Conventional coal plants are unlikely to be developed in the near-term because of climate policy uncertainty.*

- *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% 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.*

- *Resources available in the 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 CO_2 sequestration and technologies for the capture of CO_2 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 cost, declining value of the dollar against overseas currencies and market incentives for wind and other technologies. The weakening global economy and difficulty in securing credit has reversed this trend and costs are declining for most technologies. The timing and level of cost stabilization are highly uncertain.*

- *Significant risk factors 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-fuel power generation in proportion to fuel carbon content and plant efficiency. Estimated increases under the mean allowance prices assumed for this plan range from 18% ($14/MWh) for gas combined-cycle plants to 48% ($33/MWh) for coal steam-electric plants. While carbon dioxide separation and sequestration could reduce the cost of compliance, current estimates of the cost and*

[1] "Local" wind refers to wind power not relying on the development of high-capacity, long-distance dedicated transmission.

performance of plants so equipped suggest that these features would not be economic under the mean value of carbon dioxide allowance costs assumed for this plan.

- *Wind power in the Northwest has relied on existing firm capacity and balancing reserves. Continued development of wind and other variable-output energy resources (wave power, tidal current power and solar photovoltaics) will eventually require firm capacity and balancing reserve additions to sustain reliable system operation. 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 alternatives best suited for the Northwest.*

INTRODUCTION

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 processes driven by 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 irradiation to electric power).

Many primary forms of energy are found in the Northwest, including various biofuels, 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[2].

Energy storage technologies decouple electricity production from consumption and can be used to can shift energy from lower value to higher value periods and provide firm capacity, balancing reserves and other capacity-related services. Storage technologies appearing to have the greatest value for Northwest application are those with the ability to provide extended 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.

[2] 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.

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

Resource	Applications	Estimated Undeveloped Potential	Reference Capacity Cost ($/kW-yr)	Reference Energy Cost ($/MWh)	Key Issues
Renewable generating resources					
Hydropower - New	Firm capacity Energy	Low hundreds of MWa?	--	$87	Siting constraints Development cost
Hydropower - Upgrades	Firm capacity Energy Balancing	Low hundreds of MWa?	Highly variable	Variable	
Biogas - Wastewater energy recovery	Capacity Energy	7 - 14 MWa	--	$104	Cost
Biogas - Landfill gas	Firm capacity Energy	80 MWa	--	$77	Competing uses of biogas
Biogas - Animal manure	Firm capacity Energy	57 MWa	--	$101	Cost Competing uses of biogas
Biomass - Woody residues	Firm capacity Energy Cogeneration	665 MWa	--	$96 (CHP) - $123 (No CHP)	Cost CHP revenue Reliable fuel supply
Geothermal - Hydrothermal	Firm capacity Energy	370 MWa	--	$80	Investment risk (Exploration & well field confirmation)
Geothermal - Enhanced	Firm capacity Energy	Thousands of MWa?	--	Not available	Immature technology Cost of commercial technology
Marine - Tidal current	Energy	Low hundreds of MWa?	--	Not available	Immature technology Environmental impacts Competing uses of sites
Marine - Wave	Energy	Low thousands of MWa?	--	Not available	Immature technology Competing uses of seaspace
Marine - Wind	Energy	Thousands of MWa?	--	Not available	Immature technology Competing uses of seaspace
Solar - Photovoltaics	Energy	Abundant	--	$300	Cost Poor load/resource coincidence Availability and cost of balancing services
Solar - Parabolic trough CSP (Nevada)	Firm capacity Energy	600 MWa/500kV circuit	--	OR/WA $222 ID $183	Cost Lack of suitable PNW resource Availability and cost of transmission
Wind - "Local"	Energy	OR/WA - 1410 MWa ID - 215 MWa MT - 80 MWa	--	OR/WA $102 ID $108 MT $88	Availability and cost of balancing services
Wind - Alberta	Energy	760 MWa/+/- 500kV DC Ckt	--	OR/WA $135	Availability and cost of balancing services Availability and cost of transmission
Wind - Montana	Energy	570 MWa/500kV Ckt	--	ID $116 OR/WA $143	Availability and cost of balancing services Availability and cost of transmission
Wind - Wyoming	Energy	570 MWa/500kV Ckt	--	ID $120 OR/WA $150	Availability and cost of balancing services Availability and cost of transmission
Waste Heat Recovery					
Bottoming Rankine cycle	Energy	Tens to low hundreds of MW?	--	$55	Suitable host facilities Host facility viability

Resource	Applications	Estimated Undeveloped Potential	Reference Capacity Cost ($/kW-yr)	Reference Energy Cost ($/MWh)	Key Issues
Fossil Generating Resources					
Coal - Steam-electric	Firm capacity Energy	Abundant	--	No CSS ID - $103 (2020) CSS MT>WA via CTS $142 (2025)	GHG policy Immature CO_2 separation technology Lack of commercial CO_2 sequestration facility
Coal - Gasification	Firm capacity Energy Balancing Polygeneration	Abundant	--	No CSS ID - $113 (2020) CSS MT>WA via CTS $141 (2025)	Investment risk Reliability GHG policy Lack of commercial CO_2 sequestration facility
Natural gas - Combined-cycle	Firm capacity Energy Balancing Cogeneration	Abundant	$92[3]	Baseload $90 Probable dispatch $95 - 120	Gas price volatility & uncertainty
Natural Gas - Simple-cycle (Aeroderivative)	Firm capacity Balancing Cogeneration	Abundant	$166	--	Gas price volatility & uncertainty
Natural gas - Simple-cycle (Frame)	Firm capacity Balancing Cogeneration	Abundant	$127	--	Gas price volatility & uncertainty
Natural gas - Reciprocating engine	Firm capacity Energy Balancing Cogeneration	Abundant	$234	$110	Gas price volatility & uncertainty
Petroleum coke - Gasification	Firm capacity Energy Balancing Polygeneration	Abundant	--	Possible reduction in fuel cost offset by increased CO2 allowance or sequestration cost	Investment risk Reliability GHG policy Lack of commercial CO_2 sequestration facility
Nuclear Generating Resources					
Nuclear fission	Firm capacity Energy	Thousands of MW (late in planning period)	--	$109 (2025)	Public acceptance Cost escalation Construction delays Regulatory risk “Single shaft” reliability risk
Energy Storage Systems					
Compressed air energy storage	Firm capacity Balancing Diurnal shaping	Uncertain	Uncertain & site-specific	--	Confirming suitable geology Monetizing system benefits
Flow batteries	Firm capacity Balancing Diurnal shaping	No inherent limits	Uncertain	--	Immature technology Monetizing system benefits
Pumped storage hydro	Firm capacity Balancing Diurnal shaping	Numerous sites (thousands of MW)	$352	--	Project development Monetizing system benefits
Sodium-sulfur batteries	Firm capacity Balancing Diurnal shaping	No inherent limits	Uncertain	--	Early commercial technology Monetizing system benefits

[3] Incremental cost of duct-firing capacity.

Proven Technology

The Power Act requires priority be given to resources that are cost-effective, defined as a resource that is available at estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative[4]. Because the supply of resources using commercially-proven technology is sufficient to meet forecast needs over the twenty year period of the power plan, unproven resources, not being “similarly reliable and available” as those using commercially proven technologies are not included in the recommended portfolio. Unproven resources include those for which the available quantity is poorly-understood and resources requiring unproven technology. For this plan, unproven resources include salinity gradient energy generation, deep water wind power, wave energy, tidal currents, and enhanced geothermal. Because it is probable that proven technologies for use of deep water offshore wind power, wave energy, tidal currents, and enhanced geothermal will become available over the next two decades, actions to monitor and to support development of these technologies are included in this plan.

Cost Estimates

The electricity production costs cited in this chapter are forecast costs in constant 2006 year dollars, levelized over the anticipated economic life of the plant. The costs include:

- plant costs (plant development and construction, operation, maintenance, fuel and byproduct credits)
- integration costs (regulation and load following)
- transmission costs and cost of transmission losses
- carbon dioxide allowance (emission) costs

The following assumptions are used for calculating these costs: reference plant configuration and location as described, investor-owned utility financing, medium fuel price forecast and delivery to a load serving entity point of delivery. The derivation of forecast plant and transmission cost components and method of calculating levelized costs are described in Appendix I. Fuel cost forecasts are described in Appendix A. The carbon dioxide allowance costs are based on the forecast medium case developed for the wholesale power price forecast as described in Appendix D[5]. Federal production and investment tax credits and renewable energy credits are excluded in an effort to yield a more accurate comparison of societal costs. Accelerated depreciation is included. Actual project costs may differ, to a greater or lesser degree from the costs appearing here because of factors including site-specific conditions, incentives, financing and timing.

Levelized electricity costs for a given resource and technology will vary by initial year of service because of forecast escalation of fuel prices, carbon dioxide allowance costs and escalation of integration costs. Forecast technological improvements and production economies will also affect costs through time. A significant effect in the near-term is the current decline in

[4] Regional Act 3.(4)(A)
[5] The medium carbon dioxide allowance cost estimates used for the power price forecast are slightly lower in the near- and mid-term than the mean value of the distribution used for the Regional Portfolio Model (RPM) because of subsequent adjustments to the RPM distribution. The difference will have a very minor effect of the carbon dioxide allowance component of the costs appearing in this chapter and will be reconciled prior to release of the final plan.

construction costs for many resources because of the tight credit market and weak economic conditions. To facilitate more accurate comparisons among resources the costs shown in Figures 6-1 A-C are based on a common initial service year for each figure: These are 2015 for Figure 6-1A (near-term) , 2020 for Figure 6-1B (mid-term) and 2025 for Figure 6-1C (longer-term). Elsewhere in the chapter, with a few exceptions cited electricity costs are based on an initial service year of 2015. The exceptions are resources such as nuclear or coal with carbon sequestration for which a 2015 service date is clearly infeasible. The reference service dates are noted for these resources.

Finally, the cost of transmission for remote resource options requiring new long-distance transmission assumes no network credit for the transmission improvements. Network credit could reduce transmission costs for these alternatives.

GENERATING RESOURCE APPLICATIONS & SERVICES

Energy generation has been the focus of previous power plans because the Northwest hydropower system is capacity-rich and energy-limited. Increasing demand for balancing reserves[6] for integrating wind power and a prospective firm capacity shortfall in coming years has broadened to scope of this plan to the capacity as well as the energy characteristics of resources. Power generation technologies differ in their ability to deliver these services and in the cost of providing these services. Capacity issues are further discussed in Chapter 11 of this plan.

The principal power system services of interest for purposes of long-term planning are energy, balancing reserves and firm capacity (the ability to contribute to meeting peak loads)[7]. Though an electric power system could consist of a single resource such as hydropower or gas combined cycle plants capable of providing all generating services needed for reliable system operation, a power system normally consists of a mix of resource types; some specialized for the production of certain services.

Another service provided by some power plants is cogeneration (also referred to as combined heat and power or CHP). Cogeneration is the simultaneous production of electricity and useful thermal energy for industrial or commercial processes or space conditioning. In addition to providing a revenue stream to help offset the cost of electricity production, cogeneration increases the thermal efficiency of fuel use and can reduce net carbon dioxide production and other environmental impacts.

Energy

All power plants produce electric energy, but power plants used extensively for the production of electric energy (baseload plants) are those with low variable production costs. Little can be saved by curtailing operation of these plants so they are typically dispatched to the extent that

[6] Balancing reserves provide regulation and load-following for the integration of variable-output renewable energy resources. Also referred to as system flexibility.

[7] In addition to energy, seven capacity-related ancillary services are needed for reliable operation of 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.

they are available. 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 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 also operate as baseload energy generators. Production-related financial incentives such as the federal production tax credit (PTC) and renewable energy credits (RECs) affect dispatch decisions and promote energy production by lowering the effective variable production cost.

The reference levelized cost of electric energy from new generating resources is shown in Figures 6-1A-C. Figure 6-1A includes resources that could plausibly be brought into service in the near-term period of the plan (2010-14). These include resources with short development and construction lead times such as wind and combined-cycle plants, and resources such as geothermal and new hydropower. While the latter typically have long lead times, specific projects are sufficiently-advanced in the development process[8] to be brought into service in the near-term period. Costs are for projects entering service in 2015.

Figure 6-1B includes additional resources (in color) that could be brought into service in the mid-term period (2015-19). These include remote wind and solar resources requiring construction of long-lead time transmission lines, and long-lead time coal-fired steam-electric and gasification plants. Because of Montana, Oregon and Washington carbon dioxide performance standards that effectively prohibit utilities from owning or contracting for the output of coal plants not provided with carbon capture and sequestration, these coal-fired options would be limited to Idaho. Costs are for projects entering service in 2020. The effect of assumed rates of technological improvement and other factors affecting cost through time become evident in this and the following figure, especially for solar photovoltaics.

Figure 6-1C shows resources that could be brought into service in the long-term period (2020-29). New options (in color) include long lead time advanced nuclear plants and ultra-supercritical steam-electric coal technology. The latter would be limited to Idaho unless equipped with carbon separation and sequestration. Commercial-scale carbon dioxide sequestration facilities based on depleted oil and gas fields are assumed to be available by this period. These could be located in Montana, Wyoming or Saskatchewan and accessible to coal-fired plants located in eastern Montana, opening the possibility of repowering the Colstrip Transmission System (CTS) using coal gasification plants with carbon dioxide separation (Colstrip 1 and 2 will have been in service for 50 years by 2025). The estimated cost of repowering the CTS using wind power is also shown. Costs are for projects entering service in 2025.

Though the total costs shown in the figures reflect the approximate cost-effectiveness order based on energy production, these are expected values and do not incorporate the effects of risk and uncertainty evaluated in the Resource Portfolio Model.

[8] "Development" is used in this chapter in the customary sense to refer to 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 Electricity Cost of Energy Generating Options Available in the Near-term (2010-14) [9]

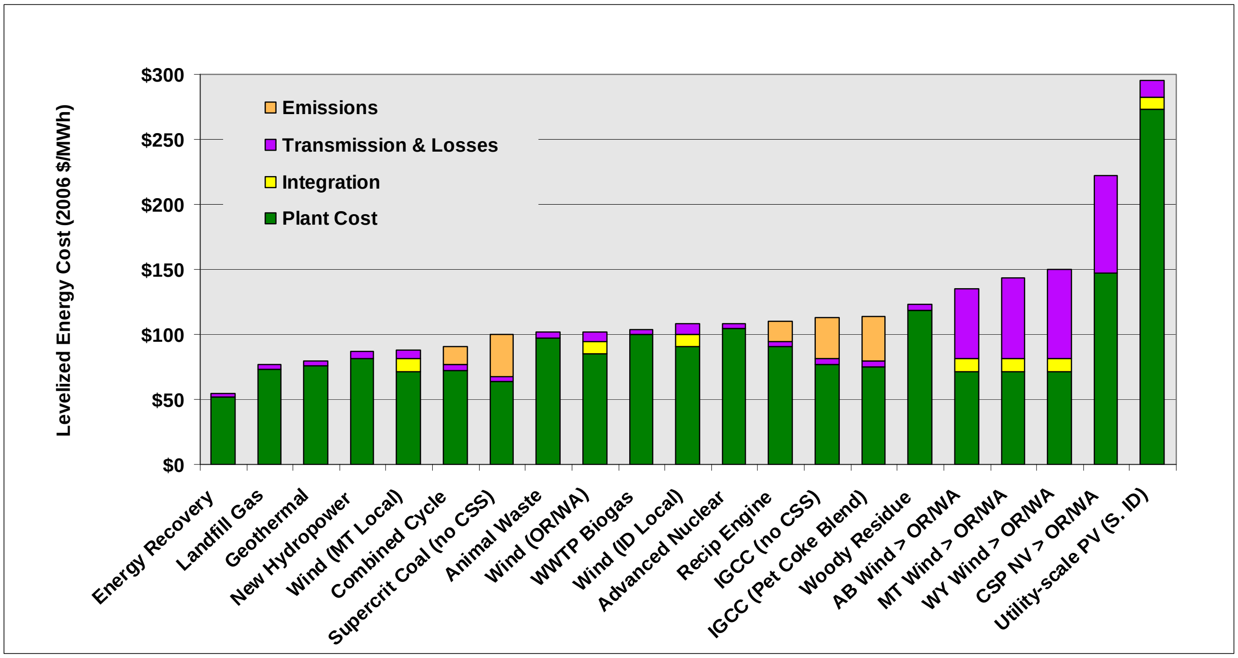
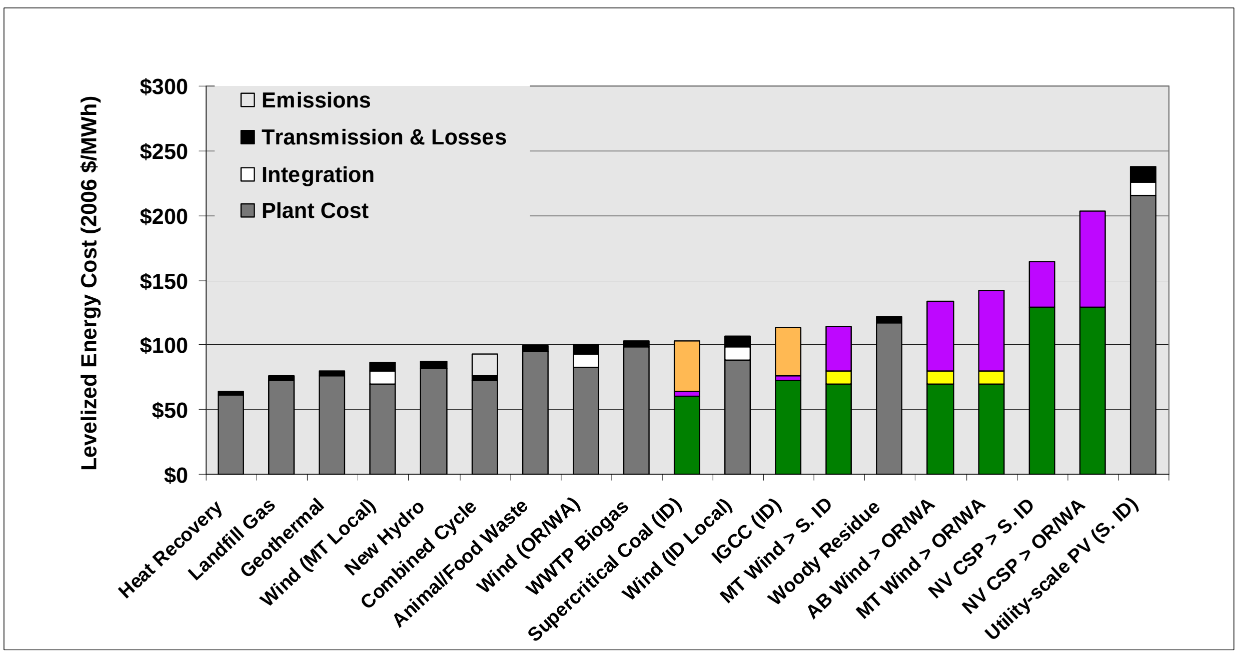
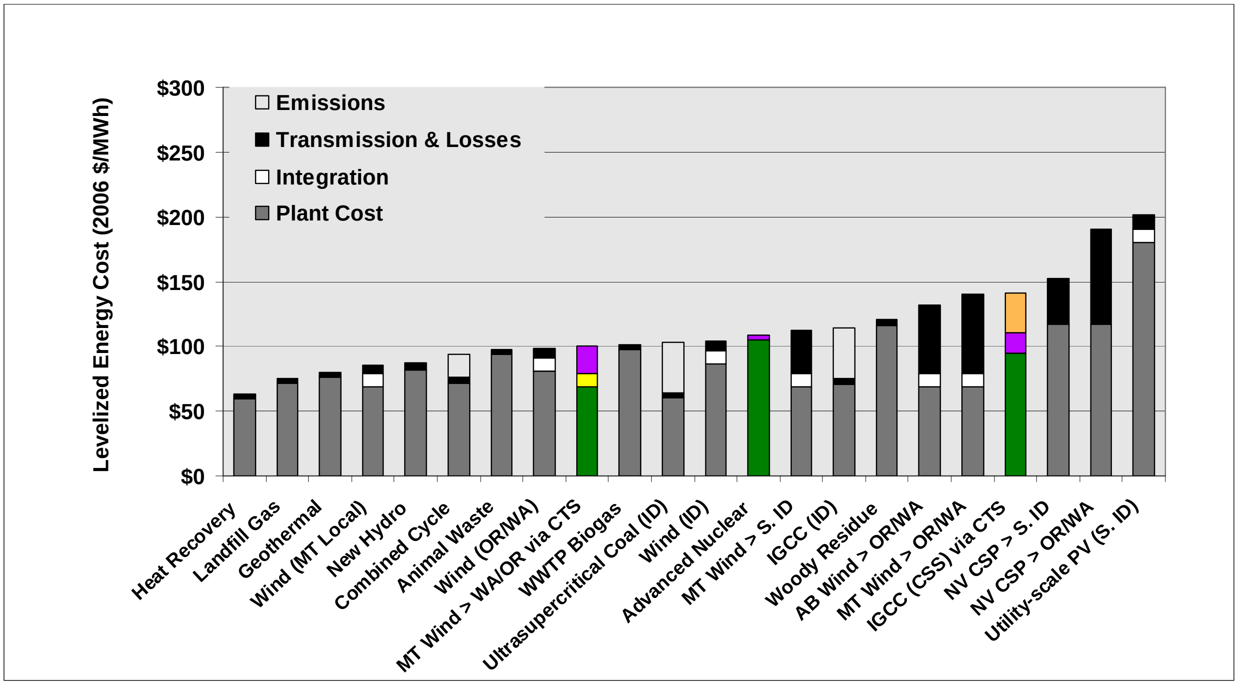


Figure 6-1B: Levelized Electricity Cost of Energy Generating Options Available in the Mid-term (2015-19) [10]



[9] Assumptions: 2015 service, investor-owned utility financing, medium fuel price forecast, wholesale delivery point. CO_2 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.
[10] Assumptions as in Figure 6.1A except 2020 service.

Figure 6-1C: Levelized Electricity Cost of Energy Generating Options Available in the Longer-term (2020-25)[11]



Firm Capacity

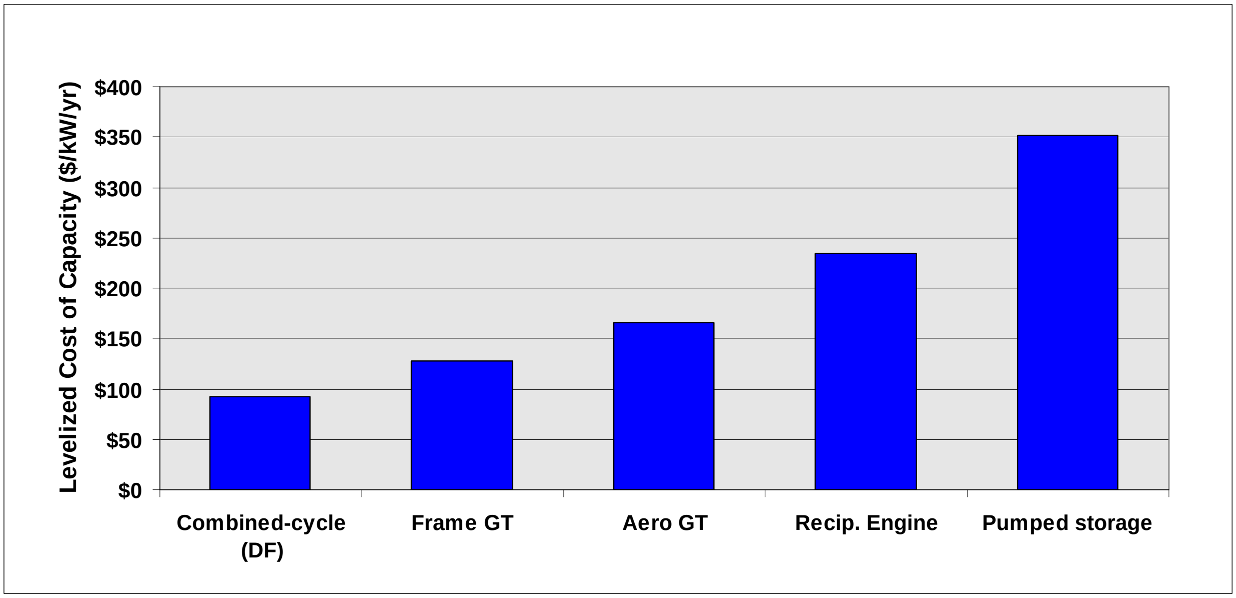
With the exception of wind and other variable-output energy resources, most power plants provide firm capacity to meet peak loads and to provide contingency reserves[12]. In general, these plants can provide capacity up to net installed capacity less an allowance for forced (unscheduled) outages. In some cases, contractual, fuel, permitting and ambient environmental conditions may limit the peak contribution of otherwise firm capacity. Some resources are developed primarily to provide firm capacity. Because these resources are operated infrequently, variable cost is less important than fixed costs. Also, units intended for peaking service may need rapid start and load-following ability to avoid displacing generation having lower variable cost.

A comparison of the fixed costs of several resources typically developed for capacity value 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 nearly always provided on combined-cycle units. But duct firing capability is limited and other capacity resources are sometimes needed. Levelized capacity costs of Figure 6-2 would not be the sole criterion for choosing among these options. The technologies have different attributes, leading to different choices depending on needs. Aeroderivative 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 requires additional condenser cooling water, whereas simple-cycle gas turbine and reciprocating units require no condenser cooling, a factor of importance in arid regions.

[11] Assumptions as in Figure 6.1A except 2025 service.
[12] Capacity held for use in case of a contingency event such as unplanned loss of generation.

Moreover, anticipated operating conditions can affect fixed costs. Gas turbines, if located in a non-attainment area may need expensive air emission controls. Several prospective capacity options are omitted from the figure because they are uncertain at present.

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



Regulation and Load-following

The addition of large amounts of wind power to the Northwest power system has increased the 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 windpower 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 generation and actual load. Load-following is currently provided by operating capacity reserves set to provide either upward (incremental) regulation ("inc") or downward (decremental) regulation ("dec"). The need to prepare for unpredictable rapid upward and downward ramps in wind output is increasing demand for load-following capability.

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, low capital cost and near-market operating costs. Other desirable attributes include siting flexibility and low standby emissions. Among generating resource options, combined-cycle gas turbines, simple-cycle gas turbines and reciprocating engines offer the greatest potential for supplying regulation and load-following services. Long-duration storage technologies including pumped-storage hydro, compressed air energy storage, flow batteries and sodium-sulfur batteries offer similar capability.

Further assessment of the relative cost and value of these options in the context of the Northwest power system is needed. Action GEN-6 calls for an assessment of flexibility augmentation options with priority given to resources or combinations of resources that can jointly satisfy peak load and system flexibility requirements. This effort 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) is the joint production of electricity and useful thermal or mechanical energy for industrial process, space conditioning or hot water loads. The fundamental attribute of cogeneration is higher thermodynamic efficiency compared to separate production of electricity and the thermal or mechanical services. Improved efficiency is achieved through higher initial temperatures and pressures and by use of otherwise wasted thermal energy. Benefits of cogeneration include 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.

Cogeneration includes diverse combinations of fuels, technologies and applications, making it difficult to characterize a definitive cogeneration project. Fuels used for cogeneration include waste heat from industrial equipment and processes, natural gas, wood residues, 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 cogeneration are provided in Table 6-1.

About 3970 megawatts of cogeneration is installed in the Northwest. About 1790 megawatts of this capacity is industrial cogeneration, closely integrated with the host facility and sized to the thermal load. The remaining 2180 megawatts are utility-scale combined-cycle plants at which steam is extracted to serve a nearby thermal load. Operation of industrial cogeneration is generally determined by thermal demand (i.e., the operation of the thermal host), whereas operation of utility-scale combined-cycle cogeneration is largely determined by fuel and electricity prices. Fifteen cogeneration plants totaling 143 megawatts of cogeneration capacity has been constructed in the Northwest since release of the Fifth Power Plan. All of these new plants are industrial cogeneration and most are fuelled by bio-residues.

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

A 2004 assessment[13] identified 14,425 megawatts of technical cogeneration potential for Idaho, Oregon and Washington[14]. Under "business-as-usual" assumptions (little improvement in technology, no incentives and continuation of standby charges) the economic potential through 2025 was estimated to be about 1030 average megawatts of energy. No applications using woody biomass residues were considered, nor were any applications involving capture of waste energy such as from 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 cogeneration are rarely seen by the individual parties (utility, host facility, developer) involved in the decision to develop cogeneration. Many of the barriers to cogeneration 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 plus possible loss of load.
- Limited capital and competing investment opportunities often constrain the host facility's ability to develop cogeneration.
- Energy savings benefits to the host facility may not be worth the hassle of installing and operating a cogeneration plant.
- Difficulty in establishing a guaranteed fuel supply for wood residue plants.
- Uncertainties regarding the long-term economic viability of the host facility.
- The locational value of cogeneration is often not reflected in electricity buy-back prices.
- 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 cogeneration and small-scale renewable energy resource development opportunities.
- Resource evaluation criteria that fully reflect costs and benefits including energy, capacity and ancillary services values, avoided transmission and distribution costs and losses and environmental effects.
- Elimination of disincentives to utility acquisition of power from customer-side projects such as inability of investor-owned utilities to receive a return on investment in generation owned or operated by others.

[13] Energy and Environmental Analysis, Inc... *Combined Heat and Power in the Pacific Northwest: Market Assessment*, B-REP-04-5427-004. July 2004.
[14] CHP opportunities in Montana were not assessed in the Energy and Environmental Analysis study.

- Uniform interconnection agreements and technical standards.
- Equitable standby tariffs.
- Provision for the sale of excess customer-generated power through the utility's transmission and distribution system.

Distributed Generation

Distributed generation is the production of power at or near electrical loads. Distributed generation can provide standby power for critical loads, regulation of voltage or frequency beyond grid standards, cogeneration, use of an on-site byproduct as fuel, local voltage support, an alternative to the expansion of transmission or distribution capacity, service to remote loads, 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 individual units to create a virtual large-scale storage facility. The modularity and small-scale of distributed technologies can 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, and 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, maintenance and fuel and the lower thermodynamic efficiency. It is the additional value imparted by the factors listed above that may make distributed generation attractive. Distributed long-duration storage options include flow batteries and sodium-sulfur batteries.

HYDROELECTRIC POWER

The mountains of the Pacific Northwest and British Columbia and heavy precipitation, much of which falls as snow, produce large volumes of annual runoff that create the great hydroelectric power resource for this 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 and somewhat expensive.

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. Unfortunately, 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 (meaning power) to better match the monthly shape of 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, that is, the historical water year[15] 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 operates at about a 50 percent annual capacity factor because of water supply and limited storage. For hourly needs, the Northwest's power supply must be sufficient to accommodate increased demands 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, which is designed to provide for the six highest load hours of a day over a three consecutive 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. The potential of dam removal or of operating reservoirs at lower elevations would further reduce power production.

For the Sixth Power Plan, hydroelectric system capability over the study horizon is based on fish and wildlife operations specified in the 2008 biological opinion. The possible impacts to the resource strategy due to climate change effects on hydroelectric generation will be examined via scenario analysis. However, it should be noted that the range of potential changes to hydroelectric generation is relatively small compared to the range of 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 demand and to accommodate system operations to benefit fish and wildlife.[16] 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 to become part of the power plan. The plan is then to set forth "a general scheme for implementing conservation measures and developing resources" with "due consideration" for, among other things, "protection, mitigation, and enhancement of fish

[15] 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.

[16] For more information please see Appendix M: Fish and Wildlife Interactions.

and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival and propagation of anadromous fish."[17]

On average, fish and wildlife operations reduce hydroelectric generation by about 1,170 average megawatts (relative to an operation without any constraints for fish and wildlife).[18] For perspective, this energy loss represents about 10 percent of the hydroelectric system's firm generating capability[19]. Bonneville estimates that replacing that lost hydropower capability and funding direct fish and wildlife program expenditures have increased Bonneville's costs by over $800 million per year. That amount represents about 20 percent of Bonneville's annual net revenue requirement.[20]

These impacts would definitely affect the adequacy, efficiency, economy and reliability of the power system, if they had been implemented over a short term. 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 assessment[21] 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 specified 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 its action items, the Council addresses this need by proposing the creation of a public forum, which 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 to explore ways of taking advantage of those situations.

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 addition of generating

---

[17] Northwest Power Act, Sections 4(e)(2), (3)(F), 4(h)(2)

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

[19] 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.

[20] Bonneville's annual net revenue requirement is on the order of $3.5 billion (Bonneville's 2007 Annual Report).

[21] See http://www.nwcouncil.org/energy/resource/Adequacy%20Assessment%20Final.doc.

equipment to irrigation, flood control and other non-power water projects, incremental additions of 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 Plan estimate is representative of the current situation. Hydropower development costs are sensitive to 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 $96 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 a comprehensive assessment of new hydropower potential be undertaken to gain a clear understanding of the cost and potential of this 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 the development of 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 undertake 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 twenty 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 clear understanding of the cost and potential of this resource.

NON-HYDRO RENEWABLE ENERGY RESOURCES

Biofuels

Biofuels include combustible organic residues of the production and consumption of food, fiber and materials, and fuels obtained from dedicated energy crops. Bio-residues available for electric power generation in the Northwest include woody residues (forest residues, logging residues, mill residues, and the biogenic components of municipal solid waste), spent pulping liquor, agricultural field residues, animal manure, food processing residues and landfill and wastewater treatment plant digester gas. Hybrid poplar plantations represent the greatest potential for dedicated bio-energy production for the electrical sector in the Northwest, but typically have greater fiber than fuel value.

Landfills

Anaerobic decomposition of the organic matter in landfills produces a low-grade (~450 Btu/scf) combustible gas consisting largely 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[22]. Increasingly, the gas is used for productive purposes including direct use as low-grade fuel, upgrading to pipeline-quality gas and on-site power generation. A typical power generation facility consists of gas cleanup equipment and one or more reciprocating engine-generator sets. The principal business model is third-party development of the gas cleanup and power generation facilities with purchase of the raw gas from the landfill operator.

Six projects totaling 28 megawatts are currently in operation in the Northwest. The estimated feasible undeveloped power generation potential in the Northwest is about 80 average megawatts, represent about 94 megawatts of installed capacity. Because the gas from some landfills is being upgraded for injection into the natural gas system, a portion of this potential is unlikely to be available for power generation. The reference three megawatt project would produce electricity at an estimated cost of $79 per megawatt-hour, though the costs of specific projects will vary due to economies of scale, gas quality and gas production rates. Barriers to further development of landfill gas for power generation include competing uses, low financial incentives and cost, especially for smaller landfills.

Agricultural and Food Wastes

A combustible gas largely consisting of methane and carbon dioxide usable as a power generation fuel can be derived from anaerobic digestion of animal manure, food wastes and similar biogenic organic material. 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 reciprocating engine-generator is used to maintain digester temperature and to dry the residual fiber for use as animal bedding or soil amendment. These projects provide baseload, carbon-neutral electricity from an otherwise wasted resource. Unfortunately, the most feasible candidate facilities for installation of energy recovery facilities are limited to 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 application 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 Northwest potential, primarily at large-scale dairy operations is estimated to be 50 to 60 average megawatts. Additional potential might be secured through development of cooperative facilities jointly serving smaller dairy or food processing operations. Power generation costs are widely variable and sensitive to project size and type of digester. Costs might range from $90 per megawatt-hour for a large 2.5 megawatt project (~16000 head of cattle) to about $145 per megawatt-hour for a 450 kilowatt project (~ 2900 head). The principal impediments to greater use of the available resource include cost and collection of a sufficient supply of manure or other agricultural waste to support economically feasible projects. The principal barriers to further development of this resource are aggregation

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

of sufficient biomass for an economically-sized plant, and cost in general, particularly for smaller facilities.

Wastewater Treatment Plants

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 addition of heat for optimal operation and the common method of disposing of the biogas is to use it as a fuel for controlling digester temperature. Surplus is flared. A more productive alternative is to clean the biogas for use as fuel for a cogeneration plant where the heat rejected 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 remaining regional potential was not located, a 2005 assessment prepared for the Oregon Energy Trust estimated 2 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 to 14 megawatts.

The reference plant is an 850-kilowatt reciprocating engine generator fuelled 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 would be $127/MWh 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 $108 per megawatt-hour for larger (1 - 2 megawatts installations) to twice that for smaller installations. Though these costs appear high, the electricity is typically used to offset treatment plant loads so electricity production costs compete with retail rates. Cost, especially for smaller installations is the primary barrier to full development of the remaining potential.

Woody Residue

The largest source of woody residues in the Northwest has been the forest products industry. Currently 26 projects, comprising 290 megawatts of capacity using woody residues as a primary fuel operate in the Northwest, a slight increase since the Fifth Plan. Surveys indicate that nearly all woody residues currently produced in the forest products sector are beneficially used, for fuel or otherwise. Some undeveloped potential is available from further separation of biogenic material from municipal solid waste otherwise land-filled, but the major potential is forest thinning residues from expanded ecosystem recovery and wildfire hazard reduction efforts and from more intensive management of commercial timberlands. Additional woody residue from these sources could provide about 90 TBtu annually on a reliable, sustained basis. The price of this residue will vary depending upon the source, alternative uses and prevailing economic conditions, but is expected to average about $3.00 per million Btu in the near-term. Introduction of specialized collection and transportation equipment for bulk low-density fuels is expected to 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 cogeneration will be the chief technology for electricity generation using wood residues in the near-term. Modular biogasification plants are under development and may be introduced within the next several years. A sustained annual fuel supply of 90 Tbtu is sufficient to generate about 665 average megawatts using conventional technology.

The reference plant is a 25 megawatt stand-alone unit using conventional steam-electric technology, operating entirely on forest thinning residues. This plant would produce electricity at $123 per megawatt-hour. Capital ($51/MWh) and fuel ($40/MWh) are the two major components of the energy cost of the reference plant. The reference configuration was selected because of the limited supply of low-cost mill residues and limited opportunities for cogeneration in areas where abundant supplies of forest thinning residues are expected to be available. Lower-cost opportunities are available, however. Factors that could significantly reduce the cost of specific projects include use of refurbished equipment, availability of mill or urban wood residues, cogeneration revenue, established infrastructure, low-cost financing and financial incentives. For example, cost-reducing elements of a feasibility study by the Port of Port Angeles for a wood residue cogeneration plant in Forks, WA, included use of a travelling grate rather than a more costly fluidized bed boiler, an adjacent cogeneration load, refurbished turbine-generator and electrical equipment and a close-by supply of mill residue. Applying the reference financing assumptions used elsewhere in this chapter yields $78 per megawatt-hour energy for this plant, placing it well within the competitive range for new generating resources.

The principal barriers to development of woody biomass plants are capital costs, availability of cogeneration load and ensuring an adequate, stable, and economical fuel supply.

Pulping Chemical Recovery

Chemical recovery boilers are employed to recover the chemicals from spent pulping liquor produced by chemical pulping of wood. Lignins and other combustible materials in the spent liquor create the fuel value. Recovery boilers, usually augmented by power boilers fired by wood residue, natural gas or other fuels, supply steam to the pulping process. More efficient use of the fuel is possible by producing the steam at high pressure and extracting process steam at the desired pressures from a steam turbine-generator. When the Fourth Power Plan was prepared, 8 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 from installation of cogeneration equipment at recovery boilers not having such equipment. Mills have closed since then and upgrades have been undertaken at several of the remaining plants, including addition of a 55 megawatt generating plant at the Simpson Tacoma Kraft mill, scheduled for service this summer. 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 of this resource.

Geothermal Power Generation

The crustal heat of the earth, produced primarily by the decay of naturally-occurring radioactive isotopes may be used as a source of energy for power generation. Conventional hydrothermal electricity generation requires the coincidental presence of fractured or highly porous rock at temperatures of about 300^{o} 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 towards the surface. Basin and Range geothermal resources have been developed for electric power 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 suitable for electric power generation outside of these areas 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 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 for this plan is a binary-cycle plant consisting of three 13-megawatt units. The reference cost of electricity production is $84 per megawatt-hour - among the lowest-cost generating resources identified in this plan.

A recent U.S. Geological Survey assessment[23] yielded a mean total Northwest hydrothermal electricity generating potential of 1369 average megawatts. However, geothermal development has historically been constrained by high-risk, low-success exploration and wellfield 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 6th Plan.

Enhanced Geothermal Power Generation

The natural presence of high-temperature permeable rock and fluid at feasible drilling depth is uncommon. Much more common are high-temperature, but insufficiently permeable formations. Enhanced geothermal systems (EGS)[24] involve creation of the necessary permeability by fracturing or other means. EGS technology is one of several emerging geothermal technologies[25] that could vastly increase the potentially developable geothermal resource. Three areas of special EGS interest identified in a 2004 MIT assessment of geothermal potential[26] occur in the

---

[23] United States Geological Survey. *Assessment of Moderate- and High-Temperature Geothermal Resources of the United States*. 2008.
[24] Also known as engineered geothermal systems.
[25] Others include "Hidden" hydrothermal resources, supercritical volcanic geothermal, oil and gas co-production and geopressured reservoirs.
[26] Massachusetts Institute of Technology. *The Future of Geothermal Energy*, 2004.

Northwest and two of these (Oregon Cascades and Snake River Plain) are unique to the Northwest. The USGS study cited above identified 104,000 average megawatts of EGS potential at 95% 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. 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 operation 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 could be captured and converted to electricity. Concepts that have been advanced for the generation of electric power from salinity gradients include osmotic hydro turbines, dilytic batteries, vapor pressure turbines, and polymeric salinity gradient engines. These technologies are in their infancy, and it is not clear that current concepts would be able to operate off the natural salinity gradient between fresh water and seawater. Although the theoretical resource potential in the Northwest is substantial, many years of research, development, and demonstration will be required to bring these technologies to commercial availability.

Tidal Energy

Tidal energy originates from the loss of the earth's rotational momentum due to drag induced by gravitational attraction of the moon and other extraterrestrial objects. The conventional approach to capturing tidal energy is by means of hydroelectric "barrages" constructed across natural 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 only a few places worldwide where the landform greatly amplifies the tidal range. Environmental considerations aside, the development of economic tidal hydroelectric plants in the Northwest appear to be 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 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 my be sufficient to support tidal current generation. Several Northwest utilities have secured preliminary permits to further explore this potential.

Wave Energy

The Northwest coast is among the better wave energy resource areas, world-wide. 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 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 cost. Though it would be impractical to capture the full winter energy flux, the seasonal output of a wave energy plant would be generally coincident with winter-peaking regional loads. A further attribute of wave energy is its geographic 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 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 and impacts and remediation measures. Assessment of interconnection and integration requirements in advance of development is also essential. Northwest utilities are encouraged to support these efforts.

The cost of electricity from wave energy power plants will be site-specific. Conversion technology, depth, ambient wave energy, ocean floor conditions and distance from shore will all affect cost. A 2004 estimate of the capital and operating costs and productivity of a 90-megawatt commercial-scale plant using an array of 500 kilowatt Pelamis wave energy conversion devices optimized to Northwest conditions suggests a cost range of $140 to $270 per megawatt-hour[27] for the initial plant. Learning and economies of production will reduce costs as installed capacity increases. Given installation of 1600 megawatts of wave energy plant globally, an amount appearing feasible by the 2020s, learning curves derived from experience in the wind, solar and other industries yield expected costs to $105 per megawatt-hour and range of $80 to $150 per megawatt-hour. These costs would make wave energy potentially competitive with other generating resources.

[27] Using the reference cost assumptions used elsewhere in this chapter.

Solar

The amount of solar radiation reaching the ground and available for conversion into electricity is a function of latitude, atmospheric conditions, and local shading. The best solar resource areas of the Northwest are the inter-mountain basins of south-central and southeastern Oregon and t he 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 loads, such as irrigation and air conditioning, but is less suitable for serving general regional loads which are forecast to continue to be winter-peaking for many years. There have been no comprehensive studies of site suitability for development, though in theory, there is sufficient solar resource to support all regional electrical requirements.

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

Photovoltaics

Photovoltaic plants convert sunlight to electricity using solid-state cells. 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 loads 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 loads for which it is too costly to extend grid service. Strong public and political support has lead to attractive financial incentives, so despite the high cost and low productivity, grid-connected installations of several hundred kilowatts, or more are becoming common.

A low-cost photovoltaic plant would employ 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 cell technology. Crystalline silicon cells operate at higher efficiency, and are more durable but are more costly. At greater cost, plant productivity can be further improved by mounting cell arrays on tracking devices to improve daily and seasonal orientation. Maximum productivity is achieved by use of 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 only direct (focusable) solar radiation, so are best suited for clear southwestern desert conditions.

The reference plant is a 20-megawatt (AC net) central-station plant 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 and thereby facilitate 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 very best Northwest locations. If constructed in the near-term, this plant would deliver energy at about $300 per megawatt-hour. Costs are expected to continue to decline, on average, at the historical 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[28]. 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. Many parabolic trough plants are 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.

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 200-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 thence to the Boardman area via portions of the proposed Gateway West and the Boardman-to-Hemmingway transmission projects. One 500 kV transmission circuit could deliver about 1500 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 loads prior to 2015. A plant coming into service in 2015 could deliver energy to southern Idaho for about $180 per megawatt-hour. Delivery to the Mid-Columbia trading hub would be about $220 per megawatt-

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

hour. Technological improvements and economies of production are expected to result in continued cost reduction.

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 loads at a cost approaching that of competing low-carbon resources. The added cost and investment risk of long distance transmission needed for these plants makes 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, lying athwart prevailing southwesterlies.

Beginning in 1998 with the 25 megawatt Vansycle Ridge project, commercial wind power has grown to about 4000 megawatts of nameplate capacity, the fourth largest component of the Northwest power system. Though some geographic diversification has occurred, capacity remains concentrated in the area of the Columbia Basin east of the Columbia River Gorge. Nearly 80% 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. While the recent development rate has slightly subsided due to the tight credit market, an array of market and financial incentives and strong political support are expected to sustain robust development.

Wind power in the Northwest has variable output and little dependable capacity and therefore requires complementary firm capacity and balancing reserves. An existing surplus of balancing reserves and dependable capacity within the Northwest power system has enabled the growth of wind power without the need or cost, to date, of additional complementary capacity. Concentration of installed wind capacity east of the Columbia River Gorge, and within in single balancing area (Bonneville) has led to significant ramping events, placing demands on the ability of Bonneville, in particular to integrate additional wind development.

The least cost, and quickest solutions to accommodating the integration needs of additional wind development appear not to be construction of new flexible capacity, but rather 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. Over the longer-term, a further means of reducing the demand for flexibility may be to increase the geographic diversity of wind development by construction of transmission to import wind from remote wind resource areas. Existing system flexibility, scattered across numerous Northwest balancing areas, can be more fully accessed by the development of mechanisms to facilitate trade of balancing services concurrent with development of expanded dynamic scheduling capability and generation control. Issues of cost allocation will need resolution, especially now that substantial amounts (close to 50% of 2008 development) of Northwest wind power is marketed to California customers. Following these steps, new balancing reserves and dependable 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. Advance identification of sensitive areas and establishment of transparent and comprehensive permitting criteria and procedures will help preclude 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. Whereas the development wind for local use is ongoing, , it is unlikely that wind power from Alberta, Montana or Wyoming would be available to serve Oregon or Washington loads 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[29]

Resource	Limiting Factor	Capacity (MW)	Energy (MWa)	Cost ($/MW)
Columbia Basin > PNW Westside	Transmission at embedded cost	4060	1300	$102
Other local OR/WA	20% peak load penetration	340	110	$102
Local Southern Idaho	20% peak load penetration	725	215	$108
Local Montana	20% peak load penetration	215	80	$88
Alberta > OR/WA	+/-500kV DC transmission	2000/circuit	760	$122
Montana > ID	500kV AC transmission	1500/circuit	570	$116
Montana > OR/WA	500kV AC transmission via S. ID	1500/circuit	570	$143
Wyoming > ID	500kV AC transmission	1500/circuit	570	$120
Wyoming > OR/WA	500kV AC transmission	1500/circuit	570	$150

Because of modeling limitations the four local wind resource blocks were consolidated into a single block for purpose of the Resource Portfolio Model. For similar reasons, the Montana to OR/WA case was selected as representative of imported wind[30].

WASTE HEAT ENERGY RECOVERY

Certain industrial processes and engines reject energy at sufficient temperature and volume to justify capturing the energy for electric power production. “Waste heat” is considered a priority

[29] Estimates of capacity and energy are of delivered potential, incremental to installed capacity operating or under construction as of end of 2008.

[30] A review of the cost estimates following this initial portfolio runs suggested that Alberta wind has potential as the least-cost imported wind option for Oregon and Washington loads. Because of the larger incremental size of imported Alberta wind (2000 MW vs. 1500 MW), further analysis would be required to confirm the least-risk/least cost imported wind option.

category 3 resource by the Regional Act[31]. Candidate sources of high and medium-temperature waste heat potentially suitable for electric power generation 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 customarily equipped with recuperators, regenerators, waste heat recovery boilers and other devices to capture a portion of the reject heat for beneficial use, opportunities exist for installing bottoming cycle cogeneration on some of these facilities. Recovered energy cogeneration is attractive because of the increased efficiency of fuel use, baseload operation, and few, if any incremental air emissions or carbon dioxide production. Heat recovery boilers supplying steam turbine-generators have been the conventional approach to using waste heat for electric power generation. However, the introduction of small-scale, modular organic Rankine cycle power plants using lower-temperature energy sources have expanded potential applications for recovered energy cogeneration.

The reference plant is a 5-megawatt organic Rankine cycle generating unit supplied by the exhaust gas from the mechanical drive gas turbines of a trunkline natural gas compressor station. This unit would be operated in baseload mode with some seasonal fluctuation in coincidence with electrical load. At $66 per megawatt-hour, electricity from the reference plant would be among the lowest-cost generating resources.

An inventory of potential Northwest opportunities for the development of recovered energy cogeneration was not located for this plan, however, such opportunities are known to exist. For example, more than 50 natural gas pipeline compressor stations are located in the Northwest, many of which are powered by mechanical drive gas turbines potentially suitable for heat recovery generation. Recovered energy cogeneration facilities for trunkline compressor station applications are typically about five megawatts in capacity suggesting a 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 to develop these opportunities.

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 support all electric power needs for the 20-year planning horizon of this plan. Improvements in mining and rail haul productivity have resulted in generally declining constant dollar production costs. Climate change policy and overseas demand are the important factors affecting future coal prices. Carbon dioxide penalties would

[31] Northwest Power Act, Section 4(e)(1).

depress future demand and prices absent economical carbon dioxide separation and sequestration technologies. However, if technologies for separating and sequestering carbon dioxide for sequestration become commercial, domestic and overseas demand and prices are likely to remain stable or increase. 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 electric power in the United States as a whole, but comprises only 13 percent (7300 megawatts) of capacity in the Northwest. Pulverized coal-fired steam-electric plants, though a mature technology, continue to improve through use of higher temperature 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 to 40 percent. Ultra-supercritical units with thermal efficiencies of 41 - 43 percent are being constructed in Europe and Asia, and have been proposed in the United States.

The continued use of 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 the major fossil fuels[32]. Moreover, conventional coal-fired plants operate at lower efficiency than gas-fired plants. Despite the relatively small penetration of coal capacity in the Northwest, coal combustion is responsible for 85 to 90 percent of the carbon dioxide from the Northwest electricity sector. The approaches to reducing per megawatt-hour carbon dioxide production from coal-fired plants are 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. Fuel switching can reduce the carbon-dioxide production from existing as well as new plants. Switching from sub-bituminous to certain bituminous coals can reduce carbon dioxide production 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. While carbon capture technology for coal gasification plants is commercially available, capture technology for steam-electric plants remains under development. Though legal issues remain to be resolved, sequestration in depleted oil or gas fields is commercially proven. Suitable oil and gas reservoirs are limited in extent 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. The overriding issue is development of economical technology for separation of carbon dioxide, coupled with development of commercial-scale carbon sequestration facilities. This would pave the way to continued use of coal for new power

[32] The carbon content of petroleum coke is somewhat greater than that of coal.

generation and continued operation of existing coal-fired power plants. 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 is chemical separation of carbon dioxide from the flue gas of a conventionally air-fired furnace. Neither of these carbon removal technologies nor sequestration facilities are expected to be commercially available before the 2020s.

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. The reference plant for this period is a 400-megawatt supercritical unit. The plant would be equipped with a full suite of criteria air emission[33] control equipment and activated charcoal injection for additional reduction of mercury emissions. Because the technology is unlikely to be commercial by this time, 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, however, would not comply with Washington, Montana or Oregon carbon dioxide performance standards. Plausibly, this plant could be constructed in Idaho. The estimated levelized lifecycle electricity cost for a southern Idaho location is $103 per megawatt-hour, including forecast levelized carbon dioxide allowance costs of $39 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 400-megawatt ultra-supercritical unit, equipped for removal of 90 percent of flue gas carbon dioxide. This plant could comply with state carbon dioxide performance standards and supplement or replace existing coal-fired units. The example of Figure 6-1C is a repower of the existing Colstrip transmission system. The estimated levelized lifecycle electricity cost is $142 per megawatt-hour, including transmission costs of $16 per megawatt-hour and carbon dioxide sequestration and residual allowance costs of $30 per megawatt-hour (2025 service).

Coal-fired Gasification Combined-cycle Plants

Pressurized fluidized bed combustion and coal gasification technologies allow application of efficient 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 additional 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 fuels, 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.

[33] Emission controlled under the Clean Air act of 1990. These include sulfur dioxide, nitrogen oxides, particulates, hydrocarbons and carbon monoxide.

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. The reference plant is a 620 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 combined-cycle power generation plant that would provide firm capacity, energy and balancing reserves. This plant, however, would not comply with Washington, Montana or Oregon carbon dioxide performance standards. Plausibly, this plant could be constructed in Idaho. The estimated levelized lifecycle electricity cost for a southern Idaho location is $113 per megawatt-hour, including forecast levelized carbon dioxide allowance costs of $37 per megawatt-hour (2020 service).

By the mid-2020s, commercial-scale carbon sequestration facilities may be available, particularly those using depleted oil and gas fields. The reference plant for this period is equipped for removal of 88 percent of flue gas carbon dioxide. This plant could comply with state carbon dioxide performance standards and supplement or replace existing coal-fired units. The example of Figure 6-1C is a repower of the existing Colstrip transmission system. The estimated levelized lifecycle electricity cost is $141 per megawatt-hour, including transmission costs of $16 per megawatt-hour and carbon dioxide sequestration and residual allowance costs of $30 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 processed to remove condensable fraction (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 transportation 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 directly used for numerous residential, commercial and industrial end uses and is widely used for electric power production 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 (9100 megawatts) of Northwest generating capacity. Of this, 6960 megawatts are combined-cycle units, 1830 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 prompted interest in constructing liquefied natural gas (LNG) terminals to secure access to lower-cost overseas supplies. Interest in LNG facilities has waned following recently 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 reserves-to-production ratio of natural gas at the end of 2007 was estimated to be 63 years[34]. The North American ratio is much lower, about 10 years. However a significant amount of natural gas remains undiscovered and reserves have trended upward for many years, more than offsetting increasing consumption[35]. 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 to 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 $7.02/MMBtu in 2010 to $8.32/MMBtu in 2029 in the medium case (about 0.9%/year in constant 2006 dollars). Westside prices are expected to run about 80 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 the 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 play a major role in electric power production and are further discussed below. 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, extensively used for meeting short-duration peak loads. A wide range of unit sizes is available, from submegawatt to 270 megawatts. Low to moderate capital costs and superb operating flexibility make simple-cycle gas turbines attractive for peaking and grid support applications. Because of their relatively low efficiency and the cost of natural gas, simple-cycle gas turbines are rarely used purely for energy production unless equipped with exhaust heat recovery

[34] BP *Statistical Review of World Energy 2008*, June 2008. p22
[35] Energy Information Administration. *International Energy Outlook 2008 (DOE/EIA-0484(2008)).* June 2008. Fig. 43.

cogeneration. Gas turbine generators feature highly modular construction, short construction time, compact size, low air emissions, and low water consumption[36].

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, increasing summer peak loads and demand for regulation and load-following services are driving addition of simple-cycle gas turbines to the power system.

Gas turbine generators are generally divided into two classes: heavy-duty industrial machines specifically designed for stationary applications (often called “frame” machines), and “aeroderivative” machines using aircraft gas turbine engines adapted to stationary applications. A hybrid, intercooled design with high part-load efficiency (the GE LMS100) intended for load-following applications has recently been introduced to the market. Though a mature technology, further increases in gas turbine performance is expected to continue in the coming decades. Gas turbines for power generation benefit from research driven by military and commercial aircraft applications.

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 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 NOx control and an oxidation catalyst for CO and VOC reduction. The total plant cost for 2008 construction is $1050 per kilowatt. This unit would normally be used for sustained energy production only if provided with heat recovery for serving cogeneration loads.

The reference frame plant consists of a single 85 megawatts (nominal) capacity unit located at an existing gas-fired power plant site. Siting, fuel and air emission control assumptions are as described for the reference aeroderivative unit. The total plant cost for 2008 construction is $610 per kilowatt. Like an aeroderivative unit, a frame unit would normally be used for sustained energy production only if provided with heat recovery for serving cogeneration loads.

Reciprocating Engine-generators

Reciprocating engine-generators (also known as internal combustion, IC 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 one to 15 megawatts. Conventionally, reciprocating generators are used for small isolated power systems, emergency capacity at loads 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, and “recip farms” installed as a hedge to high power prices during the 2000-2001 energy crisis. On the load side, reciprocating units are provided for emergency service for hospitals, high-rise office buildings and other loads needing ultra-reliable electric service. Except for biogas units, these applications typically use light fuel oil stored on site.

The introduction of more efficient, cleaner and reliable reciprocating generators configured in standard modules in recent years coupled with increasing demand from wind capacity for load-

[36] 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.

following services 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. Multiple units, each with a low minimum load and flat, high efficiency curve, and rapid response yields a highly reliable plant with high and very flat efficiency across a very wide load range - ideal for providing load-following services. These plants can also be fitted with exhaust, turbocharger and lube oil heat recovery for low-temperature cogeneration loads. The reference plant consists of twelve 8 megawatt units operating on natural gas supplied on a firm gas transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC reduction. Baseload operation would yield energy at $110 per megawatt-hour. Cogeneration revenues would reduce this cost.

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, greatly increases the overall thermal efficiency of the plant. Cogeneration steam loads can be served (at some loss of electricity production) by extracting steam at the needed pressure from 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 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 comprised of 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-NOx combustors and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC control.[37] Condenser cooling is wet mechanical draft. Baseload operation (80% of full load capacity) would yield reference energy costs of $90 per megawatt-hour including forecast carbon dioxide allowance costs of $14 per megawatt-hour. Though fully capable of baseload operation, combined-cycle units, because of high fuel cost, normally operate as swing units, during heavy load hour. Capacity factors ranging from 35 to 65 percent are not uncommon. This range would result in reference electricity production costs from $95 to $125 per megawatt-hour. Cogeneration revenues could slightly reduce electricity production costs[38].

Petroleum

Petroleum fuels, 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

[37] Volatile Organic Compounds
[38] Combined-cycle cogeneration plants normally support a relatively small steam load.

backup fuel, peaking or emergency service power plants and for power generation in remote areas where its transportability and storability are essential, petroleum-derived fuels cannot compete with natural gas for electric power generation. Forecast prices for petroleum fuels 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. Petroleum coke supply is increasing as refineries increasingly crack residual fuel and draw upon lower quality crudes. EIA reports that the refinery yield of petroleum coke has increased from 4.3 percent in 1995 to 5.3 percent in 2008. 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, 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 very limited publically-available pricing information, the discount to subbituminous coal is about 80%. For this plan we assume petroleum coke prices are 80% of delivered coal prices. 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 unlikely that a plant would be fuelled purely on petroleum coke.

The net effect of petroleum coke on the cost of electricity from a gasification plant is uncertain, as it is a function the tradeoff of reduction, if any, in fuel cost achieved by use of petroleum coke and the possible additional cost of carbon dioxide allowances or sequestration costs resulting from the higher carbon content of petroleum coke.

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 nuclear fuel is comprised of a mixture of two isotopes of natural uranium - about three 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 technology developed in the 1950s. One, the 1200 megawatts Columbia Generating Station operates in the Northwest. Motivated by improved plant designs, 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 spring 2009, developers have submitted applications to the Nuclear Regulatory Commission for combined construction and operating licenses for 27 new units at 17 sites, mostly in central and southeastern states. Most proposals are planned for service in the 2015-20 period, and construction of the initial units is expected to be contingent on federal incentives. The proposed plants employ evolutionary designs with increasing use of passively operated safety systems and factory-assembled standardized modular components. These features are expected to result in improved safety, reduced cost, and greater reliability. Work is also underway on a highly modular light water design using standard 40-megawatt modules that could be built out into plants of the desired capacity.

Nuclear plants could be attractive source of dependable capacity and baseload low-carbon energy largely immune to high natural gas prices and climate policy. The reference plant is a single-unit 1100 megawatt advanced light water reactor design. The reference cost of power from this unit would be $112 per megawatt-hour (2025 initial service). Construction of a new unit in the Northwest would likely require successful completion and operation of at least one of the proposed new units elsewhere in the United States, an operating spent nuclear fuel disposal system and full development of equally cost-effective conservation and renewable resources. If these conditions were satisfied, the remaining development risks would include construction delays, regulatory uncertainties, cost escalation and the reliability risk associated with a large “single-shaft” machine.

ENERGY STORAGE TECHNOLOGIES

A major challenge to increasing the penetration of variable-output renewable energy resources including 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 loads of the power system. One approach is the use of complementary dispatchable firm generation such as the hydropower currently used to integrate wind power in the Northwest. An alternative is energy storage technologies. Energy storage technologies enable decoupling of the production and consumption of electricity, and can provide regulation, sub-hourly load following, hour-to-hour storage and shaping, firm capacity and other 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[39]. This requires megawatt-scale power ratings, run times of hours and extended charge/discharge capability. The most promising systems for this purpose currently include compressed air energy storage, flow batteries, pumped-storage hydropower and sodium-sulfur batteries.

A common constraint to the deployment of energy storage systems is a business model that permits the project developer to capture the full value of the services that these systems can provide. Value may accrue separately to the generation, transmission and distribution sectors and to the extent that these sectors are structured to impede sharing of benefits, capturing the full value of a storage project may be difficult for a project developer. No formal market exists in the Northwest for the services provided by energy storage systems and with one small exception[40], no successful example of non-utility development of a pumped-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 very little pumped storage capacity has been developed in the Northwest despite favorable sites is that most of the Northwest does not experience the daily summer afternoon peak loads and resulting opportunity for daily off-peak/on-peak arbitrage common to other areas of the country.

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 heat rate and fuel consumption. A CAES combustion turbine might have a heat rate of 4000 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 recuperation - 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%) 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 original 290 megawatt plant was placed into operation in Germany in 1978. A 110 megawatt plant using an improved design including 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

[39] Individual units need not be at a megawatt/hour scale. Megawatt/hour scale could be achieved by deployment of 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.
[40] The 40 megawatt Olevenhain - Hodges project near San Diego.

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 address the integration of variable-output renewable resources. Unlike earlier designs, these plants would use standard industrial components and would use multiple motor-driven compressors and separate multiple air expansion turbine-generators to improve efficiency, provide additional operating flexibility and to 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.

Potentially suitable 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 megawatt) CAES would employ above-ground pressure vessels or buried high-pressure piping, further increasing siting flexibility, though at greater cost.

CAES technology has potential application in the Northwest for improving 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. Charging or discharging is accomplished by pumping the electrolyte is pumped through a stack of electrolytic cells. 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 the attributes of modularity, sizing flexibility, siting flexibility and zero emission operation. A potential disadvantage is relatively low energy density. Large electrolyte storage facilities may be required 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 two megawatt capacity demonstration project is under construction in Ireland. Current cycle efficiency is 70 to

75 percent with potential for improvement. Capital costs are relatively high - one U.S. demonstration plant of 250 kilowatts capacity and two megawatt-hours of storage is reported to have cost $4000/kW. However, current cost and performance are 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 interconnected 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 to 82 percent. Seventeen pumped-storage projects comprising more than 4,700 megawatts of capacity are installed in WECC. One project is located in the Northwest - the six-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 for the daily shifting of energy from low variable cost thermal units from nighttime off-peak periods to afternoon peak load periods. 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 extreme wind ramping events.

Pumped storage projects require suitable topography and geologic conditions for the construction of nearby upper and lower reservoirs at significantly different elevations. Designs using 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 2000 megawatts and totaling nearly 14,000 megawatts have been announced in Idaho, Oregon and Washington, suggesting no shortage of suitable sites. Construction costs are highly project-specific. Important factors influencing costs include the presence of an existing water body that can be used for one of the reservoirs (usually the lower), storage capacity and transmission interconnection distance. Though $1000 per kilowatt of installed capacity is often quoted as a representative cost of pumped storage hydro, a review of available cost estimates suggests that $1750 to $2500 per kilowatt[41] is more representative. The principal constraints to development of pumped storage are development complexity and lead time, capital cost and the recovery of revenues for 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 nine megawatts of sodium-sulfur battery capacity is

[41] Overnight costs.

installed in the United States. The largest unit in operation is Rokkasho in Northern Japan, a 34 megawatt unit with 245 megawatt-hours storage capability used for integrating wind power. Advantages of sodium-sulfur batteries include high energy density, high cycle efficiency (89 percent), modularity, siting flexibility, and the ability to deploy in either centralized or distributed configurations. Current units are fairly expensive with capital costs in the $2500 - 3000 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.

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. Higher heating value (HHV) for consistency with fuel pricing.
Availability/Capacity factor: Availability ((1 - forced outage rate)*(1 - 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 financing fees and allowance for funds used during construction. Construction and fixed O&M costs are declining, so 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.
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.
Integration cost: The cost of providing regulation and sub-hourly load-following services for operational integration. These vary over the planning period. Assumed values are provided in Appendix I. Excludes the cost, if any of shaping to load on the hours to days time frame.
Transmission cost: The cost of dedicated long-distance transmission, if any plus within-region wheeling cost.
Project development and Construction periods: Months to develop a project from conception to first major expenditure; months to complete construction of one unit from the first major expenditure (typically the down payment for major equipment order).
Earliest service year: Earliest service for plants constrained by factors other than plant development and construction time (e.g., construction of long-distance transmission).
Developable potential: The estimated total developable potential of energy-limited resources over the 2010 - 2029 period.

Assumptions that are constant across all resources:

Property tax and Insurance: Annual property tax is assumed to be 1.4% of depreciated capital cost. Insurance is assumed to be 0.25% of depreciated capital cost.
Transmission losses: Within-region transmission losses are assumed to be 1.9%.

Table 6-3: Key Planning Assumptions for Reference Power Plants

Reference Plant	Plant Size (MW)	Heat Rate (HHV Btu/kWh)[42]	Capacity Factor	Total Plant Cost [43] ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Integration Cost[44]	Trans Cost ($/kW/yr)	Trans Losses	Proj Dev / Construction (mos)	Earliest Service	Developable Potential (MWa)
Biogas (animal manure)	.85	10,250	75%	$5000	$45	$15	--	$17.15	1.9%	12/12	--	50 - 60
Biogas (landfill)	2.4	10,060	85%	$2350	$26	$19	--	$17.15	1.9%	18/15	--	80
Biogas (WWTP)	.85	10,250	85%	$4000	$32	$24	--	$17.15	1.9%	18/15	--	7 - 14
Biomass (woody residue)	25	15,500	80%	$4000	$180	$3.70	--	$17.15	1.9%	24/24	--	665
Geothermal (binary)	14	28,500	90%	$4800	$175	$4.50	--	$17.15	1.9%	48/36	2010	375[45]
Hydropower (new)	0.5 - 50	--	50%	$3000	$90	Incl in fixed	--	$17.15	1.9%	48/24	--	Uncertain
Solar (CSP) (NV > ID)	750	200[46]	36%	$4700	$60	$1.00	--	$96	4.0%	24/24[47]	--	530/500kV ckt
Solar (CSP) (NV > OR/WA)	750	200[46]	36%	$4700	$60	$1.00	--	$180	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	Yes	$17.15	1.9%	24/24	--	Ltd by integration capability
Solar (Tracking PV) - NV	20	--	30%	$9000	$36	Incl in fixed	Yes	$96	4.0%	24/24[47]	2015	435/500kV ckt
Wind - ID	100	--	30%	$2100	$40	$2.00	Yes	$17.15	1.9%	18/15	2010	215
Wind - MT	100	--	38%	$2100	$40	$2.00	Yes	$17.15	1.9%	18/15	2010	80
Wind - OR/WA	100	--	32%	$2100	$40	$2.00	Yes	$17.15	1.9%	18/15	2010	1410
Wind (AB > OR/WA)	750	--	38%	$2100	$40	$2.00	Yes	$120	3.9%	18/15[47]	2015	570/500kV ckt
Wind (MT > ID)	750	--	38%	$2100	$40	$2.00	Yes	$83	4.2%	18/15[47]	2015	570/500kV ckt
Wind (MT > OR/WA)	750	--	38%	$2100	$40	$2.00	Yes	$188	6.5%	18/15[47]	2015	570/500kV ckt
Wind (WY > ID)	750	--	38%	$2100	$40	$2.00	Yes	$120	4.5%	18/15[47]	2015	570/500kV ckt
Wind (WY > OR/WA)	750	--	38%	$2100	$40	$2.00	Yes	$208	7.0%	18/15[47]	2015	570/500kV ckt
Waste heat recovery	5	38,000	80%	$4000	Incl in var.	$8.00	--	$17.15	1.9%	24/24	--	Uncertain
Combined-cycle	Baseload - 390 Peak incr - 25 Full load - 415	Baseload - 7110 Pk incr - 9500 Full load - 7250	90%[48]	$1160	$14	$1.70	--	$17.15	1.9%	24/30	2012	--
Gas turbine (aero)	90	9370	86%[48]	$1050	$14	$4.00	--	$17.15	1.9%	18/15	--	--
Gas turbine (frame)	85	11960	88%[48]	$610	$4	$1.00	--	$17.15	1.9%	18/15	--	--
Reciprocating engine	96 (12 units)	7940	96%[48]	$1275	$67	$4.80	--	$17.15	1.9%	18/15	--	--
Supercritical (coal)	400	9000	90%[48]	$3500	$60	$2.75	--	$17.15	1.9%	36/48	--	--
IGCC	620	8900	85%[48]	$3600	$45	$6.30	--	$17.15	1.9%	36/48	--	--
Nuclear	1100	10,400	90%[48]	$5500	$90	$1.00	--	$17.15	1.9%	48/72	2023	--

42 Lifecycle average.
43 Expected cost values are shown, see Appendix I for range estimates.
44 Integration cost is a function of time; see Appendix I.
45 Limited to 14 MW/yr through 2014; 28 MW/yr thereafter.
46 Equivalent heat rate for natural gas used to stabilize output.
47 Development and lead time for power plant. Long-distance transmission will require additional lead time.
48 Equivalent annual availability (maximum dispatch).

Chapter 6a: Transmission

SUMMARY OF KEY FINDINGS

For a number of years leading up to the Fifth Power Plan, 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 11.

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.

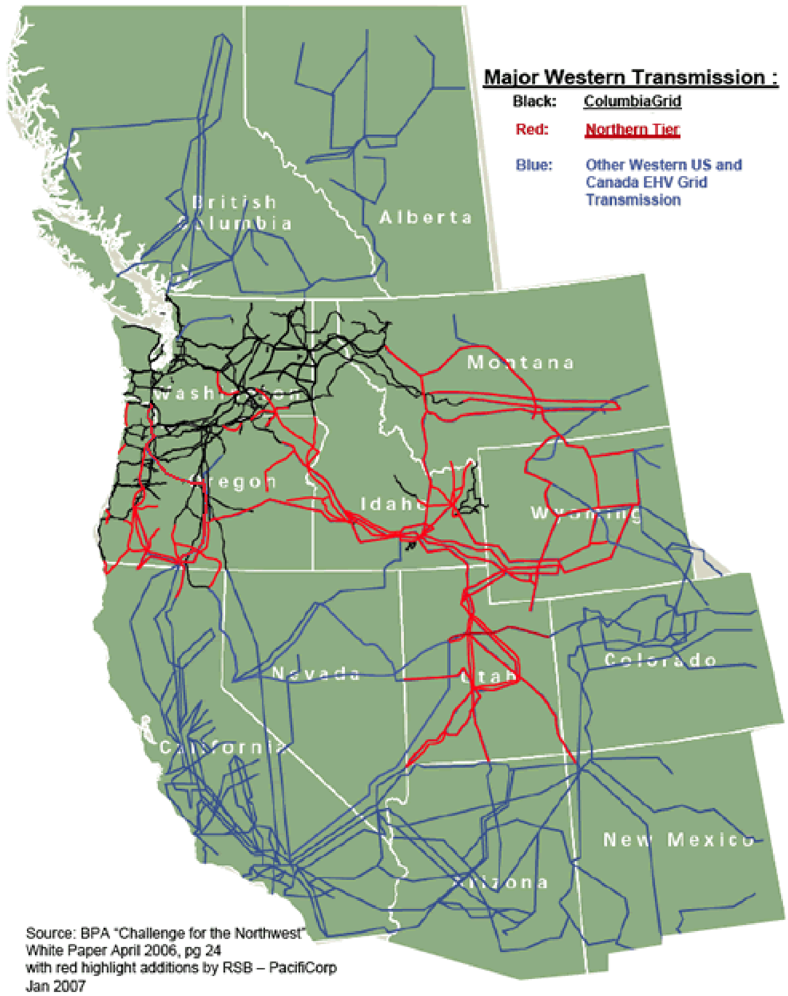
The Federal Energy Regulatory Commission (FERC) is, on a case-by-case basis, reviewing and modifying its financing and study process requirements and Bonneville has taken advantage of this to propose a useful new approach to financing transmission for access to wind resources. Currently proposed legislation 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, the region's utilities are, for the most part, 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, and for individual utilities that may be depending on getting projects sited and built on time, can present challenges 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 6a-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, though 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 further below, ColumbiaGrid and Northern Tier Transmission Group.

Figure 6a-1: Major Western Transmission



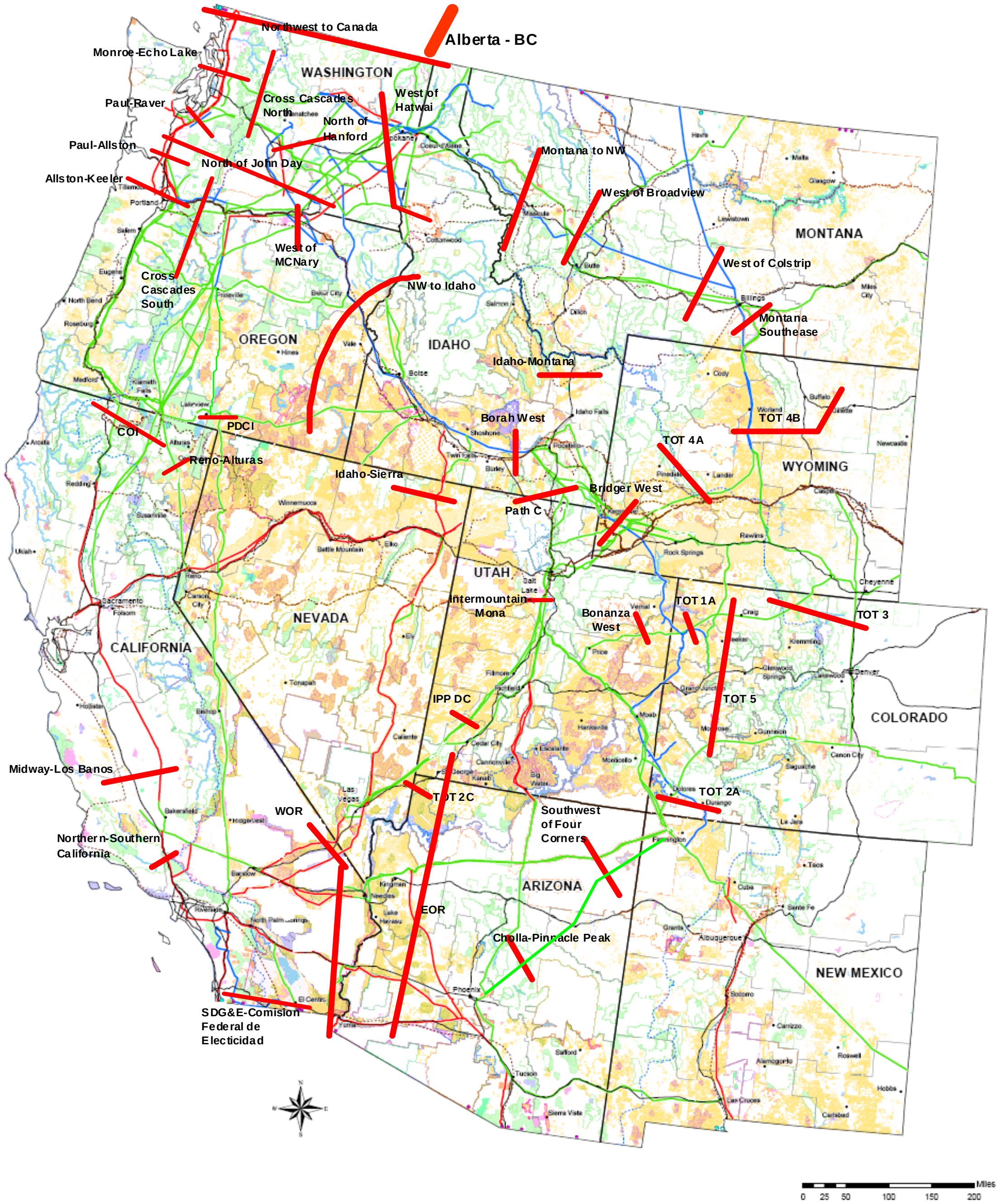
Despite the similarities, the transmission system differs from a highway system in key ways. When the highway system gets overloaded, traffic slows down or stops at one point or another. These conditions can persist for hours until the traffic volume drops down, as for instance, when an extended rush 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 loss of load, like the 2003 Northeastern blackout. Overloads can be created almost instantaneously by sudden generation or transmission outages. The operating limits that require these operator or automatic actions are set by NERC and WECC and are based on extensive computer simulations by system planners of the behavior of the transmission system under many different operating conditions. Margins for reliable operation are built into operating procedures, so that the system does not collapse when there is a sudden outage on the system. The operating procedures 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 6a-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. North of John Day). 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 that 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 so that it is no longer seriously constrained.

Figure 6a-2: Western Constrained Paths



When the loading on an individual path, controlled by individual balancing authorities in coordination with their neighbors (see Chapter 11 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 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 (500 kV transmission lines can cost $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 parties[1], 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 the case of projects designed to access cheaper energy supplies in order to reduce operating costs.

Transmission system improvements range from lower voltage upgrades which may be part of an ongoing system upgrade process at a utility to major high voltage projects which 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 no progress on improving the operation of the transmission system to allow better use of limited existing capacity on the system and there had been little activity in planning for major transmission system expansion.

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 large amounts of variable generation, primarily wind. The operational changes related to wind integration are discussed in Chapter 11.

[1] These 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.

On the transmission planning side, two subregional planning groups, ColumbiaGrid, centered on Bonneville and the Washington IOUs, 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 leading efforts to address the operational changes mentioned above and described further in Chapter 11.

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, 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. In the currently developing 2009 national energy legislation, the Waxman-Markey bill that passed in the House contains provisions for regional transmission planning entities to submit plans to FERC, and gives FERC additional backstop siting authority in the Western Interconnection for projects vetted through and supported by a regional transmission plan.

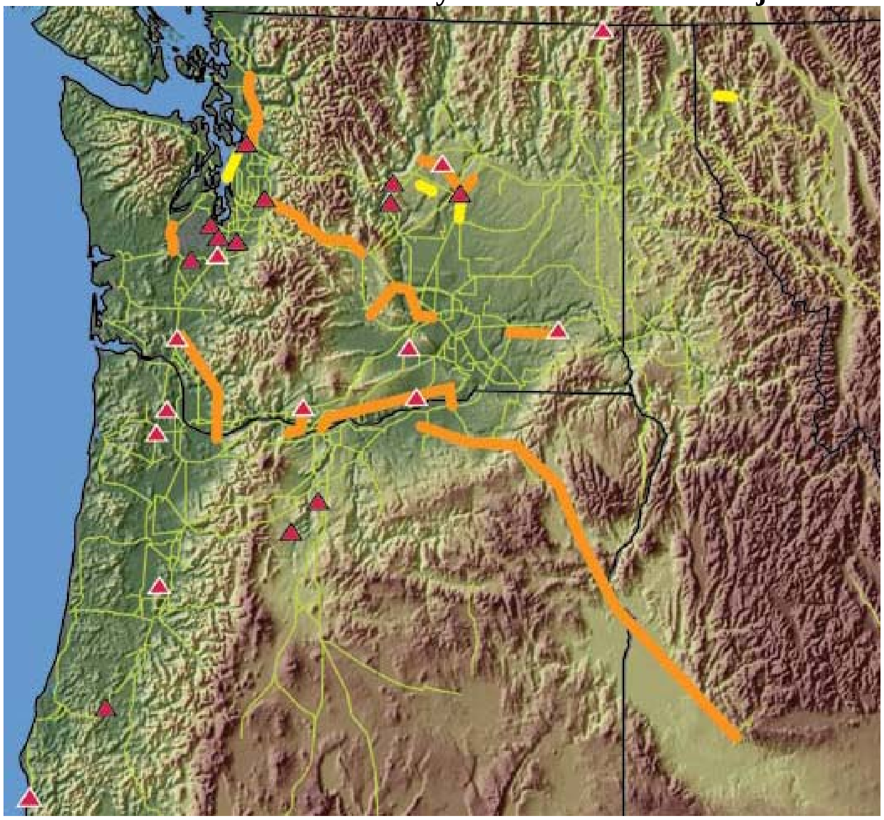
The American Recovery and Reinvestment Act of 2009 (ARRA) has provided DOE with funding for technical support of interconnection-based transmission plans, including support for state and relevant non-governmental organizations to participate, as well as support for state resource planning efforts. WECC, through TEPPC, is working with the Western Governors' Association (WGA) to develop an application for funding, which is expected to be 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, 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 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 ten 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 kV system up to wider-scale issues such as service over the 500 kV West of Cascades paths to loads in the I-5 corridor. 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 6a-3 below. The underlying transmission system shown on the map is 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 6a-3: ColumbiaGrid 2009 System Assessment - Projects Studied



Source: ColumbiaGrid

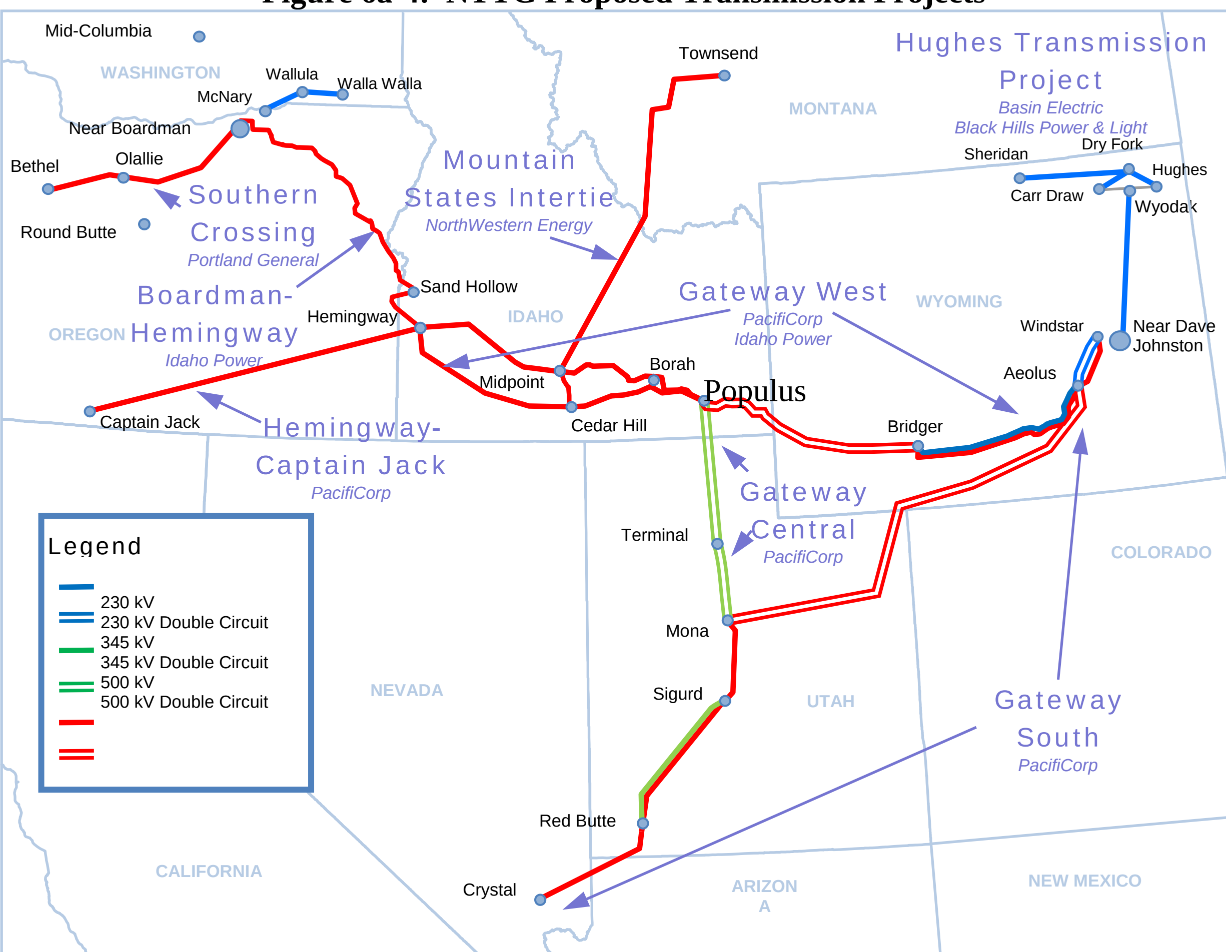
Bonneville, which is a member of ColumbiaGrid, has developed an innovative approach to financing transmission development for dispersed generation projects like wind farms. The first use of this network open season approach was in 2008 and a second open season is being conducted in 2009. The Bonneville approach, approved by FERC, provides for cluster studies of the best approach to serving a number of projects in the transmission service request queue, an offer of service at embedded cost rates with Bonneville providing the financing (to be repaid through wheeling rates when service commences) and reordering of the queue positions for those generation projects 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 was also aided in the ability to finance these projects by the availability of stimulus funding.

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 has recently 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. Recently, FERC held 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.

NTTG, 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 member have proposed a set of primarily 345 kV and 500 kV 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 6a-4 below.

Figure 6a-4: NTTG Proposed Transmission Projects

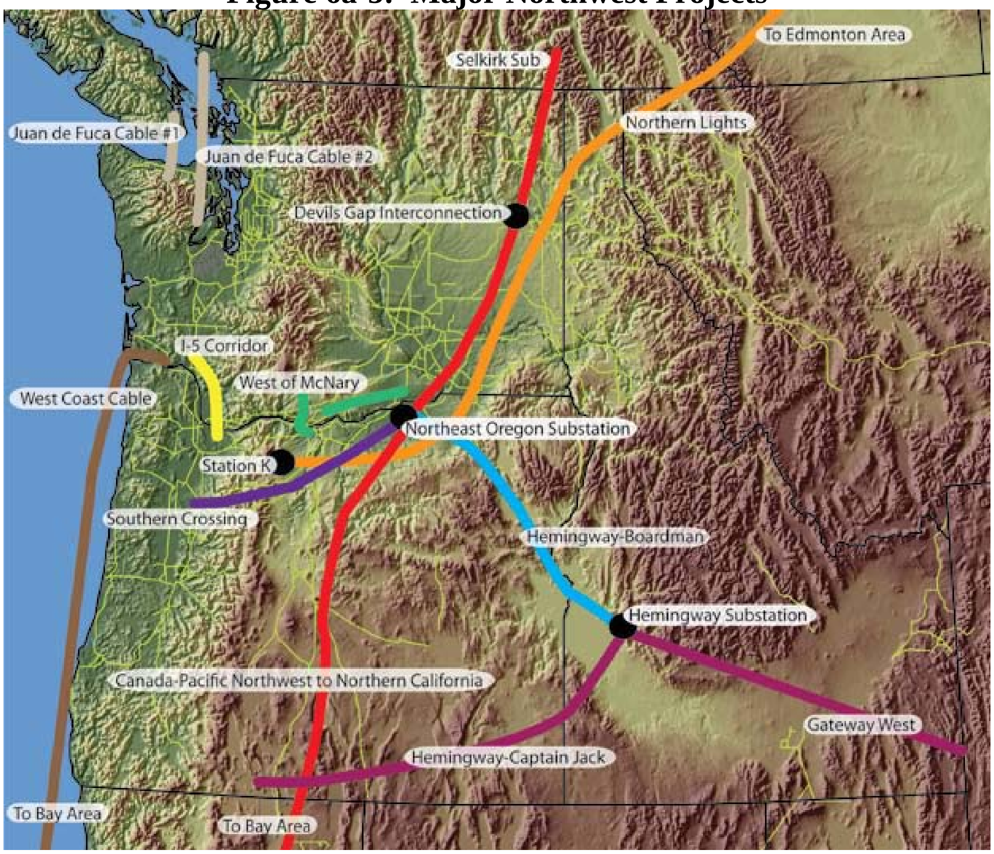


Source: NTTG

ColumbiaGrid, NTTG and the Northwest Power Pool are also jointly sponsoring a project review process to examine potential interactions among various major project proposals that connect with or pass though 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 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 6a-4 and Figure 6a-5.

Figure 6a-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 are still facing 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 furthest along in development, like Bonneville's West of McNary project, have not yet surmounted all the possible problems that may face them 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, such as 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 new renewable resources in to meet regional loads.

Chapter 7: Direct Use of Natural Gas

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 plan. While the specific issues have changed somewhat over time, three central questions have remained:

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 has been raised: 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 Analysis

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). Page 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 heat share in existing homes increased from 26 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 has also 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 Study. Portland, OR March 27, 2007. Prepared by RLW Analytics.

[4] Northwest Energy Efficiency Alliance, MultiFamily Residential New Construction Characteristics and Practices Study. Portland, OR June 14, 2007. Prepared by RLW Analytics.

Analysis of the Direct Use of Natural Gas for the Sixth 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 aMW. 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 analyses 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's results are not yet available, it is possible to forecast potential implications for the Council's final plan. 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, then the Council may decide to include specific recommendations in the final plan to address this market failure, 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 applications and both new construction and existing buildings for multi-family applications. 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 eletricity loads with conservation and traditional generating resources (including those fired by natural gas) with 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 their existing equipment fails and needs to be replaced. This analysis assumes that customers install new equipment only when their 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 consumer 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 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.

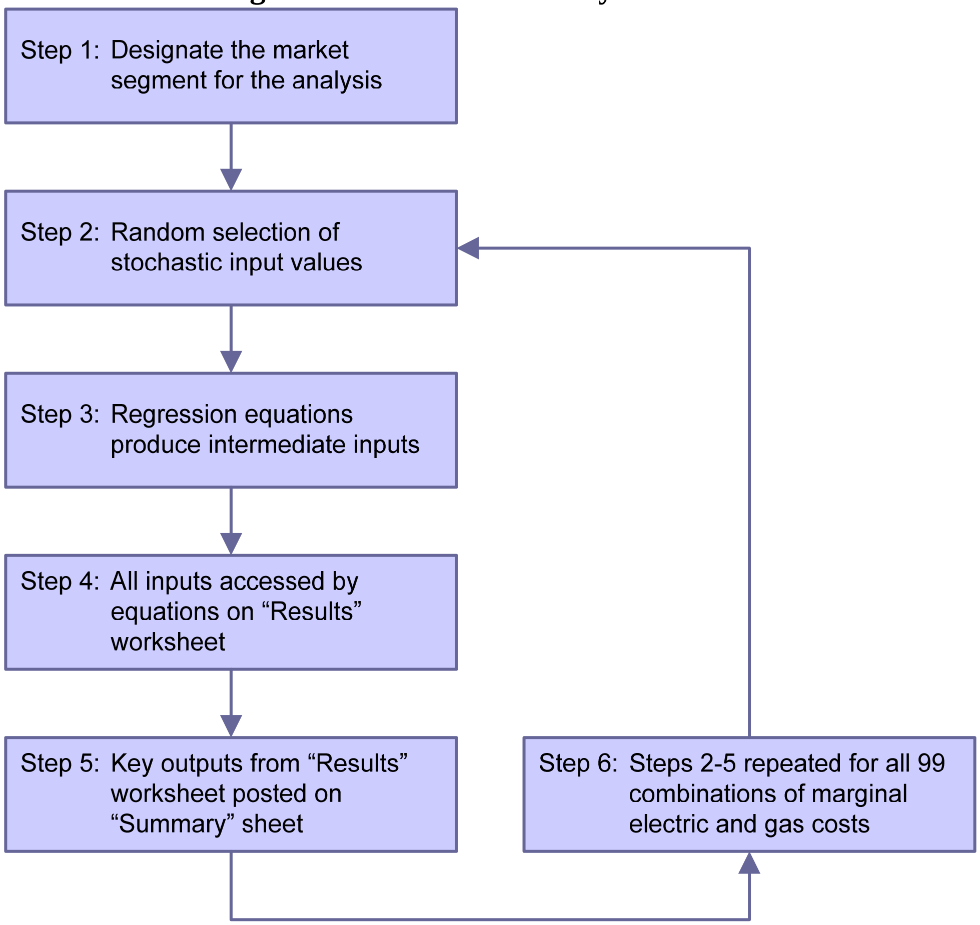
In this study each market segment consists of just one type of equipment for replacement of the failed existing equipment. Therefore, one market segment would include a gas FAF and a gas tank water heater as the retrofit equipment options for the electric FAF system and the electric resistance water 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 resultant 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 cost faced by consumers, a "Monte Carlo" model was developed similar to that used in the 1994 Council analysis. The flowchart in Figure 7-1 illustrates the "Monte Carlo" process being used in this economic analysis. It begins by designating one of the 84 market segments for the analysis. The model uses the 84 inputs, 51 of which are stochastic, meaning they are randomly selected. In the second step, the values for the 51 stochastic inputs are selected. Four of the inputs are established by regression equations in Step 3. The inputs for the regression equations are among the stochastic inputs. In Step 4, the 51 stochastic inputs, the four regression inputs, 24 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 5. Steps 2 through 5 are repeated at this point, because the model performs all the necessary calculations 1,000 times for each of the 88 market segments and for each of the 99 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 appear in Appendix O.

Figure 7-1: 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 feed into the Regional Portfolio Model (RPM). The RPM will then be used to test the economics of each technology choice over 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.

Results of the analysis will be added in the final Sixth Power Plan as well as any policy changes and action items related to the findings.

Chapter 8: Developing a Resource Strategy

INTRODUCTION

This chapter describes the Council's treatment of risk in its planning analysis. In particular it describes studies 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 recognized uncertainty. Its Fifth Power Plan, however, was the first of its 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 basic financial assumptions that are used throughout the planning analysis are described. These include rates of inflation, the cost of capital for various entities, equity to debt ratios, and discount rates. This chapter also includes a description of the way transmission is accounted for in the plan's analysis.

The chapter concludes with a discussion about effects that are not captured in the model.

DEVELOPING A RESOURCE STRATEGY

Risk assessment has been central to Council planning since the first 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 power rates 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 plan. Those portfolios 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 has also 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. Studies captured the costs associated with portfolios that adapted to changing circumstances and alternative scenarios. Moreover, the model permitted the Council to examine thousands of portfolios at a time. The studies 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.

This Sixth Plan builds on the lessons and techniques of the Fifth Plan. Council studies now incorporate uncertainty about power plant construction costs and availability. Studies track carbon production using several new techniques, and the impact of carbon penalties move to center stage. The representation of conservation and demand response continues to evolve.

The treatment of uncertainty and management of risk require suitable study concepts and techniques. 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, economic, 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 expected costs of any given portfolio, however, hide a wide distribution of potential outcomes. Changes in markets and legislative policy will cause the cost of a portfolio to vary significantly depending on the circumstances encountered.

The Council's Resource Portfolio Model (RPM) evaluates possible portfolios over 750 different possible future sets of conditions to assess how each portfolio is affected by changing conditions.

The average of the outcomes, that is, the average of NPV system costs, gives us an idea of the most likely cost outcome. Most futures will cluster around this value. Comparing average NPV system costs gives us an indication of which portfolio is most likely to achieve the Act's goal of an economically efficient system.

If the "best" portfolio is one that is economically efficient and has low NPV, what would a "bad" portfolio be? A portfolio would certainly be bad if it failed to meet the other requirements of the Act, adequacy and reliability. Consequently, the Council screens out such portfolios. 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 would be considered "bad" if it had a high NPV. This is the principal reason for the Council's risk measure.

The risk measure is the average of the highest 10 percent NPV cost outcomes across the 750 futures. We cannot know in advance what the future will bring. We cannot know whether we may find ourselves in a future that would result in a high NPV. Consequently, we endeavor to find portfolios that minimize exposure to the worst futures and outcomes envisioned.

Using these definitions of cost and risk, therefore, maximizes the chance of identifying portfolios that achieve the Act's original objectives. Such a resource portfolio is likely to be lowest-cost. It recognizes, however, that our ability to forecast is extremely poor. Consequently, it must not perform too badly even if our assumptions are wrong or the region finds itself in the worst circumstances.

Portfolio Selection

To understand the Council's approach requires a little background. Some familiarity with the meaning of several terms, as the Council uses them, is helpful.

A ***future*** is a specific combination of values for uncertain variables, specified hourly over the study 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 twenty years, combined with hourly electricity prices for twenty years, combined with hourly (or daily) natural gas prices for twenty years, and so forth. The number of sources of uncertainty considered in Council studies would render the enumeration here unwieldy, but the next section describes them generally.

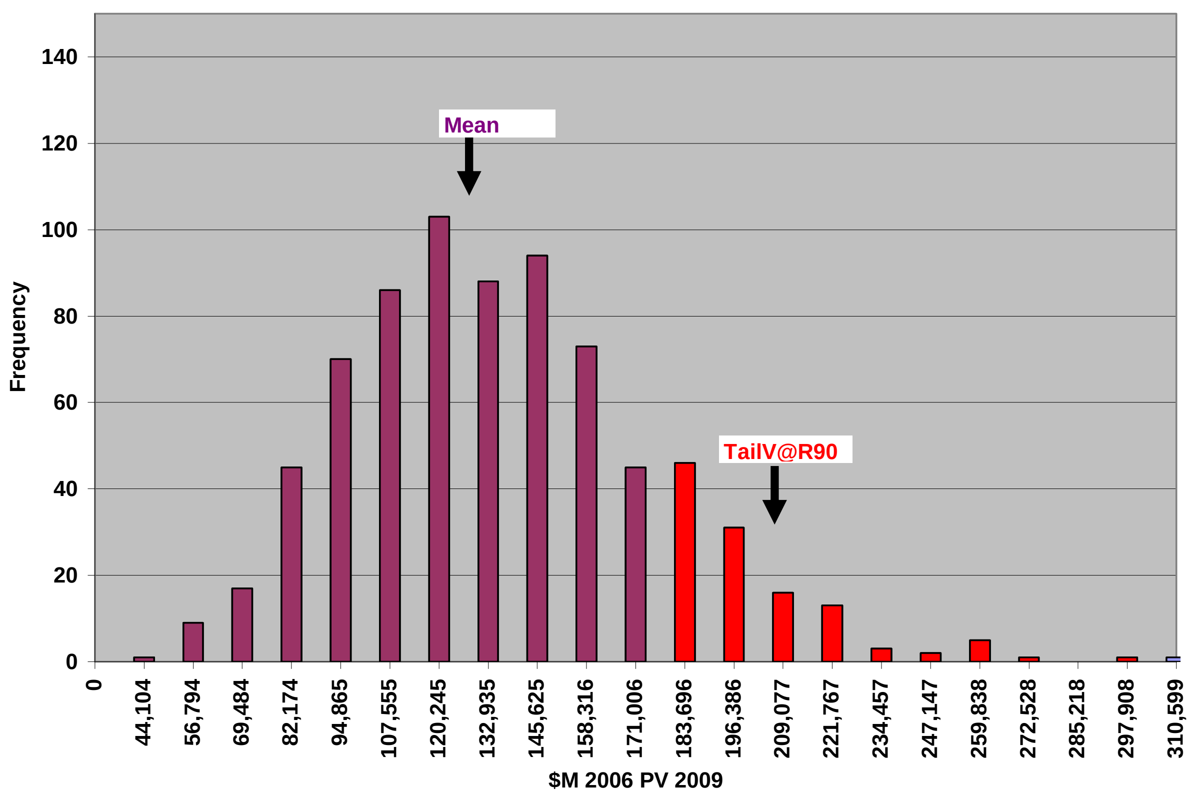
Given a particular future, the primary measure of a portfolio is its net present value total system cost. These costs include all variable costs, such as those for fuel, variable operation and maintenance (O&M), long- and short-term purchases. These costs also include the fixed costs associated with new plants and investment and with operations and maintenance. The present value calculation discounts future costs to constant 2006 dollars. Discounting and other financial assumptions are discussed in Appendix N: Financial Assumptions and Discount Rate.

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. They typically include some historically unprecedented paths for prices, loads, and other variables. A small number may have unlikely but not impossible future behavior.

The Council's treatment of uncertainty reflects the potential for a larger pool of contributing factors than history provides.   The model uses larger variation and weaker relationship among sources of uncertainty to achieve this effect. In this manner, studies provide for the possibility 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 8-1 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 8-1: Example of a Portfolio Cost Distribution



Source: "Costs Illustrated.xls", worksheet "distribution"

Because a simulation typically uses 750 futures, the resulting distributions can be complicated. Representative statistics make manageable the task of capturing the nature of a complex distribution.

The *expected* net present value total system cost captures the central tendency of the distribution. As mentioned earlier, this gives us an idea of the most likely cost outcome. Comparing average NPV system costs gives us an indication of which portfolio is most likely to be least cost.

The ***measure of risk*** that the Council adopted is TailVaR_{90}. Briefly, TailVaR_{90} 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. They capture the magnitude and likelihood of bad outcomes, rather than the predictability of or range of distribution for an outcome. As mentioned above, use of TailVaR_{90} is also consistent with the spirit of the Act.

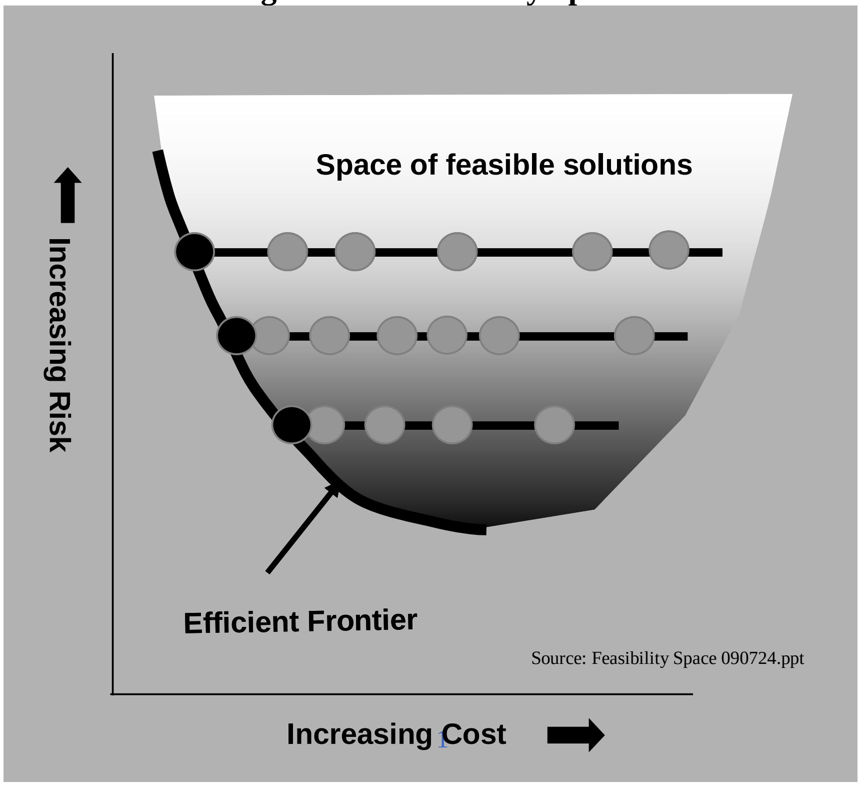
Using these two statistics, Council studies associate the cost and risk of a portfolio with a point on a graph. The horizontal axis measures the portfolio's cost and the vertical axis measures the portfolio's risk. This way, a large number of portfolios, or resource strategies, can be compared on these two measures. A typical study evaluates 2,000 to 5,000 possible portfolios. The set of all portfolios is a ***feasibility space***, an example of which appears in Figure 8-2.

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. A portfolio that does *not* lie on the efficient frontier is "inefficient" in the following sense. For any "inefficient" portfolio, there is another portfolio that is "better", because it has both lower risk ***and*** cost. This construct enables the Council to identify preferred portfolios and policies to meet its risk requirements.

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.

[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.

Figure 8-2: 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 least 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, however, often expresses itself over short periods of time. Viewed from the perspective of lifetime income, the loss of a home to fire or the cost of a serious accident may not appear so significant. This is especially so when that loss is compared to the cost of a lifetime of insurance premiums. Insurance, however, often makes it possible to weather brief but severe events. Bankruptcy is another example. It is often due to short term cash flow disruption, not lifetime wealth or even the availability of assets.

By the same token, the NPV study cost is a rather coarse sieve for evaluating portfolios that reduce risk. As we move to examine portfolios along the efficient frontier, therefore, it is appropriate to refine our study.

Before discussing the risk mitigation value of portfolios, however, we need to introduce the Council's notion of a ***portfolio***. We will see this definition is tied directly to concerns about and aspects of risk.

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 to start.

The second element of the portfolio consists of policies for conservation and demand response (DR). Policies include premiums that should be paid over market price for conservation acquisitions. Instead of the detailed optioning described above, the model specifies levels of demand response deployed in a portfolio through a limited number of prescribed schedules.

The option schedules, conservation premiums, and DR deployment for portfolios that lie on the efficient frontier are determined through a computerized search process. The model tries random portfolios but is capable of learning from the results for prior portfolios. By trying modifications of more successful portfolios, it attempts to minimize the cost of the power system at different levels of risk.

The reason for including such a resource portfolio construction rule lies with the nature of risk associated with constructing generating resources. 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 a resource that is not needed, and having insufficient resources, can cost the region. The Council's model reflects the reality that decision makers can never be sure of how the future will work out.

The opportunity to construct a resource is prescribed by a given portfolio. Given such an opportunity, the model makes a decision whether to proceed with construction. This decision is based on what the model thinks about the future value of and need for that resource. This decision is based on what prices and requirements have been in the future up to that point. In particular, it makes its decision without knowledge of what will happen subsequent to that decision.

The conservation acquired and the generating resources constructed in a given portfolio will be different in each of the 750 futures. The actual construction of generating resources and the acquisition of conservation in a study future will therefore depend on how the particular future unfolds. Candidate portfolios are tested against 750 possible futures.

Moreover, constructing the plant does not guarantee it will perform well economically. Just as in life, circumstances change without notice. The model, however, keeps track of the consequences of the portfolios it tests, and the outcomes inform the selection of better portfolios.

The resulting resource portfolio is one that addresses the risks inherent in the future, not one that is minimum cost for one specific future.   Portfolio resources will not cover their costs exactly in model simulations. Some will do very well in certain futures and poorly in others. Resources do not even cover their costs in an "average" sense across futures. For example, what determines whether they fall on the efficient frontier at the least-risk end is how they perform in the worst futures.

A traditional resource plan cannot address such scenario risks. Alternative scenarios can be tested in a traditional sense. This gives the planner an idea of how the ideal plan might change if the future turns out different. It will not, however, tell the planner how to prepare when he doesn't know 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 were stacked up against growing loads so that new resources were scheduled at a particular date to meet requirements. Uncertainty about requirements was considered by looking at different levels of load growth. Uncertainty about hydro conditions was addressed by planning for only critical water conditions. These plans did not consider uncertainty about the cost of resources, the price of market power, or 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. From a traditional load-resource balance perspective, the option schedule might suggest the region would be overbuilt.

Interpreting Portfolio Costs

Future costs of the power system in the Council's RPM are expressed in traditional planning terms. They are the net present value of future power system costs that can 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 cost and are not affected by future resource choices.

An important distinction exists between the NPV system costs shown in illustrations of the feasibility space and the ***optioning cost*** of a particular portfolio. The NPV 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 may also include some above-market cost for conservation, depending on one's view. These are decisions within the scope of what decision makers control.

It is a common misinterpretation of the efficient frontier that the region is paying the change in portfolio cost to achieve the change in portfolio benefit represented by the frontier. The costs, however, represent distinct attributes of ***outcomes***. The decision maker cannot pay the difference in cost, because he or she does not get to choose the final cost. They can pay the optioning costs of the resources, but these typically are a fraction of a percent of the average costs illustrated on the efficient frontier. The benefits of optioning resources can, on the other hand, be much larger than the scale of the efficient frontier. Again, the efficient frontier is only a screen for portfolios.

The model reports and uses NPV costs that have a special "perpetuity" adjustment. This adjustment accounts for the long-term effect of any carbon penalty, as the following paragraphs explain.

As described in Appendix L of the Fifth Power Plan, the RPM uses real-levelized costs for power plant capital costs. Briefly, this spreads the construction costs of the plant evenly over its life. Spreading the cost in this manner "matches" the cost of construction with whatever benefits or value the plant produces. Because of this, certain "end effects" are neutralized. It is typical to assume that the economics of the plant beyond the study horizon are represented by the economics of operation within the study.

This all works just fine unless we have good reason to believe that the economics during the study cannot represent operation beyond the study horizon. If a plant is profitable during the study, we have no basis for assuming it would not be after the study horizon. If a plant is more profitable than an alternative during the study period, we expect it would be after the horizon.

Such is not the case, unfortunately, with a carbon penalty. Consider a carbon penalty imposed during the last two years of a study. A plant placed into service five years before the end of the study carries the penalty for 2/5 of its life during the study. If the plant has a 20-year life, however, the penalty will apply for the remaining 15 years of its life, or 18/20 of its lifetime.

The model addresses this problem by extending all the costs in the study after that point in time when a carbon penalty appears. The model extends these costs, subsequent to any carbon penalty, in perpetuity. Portfolios can then be compared to determine the least cost and risk portfolios, but the resulting cost measures are difficult to describe in more familiar terms of revenue requirements or rates.

Even though the costs beyond the planning horizon are discounted and carry decreasing weight over time, they still increase the measure of cost significantly. For example, one study showed that the perpetuity factor increased NPV study costs from $38.5 B to $105.5 B, a difference of 175 percent.[2]

The Council does translate the portfolio cost into rate effects in order to make the results more meaningful to consumers and others. There are several steps necessary to convert the annual operating costs and construction costs for new generation into rates. First, the fixed costs of the existing power system (generating resources, transmission, and distribution) need to be added because these are still being recovered in rates. Second, portions of cost included in the planning power system costs that aren't recovered through consumer rates need to be subtracted. This is primarily the portion of conservation cost that is not paid by utilities. Third, the Act's credit for conservation, which is not present in the model's costs, is added back. These adjusted costs are divided by electricity sales, net of conservation, to get an estimate of electricity rates.

It should be noted that the model uses real levelized costs to represent costs for new generation and conservation. To the extent that utilities expense conservation, however, these costs will differ from actual costs. Moreover, if utilities depreciate assets or pass along plant construction expense non-uniformly over the life of the plant, these costs will differ. This is often the case for tax expense, for example. If costs are recovered from ratepayers non-uniformly for any reason, these costs will differ. Nevertheless, the rates presented here should be indicative.

[2] L811n future 742 versus L811 future 1987.

Interpreting Carbon Emissions and Costs

A new measure of power system performance is the emissions of carbon dioxide. 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.

Measurement of regional carbon emissions is more difficult than one might think because of electricity trade among regions. 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, is power exported from the Northwest hydroelectricity with no carbon emissions, or is it coal-fired generation with large carbon emissions?

Because the accounting treatment is not settled, the RPM 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 carbon loading, 1,053 pounds of CO_2 per megawatt hour. This corresponds to a natural gas-fired combustion turbine with a heat rate of 9,000 BTU per kilowatt hour. Regional generation averages a somewhat lower loading factor; surrounding areas average a somewhat higher loading factor during periods when the Pacific Northwest in importing. This loading factor does not reflect the fact that alternative carbon control regimes may shift the effective carbon loading. This assumption does have the advantage, however, of being simple and easy to understand. Moreover, it closely resembles the assumed carbon loading adopted by Washington State Department of Commerce[3] and the California Energy Commission.

Low Risk Portfolios

The feasibility space and efficient frontier are really a means to filter down the number of portfolios to a handful for more careful study. The Council looks beyond expected NPV cost and risk to distinguish 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. The imposition of a high carbon penalty can lead to high cost futures if the region has become over reliant on coal. The Regional

[3] See final opinion on California Energy Commission Rulemaking 06-04-009, issued September 12, 2008, which calls for a default value of 1100 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.

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 the 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 model evaluates each portfolio against about 750 future conditions; combinations of uncertain carbon costs, demand growth, electricity and fuel prices, hydroelectric conditions, and other variables. It is informative, however, to see which futures result in bad outcomes for the least-cost and least-risk portfolios. This isolates principal sources of uncertainty and may suggest alternative risk mitigation mechanisms.

Risk mitigation does not affect all futures equally. Low cost futures become more expensive; high cost futures become less expensive. 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.

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.[4]

In general, portfolios near the lower risk end of the frontier contain more resources and rely less on the wholesale power market. By reducing price volatility and building more resources these low-risk portfolios are more consistent with regulatory preferences and utility planning criteria than the lower cost but higher risk portfolios.

SOURCES OF UNCERTAINTY

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.

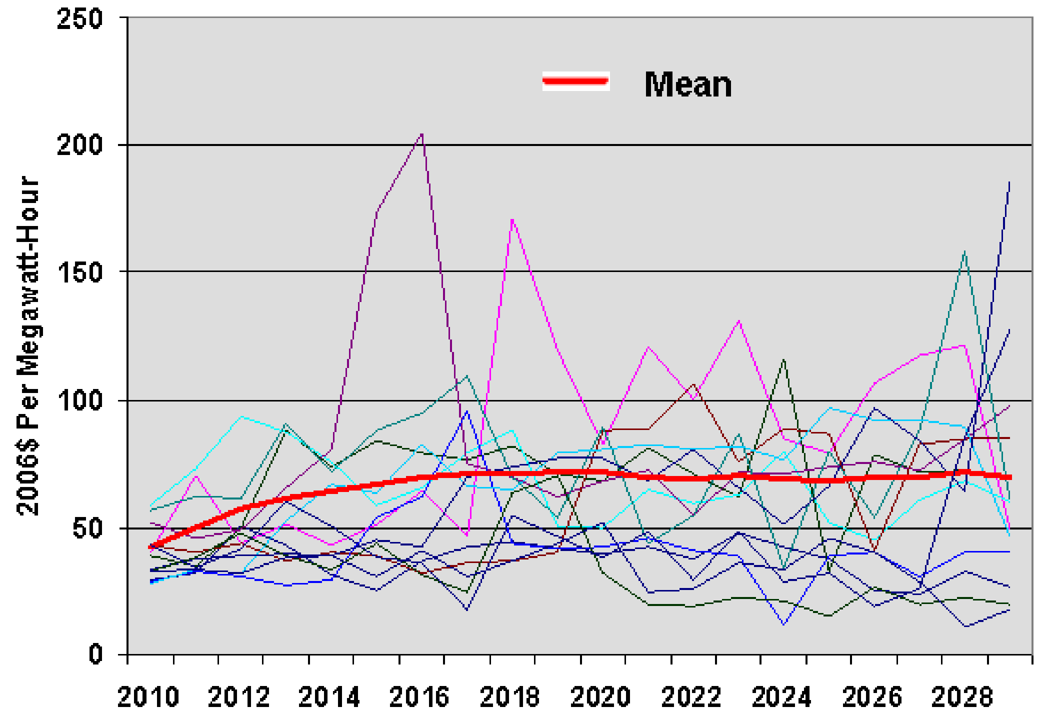
Whether a utility has surplus generation or needs to purchase power affects the magnitude and direction of change in costs to electricity consumers when wholesale power prices rise. That is, if electricity market prices go up, consumers' costs can go up if the utility needs power. If the utility has surplus power to sell into the market, however, and electricity market prices go up, electricity costs will come down. This illustrates that uncertainty in wholesale power prices, like other uncertainties, does not necessarily lead to risk. Risk resides with a utility's overall portfolio of requirements and resources, rather than with one resource, one requirement, or one kind of fuel.

[4] Northwest Power and Conservation Council. The Fifth Northwest Electric Power and Conservation Plan. Volume 2, Chapter 7.

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 Council studies.

Figure 8-3 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.

Figure 8-3: Electricity Price Future



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. In a section below, this chapter elaborates on the uncertainty associated with new technologies.

Figure 8-4: Load Futures

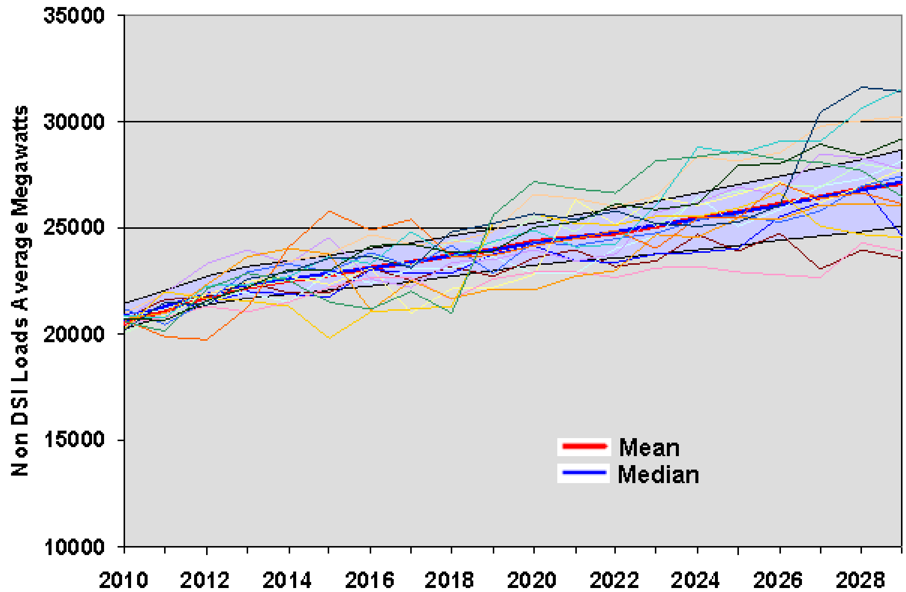
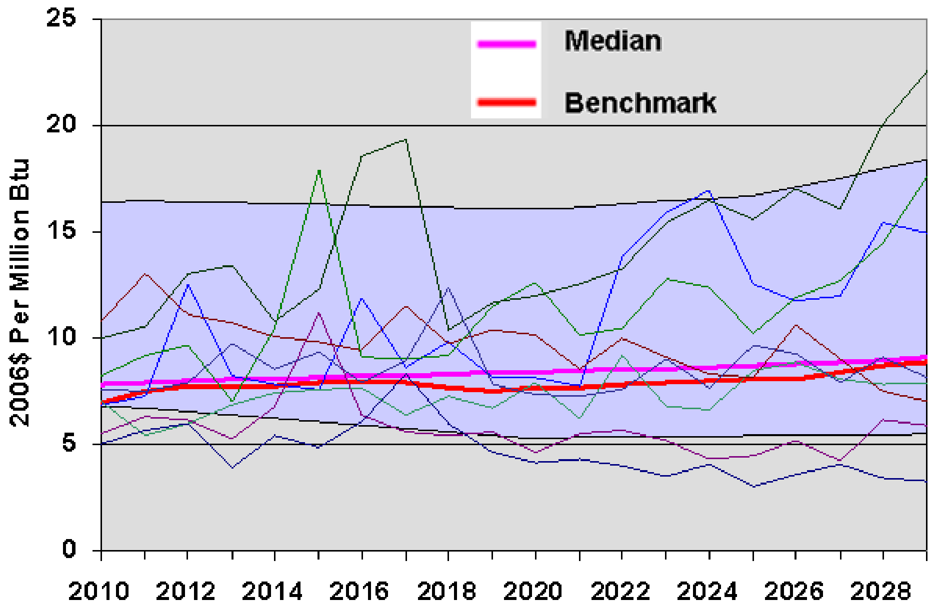


Figure 8-4 displays a sample of load futures from the Council's model simulations compared to the shaded trend forecast range. Detailed description of the Council's official load forecast appears in Chapter 3.

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 8-5 illustrates some natural gas price futures from the portfolio model simulations (2006$).

Figure 8-5: Gas Price Futures



Hydro Generation

A 70-year history of streamflows and generation provide the basis for hydro generation in the model. The hydro generation reflects constraints associated with the NOAA Fisheries 2008 biological opinion. Moreover, studies evaluate resource choices assuming no emergency reliance on the hydro system, even though such reliance might not violate 2008 biological opinion constraints.

In addition to meeting fish and wildlife requirements, hydro operation must satisfy other objectives. These objectives include standard flood control, river navigation, irrigation, recreational, and refill requirements. All studies incorporate these constraints.

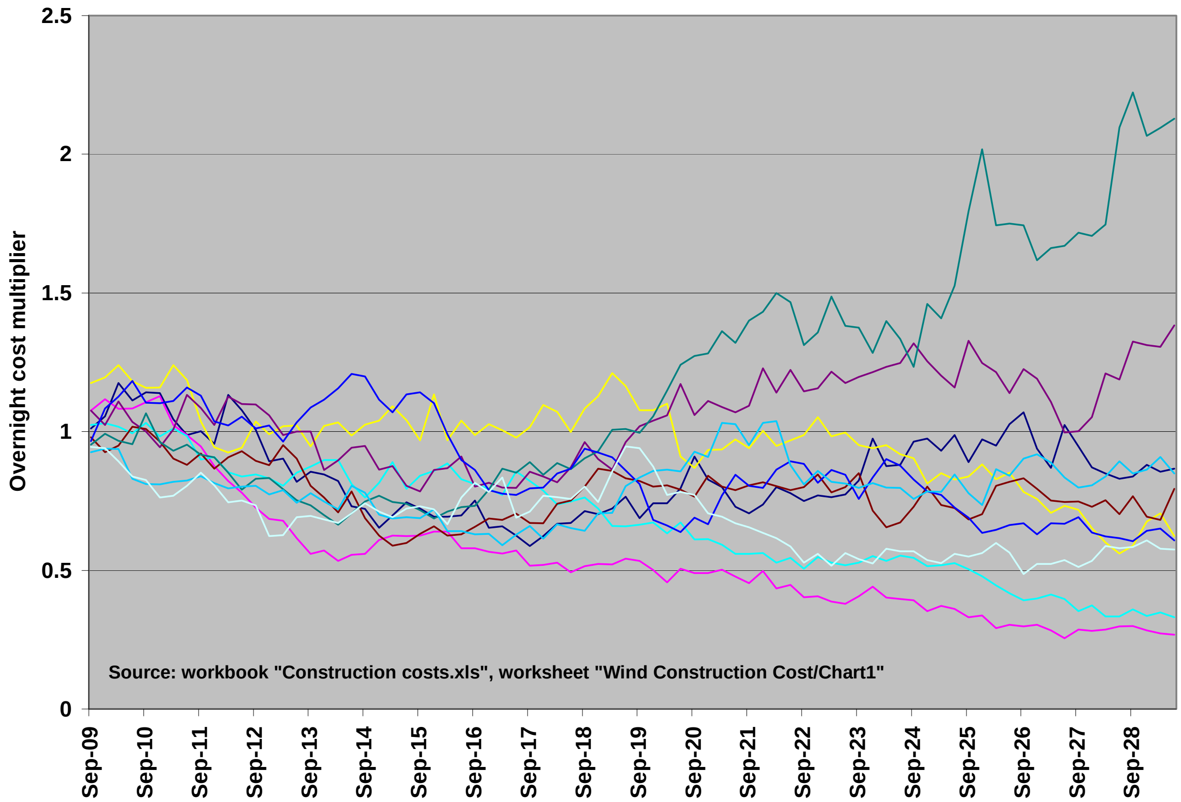
The modeling assumes no decline of output over the 20-year study period due to relicensing losses or other factors that might lead to capability reduction. Nor does it assume any increases due to deployment of removable spillway weirs or turbine upgrades. Chapter 9 does feature, however, a study of the potential effects of possibly 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 of this plan. 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.

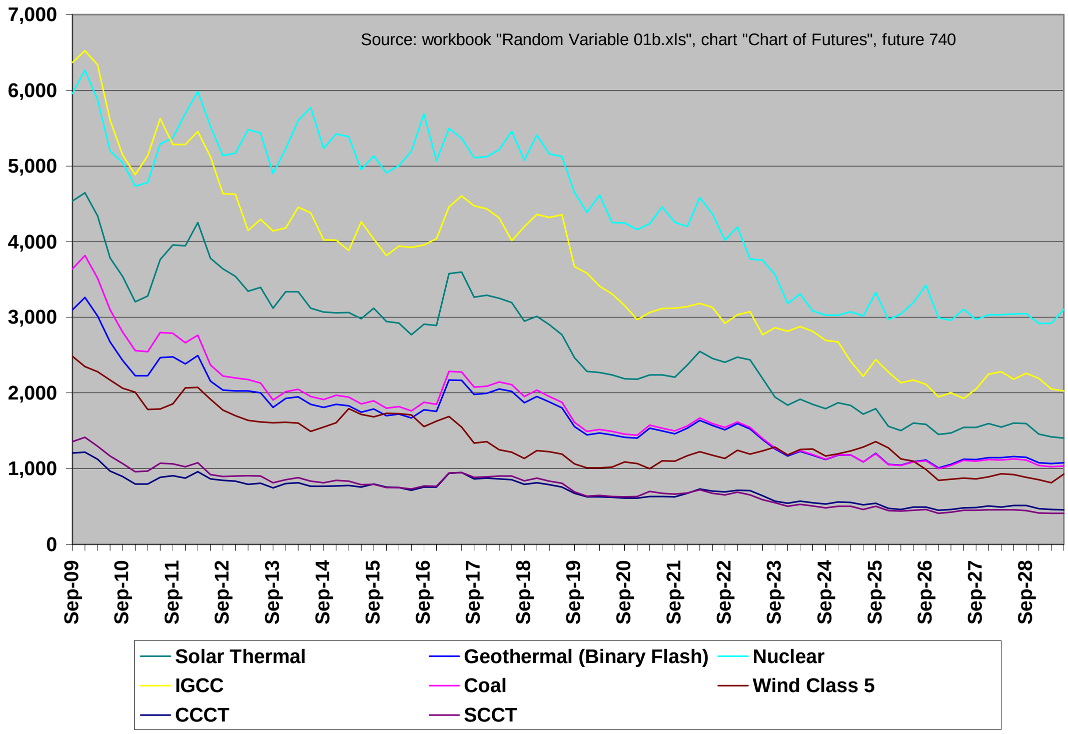
Figure 8-6: Construction Cost Futures for Wind Generation



Several cost futures for wind generation resources appear in Figure 8-6. 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 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 8-6 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.

An example of a ***single*** construction cost future for several generation technologies appears in Figure 8-7. 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 Figure 8-7.

Figure 8-7: 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 enacted at the federal, West-wide, or state level.

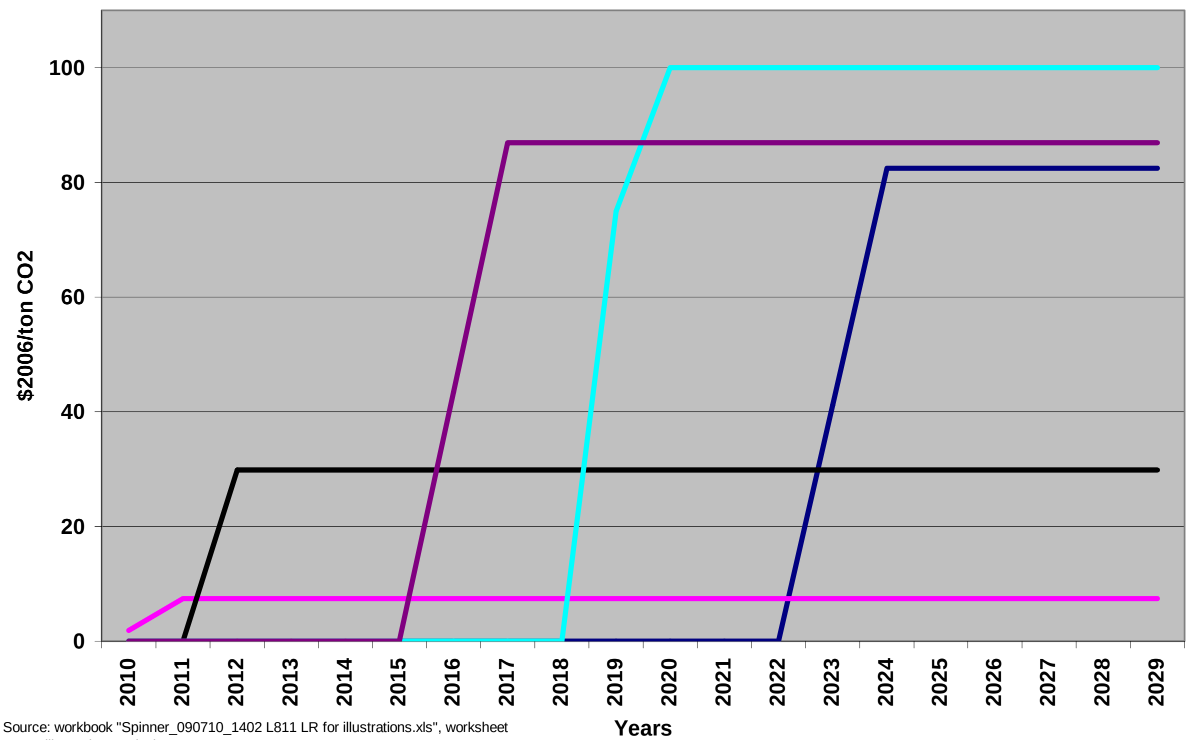
It is unlikely that reduction in carbon dioxide production can be achieved without cost. Consequently, future climate control policy can be viewed as a cost risk to the power system of uncertain magnitude and timing. A cap and trade allowance system appears to have been a successful approach to SO2 control and may be used again for CO_2 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 studies use a fuel carbon content tax as a proxy for the cost of CO_2 control, whatever the means of implementation. When considered as an uncertainty, studies represent carbon control policy as a penalty (dollars per ton CO_2) 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 (See Figure 8-8.) The progression of carbon penalty over time is unlikely to resemble any of these futures. Nevertheless, we believe using a large number of futures should give us a fair idea of the risk associated with most paths.

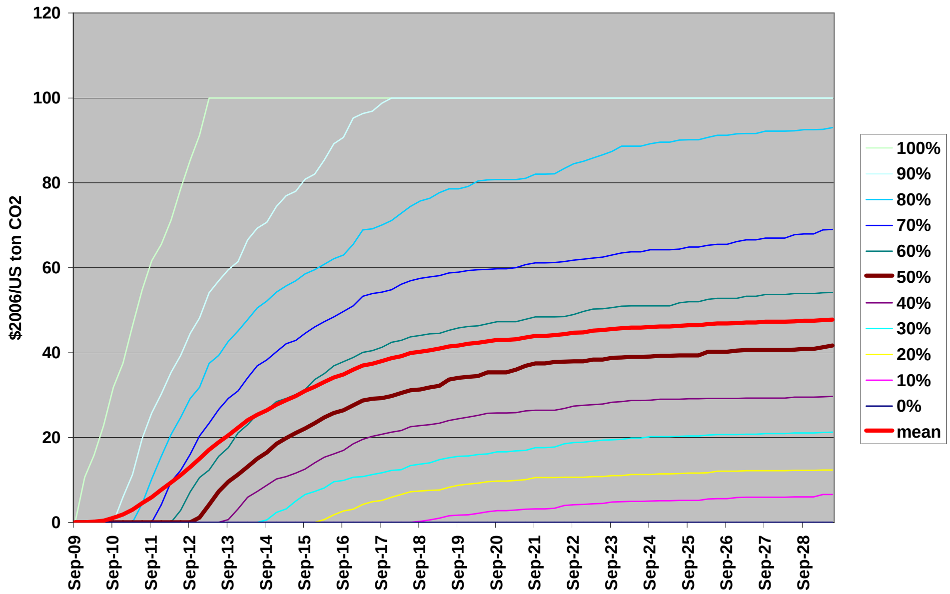
Figure 8-8: CO_2 Penalty Futures



Source: workbook "Spinner_090710_1402 L811 LR for illustrations.xls", worksheet "CO2_illustration" and Chart1

In the Council's studies, a carbon penalty can arise at any time. The probability of such a penalty being enacted at some time during the forecast period is ninety-five percent. If a penalty is enacted, its value is selected from a uniform distribution between zero and $100 per ton (2006$). The resulting probability of finding a carbon penalty at or below various levels in each period appears in Figure 8-9. 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 CO_2 by the quarter June – August 2029. As discussed in Chapter 10, the distribution corresponds to the range of outcomes that EcoSecurities, Ltd., provided the Council.

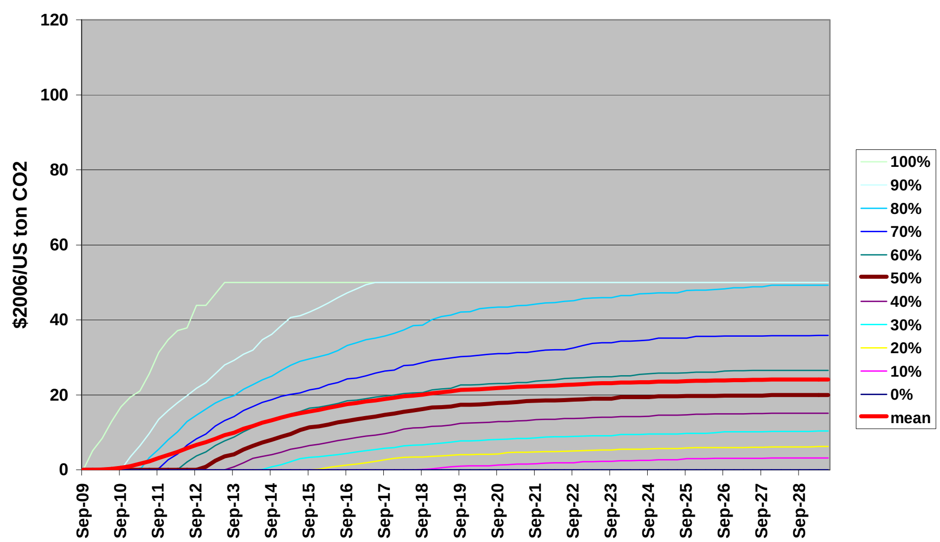
Figure 8-9: Deciles for Carbon Penalty



Source: workbook "New CO2 Distribution 090425.xls", chart "Carbon Distribution"

An alternative carbon penalty distribution, with a cap of $50 per ton instead of $100 per ton, appears in Figure 8-10. The average of this distribution rises to about half that of the first distribution, $24.12 per ton. Chapter 9 will show that the alternative carbon penalty distribution results in substantially the same plan for the first decade of the study as does the first distribution.

Figure 8-10: Study of a $50/ton Cap on Carbon Penalty



Source: "CO2_Penalty.xls", and module mod_Deciles of "L811q auditor.mdb"

There are mechanisms in addition to carbon penalties and trading programs to meet carbon emission objectives. Studies considered displacement of existing resources with new renewables or more efficient gas-fired plants. The Council also evaluated direct curtailment and retirement of existing units. Results of these analyses appear in the last section of Chapter 9.

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.

Aluminum Smelter Load Uncertainty

Aluminum smelters in the Pacific Northwest have represented a substantial portion of regional loads in the past. Today, there are only three smelters in partial operation and the associated uncertainty in energy requirements is smaller. The Council has nevertheless retained smelter load uncertainty in its studies.

The difference between the price of aluminum and the price of a key ingredient, electric power, drive smelter activity. Council studies examine 750 futures for aluminum price and electricity price. It also considers the likelihood of permanent aluminum plant closure if a plant is out of operation for an extended period.

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 cost of qualifying resources become competitive. Moreover, federal budget constraints may eventually force reduction or termination of the incentives.

In the model, two events influence PTC value over the 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 PTC remaining indefinitely or expiring immediately. The second event that modifies the PTC in the Council's model is the advent of a carbon penalty. The value of the PTC subsequent to the introduction of a carbon penalty depends on the magnitude of the carbon penalty[5].

The Council did not want any reduction in PTC value to exceed the advantage afforded renewables by a CO_2 penalty. Such an outcome would be contrary to the likely intent of a CO_2

[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 CO_2) to $/MWh is achieved with a conversion ratio 1.28 #CO_2/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.

control policy. This concern determines the model's PTC value due to the magnitude of any carbon penalty that arises in a given future.

Production tax credits (PTCs) amounted to $15 per megawatt hour when first adopted and have escalated with inflation. Its current value for wind, closed loop biomass and geothermal is $21 per megawatt hour. Investors receive credits only for the first ten years of project operation. Council studies 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.

In the Sixth Plan, the Council models the Montana, Oregon, and Washington Renewable Portfolio Standards (RPS). The RPS requirements of these states require an obligated utility to retain the REC unbundled from the power produced to meet the standard. That is, the REC may not be sold and the REC value may not be realized. 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. The value of RECs therefore plays a much smaller role in the selection of resources than it did in the Fifth Plan.

OTHER ASSUMPTIONS

Discount Rate and Other Financial Assumptions

Investment analysis, such as that for the Council's resource portfolio, typically has to compare projects with different time patterns of costs. A conservation project or a wind turbine installation, for example, is characterized by high fixed investment costs and low operating expenses. With initial capital costs repaid over time, the time pattern of costs for this type of investment will typically look generally flat over its lifetime. Contrast this with, for example, a combustion turbine investment, where the bulk of the cost is in the fuel rather than the fixed cost. With any escalation in real terms – above the general level of inflation – the biggest part of the lifetime cost will come in future years.

The discount rate is a fundamental piece of the Council's resource analysis for the power plan. The discount rate is the piece that embodies the rate of time preference being applied to the analysis; that is, how much relative importance is given to costs and benefits in different years in the future. The discount rate is used to convert future costs or benefits to their present value. A higher discount rate reduces the importance of future effects more than a lower discount rate. All else equal, a higher discount rate would tend to value a combustion turbine over a wind project, for example, by disproportionately reducing the higher fuel costs in future years. On the other hand, a low discount rate would not reduce the effects of those future costs so much. A zero discount rate, for example, would treat costs in all years the same. Regardless of whether the costs happened next year or 30 years from now, their impact on an investment decision taken now would be the same.

This notion of time preference is not, however, an abstract preference for the short term versus the long term. Time preference is directly tied to the concept of a market interest rate. Putting aside questions of risk, a dollar to be paid next year is less of a burden than a dollar to be paid this year. That is because one could invest less than a dollar today and, assuming sufficient return on that investment, use the proceeds to pay the dollar cost next year.

From the other side, a dollar benefit this year is more valuable than the same dollar benefit next year. Investing the dollar can turn it into more than a dollar next year. The important point here is that dollars at different times in the future are not directly comparable values; they are apples and oranges. Applying a discount rate turns costs and benefits in different years into comparable values. Because the Council's analysis looks at annual cost streams of various resource types, discounting is required in order to calculate and fairly compare total costs of alternative policies.

Market interest rates embody the effect of everybody's rates of time preference. Individuals and businesses that value current consumption more than future consumption will tend to borrow, and those that value future consumption more will save. The net effect of this supply and demand for money is a major factor in setting the level of interest rates. The actions of the Federal Reserve in setting the federal funds rate also affects interest rates by influencing inflation expectations. Market interest rates also embody considerations of uncertainty of repayment, inflation uncertainty, tax status, and liquidity, which together account for most of the variations among observed interest rates.

The approach builds on two sets of assumptions. The first is a set of forecast data developed by HIS Global Insight, a national economic consulting firm. Their forecasts are used for various purposes by the Council and data from utility IRPs. HIS Global Insight provides forecasts of various kinds of interest rates, inflation, and economic and demographic growth that are used throughout the Council's planning. The second is the relative shares of future investment decisions made by different actors (BPA, publicly owned utilities, IOUs and residential and business customers).

Plausible changes from the reference assumptions on shares of future decisions by various actors would affect the ultimate discount rate somewhat. Because of that, both the reference assumptions and a range of assumption values on these shares have been examined. Moreover, the final calculated value has been rounded rather than an attempt being made to capture unrealistic precision. Summary financial assumption information and the range of assumptions for the discount rate calculation are shown in Table 8-1. The discount rate is the weighted after-tax costs of capital in the IOU case. Details are given in Appendix N.

Table 8-1: Summary of Financial Assumptions

Item	Value	Range
Inflation	2.0%	NA
Municipal/PUD real discount rate	3.3%	NA
Co-op real discount rate	4.6%	NA
IOU real cost of equity	8.8%	NA
IOU real cost of debt	5.5%	NA
IOU real discount rate (tax-adjusted)	5.3%	NA
BPA real discount rate	4.5%	NA
Residential consumer real discount rate	3.9%	3%-5%
Business consumer real discount rate	7.7%	7%-9%
Real discount rate for plan	4.9%	4.7%-5.5%

Taking account of the range of assumptions above, the plan rounds to a real discount rate of 5 percent. The Council expects that individual entities may well have different values based on their own financing costs, rather than using a regional average, at the point at which they actually make investment decisions.

While proper treatment of discount rate is critical, studies have revealed the least-risk portfolio is largely insensitive to discount rate variation of 1 percent. Using a discount rate that is 1 percent higher results in a least-risk plan with 50 average megawatts less conservation by the end of the study. The resource plan is substantially the same.

Treatment of Transmission

The Council has traditionally not engaged in transmission planning, for several reasons. First, transmission expansion, beyond that required for local reliability, necessarily follows the choice and location of new resources, for which the Council does offer guidance in its power plan. Second, such planning is a highly technical effort in which the Council does not have expertise.

However, the Council incorporates information about the costs of transmission expansion into its analysis of resource choices for the Plan. All resources are treated on a comparable basis with respect to transmission costs. The primary driver for most transmission expansion, new resource type and location, therefore incorporates the relevant transmission information.

The Council also tracks and participates in the various transmission planning efforts. The Council encourages both transmission planning, aimed at getting new wires up, and improvements in transmission system operations. Improved operations assure the system can deliver and integrate economically the portfolio resources the Plan recommends.

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.

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 effectively mandated conversion to compact florescent lighting throughout the nation beginning 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 study 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, have therefore chosen a rate of acquisition which it considers aggressive, but achievable.

The Council adopts a 160-average-megawatts-per-year constraint assumption on the development of discretionary conservation. Would a lower or higher rate of conservation development be less costly or reduce risk? This question is discussed in Chapter 4 and Chapter 9.

Existing Renewable Portfolio Standard Resources

Table 8-2 lists the 843 average megawatts of existing renewables. The table includes about 2,500 megawatts of wind that the region has completed or will soon complete. After the release of the Fifth Power Plan, the Council discovered that there was considerable confusion about the amount of renewable generation that the Plan had assumed. In particular, while studies included them, the Fifth Plan often neglected to mention existing and nearly constructed renewables. Those renewables that were completed or would soon be completed were not relevant to construction decisions going forward. They are therefore pointed out here.

Table 8-2: Base of RPS Resources

					Allocation by State (%)			
Project	**Capacity (MW)**	**Service Year**	**Type**	**Load**	**CA**	**MT**	**OR**	**WA**
Biglow Canyon Ph I	125.4	2007	Wind	PGE			100%	
Broadwater	10.0	1989	Hydro	NWE		100%		
Clearwater Hatchery (Dworshak)	2.9	2000	Hydro	BPA			22%	78%
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%
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%
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%
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%		
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%
Wolverine Creek	64.5	2005	Wind	PAC	4%		74%	22%

Source: workbook "RPS Estimates 021909b for table.xls", worksheet "Commitments", created 7/19/2009

Forced-in RPS Requirements

As have many other states in the west, Montana, Oregon, and Washington have adopted Renewable Portfolio Standards. These legislated goals 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 utilities meet their nominal RPS goals. This representation, however, does not capture the possibility that utilities will fail to meet 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. Council studies, however, do capture diminished RPS requirement due to load reduction from conservation.

Adoption of RPS legislation by other states, in particular California, is expected to impact 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.

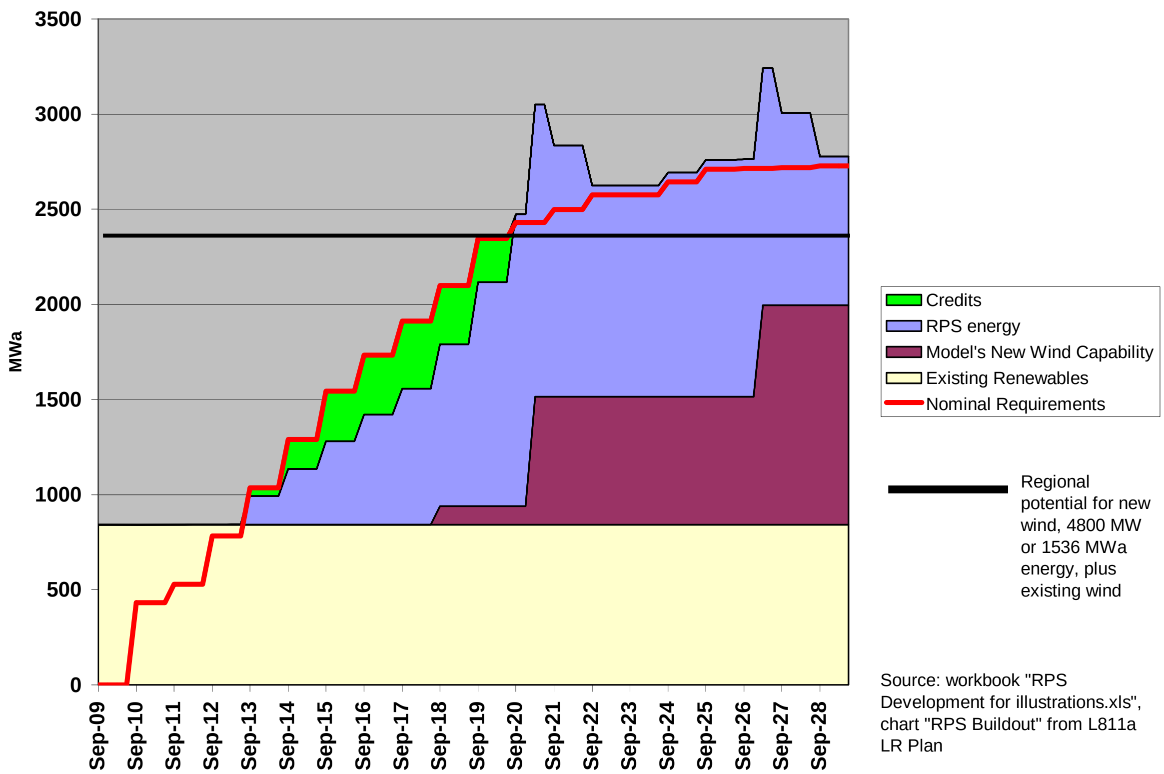
Renewable resources constructed to meet RPS requirements do not receive a cost reduction due to the sale of Renewable Trading Credits (RECs). When regional utilities acquire renewables to meet their state's requirements, they must retain any RECs associated with the resource. This has the effect of increasing 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.

Acquisition of renewables for compliance with RPS requirements also removes from the model's discretionary selection the region's total potential of new renewable development. By the end of the study, we estimate that all of the wind generation available without special transmission additions would be necessary to meet RPS requirements. Council studies do, however, consider portfolios in which the renewables are constructed ahead schedule and RECs are sold, at least prior to RPS schedules. The model, however, can never exceed the renewable development potential in the region.

Figure 8-11 provides an example of how existing RPS resources, banked RECs, wind selected and built by the model, and new RPS resources play out in a particular future. The heavy red line shows total RPS requirements. The green area shows the use of banked RECs. The blue area is RPS credit that the model must purchase in addition to the wind generation that has been added in this future. The model uses the cost of new wind generation, about $90 per megawatt hour in 2006 dollars, for this purpose.

There are spikes in the amount of RPS energy acquired to meet requirements in Figure 8-11. These spikes occur when new wind is added to the system and cause the total RPS energy to exceed the RPS requirement. This is a consequence of annual RPS accounting in the model. This anomaly will be absent in the model used for the final Plan.

Figure 8-11: RPS Source Development



Independent Power Producers' Resources

IPPs 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 energy market. The IPP owners, however, receive the benefits of any energy sold, not the region. There are about 3,342 megawatts 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 IPPs modeled in Council studies appears in Table 8-3.

Table 8-3: Independent Power Producers

Plant name	Uncommitted share	Project Owner	January Capacity (MW)
Big Hanaford CC1A-1E	100%	TransAlta	235.6
Centralia 1	85%	TransAlta	623.1
Centralia 2	100%	TransAlta	623.1
Grays Harbor Energy Facility (Satsop)	100%	Invenergy (dba Grays Harbor Energy)	617.5
Hermiston Power Project	100%	Calpine, dba Hermiston Power Partners	503.5
Klamath Cogeneration Project	100%	Iberdrola Renewables	456.0
Klamath Generation Peakers 1 & 2	100%	Iberdrola Renewables	45.0
Klamath Generation Peakers 3 & 4	100%	Iberdrola Renewables	45.0
Lancaster (Rathdrum CC)	100%	Cogentrix	264.1
Morrow Power	100%	Morrow Power (Subsidiary of Montsano Enviro Chem Systems)	22.5
		Discounted total	3341.9

Source: workbook "Table of IPPs.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 8-4, below.

Table 8-4: New Resource Candidates

- Conservation
    - Discretionary conservation limited to 160 average megawatts per year
    - phased in up to 85% 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 (PTC), transmission, and firming and integration cost
- 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 (1100 MW), available 2023, 4400 MW by end of study
- Supercritical pulverized coal-fired power plants (400 MW), available 2016
- IGCC (518 MW) available 2023, with carbon capture and sequestration
- Wind imported from Montana, with new transmission, available 2011, 1500 MW by end of study
- Five classes of demand response, 2000MW available by end of study, 1300 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 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 8-5 shows relatively new resources that are not listed in Table 8-2.

Table 8-5: Recent Construction

Project	Capactiy (MW)	Fuel Type	In-service Month
Mint Farm	319	Natural Gas	Jan 2008
Raft River I	15.8	Geothermal	Jan 2008
Hay Canyon	100.8	Wind	Dec 2008
Grays Harbor Energy Facility	650	Natural Gas	Jul 2008
Bettencourt Dry Creek Dairy	2.25	Biomass	Sep 2008
City of Albany (Vine Street WTP)	0.5	Hydro	Feb 2009
Danskin (Evander Andrews) CT1	170	Natural Gas	Jun 2008

In order to keep the analysis manageable, only new resources that are found to be competitive and of significant potential6, or required by law, are considered in the model. The RPM, because it evaluates large numbers of possible portfolios under many scenarios 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-hydrogeneration, solar thermal, and other smaller sources are assumed to be captured under States' RPS programs.

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. The hydro generation insufficiency of the early 1970s and the 2000-2001 energy crisis of the west coast come to mind. Overbuilding in the late 1970s and the unprecedented rate increases and financial failures that ensued illustrate the dangers of overbuilding.

The power system has other requirements, however. Power system balance on the sub-hourly level is critical to integration of wind and other renewable resource. 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 may otherwise become inefficient.

In modeling wind, an additional integration and firming cost is added to that of direct wind turbine costs. The model does not include, however, any additional resources that may be required to provide these services. The model, moreover, does not have the capability to evaluate any incremental need for within-hour load following or regulation. The Action Plan supports work underway by the Regional Wind Integration Forum to evaluate those requirements.

The RPM uses an economic valuation approach to evaluating peaking contribution. The RPM does not have the information it needs to determine energy contribution to peak load. Instead, the Council relies on a model dedicated to that calculation, **GENESYS**. It is certainly ***possible*** to estimate peak contribution from distributions in the RPM, but not without additional logic development.

Having said that, we believe there are reasons why the model has produced resource portfolios that meet peaking requirements. The model can discern economic value that arises from hourly

[6] The cutoff for consideration is around 300 MW of cost-effective potential by the end of the study.

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 to us, the RPM would build more resources in this situation specifically to avoid exposure to these high prices.

There is no guarantee that the model will always build portfolios that meet energy peaking requirements. Consequently, staff evaluates recommended portfolios using the **GENESYS** model. So far, however, we have not seen a situation where economic adequacy has failed to produce energy adequacy and to meet peaking requirements. The Plan addresses flexibility extensively in Chapter 11.

Electricity Price Cap

Prices for wholesale electricity price are capped at $325 per megawatt hour on average for a quarter. This value corresponds to the $400 per megawatt hour price caps imposed in 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 portfolio model.

BEYOND ECONOMIC COST AND RISK

The studies that the Council performs attempt to address sources of uncertainty that the preceding overview ignores. They are significant to the selection of the portfolio. The following is a brief description of more prominent issues.

The Protection of Fish and Wildlife

Concurrent with the development of its resource portfolio, the Council has updated its fish and wildlife program. This program to “protect, mitigate, and enhance fish and wildlife” informs resource decisions and hydro operation, in particular. Of particular significance to fish and wildlife is a resource portfolio that does not place extraordinary burden on the hydroelectric system. This consideration is especially important when addressing reliability, adequacy, and system flexibility. It is under reliability events that fish are at the greatest risk, because inadequate resources would increase the likelihood that the region would need hydrogeneration to maintain system reliability.

To minimize impact on fish and wildlife, the Council’s portfolio model assumes the hydroelectric system is ***never*** used to meet extraordinary requirements. This places the burden for minimizing cost and risk on new resource candidates. It also reflects the value that such resources have in providing protection to fish and wildlife.

Other Effects on the Region

The Council recognizes the economic opportunities and costs associated with the selection of power resources. The preceding section referred to risk-constrained, least-cost planning. The referenced costs and risks are taken to mean strictly those that regional electricity consumers bear, both in their utility bills and in the consumers' share of conservation investments. The Council also recognizes, however, that resource and policy choices impact regional communities and industries. The economic welfare of the region extends beyond its electric power rates. Consequently, the Council endeavors to understand and recognize those impacts.

The next chapter presents the Council's preferred resource portfolio. Chapter 9 then returns to address the non-economic issues raised in the preceding section.

Chapter 9: Recommended Resource Strategy

SUMMARY OF KEY FINDINGS

The resource strategy of the Sixth Power Plan was developed by examining a number of different planning scenarios. The Resource Portfolio Model (RPM) identifies resource plans that minimize the cost and risk of future power system costs as described in Chapter 8. As in previous plans, improved efficiency of electricity use is the most cost-effective and least risky resource available to the region. The value of conservation was recognized in all planning scenarios and all scenarios call for developing significant amounts of conservation. The amount of conservation that is cost-effective changes very little regardless of assumptions about carbon costs and policies. Due to advancing technologies, new applications, much higher energy costs, and the risk of carbon emission penalties, much more conservation is available and cost-effective in the Sixth Plan. Therefore, the Sixth Power Plan calls for aggressive development of conservation. There is enough cost-effective conservation in the resource portfolio to provide a substantial portion of the region's load growth.

In addition to efficiency improvements, 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 readily accessible wind potential (5,300 MW) in the region. In addition to the wind, some geothermal resources enter the plan. However, the amount of geothermal potential is considered quite limited. In planning scenarios without the RPS requirements, about one third less renewable development would be optimal given the carbon price risk considered. Instead more conservation would be developed and some additional gas-fired generation would be optioned.

Reducing carbon emissions from the power system will increase the future cost of electricity and increase consumers' electric bills. The risk of carbon prices between $0 and $100 is estimated to increase average electricity rates by about 2.4 to 9.3 compared to current policies that only include renewable portfolio standards, renewable energy credits and limits on new power plants carbon emissions. The effect on average residential consumers' monthly bills is estimated as an increase 1.4 to 7.1 percent.

The effects of carbon pricing risk are reduced in the Pacific Northwest by the existing hydroelectric system and the relatively minor role of coal-fired generation. The resource strategy focus on conservation and renewable generation also help avoid future cost impacts.

ROLE OF ANALYSIS IN THE RESOURCE STRATEGY

The Council uses several computer models in the process of developing its Power Plan. These include demand forecasting models, market price forecasting models, hydroelectric simulation models, resource financial costing models, and the Regional Portfolio Model (RPM) discussed in Chapter 8. All of these models help the Council combine the best information available to identify a resource strategy that minimizes the future cost of the power system as required by the Northwest Power Act, and also includes strategies to mitigate the risks of unknown future conditions.

The Council's models and analyses help inform the resource strategy, but models are limited in their ability to address all of the considerations that need to go into the Power Plan. The Council's plan recognizes that available models do not capture the local limitations of the transmission system, for example, or the unique situations faced by all individual utilities. As a result, the resource strategies that result from particular model analyses are supplemented by additional information to come up with the Council's recommended resource strategy.

In addition, the resource strategy is supplemented by additional information about potential future resources, explanations of special challenges facing the power system, and an action plan containing steps the region should take to implement the plan. The action plan addresses important issues like wind integration, conservation acquisition, resource development and confirmation, and research and demonstration projects.

THE RESOURCE STRATEGY

Planning Scenarios

The Resource Portfolio Model analyzes the Power Plan's forecasts of demand, conservation supply, and generating resource alternatives. The RPM is unique because it is acknowledges that forecasts are well-informed but uncertain. The RPM considers risk in its analysis, including the risk that the Council's forecasts are incorrect. It adds a range of climate policy and other unknown future conditions to identify least-cost and least-risk plans along an efficient frontier of least-cost resource plans. This process is described in Chapter 8. The RPM searches through thousands of potential portfolios to estimate how each one would perform in 750 futures. This analysis allows the program to find the lowest cost resource portfolios for different levels of risk. In more typical planning these futures would generally be called "scenarios." In the RPM the

Council refers to these as "futures," and the term "scenario" is reserved for different RPM runs as described below.

In developing its resource strategy, the Council evaluated several scenarios focused primarily on different climate policy approaches to see if the resource strategy is sensitive to such differences. Below is a list of scenarios considered. Each scenario analyzed produced a least-cost and least-risk mix of resources. The scenarios are described here in terms of their least-risk portfolio of resources. Resource plans at the lowest cost end of the frontier tend to rely on electricity markets instead of optioning and building resources. Plans at the low-risk end of the efficient frontier produce more adequate and reliable power systems, reduce electric price volatility, and provide more information about the types and amounts of resources needed. For these reasons the Council has focused on least-risk plans.

- *Current Policy* is a scenario that includes renewable portfolio standards that exist in three of the four Northwest states, renewable energy credits, and new carbon emissions performance standards that preclude the construction of new coal plants. The current policy scenario does not, however, include the stated emissions reduction goals that some states have adopted as policy.

- *No Policy* is a scenario that assumes no renewable portfolio standards or other policies aimed at reducing carbon emissions exist. However, it does not allow new coal-fired generation.

- *$0 to $100 Carbon* is a scenario that adds to the Current Policy scenario uncertain carbon pricing policy that can vary from zero to $100 per ton of carbon emission. The carbon cost range for this scenario was based on staff analysis and a study that reviewed various cost estimates that would successfully achieve carbon reduction.

- *No RPS* takes renewable portfolio standards out of the $0 to $100 Carbon scenario to test whether a strategy to mitigate risk of future carbon pricing would develop as much renewable generation as the RPS requirements.

- *$0 to $50 Carbon* tests the effects of a smaller range of potential carbon price risks on the resource plan.

- *$100 Carbon* puts a firm price on carbon emissions of $100 per ton. The price is not a risk in this scenario, it is a known cost.

- *$20 Carbon* puts a price on carbon emissions of $20 per ton. As in the $100 scenario, it is a known cost.

- *Retire Coal w/ CO2* phases out existing coal plants between 2015 and 2020 but retains uncertain carbon pricing policy that can be between $0 and $100.

- *Retire Coal w/0 CO2* phases out existing coal plants between 2015 and 2020 but considers that action a substitute for carbon pricing policy and does not include carbon price risk.

- *Dam Removal* assumes that the four Lower Snake River dams are removed in 2020 in order to test the value of the hydroelectric capability of the power system.

- *Low Conservation* assumes a reduced acquisition rate for discretionary conservation and lower penetration of lost-opportunity conservation.

- *High Conservation* assumes a higher acquisition rate for discretionary conservation.

The Resource Strategy

The Council developed a resource strategy based on analysis of the results of all of these scenarios as well as other considerations to supplement the model results. What emerges is a clearly focused strategy for near-term actions and flexible guidance on future resources and actions.

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 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.

- **Conservation:** The region should aggressively develop conservation with a goal of acquiring 1,200 average megawatts by 2014, and 5,800 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 that would address climate change concerns.

- **Renewables:** The region should meet existing renewable portfolio standards. 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. Wind’s variable energy production creates little dependable peak capacity and increases the need for within-hour balancing reserves. The Council encourages the development of other renewable alternatives that may be available at the local, small-scale level and cost-effective now. The Council also supports research and demonstration into different sources of renewable energy for the future. On average, the renewable resources developed to fulfill state RPS mandates should contribute 1,800 average megawatts of energy, or 5,600 megawatts of installed capacity.

- **Wind Integration:** The Plan encourages the region to improve wind scheduling and system operating procedures as a more cost-effective and more quickly achievable alternative to new gas-fired generation for the purpose of wind integration.

- **Natural Gas:** The region may need to develop new natural gas resources, depending on load growth and the possible need to displace coal use to meet high 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 cases, the strategy relies on natural gas-fired generation to provide energy, capacity, and ancillary services.

- **Future Resources:** In the long term, the Council encourages the region to expand the alternative resources available to the region. Among these are additional sources of renewable energy, improved regional transmission capability, new conservation technologies, new energy storage techniques, carbon capture and sequestration, smart grid and demand response resources, and new or advanced 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 Fish and Wildlife Program.

The following sections describe the basis for the resource focus on conservation, renewable generation and natural gas.

Conservation

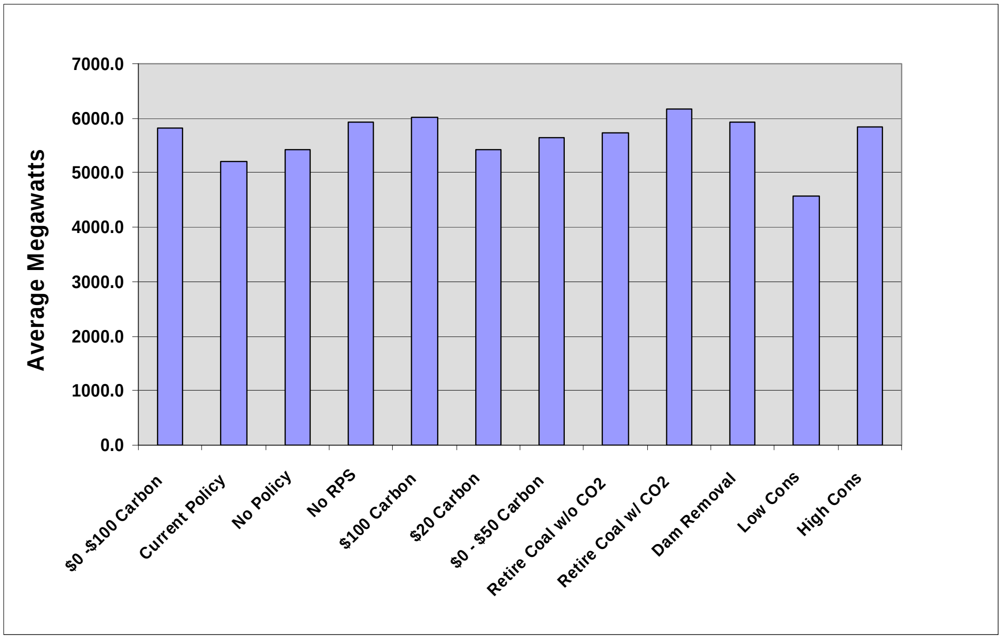
The Council's research on conservation potential demonstrated a large potential for improved efficiency of electricity use. Increased costs of electricity generation, new areas of application and changing technologies mean this potential is much larger than the potential identified in the Council's Fifth Power Plan.

Conservation is the clear priority resource as evaluated by the RPM. It is by far the lowest cost resource and provides protection against the risks of volatile natural gas prices, high electricity prices and the possibility of carbon pricing policies. Conservation also has the risk advantages associated with small scale resources that require less time to develop.

Each portfolio, regardless of the scenario analyzed, contained conservation in the range of 5,200 and 6,200 average megawatts. The one exception is the Low Conservation scenario in which the rate of development for conservation was further limited. Figure 9-1 illustrates the level of conservation included in the least-risk plan for each scenario.

Similar amounts of conservation are cost effective regardless of the assumption about climate policies. Even in the Current Policy and No Carbon Policy scenarios, conservation was demonstrated to have clear advantages. It is interesting to note that Current Policy reduces the amount of conservation compared to No Carbon Policy. Renewable portfolio standards force the addition of renewable generation and both reduce resource needs and mitigate some of the risk from fuel prices. The fact that varying levels of conservation are driven partly by resource needs is also evident in the other scenarios. Scenarios with high-carbon prices result in reduced operations of existing coal plants, making replacement energy more valuable. This effect is most clear in the scenarios that retire currently generating coal plants.

Figure 9-1: Cost-Effective Conservation Resources



Renewable Generation

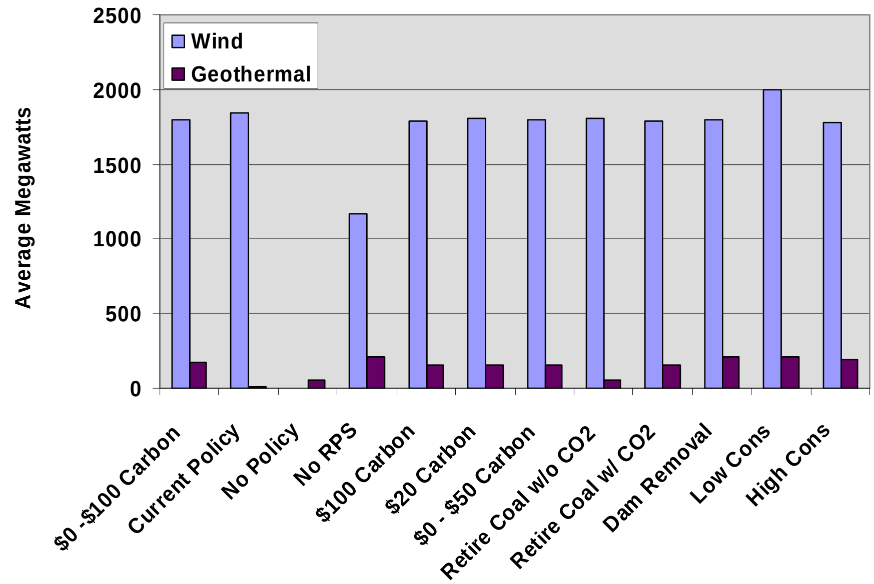
Renewable resources are mostly modeled as wind in the RPM. A limited amount of geothermal is included in the resource alternatives and is generally an attractive resource choice. The Council has recognized that additional small-scale renewable resources are likely available and cost-effective and the Plan encourages development of them. 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 resources.

Wind development in the various scenarios is driven primarily by state renewable portfolio standards. The amount of wind 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 the amount of wind developed on average is 1,800 average megawatts. In terms of available capacity, that is 5,600 megawatts of installed wind capacity, but only about 300 megawatts of firm peaking capacity.

Figure 9-2 shows the amounts of wind and geothermal energy acquired on average in the various scenarios studied. 860 average megawatts of wind (2,700 megawatts of available capacity) exists in all scenarios because that level of development already exists or is committed to be developed. In all cases with renewable portfolio standards in place, the development of wind is limited to 1,800 average megawatts as required by the standards when the state's goals are combined. The only exception to this is when low rates of conservation are assumed. In that case, an additional 200 megawatts of wind is developed.

In the two scenarios without renewable portfolio standards, No Carbon Policy and No RPS, the results are different. In the No Carbon Policy scenario no additional wind is developed. In the No RPS scenario, which includes the risk of carbon prices between $0 and $100 per ton, additional wind is developed, but only about 1,200 average megawatts instead of the 1,800 average megawatts in the scenarios that include renewable portfolio standards.

Figure 9-2: Renewable Resource Development



Geothermal energy is considered cost-effective in many of the scenarios although the amount available is quite small. The Council expects that the geothermal resource may be representative of other small-scale, locally available renewable generation that offers dependable energy capability and peaking contribution.

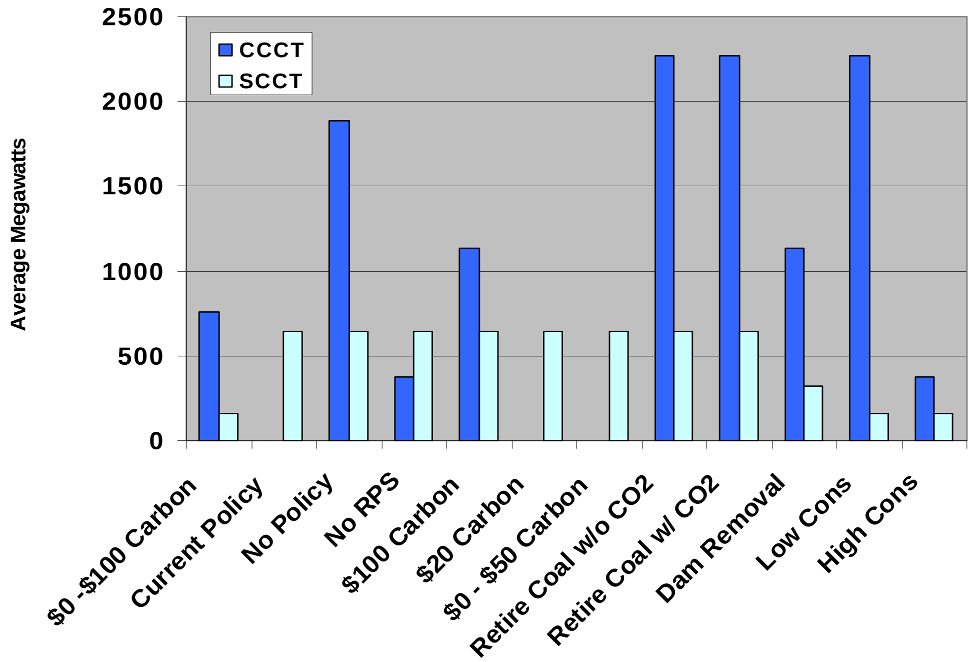
Natural Gas

There are two types of natural gas-fired generation considered in the RPM: simple-cycle turbines (SCCT) that are most suitable for providing peaking capacity, and combined-cycle turbines (CCCT) that are more suitable to providing base-load energy as well as peaking capacity.

While the amount of conservation and wind was fairly consistent across all scenarios examined, the future role of natural gas-fired generation is variable and specific to the scenarios studied. Figure 9-3 shows the average amounts of SCCT and CCCT optioned among the 750 futures considered in each scenario. The gas-fired plants are optioned (sited and licensed) so that they are available to develop if needed in each future. The actual amount of natural-gas fired generation constructed will vary in each future. For example, on average in the $0 - $100 Carbon scenario 162 average megawatts of CCCTs are optioned by the end of the planning period, but are constructed only in about 30 percent of the futures.

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 like the retirement 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.

Figure 9-3: Natural Gas-Fired Resource Options



The particular type of natural gas-fired generation optioned and added 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 conservation 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.

CHARACTERISTICS OF SCENARIOS

The most important considerations for selecting a resource strategy are the cost, risk, and carbon emissions of the various scenarios considered. The measurement of these attributes was discussed in Chapter 8. Although the Council's resource strategy is based on the analysis of several different scenarios, a comparison of the characteristics of the scenarios provides important information about the value of conservation achievement and the cost and effectiveness of various carbon policy approaches.

This section summarizes the analysis results of the various scenarios the Council considered in developing its resource strategy. The tables provide information on average values over 750 futures for costs, carbon emissions, conservation acquisition, and wind development. The resource planning costs have been converted into estimated retail rates. These are presented as levelized rates over the planning period. It also provides the amounts of other generation that are optioned by the end of the planning period.

In many of the tables and discussions the different scenarios are compared to the $0 to $100 Carbon scenario. This scenario is chosen as a matter of convenience to illustrate the varying effects of the scenarios. The results of this scenario are also representative of the Council's resource strategy in terms of the amount of conservation and wind development recommended.

Conservation Scenarios

The Council's draft Sixth Power Plan includes significantly more conservation than previous Council plans. The conditions that led to this increase in cost-effective conservation are discussed in Chapter 4. In essence, conservation provides a low-cost resource to the power system that is without risk of increased fuel prices and carbon prices.

Two scenarios were developed to test the value of conservation to the power plan. Both scenarios were based on the $0 to $100 Carbon scenario assumptions with variations in the conservation assumptions. In the Low Conservation scenario, the amount of conservation was reduced from the $0 to $100 Carbon scenario by assuming that no more than 100 average megawatts per year of retrofit conservation could be developed, instead of 160 in the $0 to $100 Carbon scenario, and that lost-opportunity conservation ramp-up would take 20 years to reach 85 percent annual penetration, instead of 15 years used in the $0 to $100 Carbon scenario. The Low Conservation scenario only develops 800 average megawatts in the 5-year action plan period, compared to 1,200 average megawatts in the $0 to $100 Carbon scenario.

The second conservation scenario explores the effects of raising the assumption about conservation development. For this High Conservation scenario, the Council assumed it would take 10 years to develop the first 2,400 average megawatts of retrofit conservation, instead of the 15 years assumed in the $0 to $100 Carbon scenario. This equates to an average pace of 220 average megawatts per year for retrofit conservation, but no increase in the ramp-up for lost-opportunity conservation. In the High Conservation scenario, 1,500 average megawatts of conservation is developed over the first five years of the action plan.

Table 9-4 shows a summary of the results of the Low and High Conservation scenarios compared to the $0 to $100 Carbon scenario. The amount of conservation achieved in the Low Conservation scenario is reduced significantly. It is lower than the amount found cost effective in any of the carbon scenarios, including the No Policy scenario. However, the High Conservation scenario changes only slightly the amount of conservation achieved over the planning period. This is because the High Conservation scenario accelerates discretionary conservation. The total amount of conservation available does not change. In addition, the lost opportunity conservation was not changed for the High Conservation scenario.

The Low Conservation scenario results in a 4.4 million ton increase in average annual carbon emissions, but the High Conservation shows approximately the same level of carbon emissions as found in the $0 to $100 Carbon scenario.

Reduced conservation achievements in the Low Conservation scenario are made up for by increased gas-fired combined-cycle generation and more renewables. Three times as many combined-cycle combustion turbines are optioned in the Low Conservation scenario as in the $0 to $100 Carbon scenario. New renewable generation capability increases by 196 average megawatts.

Under the Low Conservation scenario, power system costs are increased by $5 billion in added resource acquisition costs and carbon penalties if conservation is developed at this limited level. If this scenario excludes any anticipated carbon penalties, limiting conservation achievement increases power system costs by $3.7 billion over the 20 years of the power plan. These changes are reflected in the first line of Table 9-4.

Not only is the power system more expensive if 1,000 megawatts of conservation is replaced with primarily gas-fired generation, risk is also increased. Although the average cost of the power system, including carbon penalties, increases by 8 percent in the Low Conservation scenario, the risk of the power system increases by 12 percent, from $155.5 to $173.9 billion. Risk is a measure of the average cost of the 75 highest cost futures. The increase in risk demonstrates the value of conservation in reducing the risk of futures that feature high carbon costs.

Table 9-1: Low and High Conservation Scenarios versus the $0 to $100 Carbon Scenario

	$0 to $100 Carbon	Low Conservation	High Conservation
Cost (billion 2006$ NPV)			
With Carbon Penalty	$105.60	$114.30	$103.80
Without Carbon Penalty	$85.10	$88.70	$84.80
Retail Rates - Change (%) from $0 to $100 Carbon Scenario			
With Carbon Penalty		- 1.4%	+ 0.6%
Without Carbon Penalty		- 2.4%	+ 0.9%
Carbon Emissions (Gen) (Million Tons/Year)	37.1	41.0	36.6
Resources 2030			
Conservation (MWa)	5,827	4,566	5,849
Wind (MWa)	1,800	1,996	1,778
Geothermal Options (MWa)	169	208	195
CCCT Options (MWa)	756	2268	378
SCCT Options (MWa)	162	162	162

The cost-effective level of conservation is consistent across each climate change scenario examined. The amount of conservation selected in the several climate change scenarios described in the previous section falls consistently between 5,000 and 6,000 average megawatts. Figure 9-1 illustrates this fact. Thus the importance of conservation in the Sixth Power Plan is not dependent on any particular view about climate change or specific climate change policies; it is a simple reflection of cost and risk. Risk associated with demand growth, water conditions, natural gas prices, and other uncertainties provide justification for conservation development even in the absence of carbon price risks.

Carbon Policy Scenarios

The discussion of the carbon policy scenarios first compares the No Policy and Current Policy scenarios to the $0 to $100 Carbon price risk scenario. Then other approaches to carbon pricing or other control policies are compared to the $0 to $100 Carbon scenario.

Current Policy Scenario

The Current Policy scenario tests the effect of only known, instituted carbon policies on the plan's resource strategy. As the name implies it includes current RPS requirements, new plant carbon dioxide performance standards, and renewable energy credits, but ignores the potential risk of carbon pricing policies in the future, as are being discussed by individual states, the WCI, and in proposed federal legislation.

This scenario shows that carbon emission levels of the regional power system could be stabilized with existing policies, but carbon emission reduction goals would not be achieved. Compared to the least-risk portfolio, as shown in table 9-2, future power system costs would be reduced by 17 percent compared to the $0 to $100 Carbon scenario if utilities are provided free emission allowances for most of the planning period. In this scenario, the effects on electricity retail rates would be very small. The cost reduction would be nearly one third larger if the carbon emissions allowances are assumed to be entirely auctioned in the $0 to $100 Carbon scenario, that is, if utilities had to pay the full cost of allowances. National policy proposals would provide free allowances to utilities for most of the planning period and therefore are much closer to the free allowance end of the range. Tables in this section show power system costs both with free allowances and with allowance costs paid entirely by the power system in scenarios that include carbon pricing policy.

Compared to the $0 to $100 Carbon portfolio the Current Policy scenario would develop less conservation and natural gas-fired combined-cycle generation would shift to simple-cycle turbines to provide capacity for integrating wind power into the regional power system. Because the Current Policy scenario does not include carbon pricing policy risk, the region's existing coal plants continue to provide base load energy for the power system, whereas in the $0 to $100 Carbon scenario coal plants are dispatched less to mitigate carbon costs. Table 9-5 compares the Current Policy scenario to the $0 to $100 Carbon scenario.

Table 9-2: The Current Policy versus the $0 to $100 Carbon Scenario

	Current Policy	$0 to $100 Carbon
Cost (billion 2006$ NPV)		
With Carbon Penalty	$70.50	$105.60
Without Carbon Penalty	$70.50	$85.10
Retail Rates - Change (%) from Current Policy		
With Carbon Penalty		+ 9.3%
Without Carbon Penalty		+ 2.4%
Carbon Emissions (Gen) (Million Tons/Year)	52.1	37.1
Resources 2030		
Conservation (MWa)	5,197	5,827
Wind (MWa)	1,845	1,800
Geothermal Options (MWa)	13	169
CCCT Options (MWa)	0	756
SCCT Options (MWa)	648	162

The figures for carbon emissions, conservation, and wind development are averages across all futures at the end of the study. The cost and rates without carbon penalty do not include the penalty applied to CO_2 production. There is still an economic effect on the dispatch order of resources included in these costs.

No Policy Scenario

One question the Council has been asked to address is: what will be the cost of reducing carbon emissions from the power system? To address that question a scenario was developed that excluded not only the risk of potential future carbon pricing penalties, but also excluded the RPS requirements, new plant carbon dioxide performance standards, and RECs. However, this No Policy scenario did not assume that new pulverized coal plants would be available for development.

Table 9-3 compares the result of the No Policy scenario to both the Current Policy and $0 to $100 Carbon scenarios. Costs of the power system would be increased from $56.5 billion in the No Policy scenario to $70.5 billion with Current Policy, and to $85.1 billion in the $0 to $100 Carbon scenario. The $0 to $100 Carbon scenario increases the cost of the regional power system by 50 percent compared to a scenario that ignores current climate policy and potential future climate policy risks. If carbon penalties were borne by the power system, the cost increases associated with addressing climate policy would be greater. In that case, the power system costs in the $0 to $100 Carbon scenario would be nearly double to cost of the No Policy scenario. The effect on retail rates is an increase of between 5 and 12 percent on average over the planning period depending on whether or not carbon penalties are included in utility costs.

In the absence of any climate policy, carbon emissions would continue to grow. By 2030 carbon emissions from the power system would increase by 5 percent over 2005 levels. Interestingly, under the No Policy scenario, the amount of conservation that is developed is smaller than the $0 to $100 Carbon scenario but more than that developed under the Current Policy scenario. However, no new renewable resources are developed in the No Policy scenario except for a small amount of geothermal; and a large amount of natural gas-fired resources are added. Table 9-3 summarizes the comparison.

Table 9-3: The No Policy Scenario Versus the Current Policy and $0 to $100 Carbon Scenarios

	No Policy	Current Policy	$0 to $100 Carbon
Cost (billion 2006$ NPV)			
With Carbon Penalty	$56.50	$70.50	$105.6
Without Carbon Penalty	$56.50	$70.50	$85.10
Retail Rates - Change (%) from No Policy Scenario			
With Carbon Penalty		+ 2.8%	+ 12.3%
Without Carbon Penalty		+ 2.8%	+ 5.3%
Carbon Emissions (Gen) (Million Tons/Year)	60.0	52.1	37.1
Resources 2030			
Conservation (MWa)	5,432	5,197	5,827
Wind (MWa)	0	1,845	1,800
Geothermal Options (MWa)	52	13	169
CCCT Options (MWa)	1,890	0	756
SCCT Options (MWa)	648	648	162

No Renewable Portfolio Standards

Three of the four states in the region have some form of renewable portfolio standard that requires a certain share of electricity consumption to be supplied from qualifying renewable generation. This policy favors one particular solution to carbon emissions, but encourages development of new forms of electricity generation. Questions the Council considered were whether an RPS would be necessary if there is a perceived risk that a substantial carbon penalty could be imposed in the future, and whether other policies might be as effective in reducing carbon emissions. To explore this question, a scenario was run that removed RPS requirements from the $0 to $100 Carbon scenario.

Table 9-4 compares the results of the $0 to $100 Carbon scenario and the No RPS scenario. The results show only a small effect from the additional effect of RPS on the cost of the least-cost, low-risk resource portfolio. Cost is slightly lower without the RPS, and carbon emissions are higher. Significantly less renewable generation is developed, more conservation is acquired and more natural gas-fired generation is optioned in the No RPS scenario.

Table 9-4: The No RPS Scenario versus the $0 to $100 Carbon Scenario

	$0 to $100 Carbon	No RPS
Cost (billion 2006$ NPV)		
With Carbon Penalty	$105.60	$101.40
Without Carbon Penalty	$85.10	$79.30
Retail Rates - Change (%) from $0 to $100 Carbon Scenario		
With Carbon Penalty		- 1.2%
Without Carbon Penalty		- 1.7%
Carbon Emissions (Gen) (Million Tons/Year)	37.1	40.3
Resources 2030		
Conservation (MWa)	5,827	5,935
Wind (MWa)	1,800	1,171
Geothermal Options (MWa)	169	208
CCCT Options (MWa)	756	378
SCCT Options (MWa)	162	648

This scenario indicates that RPS requirements make an additional contribution to meeting carbon targets at a modest cost. RPS is a policy that can be, and has been, put in place to move the region toward a lower carbon future while other policy solutions are being developed at the national, regional, and state level. These potential future policies can have an effect on resource decisions even though they are not yet enacted because of the risk they pose for future carbon penalties. Unfortunately one of those effects may be to delay needed resource decisions because of the uncertainty. A similar situation occurred in the mid-1990s. Fear that federal policy would restructure the electric industry caused utilities to delay resource development decisions, which eventually led to an inadequate power system and the 2000-01 electricity crisis.

Retiring Existing Coal Plants

Existing coal plants account for over 85 percent of power system carbon emissions in the Pacific Northwest. Therefore any significant reduction in carbon emissions from the power system must include reduced operation of these power plants. In the $0 to $100 Carbon scenario, the ability to reduce carbon emissions to below 1990 levels results partly from coal plants being displaced in favor of renewable generation and conservation. In futures with high-carbon costs, natural gas plants become lower in cost than coal and as a result coal is dispatched less often.

If coal plants are dispatched less but remain available to run under some future conditions, carbon emissions become more variable. When low-carbon prices are assumed for a future, the coal plants will operate and they may operate more when water conditions are low or demand is high. As a result, reduced carbon emissions are not assured even though they are lower on an expected or average basis. There are also questions about the viability of continued operation of these plants if they are used infrequently or at minimum capacity. It may be unrealistic to expect coal plants to run as natural gas plants currently do. Coal plants are less flexible and have higher fixed operating and maintenance costs.

An alternative approach was considered in two coal retirement scenarios. It was assumed that the regional coal plants are phased out between 2012 and 2020. They could be retired or mothballed, but they are not considered available to meet loads and their output must be replaced with other resources. The two Retire Coal scenarios are distinguished by two different assumptions regarding the existence of carbon pricing policies, with carbon penalties and without carbon penalties. Table 9-5 shows the results of these scenarios compared to the $0 to $100 Carbon scenario.

Table 9-5: The Retire Coal Scenarios versus the $0 to $100 Carbon Scenario

	$0 to $100 Carbon	Retire Coal w/ CO2	Retire Coal w/o CO2
Cost (billion 2006$ NPV)			
With Carbon Penalty	$105.60	$122.20	$94.70
Without Carbon Penalty	$85.10	$109.70	$94.70
Retail Rates - Change (%) from $0 to $100 Carbon Scenario			
With Carbon Penalty		+ 4.7%	- 0.4%
Without Carbon Penalty		+ 8.0%	+ 6.2%
Carbon Emissions (Gen) (Million Tons/Year)	37.1	14.7	14.0
Resources 2030			
Conservation (MWa)	5,827	6164	5,739
Wind (MWa)	1,800	1,787	1,809
Geothermal Options (MWa)	169	156	52
CCCT Options (MWa)	756	2268	2268
SCCT Options (MWa)	162	648	648

The retirement of the coal plants results in a dramatic reduction of carbon emissions. In 2030 the average emissions are reduced by 70 percent from 2005 levels. These reductions are approaching some of the targets proposed by the Intergovernmental Panel on Climate Change for 2050.

In the scenario where coal plants retirement is treated as a substitute for carbon pricing policy (Retire Coal without CO2), costs are decreased compared to the $0 to $100 Carbon scenario without free allowances. However, if coal is retired in combination with carbon pricing policy (Retire Coal with CO2) and free allowances are not granted, the power system costs increase by 16 percent. In rough terms, these cost increases would translate into real (without general economic inflation) average retail electricity price increases of 6 and 8 percent with free allowances.

The amounts of conservation acquired change moderately under each of these scenarios. The bulk of the coal capability is replaced by additional options on combined-cycle gas-fired generation, which has about 38 percent of the carbon emissions of an existing coal plant.

Like the RPS, a policy of retiring coal plants is an alternative carbon control policy. It also focuses on one particular solution without creating wide-spread incentive to find creative and low-cost solutions to reducing carbon emissions in every sector that produces carbon. Nevertheless, the results are more predictable and the policy could be implemented through regulations at the state level. It could be a viable alternative in a region like the Pacific Northwest where coal is not the dominant power supply, but is the dominant carbon emissions source. Replacement by natural gas is the alternative assumed here, but in the longer term other options may become available such as carbon capture and sequestration, advanced nuclear, or additional renewable generation technologies.

Fixed Carbon Price Scenarios

The $0 to $100 Carbon scenario assumes risk associated with an uncertain carbon pricing policy in the future. One question posed is: would the plan resource strategy change if a fixed carbon price were assumed? Two scenarios were tested: one with a $100 per ton carbon price and one with a $20 a ton carbon price. These scenarios generally cover the range of prices used in utility and other analyses. Table 9-6 shows the results of these two scenarios compared to the $0 to $100 Carbon scenario.

Table 9-6: The Fixed Carbon Price Scenarios versus the $0 to $100 Carbon Scenario

	$0 to $100 Carbon	$100 Carbon	$20 Carbon
Cost (billion 2006$ NPV)			
With Carbon Penalty	$105.60	$143.70	$89.70
Without Carbon Penalty	$85.10	$97.40	$72.30
Retail Rates - Change (%) from $0 to $100 Carbon Scenario			
With Carbon Penalty		+ 14.3%	- 2.1%
Without Carbon Penalty		+ 7.1%	- 1.0%
Carbon Emissions (Gen) (Million Tons/Year)	37.1	26.1	43.5
Resources 2030			
Conservation (MWa)	5,827	6,025	5,427
Wind (MWa)	1,800	1,790	1,808
Geothermal Options (MWa)	169	156	156
CCCT Options (MWa)	756	1134	0
SCCT Options (MWa)	162	648	648

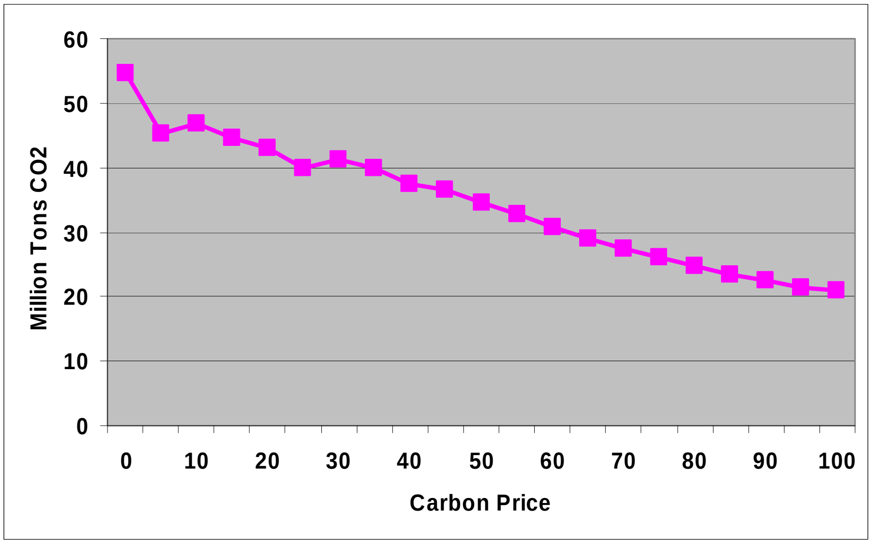
As would be expected, the $100 Carbon scenario reduces average carbon emissions far more than does the $0 to $100 Carbon scenario, which has an average carbon price that only reaches $47 per ton by 2030. The $20 carbon cost does not achieve these substantial reductions. Conservation does not increase substantially with $100 carbon costs because most of the available conservation was developed in the $0 to $100 Carbon scenario. There is a 400 average megawatt (7 percent) reduction of conservation in the $20 scenario. The development of renewable generation changes little among these scenarios and is largely determined by RPS requirements.

An interesting result is apparent in the changes of natural gas-fired generation options. With fixed carbon prices of $100 there is a large increase in the optioning of natural gas combined-cycle turbines, whereas with fixed $20 carbon costs more simple-cycle turbines are optioned. In the $100 Carbon scenario significant reductions in carbon emissions are achieved by displacing existing coal plants. The combined-cycle plants are being optioned to provide base-load energy and capacity to displace the coal plants. In the $20 Carbon Cost scenario the coal plants remain viable base-load plants and additional capacity is provided by simple-cycle turbines to provide capacity. In the $100 Carbon scenario, the question again arises of whether coal plants would remain viable at low-capacity operations.

These results are consistent with preliminary estimates done by the Council of carbon emissions using the AURORA$^{xmp®}$ Electric Market Model. The results of those studies showed that carbon prices of between $40 and $70 per ton are required to change the dispatch order of coal and natural gas-fired generation. The exact point of change will depend on the price of natural gas relative to the carbon price and will vary for individual plants. The future price of natural gas and carbon costs cannot be known. The $0 to $100 Carbon scenario, therefore, models the risks of alternative futures for both carbon cost and natural gas price to find a resource strategy that reduces the risk associated with these uncertainties.

Another approach to the question of how carbon prices are related to emission levels was done using the Regional Portfolio Model in a deterministic mode (i.e. using expected values of variables instead of stochastic analysis). The $0 to $100 Carbon scenario resource strategy was tested with costs for carbon emissions varying in $5 increments from $0 to $100. Figure 9-4 shows the results. Increasing carbon costs lead to reduced emissions. Again prices of carbon above $40 per ton begin to push carbon emissions below 40 million tons by 2030, and emissions could be cut in half from that level with institution of a carbon cost of $100 per ton. These results should not be expected to match closely the results for the $0 to $100 Carbon scenario in the tables in this section because of the effects of varying levels of demand, natural gas prices, hydro conditions, and other varying future conditions modeled in the $0 to $100 Carbon scenario.

Figure 9-4: An Estimated Relationship between Carbon Price and Emissions



Random Carbon Penalty up to $50

If a cap and trade system is implemented, the price of carbon emission permits will be determined in a market with multiple buyers and sellers. The price in that market will depend on the demand for allowances and the cost of reducing carbon emissions. Although there are estimates of the future cost of carbon emission allowances under the proposed Waxman Markey Bill, the actual costs experienced will depend on supply of and demand for allowances and on the role and geographic scope of any offsets that may be allowed to meet carbon reduction requirements.

To test this, the Council looked at a scenario where carbon prices could vary from $0 to $50 instead of the range of $0 to $100 assumed in the $0 to $100 Carbon scenario. The expected value of this smaller range of prices by 2030 is about $20 compared to the $47 average in the $0 to $100 Carbon scenario. Table 9-7 compares the results of the two carbon price risk scenarios.

Table 9-7: The $0 to $50 Carbon Scenario versus the $0 to $100 Carbon Scenario

	$0 to $100 Carbon	**$50 CO2 Price Maximum**
Cost (billion 2006$ NPV)		
With Carbon Penalty	$105.60	$91.60
Without Carbon Penalty	$85.10	$78.30
Retail Rates - Change (%) from $0 to $100 Carbon Scenario		
With Carbon Penalty		- 3.6%
Without Carbon Penalty		- 1.0%
Carbon Emissions (Gen) (Million Tons/Year)	37.1	41.7
Resources 2030		
Conservation (MWa)	5,827	5,638
Wind (MWa)	1,800	1,798
Geothermal Options (MWa)	169	156
CCCT Options (MWa)	756	0
SCCT Options (MWa)	162	648

With a lower carbon price range, the cost of the power system is less, especially when carbon emission allowance costs are included in the costs. However, the costs that result from different resource choices and operations are only reduced by 8 percent. Carbon emissions are increased about 12 percent.

Most importantly, the Power Plan's basic resource strategy is not significantly changed by the lower carbon price range. Conservation remains the dominant resource choice, renewable development is driven by RPS requirements and does not change significantly, and natural gas remains the fuel-based resource for other needs.

Value of the Hydroelectric System

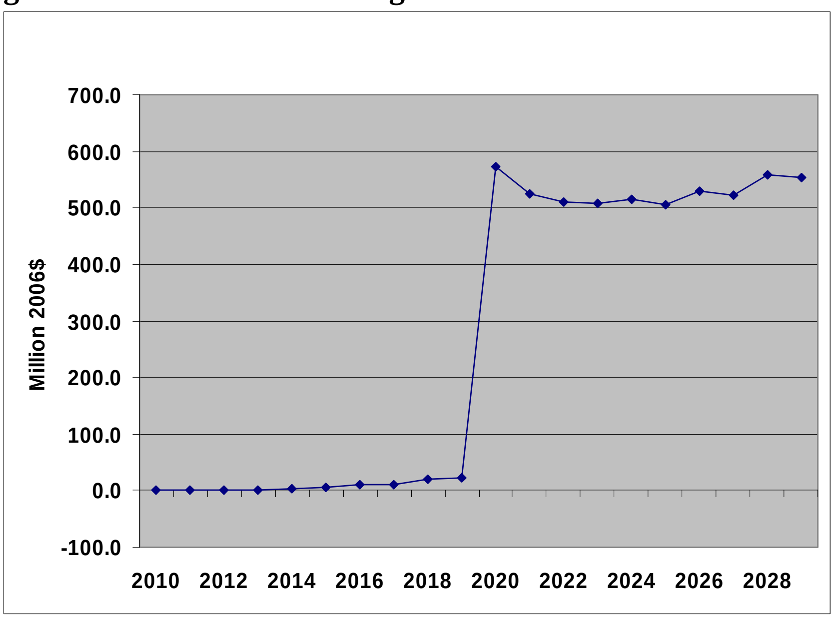
The Pacific Northwest power system emits about half the carbon dioxide per kilowatt-hour of the nation or the rest of the western states. This is due to the large role played by the hydroelectric system of the region. The value of this system is sometimes overlooked. To illustrate this tradeoff a scenario was run to examine the effects of removing the lower Snake River dams on costs, carbon emissions, and replacement resources that would be required for the power system. The capability of the dams was removed from the $0 to $100 Carbon scenario. The results of the scenario, however, could apply to other changes that reduce the capability of the hydroelectric system for any reason. For this scenario, it was assumed that the dams are removed in 2020 and the energy and capacity are replaced by the Regional Portfolio Model. The results are compared to the $0 to $100 Carbon scenario in Table 9-8.

Table 9-8: The Dam Removal Scenario versus the $0 to $100 Carbon Scenario

	$0 to $100 Carbon	Dam Removal
Cost (billion 2006$ NPV)		
With Carbon Penalty	$105.60	$112.50
Without Carbon Penalty	$85.10	$88.80
Retail Rates - Change (%) from $0 to $100 Carbon Scenario		
With Carbon Penalty		+ 1.7%
Without Carbon Penalty		+ 1.0%
Carbon Emissions (Gen) (Million Tons/Year)	37.1	40.2
Resources 2030		
Conservation (MWa)	5,827	5,923
Wind (MWa)	1,800	1,801
Geothermal Options (MWa)	169	208
CCCT Options (MWa)	756	1134
SCCT Options (MWa)	162	324

Dam removal increases both the carbon emissions and cost of the power system. Small increases in conservation and renewable resources occur in this scenario, but the primary replacement of the dams is provided by natural gas-fired combined-cycle combustion turbines. Figure 9-5 shows the annual pattern of cost changes for the Dam Removal scenario. Annual cost of the power system increases in 2020 by about $550 million dollars and remains higher.

Figure 9-5: Annual Cost Changes for the Dam Removal Scenario



Summary

Figure 9-6 summarizes the results of the various scenarios described above. Significantly reducing carbon emissions from the regional power system will increase costs of electricity. The costs shown in this summary assume that carbon penalties are excluded from utility revenue requirements through free emission allowances or other mitigation. The Current Policies scenario demonstrates the region can stabilize emissions near 2005 levels by 2030, but not reduce them without additional actions aimed at reducing carbon emissions. Without the current policies in place now, however, carbon emissions from the power system would continue to grow. Because over 85 percent of these carbon emissions are from existing coal plants serving regional loads, any significant reduction requires reduced reliance on these coal plants. Carbon prices above $40 per ton can reduce coal plant use, but an alternative policy would be to retire coal plants. In either scenario, the future cost of electricity would be increased.

Another way of looking at these results is to compare scenarios in terms of changes relative to the $0 to $100 Carbon scenario. Figure 9-7 shows changes in net present value system costs as bars and changes in carbon emissions as diamonds measured from the left hand scale. There is only one scenario in which costs and carbon emissions move in the same direction. That is the Dam Removal scenario where the policy choice is not intended to reduce carbon emissions, but rather to improve salmon and steelhead survival.

Figure 9-6: Summary of Costs and CO2 Emissions in Climate Policy Scenarios

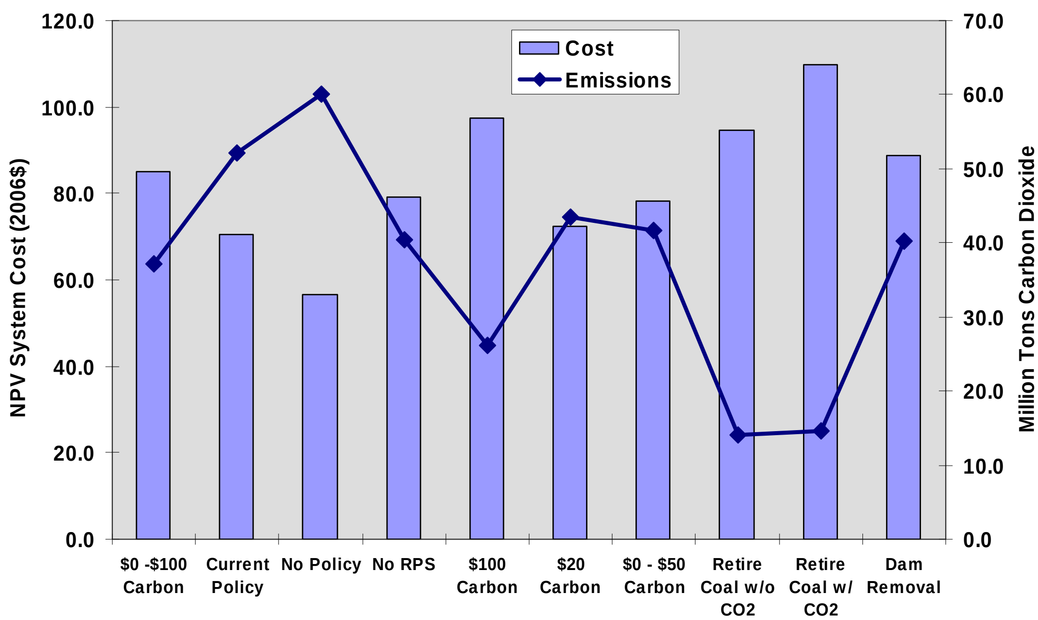
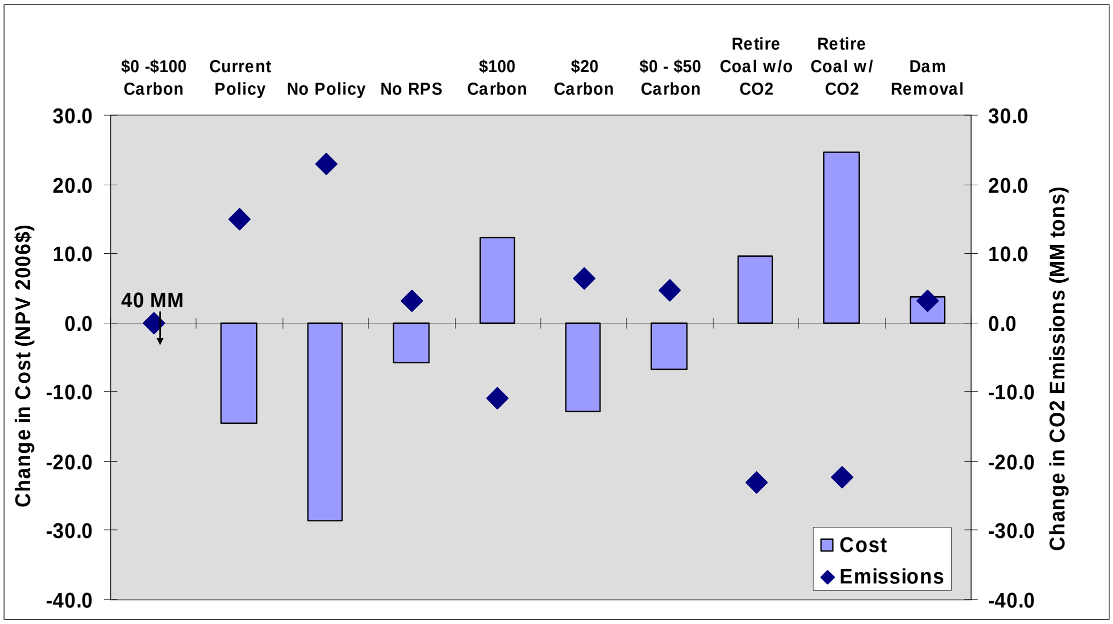


Figure 9-7: Summary of Costs and CO_2 Emissions: Changes from \$0 to \$100 Carbon Scenario



Consumer Electric Rates and Monthly Bills

The net present value system costs that are the basis for resource planning do not mean a great deal to the region's citizens. They are more likely to be interested in their monthly electricity bills or the electricity rates that they pay. In this section, the effects of the various scenarios used to develop the Council's resource strategy for the Sixth Power Plan on consumers bills and rates are discussed.

By law, the Council's Power Plan is to minimize the cost of energy services, such as heat or light. The Council is not charged with minimizing electricity rates. The objective of the Plan is to minimize consumers' electric bills. There are a number of steps involved in estimating rates or bills from the going forward system costs that are the planning criteria for the Council's Plan. Most notably, the fixed cost of the existing power system must be recovered through rates (paid for in bills) but is not included in the system costs of the Council models. In addition, some of the costs of conservation are not paid through electricity bills, but are paid directly by consumers. For example, an energy efficiency standard will improve the efficiency of appliances and to the extent it results in higher cost appliances, consumers will pay for the increased efficiency directly, rather than through electricity bills. There are other adjustments as well. For example, as described in Chapter 8, it is not clear what amount of any carbon tax or carbon emissions allowance cost will have to be recovered through electricity rates.

The Council has calculated costs, rates and bills including both all and none of these carbon penalty costs to provide a range of effects. From a societal perspective someone will pay these costs to reduce carbon emissions, but it isn't clear how much of the reduction will be accomplished in the electricity sector, nor how much will show up in bills and rates.

In the rates and bills calculations in this section, the fixed cost of the existing power system is assumed to remain constant in real terms. Depreciation of existing assets is assumed to be offset by equipment upgrades and replacements. To the extent that major transmission upgrades are needed in the future, these costs are not included in these estimates. Those costs are likely to occur regardless of the resources chosen for the Council's resource strategy, although aggressive conservation will reduce the need for additional transmission along with reducing the need for new electricity generation capability. One exception is the cost of upgrading transmission to access remote wind resources; these costs are recognized in the Council's planning.

Figure 9-8 shows a comparison of electricity rates among the scenarios considered in the Plan. The rates are shown both with and without the carbon penalties. The variation in rates is not as large as the variation shown earlier in power system planning costs. That is because a large portion of the revenue requirement that has to be recovered in rates and bills is fixed and does not change among the scenarios. It is important to remember that these rates are averages over 750 futures. There will be very significant variations among these futures depending on natural gas prices, hydroelectric conditions, the need to build new generation, and electricity market prices.

Another reason for relatively little variation in rates is the fact that conservation accounts for the majority of new resources. The low and high conservation scenarios show that the effect on electricity rates is not large. Conservation does tend to raise the rates for electricity, but as can be seen in Figure 9-9 it reduces electricity bills because less electricity is used.

The $0 to $100 Carbon scenario is one that is estimated to attain on average the carbon reduction goals in Oregon and Washington and in proposed federal legislation. It is therefore interesting to examine the estimated rate and bill effects of that scenario compared to the Current Policy scenario. The implicit assumption in these comparisons is that the electricity sector would be required to meet a similar percent reduction in emissions as the economy at large. The rates in the $0 to $100 Carbon scenario are between 2.4 percent and 9.3 percent higher than the Current Policy scenario. The range depends on how much of the carbon penalty has to be recovered through electricity sale revenues. The effect on electricity bills is to increase average monthly bills for a residential consumer by between $.94 and $5.58.

The largest effect on bills and rates is in the fixed $100 Carbon scenario. The second largest effect is in the coal retirement scenarios. Unless replacement of existing coal-fired generation is subsidized in such a policy scenario, the cost would be expected to be recovered through electricity revenues.

Figure 9-8: Levelized Retail Rates in Alternative Scenarios

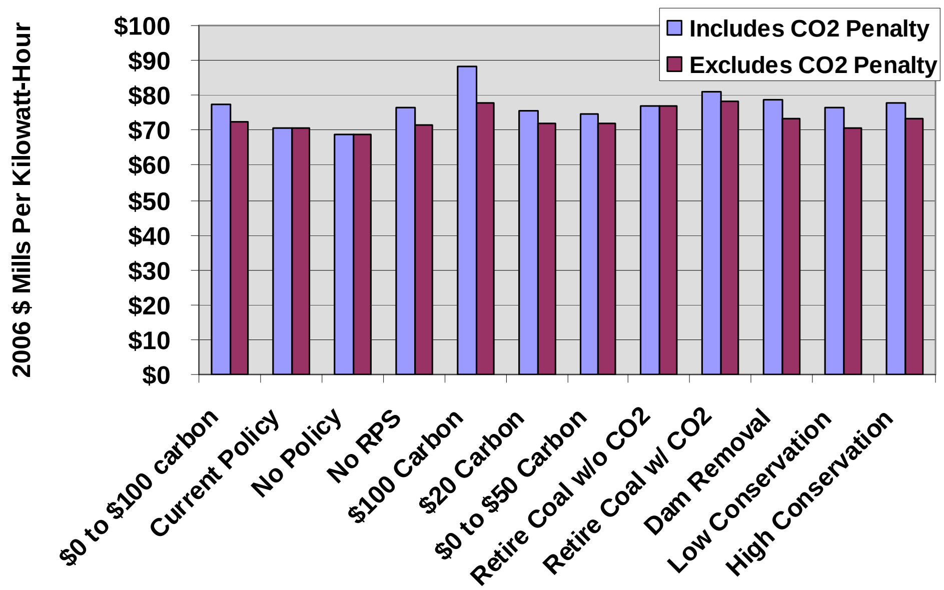


Figure 9-9: Levelized Residential Monthly Electricity Bills in Alternative Scenarios

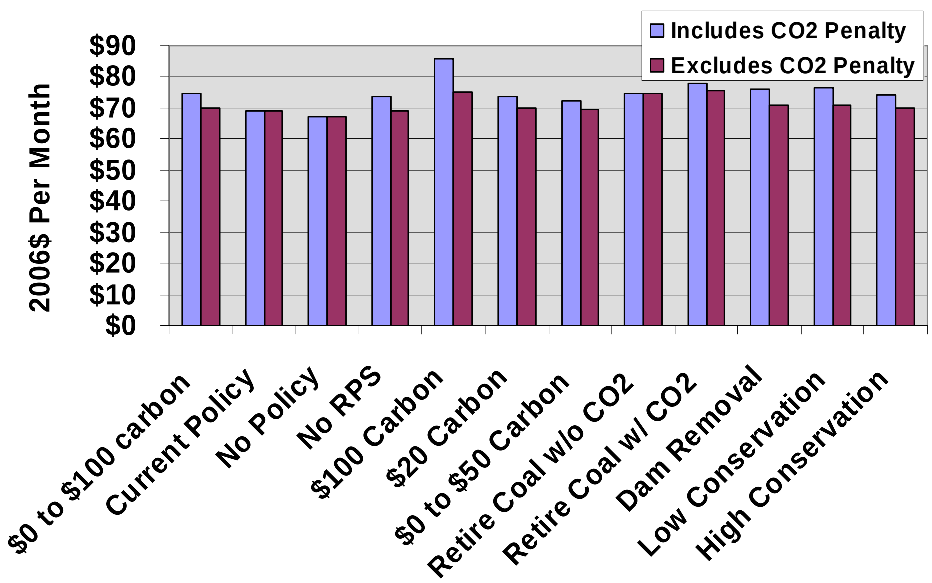


Figure 9-10 shows forecasts of monthly residential electricity bills over time for three scenarios; No Policy, Current Policy, and the $0 to $100 Carbon price risk assessment scenario. The $0 to $100 Carbon scenario bills are shown both with and without carbon costs included in the rates. This graph illustrates that attaining significant carbon reductions will increase electricity rates and bills. Without carbon price risk in the Current Policy scenario average bills would remain about the same over time. In the $0 to $100 Carbon scenario bills would be expected to increase by about 0.8 percent per year during the planning period if cost penalties are included. In the same scenario electricity rates would increase by 1.2 percent per year.

The increases seem small relative to some of the changes in planning costs. The effects of carbon pricing are minimized by the large role of conservation and renewables in the plan and the fact discussed above that a large share of electricity bills goes to cover existing infrastructure costs that are assumed not to change. In addition, a carbon penalty impacts the Pacific Northwest less than other regions because of the large role of our hydroelectric system and limited reliance on coal-fired generation.

Figure 9-10: Monthly Residential Electric Bills in Three Scenarios

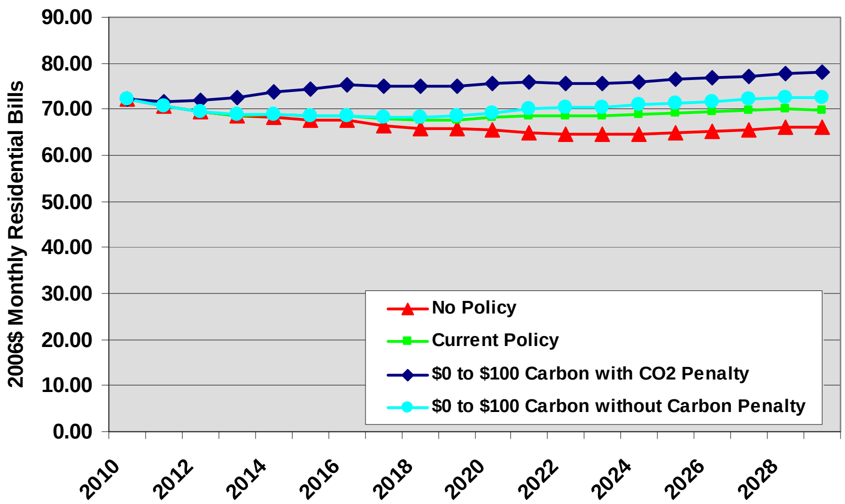
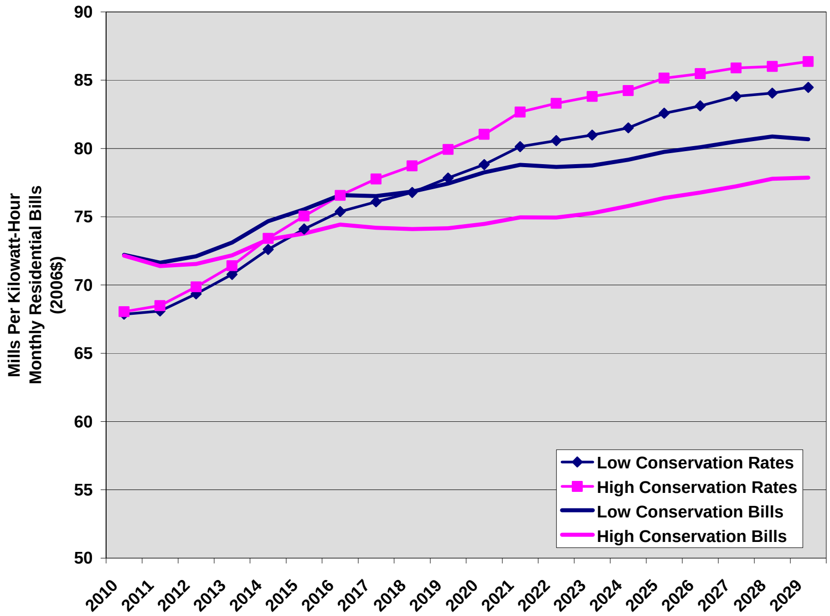


Figure 9-11 illustrates the effect of conservation costs on rates and bills. Conservation imposes cost on the power system, but reduces electricity sales. To recover the costs, therefore, utilities are required to raise electricity rates per kilowatt-hour. At the same time, however, consumers' use of electricity decreases. The net effect is that on average, consumers' monthly electricity bills are reduced. This is illustrated in Figure 9-11 by comparing rates and bills between the Low Conservation scenario and the High Conservation scenario. With low conservation, rates are reduced but bills are increased.

Figure 9-11: Electric Rate and Bill Effects of Low and High Conservation Scenarios



Detailed Scenario Results

The table below summarizes the most important results from the scenario analyses. It includes information of the costs, retail rates, carbon emissions, and resource choices. The differences between the Current Policy (Zero Carbon Risk) and other scenarios are calculated. In addition, for rates alternative scenarios are compared to both the Current Policy scenario and the $0 to $100 Carbon scenarios.

Scenario Comparison	No Policy	Zero Carbon Risk Current Policy	$0 to $50 Carbon risk	$0 to $100 Carbon risk	No RPS	Retire Coal with CO2	Retire Coal w/o CO2	$100 Carbon	$20 Carbon	Dam Removal	High Conservation	Low Conservation
Cost (billion 2006$ NPV) **with** Carbon Penalty	$56.5	$70.5	$91.6	$105.6	$101.4	$122.2	$94.7	$143.7	$89.7	$112.5	$103.8	$114.3
NPV Change from Current Policy	-$14.0	$0.0	$21.1	$35.1	$30.9	$51.7	$24.2	$73.2	$19.2	$42.0	$33.3	$43.8
% Change from Current Policy	-20%	0%	30%	50%	44%	73%	34%	104%	27%	60%	47%	62%
Cost (billion 2006$ NPV) **without** Carbon Penalty	$56.5	$70.5	$78.3	$85.1	$79.3	$109.7	$94.7	$97.4	$72.3	$88.8	$84.8	$88.7
NPV Change from Current Policy	-$14.0	$0.0	$7.8	$14.6	$8.8	$39.2	$24.2	$26.9	$1.8	$18.3	$14.3	$18.2
% Change from Current Policy	-20%	0%	11%	21%	12%	56%	34%	38%	3%	26%	20%	26%
Retail Rates - **with** Carbon Penalty	68.87	70.80	74.60	77.37	76.48	80.97	77.03	88.44	75.78	78.70	77.83	76.28
% Change from $0 to $100 Carbon Risk	-11.0%	-8.5%	-3.6%	0.0%	-1.2%	4.7%	-0.4%	14.3%	-2.1%	1.7%	0.6%	-1.4%
% Change from Zero Carbon Risk	-2.7%	0.0%	5.4%	9.3%	8.0%	14.4%	8.8%	24.9%	7.0%	11.2%	9.9%	7.7%
Retail Rates - **without** Carbon Penalty	68.87	70.80	71.78	72.51	71.30	78.28	77.03	77.68	71.79	73.21	73.17	70.75
% Change from $0 to $100 Carbon Risk	-5.0%	-2.4%	-1.0%	0.0%	-1.7%	8.0%	6.2%	7.1%	-1.0%	1.0%	0.9%	-2.4%
% Change from Zero Carbon Risk	-2.7%	0.0%	1.4%	2.4%	0.7%	10.6%	8.8%	9.7%	1.4%	3.4%	3.3%	-0.1%
Carbon Emissions Comparison												
Carbon Emissions (Gen) (Millions Tons/year)	60	52.1	41.7	37.1	40.3	14.7	14	26.1	43.5	40.2	36.6	41
Millions of tons Saved Compared to Current Case over 20 yrs.	-158	0	208	300	236	748	762	520	172	238	310	222
Resources 2030												
Conservation (MWa)	5,432	5,197	5,638	5,827	5,935	6164	5,739	6,025	5,427	5,923	5,849	4,566
Wind (MWa)	0	1,845	1,798	1,800	1,171	1,787	1,809	1,790	1,808	1,801	1,778	1,996
Geothermal Options (MW)	52	13	156	169	208	156	52	156	156	208	195	208
CCCT Options (MW)	1890	0	0	756	378	2268	2268	1134	0	1134	378	2268
SCCT Options (MW)	648	648	648	162	648	648	648	648	648	324	162	162

Chapter 10: Climate Change Issues

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 affect future resource choices. There remains a great deal of uncertainty surrounding both of these issues. This chapter describes the second of these issues, namely how current policies affect the plan's resource strategy and what future policies may help achieve green house gas emission reduction goals. The first issue, relating to physical changes resulting from climate change is discussed in Appendix L.

The focus of climate policy especially for the power generation 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 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 and nuclear, or from sequestering carbon.

Reductions in carbon emissions can be encouraged through various policy approaches including, regulatory mandates (e.g. renewable portfolio standard or emission standards), emissions cap-and-trade systems, emissions taxation, and efficiency improvement programs. Policy responses to climate change concerns for the Northwest states have focused on renewable energy and new generation emission limits. National and west-wide 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.

The Council's "$0 to $100 per ton carbon penalty" scenario assumes current climate policies that include renewable portfolio standards (RPS), new generation emissions standards and renewable energy credits. The scenario also assumes various future carbon penalty cost trajectories that vary between zero and $100 per ton and average $47 per ton by 2030. The least risk resource portfolio in this scenario includes a combination of conservation, renewable resources and gas-fired resources and results in a reduction of power system carbon emissions from 57 million tons per year in 2005 to an average of 37 million tons in 2030. This expected reduction, which is below the 1990 emission level of 44 million tons, is generally consistent with targets adopted by Northwest states. This expected reduction is the average of 750 futures, which means that about half of all futures have greater reductions and about half have less reductions.

If no future carbon pricing policies are assumed, a least-cost resource strategy would only stabilize carbon emissions at about current levels. Therefore, relying only on existing policies will not achieve the WCI carbon emission goals or those of individual states in the region. To significantly lower carbon emissions, existing coal-fired generation must be reduced. In the $0 to $100 per ton carbon penalty scenario, these plants are simply used much less frequently because of cost. However, there are potential future conditions where coal generation would be needed. In order to ensure a reduction in emissions, coal plants must be retired. Analysis of a scenario in which all regional coal plants are phased out between 2012 and 2020 showed that carbon emissions could be reduced to about 15 million tons by 2030. A number of alternative scenarios were analyzed to investigate the relationship between future carbon cost levels and emissions.

The Columbia River hydroelectric system provides most of the region's energy, capacity, and flexibility supply. As a carbon free resource, it is extremely valuable to the region. Primarily because of the hydroelectric system the region's carbon emissions are half of those for the nation as a whole. 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. The region should carefully consider future fish and wildlife operations because loss of hydroelectric capability will increase carbon emissions. For example, removing the lower Snake River dams would undo 40 percent of the carbon reductions expected to be accomplished through the Council's plan.

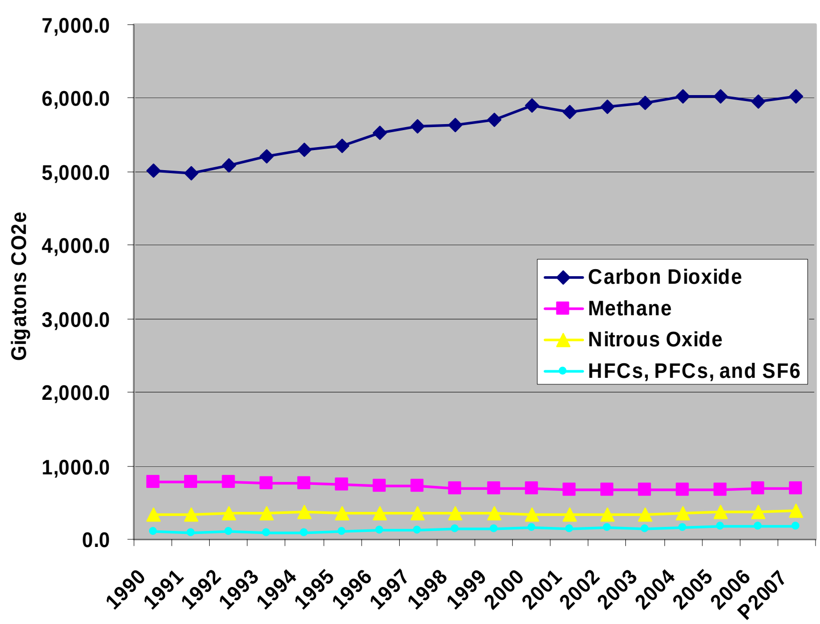
BACKGROUND

A large uncertainty facing future plans for electricity generation and use is climate change and associated policies aimed at controlling greenhouse gas (GHG) emissions. This chapter focuses on sources of GHGs related to the production and consumption of energy, especially the burning of fossil fuels, which are the focus of these policies. It does not address the phenomenon of climate change or its likely effects, but rather on how concerns and policies about those affect the region's energy system planning. Appendix L examines the physical implications of some specific climate change scenarios on the region's power system.

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 CFC refrigerants. Different gases have different degrees of effect on warming and these are measured as global warming potential (GWP). Carbon dioxide, which has become almost synonymous with GHG, has the least global warming potential of the GHGs. Many of the other GHGs have global warming potentials thousands of times greater than that of carbon dioxide. Nevertheless carbon dioxide has become the primary focus of climate policy and discussion. The reason is that carbon dioxide accounts for more than three quarters of global GHG emissions. In the U.S. carbon accounts for 85 percent of GHG emissions and it is a growing source. Figure 10-1 shows that growth in carbon dioxide emissions are the primary reason for total U.S. GHG emissions growing since 1990. Levels of emissions from most other GHGs 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 efficiency of energy use. The combustion of fossil fuels accounts for 94 percent of U.S. carbon dioxide emissions. Therefore declining carbon dioxide emissions reflect a corresponding decline in energy use per dollar of gross domestic product.

Figure 10-1: Sources of U.S. Greenhouse Gas Emissions, 1990 to 2007



Source: U.S. Energy Information Administration

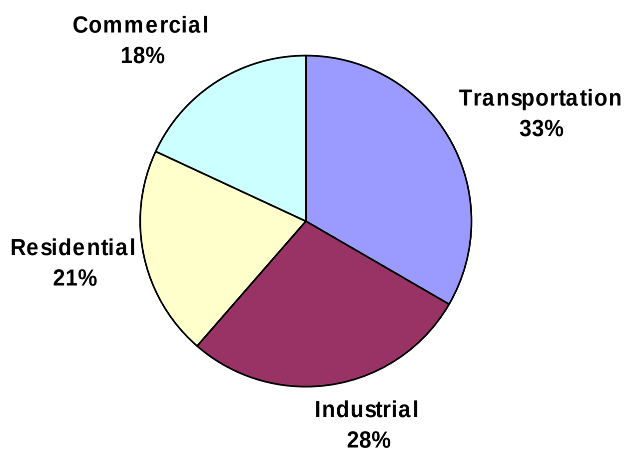
[1] The source of information for much of the following discussion is from the Environmental Protection Administration. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006. April, 2008. USEPA #430-R-08-005. http://www.epa.gov/climatechange/emissions/usinventoryreport.html

The National View

For the United States as a whole, electricity generation is the largest source of carbon dioxide emissions. Electricity generation accounted for 34 percent of carbon dioxide emissions in 2006. The next largest emissions 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 to be used in other sectors. When the carbon dioxide emissions from electricity generation are allocated to the sectors using the electricity, and added to those sectors' direct combustion of fossil fuels, a different mix of emissions sources results. In that accounting framework, which relates carbon emissions to the underlying human activities, transportation becomes the largest carbon dioxide emitting sector. Figure 10-2 shows the sources of carbon dioxide emission by end use sector in the U.S.

For electricity planning, the implication of this information is that, to reduce carbon dioxide emissions from the electricity sector, policies should address both the generation of electricity and the efficiency of electricity use. Carbon emissions from electricity generation can be addressed through 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. On the electricity use side, improved efficiency of use reduces the need to generate electricity. Policies should target both sides of the electricity equation with priority given to the lowest cost mitigation approaches. Further, policies should also address emissions from the direct use of fossil fuels in other sectors, including transportation.

Figure 10-2: Carbon Dioxide Emissions by Sector, 2006

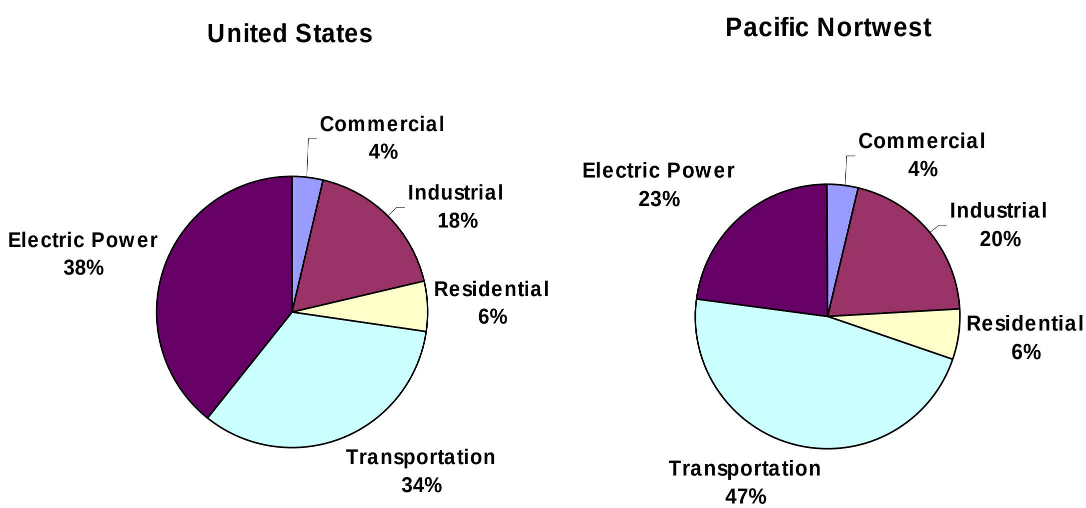


Note: Electricity generation emissions allocated to end use sectors
Source: U.S. Environmental Protection Agency

The Pacific Northwest Regional View

The sources of carbon emissions in the Pacific Northwest are not typical of the U.S. as a whole. Figure 10-3 compares the shares of carbon dioxide emissions from economic sectors for the U.S. and the 4 states in the Northwest. Unlike Figure 10-2, emissions from electricity generation are included in the electric power sector in Figure 10-3. 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. electric power 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 electricity supply.

Figure 10-3: Energy Carbon Emissions by Sector, 2005

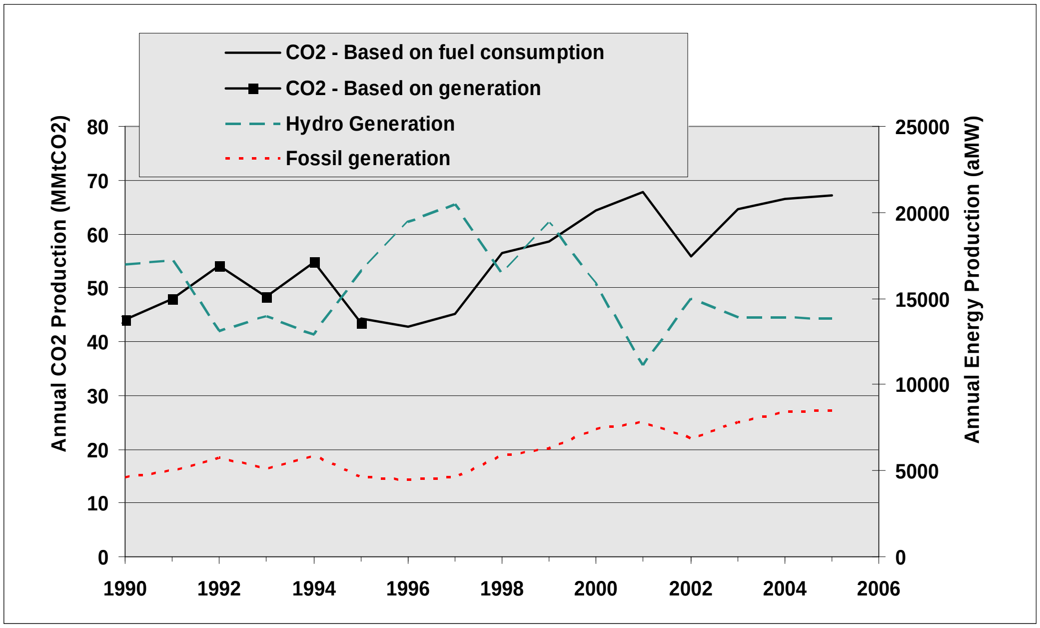


The years 1990 and 2005 are frequently used as benchmarks in policies for the control of greenhouse gasses.[2] The 1990 production of carbon dioxide from the Pacific Northwest power system is estimated to have been about 44 million tons, based on electricity production records of that year. Load growth, the addition of fossil-fuel generating units, the loss of hydropower production capability, and the retirement of the Trojan nuclear plant resulted in growing CO_2 production over the next 15 years. By 2005, the most recent year for which electricity production or fuel consumption data are available, CO_2 production increased 52 percent to 67 million tons (Figure 10-4). This is approximately the CO_2 output of 23 400-megawatt conventional coal-fired power plants, 56 400-megawatt gas-fired combined-cycle plants or about 11.7 million average U.S. passenger vehicles.

[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 CO_2 emissions to the 1990 rate by 2020. Washington Governor Gregoire's climate-change executive order includes the same target for CO_2 reductions. Oregon House Bill 3543, passed by the legislature and signed by Governor Kulongoski in August, declares that it is state policy to stabilize CO_2 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 GHG emissions to 15 percent below 2005 levels by 2020.

The regional CO_2 production estimates from 1995 through 2005 shown in Figure 10-4 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 10-4: Growth of CO_2 Emissions from Electricity Generation in the Pacific Northwest



Annual hydropower conditions can greatly affect power system CO_2 production. Average hydropower production in the Northwest is about 16,400 average megawatts. As shown by the plot of Northwest hydropower production in Figure 10-4, the 1990 water year was nearly 17,000 average megawatts, slightly better than average. Other factors being equal, this would have slightly reduced CO_2 production that year by curtailing 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 CO_2 production. The effect of hydropower generation on thermal plant generation and CO_2 production is apparent in Figure 10-4.[3]

If normalized to average hydropower conditions, actual generating capacity, and the medium case loads and fuel prices of the Fifth Power Plan, the estimated CO_2 production in 2005 would have been 57 million tons, a 29 percent increase over the 1990 rate. This is the value used for comparison in this paper.

[3] In Figure 10-4, 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.

ACTIONS TO REDUCE GREENHOUSE GAS EMISSIONS

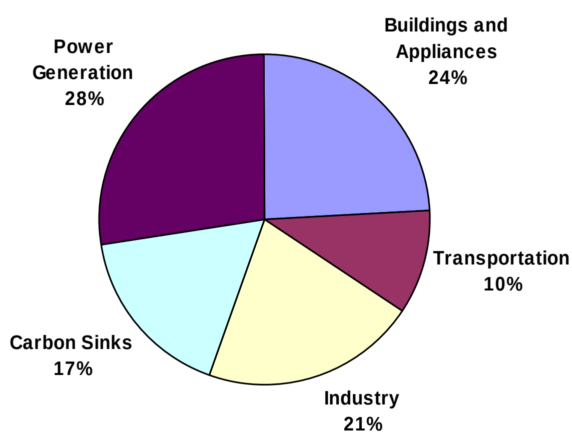
Because GHG emissions are dominated by carbon dioxide emissions from burning fossil fuels, and that is the primarily source of emission from electricity generation, the focus in this section is on carbon dioxide emissions. From a broad perspective, there are three general kinds of actions that can be taken to reduce carbon dioxide emissions; electricity could be generated from lower or zero carbon emitting fuels, the use of electricity could be reduced, or carbon that is released could be sequestered or offset. Similar possibilities exist for other uses of energy from fossil fuels besides electricity generation.

In 2007, McKinsey and Company undertook a study of how much GHG reduction was possible in the U.S. and what it might cost.[4] The McKinsey report looked at alternative actions to reduce GHG emissions. They assumed that without actions GHG 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 the reduction could be done at negative cost. Nearly all of this came from improved efficiency of energy use in buildings or vehicles. The remaining 60 percent of GHG reduction came from an array of actions that increased in cost as reductions grew. The most expensive option used 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 10-5. As was the case for Figure 10-2 emissions reductions from more efficient use of electricity are counted in the sector where electricity is consumed.

Figure 10-5: Estimated Sources for a 3 Billion Ton Reduction of GHG Emissions by 2030



[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.

There are some interesting observations to make about the McKinsey results. Although a great deal of the policy discussion on GHG reduction centers 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 and potential is hybrid vehicles. In the McKinsey analysis, it is the most expensive alternative shown (around $90/ton) and it has relatively small potential for GHG reduction. The plug-in hybrid option was not needed to reach the 3.0 billion ton reduction case described above. Improved efficiency of conventional vehicles has far greater and cheaper potential.

If the goal is to stabilize GHG 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 GHG 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 emissions of GHG would need to be reduced to about one quarter of today’s emissions by 2100 to stabilize atmospheric concentrations of GHG.

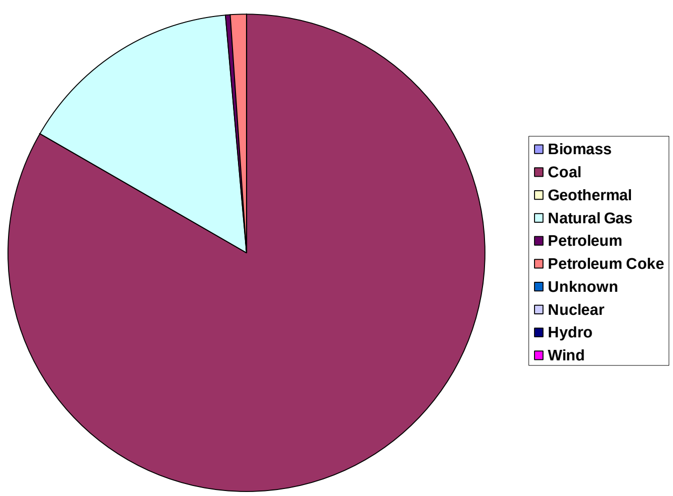
There have been many studies of the costs of particular policies or goals for GHG reduction. The usual purpose has been to try to estimate the price of carbon that is likely to be associated with a policy. The Council had a study done by EcoSecurities Consulting Limited to provide a range of likely carbon costs during the period of the Council’s power plan. EcoSecurities reviewed many studies and provided a set of alternative estimates of carbon prices based on their models of supply curves for carbon mitigation actions. Point Carbon reviewed the results of 7 studies of the Lieberman-Warner bill for Bonneville, 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 assumed. 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 EcoSecurties report estimated that carbon prices might need to reach about $50 a ton by 2030 to progress toward the Intergovernmental Panel of Climate Change goal of stabilizing GHG 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 horizon. This possible but uncertain cost of carbon emissions has a significant influence on the plan’s resource strategy. Conservation, 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 expected costs, it is clear that improved efficiency is available in significant amounts and at low cost without adding to 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 next most expensive. Many other renewable resources, coal with carbon separation and sequestration, and advanced nuclear may become available within the Council's planning horizon, but are not currently available or are very expensive.

To achieve very 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 10-6, existing coal-fired power plants account for about 88 percent of the region's emissions. Therefore, for example, the region could not reduce its power system emissions below 1990 levels, as some targets suggest, if the region's coal plants continue to operate as they do now. Thus 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 face additional investment to extend their lives 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 CO_2 Emissions from the Northwest Power System, 2005



POLICIES TO REDUCE GREENHOUSE GASES

There are many possible policy approaches to reduce carbon emissions. They include GHG cap-and-trade programs, direct taxation of GHG emissions, regulatory programs that limit emissions or require non-emitting resources to be developed, and efforts to improve the efficiency of energy use. Choices among these approaches have varied. 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 emissions of new power plants have been the focus of much policy. The Council has primarily focused on efficiency of electricity use, and states, utilities, and the Federal Government have initiatives in efficiency improvement 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 of these approaches has advantages and disadvantages.

Mandates

A number of mandates direct companies and individuals to acquire or produce energy-using equipment that meets an approved standard of energy efficiency, or uses approved types of energy. One example of such mandates 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 don't 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 region and a number of states elsewhere in the country have passed laws (Renewable Portfolio Standards) that require utilities to increase the level of electricity generated by renewable resources. These or related laws have in some cases also required generators that use non-renewable fuels to meet maximum emissions per kilowatt-hour standards (e.g. Washington and California).

Mandates have the advantage of relative simplicity and are fairly simple to enforce. They have the disadvantage that they are inflexible in the face of changed technology or other conditions. For example, future reductions in emissions from a state renewable portfolio standard might well cost more per ton than subsidizing modernization of generation in China, or expanded forests in South America. But unless the mandate has been made sufficiently flexible, it would not recognize these new alternatives as satisfying the mandate.

Tax Incentives

Tax incentives may reduce the cost of investment in preferred equipment such as hybrid cars or energy-efficient equipment or equipment that captures renewable energy, by allowing accelerated depreciation, tax credits or various forms of tax exemptions. Tax incentives of these types have been extended to hybrid cars, electricity generators powered by wind, and 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 of rewarding the final product desired, 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 SO_2 and NO_X was established as part of the Clean Air Act Amendments of 1990. This policy is generally regarded as a success, resulting in faster reductions in SO_2 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 be expected to 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 retail prices of energy, providing appropriate price signals to final consumers of energy or of products produced using energy.

As a policy with the goal of reducing emissions of greenhouse gasses, 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, the carbon tax policy, described next, has a more predictable total cost, but a less predictable total reduction in emissions.

Finally, cap-and-trade programs require the development of a market to trade emission allowances. The market mechanism offers the potential for emission reductions at low costs, but the development of a market trading newly-created assets like emission allowances requires careful consideration to have confidence that the market will function as expected.

Carbon Taxes

A carbon tax would likely apply not only to carbon, but also to all greenhouse gasses in proportion to their climate-changing effects. The climate impacts of the non-CO_2 gases are generally expressed as "CO_2 equivalents," so for this discussion all such taxes will be referred to as a carbon tax. It would tax emissions of greenhouse gasses at a level that would be expected to reduce emissions to the level chosen to control and mitigate climate change.

At the margin, the effect on overall emissions of a carbon tax of a certain cost per ton of carbon equivalent emitted should be the same as a cap-and-trade policy that results in an allowance price of the same cost per ton of carbon equivalent emitted. But as was pointed out above, the tax makes the total cost of emissions reduction reasonably predictable while leaving total reductions unpredictable, while a cap-and-trade program makes reductions more predictable and leaves the total cost less predictable.

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 gasses.

CURRENT POLICIES AND GOALS AFFECTING THE PACIFIC NORTHWEST

At present, CO_2 reduction policies regionally, nationally and globally are still very much in a state of flux. CO_2 reduction goals range from stabilizing emissions at current levels to reducing emissions to 1990 levels or below. Many different policy initiatives and actions have been proposed (see above) to achieve these reduction goals. This section describes policies and actions that are currently being implemented on an international, federal and regional basis.

International Initiatives

Significant international initiatives targeted at climate change can probably be dated from 1992, when the U.N. 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 targets for developed countries reductions by 2008-2012. The Kyoto Protocol, in spite of the withdrawal of the U.S. in 2001, has been ratified by 182 countries including 37 industrialized countries who account for over 60 percent of developed countries' emissions. It is hoped that a conference in Copenhagen in late 2009 will result in agreement on international action after 2012.

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 carbon dioxide emission reductions. The system has experienced episodes of price volatility, which has been attributed to imperfect data and 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 Change[5] has identified a goal of limiting global warming to 2 degree Celsius (3.6 degrees Fahrenheit) and has translated that goal into emission reduction targets for developed countries. Those targets call for an 80 to 95 percent reduction in emissions relative to 1990 levels by 2050.

[5] Information on the Intergovernmental Panel on Climate Change (IPCC) can be found at http://www.ipcc.ch/.

Federal Policies

The Waxman-Markey draft legislation, entitled "The American Clean Energy and Security Act of 2009," proposes a comprehensive strategy for energy planning and use. This legislation has four parts (or titles in legislative terms), which 1) promote clean energy production, 2) encourage energy efficiency, 3) reduce emission of greenhouse gases and 4) protect U.S. consumers and industry during the transition to a clean energy economy.[6]

Title I requires electricity suppliers to meet 6 percent of their load in 2012 and 25 percent of their load in 2025 with a combination of renewable resources and energy efficiency. It includes a carbon capture and sequestration (CCS) demonstration program, incentives for adoption of CCS, and performance standards for new coal-fired power plants. The title contains provisions to encourage the modernization and expansion of the electrical transmission system. Finally, it offers federal assistance to state clean energy and energy efficiency projects, and allows federal agencies to sign long-term contracts to buy electricity generated from renewable sources.

Title II includes a range of federal assistance measures to improve the energy efficiency of new and existing buildings. It strengthens efficiency standards for lighting and appliances, and improves the U.S. Department of Energy process for setting these standards in the future. It sets standards for electricity and natural gas distribution companies to help their customers accomplish energy efficiency. Finally, it calls for the establishment of standards for industrial energy efficiency, and extends eligibility for grants and loads for energy efficiency to nonprofit and public health hospitals.

Title III establishes a program that covers emitters responsible for about 85 percent of total U.S. greenhouse gas emissions. The program creates tradable allowances that must be surrendered for each ton of GHG emitted. The total amount of allowances is reduced over time so that aggregate emissions by the covered entities is reduced in stages to a level that is 83 percent lower than their 2005 levels by 2050. The title includes measures for the establishment and regulation of the market for trading allowances, and gives responsibility to the Federal Energy Regulatory Commission for regulating the cash market for allowances.

Title III directs the Environmental Protection Agency (EPA) to enter into agreements to reduce GHG concentrations by preventing international deforestation. The bill allows both domestic and international offsets not to exceed 2 billion tons yearly. The bill allows banking allowances to be used in later years, allows borrowing allowances that must be repaid the next year, and creates a strategic reserve of allowances to be used to limit market price volatility. Finally, the bill directs the EPA to set emission standards for sources not covered by the cap-and-trade program, and the bill creates special programs to reduce emissions of two pollutants that contribute to global warming: hydro fluorocarbons (HFCs) and black carbon.

Title IV is focused on the process of adjusting to a clean energy economy. It authorizes the Secretary of Education to award grants to colleges and universities to develop training programs to prepare students for careers in renewable energy, energy efficiency, and other climate change mitigation work. This section also establishes an interagency council to integrate federal

[6] Citation on internet for language of bill

response to the effects of global warming, and establishes an adaptation fund to provide support for state, local and tribal adaptation projects.

Regional Policies

The Western Climate Initiative (WCI) is a broad regional effort to implement policies to reduce greenhouse gas (GHG) emissions. The governors of Oregon, Washington, and Montana have joined governors from five other western states and the premiers of four Canadian provinces to collaborate on implementation of policies to address climate change. The overall goal of the WCI is to reduce the region's GHG emissions to 15 percent below 2005 levels by 2020. The primary policy objective of the WCI is implementation of 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 fuels and from fuels burned at industrial, commercial, and residential buildings.

The process of developing the WCI has made it clear that a regional cap-and-trade program faces problems that are reduced if the program is made national or international. For example, individual states and provinces have significant flexibility to affect their jurisdiction's GHG reduction targets. The shares of the total reduction target that result are a source of potential conflict. Another example is the potential for "leakage," which can result from shifting emissions from inside the WCI to outside it. Such a shift would allow WCI emission targets to be met, but no net reduction in overall (global) emissions. Leakage becomes less likely as geographic scope of the cap-and-trade program increases to national or international.

State Policies

Policy initiatives at the state level to address climate change are numerous. This section narrows the focus to three types of state policy: GHG reductions goals; renewable portfolio standards; and emission performance standards. This selective summary misses 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 GHG production. The intent is to focus on policies that have the greatest relevance to the Sixth Power Plan.

Greenhouse Gas Emission Reduction Goals

The 2007 Oregon State Legislature set GHG 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 State Legislature is also considering WCI cap-and-trade legislation. House Bill 1819 and Senate Bill 5735 would codify the states 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.

The Oregon and Washington emission reduction goals for 2020 have a direct bearing on the Sixth Power Plan. The Council's current modeling framework does not model each state separately, so its results can be interpreted as averages across the region as a whole. Analysis described later in this chapter examines the feasibility, cost, and best method of reducing Northwest power sector carbon dioxide emissions to 1990 levels by 2020.

Renewable Portfolio Standards

Renewable resource portfolio standards targeting the development of certain types and amounts of resources have been adopted by three of the four states in the region (Oregon, Montana, and Washington) since adoption of the Fifth Power Plan. Similar standards have also been adopted by Arizona, British Columbia, California, Colorado, New Mexico, and Nevada. The key characteristics of the Pacific Northwest state 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 draft plan 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 fuelled by coal unless a minimum of 50% 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%.

Oregon: Since 1997, the developers of new power plants in Oregon have had to offset their carbon dioxide emissions to a level 17% 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 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 established by the State Department of Energy is to 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 fuelled by natural gas.

Washington: Since 2004, Washington has required fossil fuelled power plants subject to state site certification (generally plants of 350 MW, or greater) to offset or otherwise mitigate carbon dioxide emissions by 20%. Substitute Senate Bill 6001, 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 without the state. Modeled on California Senate Bill 1368, the law defines baseload electrical generating facilities as facilities designed to produce electricity at a 60% capacity factor or greater. The law adopts the initial California limit of 1,100 lbs/CO_2 per MWh, 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/CO_2 per MWh (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 provide carbon dioxide separation and sequestration as long as average lifetime emissions comply.

EVALUATION OF CARBON STRATEGIES

Existing climate change policies and proposed future policies have had a very significant effect on the development of the Sixth Power Plan resource strategy. In this section the effects of alternative policy assumptions are described. The intent is not to recommend any particular approach, but to provide information to policy makers about the likely effects of different approaches on the cost of the power system and its future carbon emissions.

The recommended actions in the Sixth Power Plan reflect existing carbon emissions policies that are assumed to continue. That is, the renewable portfolio standards (RPS) 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. 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. 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. The plan includes resource actions that mitigate carbon risk 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 comparisons with a report by Ecosecurities Consulting Ltd. The assumptions are included in the Regional Portfolio Model as a distribution of 750 carbon price trajectories that range from zero to $100/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 has included in its analysis is generally consistent with assumptions used in utility IRP analysis.

Accounting for regional power system carbon emissions requires a decision regarding the treatment of emissions associated with electricity that is imported and exported. The approach used for the Council's modeling is to count emissions by several generators that are located outside the region but whose output is committed to serving regional loads. 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. Other imports and exports of energy are treated in two alternative accounting frameworks. One is referred to as "generation based" and counts emission from plants located within the region or contracted to regional utilities. The other approach is referred to as "load based" and 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.[7]

There are also some complications in how to account for the estimated cost to the regional power system of carbon pricing policies. The default accounting of power system costs 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 the development and operating decisions of the power system. However, the default accounting can significantly overestimate the total costs that the power system would recover from ratepayers, depending on the specific form of carbon penalty that the system faces. In particular, the current language of the U.S. 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 impact on the power system, compared to a carbon tax on all emissions. To allow the reflection of different forms of carbon penalties, the portfolio model has an alternative accounting that excludes the amount of tax revenues. This alternative accounting provides a better estimate of the cost 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 described above. A combination of aggressive conservation development, 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 37 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 carbon cost risk assumptions play an important role in these results. If only current policies are assumed in the future, that is if no carbon pricing policies are implemented or expected, a least cost resource strategy would only stabilize carbon emissions from the power system at about current levels. Existing policies will not achieve the carbon emissions goals that exist in the WCI or some individual states in the region.

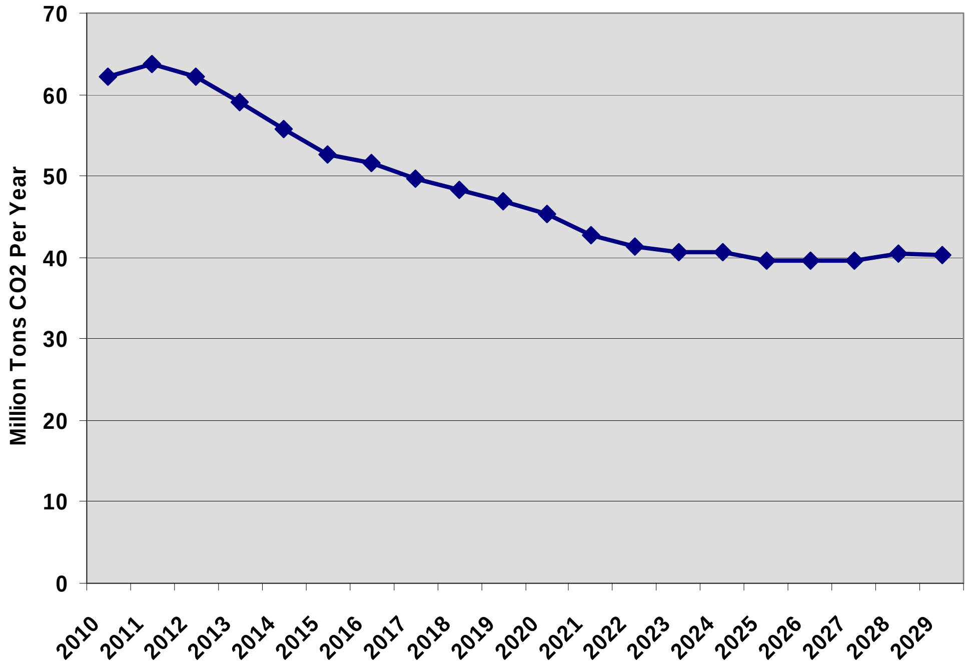
[7] Northwest Power and Conservation Council. Carbon Dioxide Footprint of the Northwest Power System. November 2007. (Council Document 2007-15)

The cost of moving from current policies to the $0 to $100 per ton carbon penalty scenario is significant. Response to the assumed carbon penalties increase power system costs by between 20 and 50 percent. The range in cost estimates depends on how policy is structured as described above. Current proposed federal policy provides free emission allowances under a cap-and-trade system for many years, which would put the cost impacts at near the lower end of the range. If power system costs increase by 20 percent, average retail rates would increase by about 3 percent compared to current policies.

To significantly lower carbon emissions from the power system, reliance on existing coal-fired generation would have to be reduced. This is not a surprising result because existing coal plants account for about 88 percent of the carbon emissions from the regional power system. In the $0 to $100 per ton carbon penalty scenario, these plants are simply used much less frequently. If they are used in that way, maintaining the plants may not be feasible for utilities. An alternative policy would be to phase out the existing coal plants or some portion of them. An analysis of phasing out all of the regional coal plants between 2012 and 2020 showed that power system 2030 carbon emissions could be reduced from 40 million tons in the $0 to $100 per ton carbon penalty scenario to about 15 million tons. Replacing the energy and capacity from the coal plants would increase average power system costs by about 30 percent. While this is an alternative policy approach to consider, it would not have the broad effects on other sectors and resource decisions that a cap-and-trade or tax system would have.

A number of scenarios addressed the issue of what level of carbon penalty would be required to meet alternative carbon emission reduction levels in 2030. The $0 to $100 per ton carbon penalty scenario, with average carbon prices growing to $47 per ton and possible futures between zero and $100, reduces average carbon emissions in 2030 to about 15 percent below 1990 levels. That is the WCI target for total greenhouse gas reduction by 2020. As shown in Figure 10-7, the $0 to $100 per ton carbon penalty scenario attains these reductions by 2020. However, these average reductions are not assured. In some futures, depending on demand, natural gas prices, hydroelectric conditions and carbon prices, emissions may not be reduced at all. These are cases where existing coal plants are utilized more intensively. The scenario where coal plants are retired results in more assured carbon reductions.

Figure 10-7: Average Sixth Power Plan Annual Carbon Emissions



Sensitivity analysis with the Regional Portfolio model and the AURORA$^{xmp®}$ Electric Market Model indicate that carbon costs of between $40 and $70 per ton would likely be required to reduce carbon emissions from the regional power system to below 1990 levels.

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 conservation, the region's carbon emissions are half of that of the nation 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. The region should further reduce hydropower generation for salmon migration with careful analysis of the costs, risks and benefits of any proposed salmon mitigation action. 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 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 11: Capacity and Flexibility Resources

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.

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 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. For historical reasons, over most of the past 40 years the Northwest's resource planning problem has been simpler, to meet the annual energy need 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.

The shift in the region's focus to flexibility at the minute-to-minute time scale 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 to 8 percent of demand for most utilities.

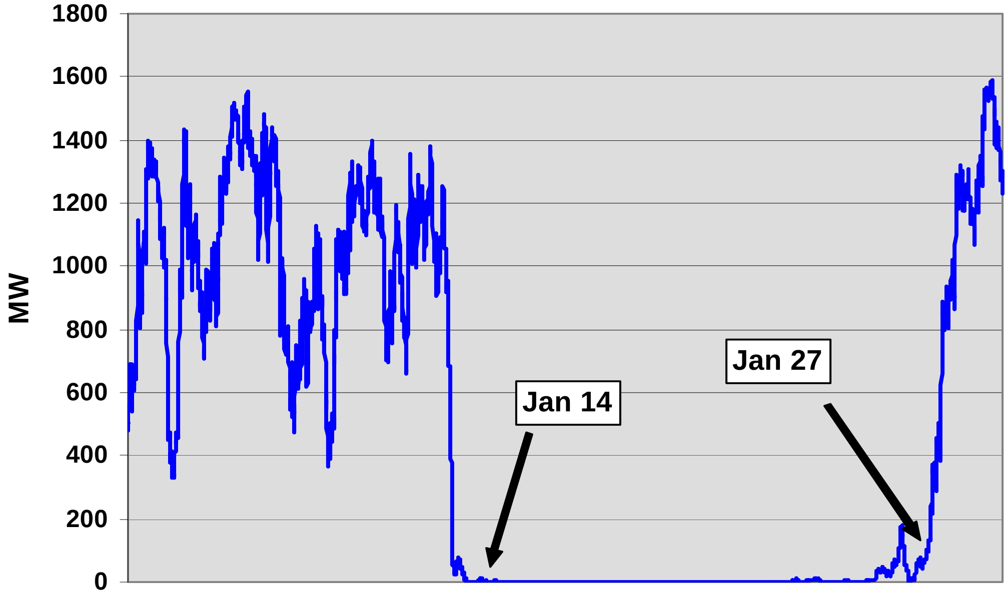
For hydroelectric generation, measuring capacity can be problematic. The total output of the hydrosystem is limited by its fuel supply, water, which is extremely variable from year-to-year. It is also limited by the fact that the reservoir system can only store about 30 percent of the annual runoff volume 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 Adequacy Forum is described more fully in Chapter 13.

Wind generation capacity is also difficult to define. 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." 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 may be 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 11-1 illustrates the loss of wind generation during a recent winter period. While efforts to better define the reliable capacity of wind generators are ongoing, 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 11-1: Bonneville Wind Generation
January 5 - 28, 2009



The current adequacy assessment (Chapter 13) 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 resource portfolio results of the Council's analysis, as well as their implications for meeting capacity and energy requirements of the system, is in Chapter 9 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 authorities[1] 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.

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

[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.

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.

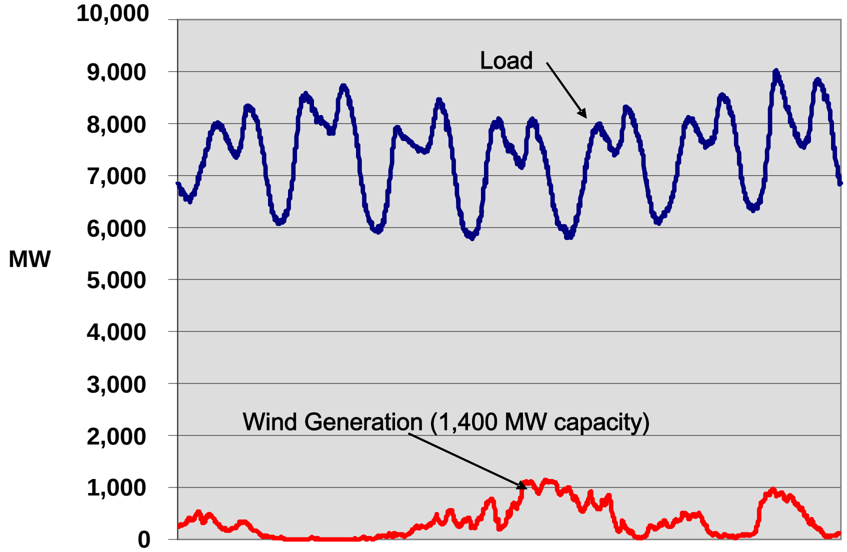
Balancing authorities do this by operating in a basic time frame of one hour, every hour of the day. The basic test of success in this balancing is called Area Control Error (ACE). ACE is a measurement, calculated every four seconds, of the imbalance between load and generation within a balancing area, 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.

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 2,100 megawatts of installed wind capacity). Figure 11-2 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.

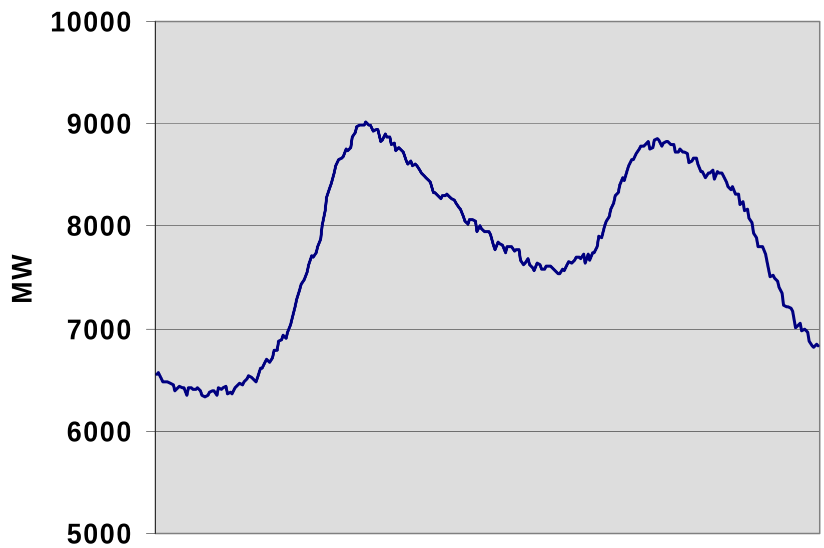
It also shows the Bonneville balancing area wind generation from the same period, illustrating the irregular pattern typical of wind generation. The data from this week will be used in several subsequent graphs, focusing on shorter time intervals and illustrating particular issues.

Figure 11-2: Example Load and Wind Pattern
BPA January 1-7, 2008, Midnight to Midnight



Focusing on a single day, January 7, 2008, Figure 11-3 highlights a single operating hour, from 6:00 a.m. to 7:00 a.m.

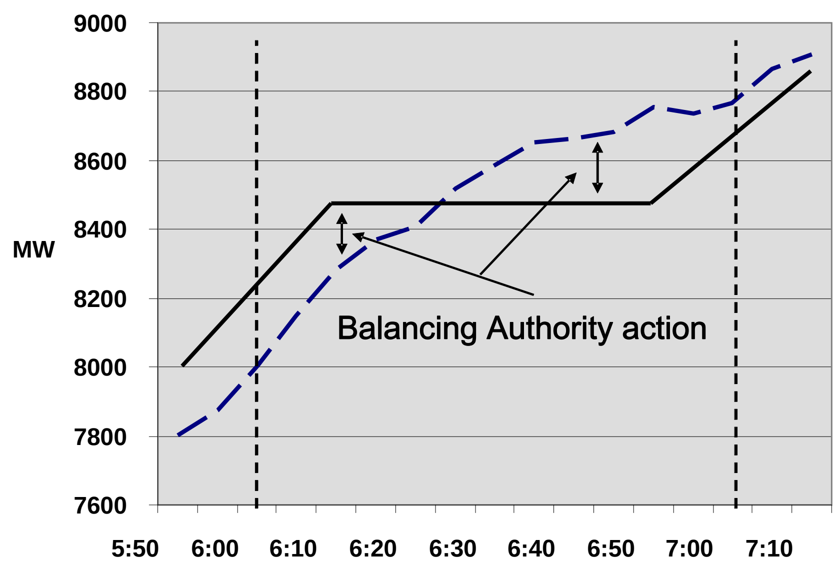
Figure 11-3: Daily Load Curve - BPA January 7, 2008
Midnight to Midnight



A balancing authority has to deal with a load ramp like this one, 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 11-4 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 11-4: 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 8-3 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 11-5, 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 11-5: Example Load at Four-Second Intervals Over Five Minutes

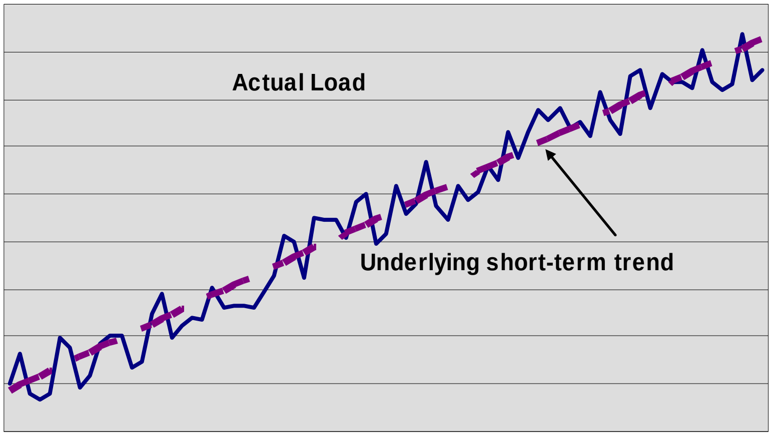
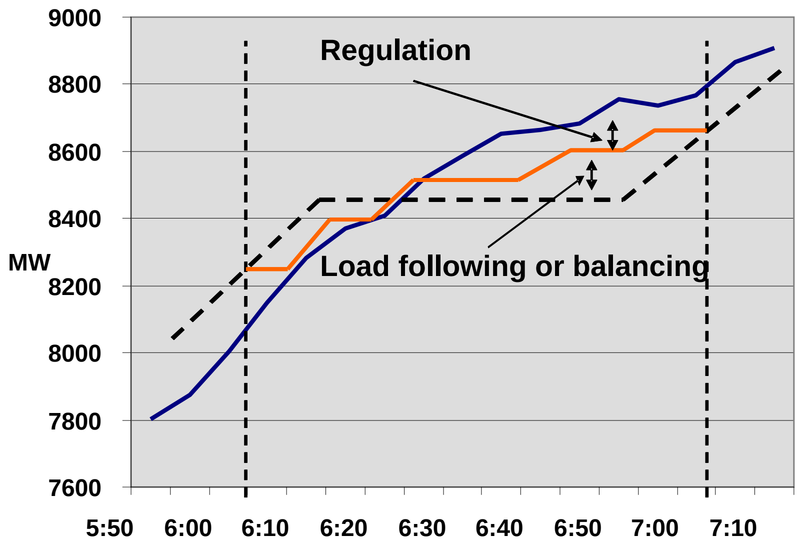


Figure 11-6 illustrates one pattern of breaking that requirement up, separating the regulation requirement for generation on AGC from the remaining requirement, usually called load following or balancing.[2]

Figure 11-6: 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 otherwise would in order to have the ability to decrease generation and provide decremental load following.

[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.

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.

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 control problem has raised awareness of the cost of providing these services. Improvements in operating procedures and business practices, described below, should help to hold down integration costs, but they will likely increase over time as more variable generation is added to the system.

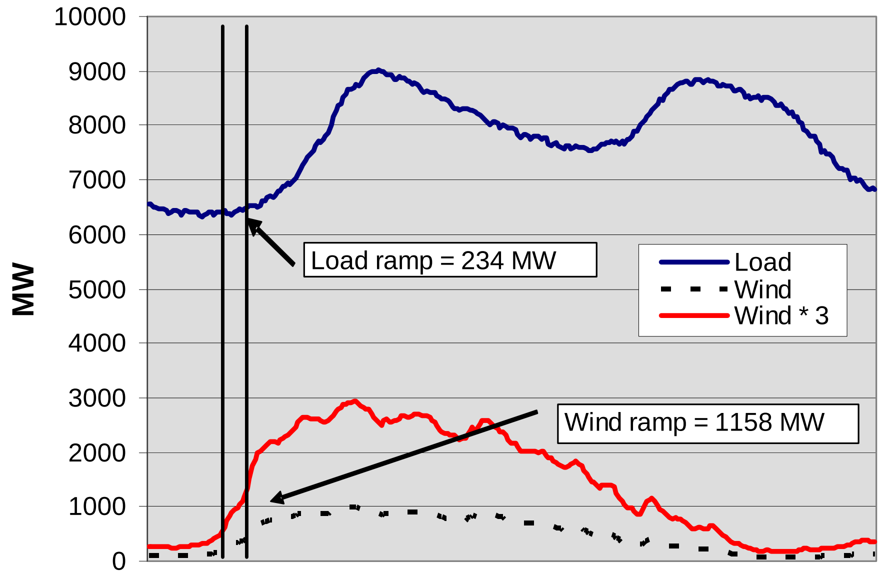
FLEXIBILITY ISSUES RAISED BY WIND GENERATION

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 11-7 highlights 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 11-1, and the effect of wind generation if its capacity were three times greater than what was operating on January 7, 2008. Note that Bonneville already has about 2,100 megawatts of installed wind capacity, instead of the then 1,400 megawatts. Bonneville expects as much as 3,000 megawatts by 2010, and is concerned about the potential of over 6,000 megawatts by 2013.

Figure 11-7: 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 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.

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 that by 2012 it might need to set aside up to 1,700 megawatts of generation to respond to unexpected drops in wind generation, and 2,200 megawatts of generation to respond to unexpected increases in wind generation. The exact amount will depend in part on the result of the actions described below. For Bonneville's needs specifically, see also the discussion in Chapter 12.

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 the wind generators in producing the schedules that they send to the balancing authorities or by 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 the current method) as the forecast for the next hour would substantially reduce the forecast error and the amount of balancing reserves needed to be set aside ahead of time. More sophisticated wind modeling is also being explored.

Standardizing within-hour schedule changes by going to, for example, a 10-minute scheduling window instead of the current whole-hour scheduling, would 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 examining the creation of 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 communication link set-ups 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 to 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 LMS 100 (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 12: Bonneville's Obligations

SUMMARY OF KEY FINDINGS

Bonneville has engaged in an extensive, multi-year set of regional processes, culminating in the Regional Dialogue, 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 have been addressed in the Regional Dialogue.

Bonneville has adopted a Regional Dialogue Policy, which has 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 BPA's balancing area. Its obligations to provide flexibility for wind balancing are also driven by its obligations under NERC standards as the host balancing authority for wind 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 BPA obligations that are not addressed in detail in the 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 BPA's balancing area whether to serve BPA's customers, other regional utilities or for sales 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 (Bonneville) 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 Power Planning and Conservation Council (Council), the interstate compact created under 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 resources in the region. 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 the 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 hydro-electric projects in the Columbia River 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 rate-payer 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 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 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 were ultimately 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 FYs 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; most importantly, preserving the region's low cost hydroelectric resources through long-term contracts, 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, and providing benefits to the residential and small farm customers of the region's investor-owned utilities that are equitable and predictable.

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 FY 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 will likely 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 5(b)/9(c) policy. The TRM was to be developed in a separate 7(i) process, as were rates to be effective for power sales under the Regional Dialogue contracts in FY 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[Also okay] 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 has also 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 and 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 was 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 then distilled the plan's regional resource strategies into a set of specific resource acquisition strategies that Bonneville is to act consistent with as it meets its needs into the future.

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 BPA 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 will thus 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, in as efficient and cost effective way 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 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 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 megawatts in each rate period, that is, in any two year period. Of the 250 megawatts, Bonneville has designated 40 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. The extent of this Tier-2 rate service is unknown at this time. 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 customers has not been determined and could require additional resource acquisitions in the future. As of the time of this draft, Bonneville and the DSIs 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 hydro 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 will also 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 is currently engaged in developing a Resource Program for meeting these various requirements. The first step in developing that program is a Needs Assessment. The Council will continue to work closely with Bonneville to ensure that the Sixth Power Plan takes account of Bonneville's estimates of its future resources needs.

However, a number of the key factors that will establish the levels of those obligations are not known at the time of the draft Plan, and some will not be known by the time the Sixth Plan is adopted. These include any additional energy and capacity needed for loads served at Tier 1 rates, the levels of the loads to be served at Tier 2 rates, both energy and capacity, that will be placed on the agency, the responsibility for Resource Support Services, and the other needs for balancing services for Bonneville's balancing authority.

Not only are the magnitudes of the requirements unknown at this time, 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 could also 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, could also 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 by any in-region load serving entity. (For more on this distinction, see Chapter 13.) For any in-region utility, they are potential resources, like others, that would need to be evaluated based on cost and risk.

Second, Chapter 11 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 are 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 11 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 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.

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.

Chapter 13: Regional Adequacy Standards

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. In 2001, the second driest year on record in the Northwest coupled with a failed 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 intermittent 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 periodically 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 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 risk factors and 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 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 resources, in aggregate, exceed the standard's minimum threshold. However, the minimum threshold should not be mistaken as a resource planning target or acquisition strategy. The Council's Power Plan, developed through an integrated resource planning process, provides a blueprint for the types and amounts of resources the Northwest should acquire to assure that the region has an "adequate, efficient, economical, and reliable power supply." In this sense, the Power Plan includes resources beyond minimum need.

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.

Adding to the issue of power supply adequacy are changes in the energy environment that have made ensuring the region's power supply more challenging. Greater constraints on the operation of the hydroelectric system, increasing development of intermittent and dispersed resources, and the growth of a Westside 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).

In practice, however, the region has strayed from strict critical period planning. Generally, reservoirs behind the dams were 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 (DSI). These kinds of contractual agreements with the remaining DSIs no longer exist, but the Northwest is still connected to the Southwest. Both regions should be able to benefit from their different peak-demand seasons. 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, hydro-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 the annual Power Supply Assessments for the last two 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 (PUC), have the ability to implement adequacy standards for the utilities they regulate. For example, the California PUC 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 PUC order also requires load-serving entities to forward contract 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.

THE PACIFIC NORTHWEST ADEQUACY STANDARD

In 2005, the Council and the Bonneville Power Administration initiated the Pacific Northwest Resource Adequacy Forum. The forum includes representatives from the region's electric utilities and utility organizations, public utility commissions and public interest groups, as well as from BPA 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 defined through the development of the Council's power plan.

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 standard[2] 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 more easily use. These simpler measurements are provided both for annual energy needs and peak hourly capacity needs.

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

[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.

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 electricity needs of the region. The measure for this is the planning reserve margin, or the surplus sustained-peaking 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 the Bonneville Power Administration'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 is 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. 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 2013.
- This puts the region in a "yellow alert" situation, which triggers specific actions that include a review of all load and resource data and a review of the methodology used to assess adequacy.
- The Council and regional utilities are actively developing resource acquisition strategies, which take economic risk, carbon emission policies and other factors into account.
- Adding the plan's expected resource additions keeps the power supply adequate until about 2029.

Assessment

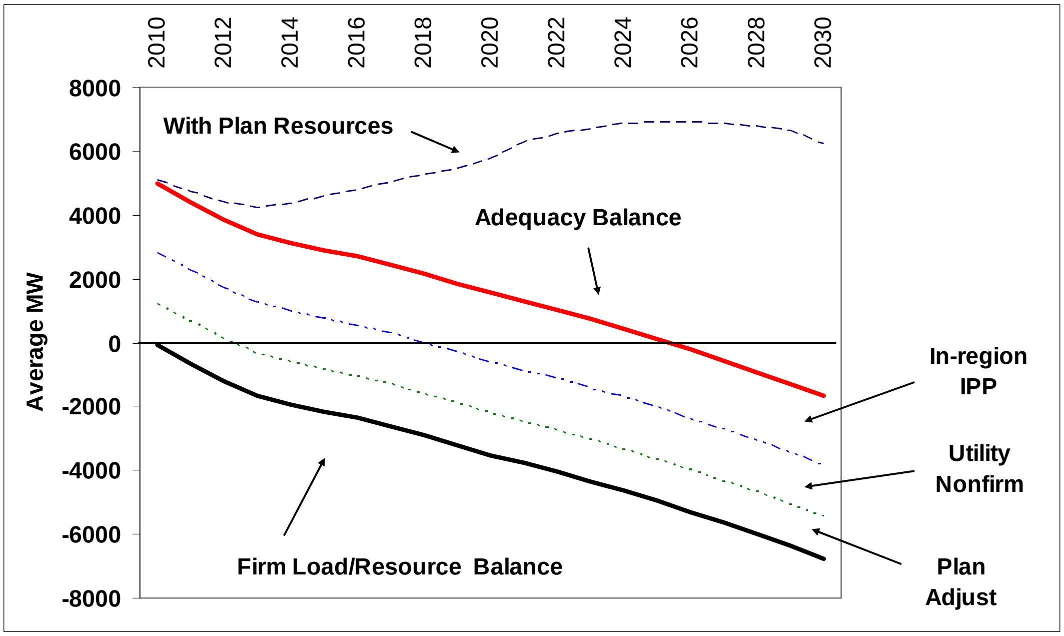
The Northwest Adequacy Standard, developed by the Resource Adequacy Forum and adopted by the Council in 2008, specifies minimum thresholds for annual energy load/resource balance and for winter and summer surplus capacity margins. Normally the adequacy assessment is targeted for 3 and 5 years out, but because this year the Council is releasing its 20-year power plan, it seems appropriate to make the assessment throughout the study period. Figures 13-1 through 13-3 show the assessed annual load/resource balance and capacity reserve margins through the year 2030.

As apparent in Figure 13-1, 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-firm hydroelectric generation. Regional utilities also own non-firm resources in that some of their resources are not fully declared as firm. These resources amount to about 1,600 average megawatts. 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

[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.

the balance. Adding the non-firm resources to the calculation yields the solid red line in Figure 13-1, which shows the region well above the adequacy threshold until about 2025 (red line). Adding new resources suggested by the power plan increases the surplus relative to a physical adequacy need (but are needed for economic and risk aversion needs).

Figure 13-1: 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 13-2 and 13-3 show that assessment 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 6 highest load hours per day over 3 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, raises the reserve margin above the threshold until about 2030. Again, adding the plan resources makes the reserve margin even higher.

The story is a little different for July. Looking at Figure 13-3, the reserve margin, including defined non-firm resources, only keeps the region above the minimum threshold through about 2013. According to the standard, this puts the region in a “yellow alert” situation, triggering specific regional actions, which are currently underway. First, regional planners are reviewing all load and resource data. Second, the methodology used to assess the minimum thresholds is in the process of being reviewed. Third, the Council and regional utilities are actively developing resource acquisition strategies to offset this projected need. Adding plan resources to the reserve margin in Figure 13-3 puts it above the minimum threshold through nearly the entire study horizon.

Figure 13-2: January Capacity Adequacy Assessment

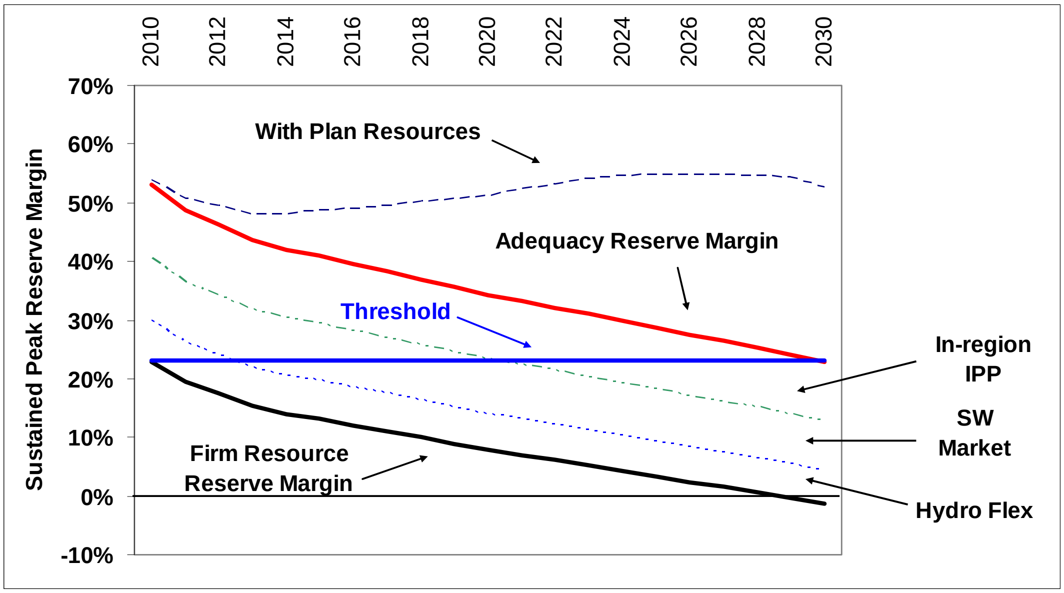
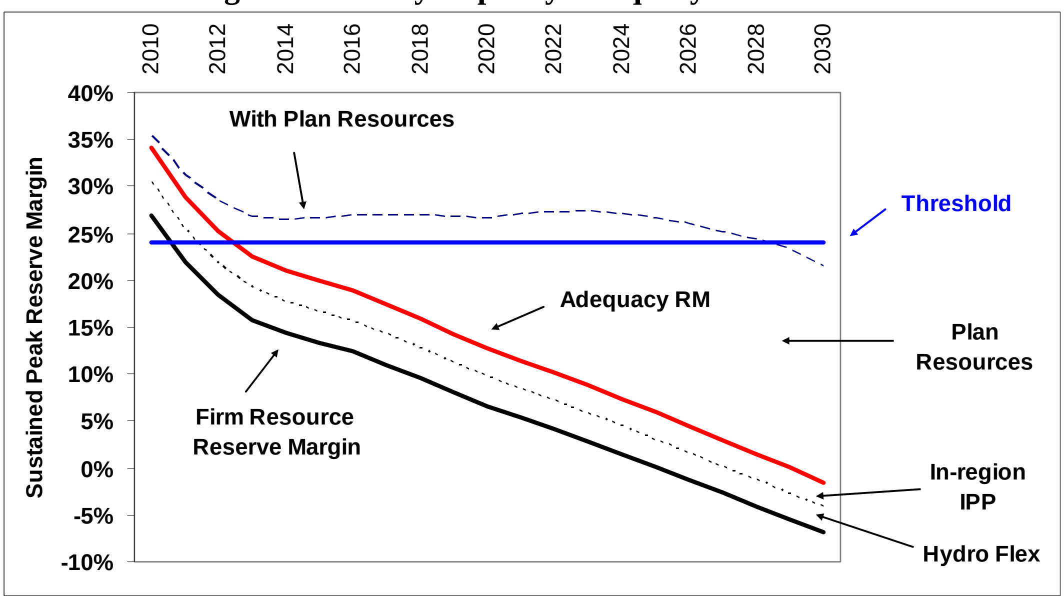


Figure 13-3: July Capacity Adequacy Assessment



Adequate vs. Optimal Power Supply

There has been considerable confusion about the relationship between the resource recommendations in the Council's power plan and the results of the Council's resource adequacy analysis using procedures developed by the Resource Adequacy Forum. The adequacy assessment implies that by acquiring the resources proposed in the power plan, the region will create a large energy surplus by the end of the study horizon (see Figure 13-1). Utility planners have questioned the need for such a surplus.

The adequacy assessment is meant to be an early warning system to alert the region if and when resource development falls dangerously short -- it is not intended to be a resource planning target. Unlike the adequacy assessment, the power plan is intended to provide guidance to regional utilities regarding the types and amounts of resources to acquire. The Council uses sophisticated analytical tools to develop its resource strategy, which is designed to keep costs low and to minimize economic risk. Plan analysis indicates that relying too much on market supplies is not in the best interest of the region. Thus, the plan suggests acquiring firm resources for economic reasons and also as a hedge against potential future carbon polices. Removing non-firm and market supplies from the load/resource balance shown in Figure 13-1 paints a different story, as described below.

Interpreting Load/Resource Balance in the Power Plan

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 NRF provides an aggregate look at utility resource needs. That calculation assumes firm loads and resources, which include critical hydro generation but no market resources. The general takeaway from this simple metric is that when the average annual load is greater than the firm supply, additional resources are likely needed. For a resource "needs" assessment this assumption makes sense. However, once a need is identified, the decision regarding how to fill that need requires a more sophisticated analysis.

While the power plan provides a general indication of the types and quantities of cost effective resources for the region, each utility's situation is unique and may require a different solution. For example, some may not have full access to market supplies (i.e. transmission limitations); others may want to limit their exposure to volatile market prices or may want more control over the resources they rely on. A full integrated resource plan assessment must be made to determine the operational reliability and cost of different resource combinations, to help lay out strategies to mitigate major risks that utilities face (such as dealing with carbon emissions) and to detail the types and quantities of required resources.

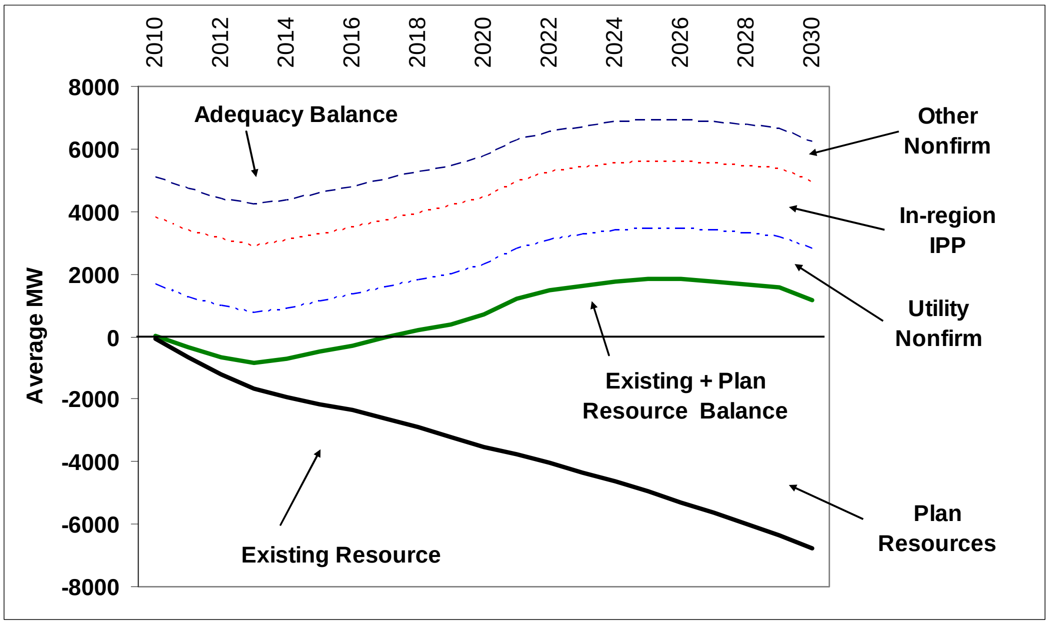
Nonetheless, the load/resource balance still provides a useful guide in assessing the status of the power supply. Figure 13-4 shows the same annual average load/resource balance as in Figure 13-1 but slightly rearranged. In this figure, we begin by counting only firm loads and existing firm resources. That assessment, illustrated in Figure 13-4 as the curve labeled "Firm Balance," indicates that the region currently is in approximate firm load/resource balance and becomes quite deficit by 2030 -- thus indicating a resource need. Adding new resources derived from the Council's plan raises the balance to positive values in later years but leaves the region somewhat deficit during the first 5 year period (solid green line). This small deficit in the near term is acceptable from an adequacy point of view because the amount of non-firm resources required to fill gap in the first 5 years is a fraction of the available market supply.

One source of non-firm generation comes from existing regional firm resources that are not expected to be fully dispatched. For example, a utility may have a simple cycle combustion turbine that it intends to use for peaking purposes only. The firm part of this resource may only be 5 percent of its availability but the other 95 percent should be available during periods of unexpectedly high demand. The area in Figure 13-4 labeled "Utility Nonfirm" represents the amount of this type of non-firm regional resource (dashed blue line). On average this value is about 1,600 average megawatts.

Another source of non-firm generation comes from uncommitted independent power producers in the region, which is labeled in Figure 13-4 as "In-region IPP" (red dashed line). All uncommitted IPP generation is assumed to be available for Northwest use during winter but only 1,000 average megawatts is assumed to be available in the summer (because of competition with the Southwest). On an annual average basis this amounts to 2,156 average megawatts.

Finally, there remains the out-of-region market supply and availability of non-firm hydroelectric generation. A loss-of-load probability analysis is used to assess how much the region should rely on these resources. That amount is reflected in the area labeled "Other Nonfirm" in Figure 13-4 and on average is 1,300 average megawatts. Putting all these pieces together yields the load/resource balance used for an adequacy assessment, which is labeled "Adequacy Balance" in Figure 13-4 (top line).

Figure 13-4: Energy Load/Resource Balance



The adequacy load/resource balance in Figure 13-4 is 5,180 average megawatts (MWa) in 2010. Subtracting the non-firm contributions results in a near zero load/resource balance for the needs assessment, which is consistent with the NRF value. Looking toward the future, the Council's power plan and utility plans (in aggregate) all indicate a need for new resources. The Council's planning approach, which is similar to methods used by many utilities, indicates that adding lost-opportunity and discretionary conservation is very effective in reducing both long-term cost and economic risk. In addition, the Council's plan includes renewable resources that would be acquired under the renewable resource portfolio standards that have been adopted in three of the four Northwest states.

The resource strategy outlined in the plan can be a useful starting point for utilities in terms of identifying the types and amount of new resources that may be cost effective for them. Of course, each utility's situation is different and may require more or different types of resource to address their own particular needs. For example, the Bonneville Power Administration, which is a balancing authority, must provide reserves to accommodate within-hour balancing operations. This may require that Bonneville acquire additional resources to provide this service.

Assessing Hourly Needs

Although not used as often in the past, capacity load/resource balances (usually computed as reserve margins) 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. Figure 13-5 and Figure 13-6 show the same sustained peak reserve margin calculations for January and July as in Figures 13-2 and 13-3 but again slightly rearranged. Based on existing firm resources only, the 2010 reserve margins are 23 percent for January and 27 percent for July. Without counting any new or non-firm resources, these reserve margins decline rapidly over the 20-year study horizon. It has not yet been clearly defined what the minimum reserve requirement should be for a firm sustained peak reserve margin calculation. In other regions, a 15 to 17 percent reserve margin is typically used but that is based on a single hour peak requirement in mostly thermal systems.

For adequacy assessments, minimum sustained peak reserve margin thresholds have been estimated using a loss-of-load probability analysis. Those thresholds are 23 percent for January and 24 percent for July. However, these minimum thresholds cannot be compared to the firm reserve margin values because they include contributions from non-firm resources, which are illustrated in Figures 13-5 and 13-6. 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. Adding the non-firm components and the plan's new resource additions to the firm reserve margin calculation yields 54 percent for January and 35 percent for July, both above the minimum thresholds required for system adequacy.

Figure 13-5: January Sustained Peaking Reserve Margin

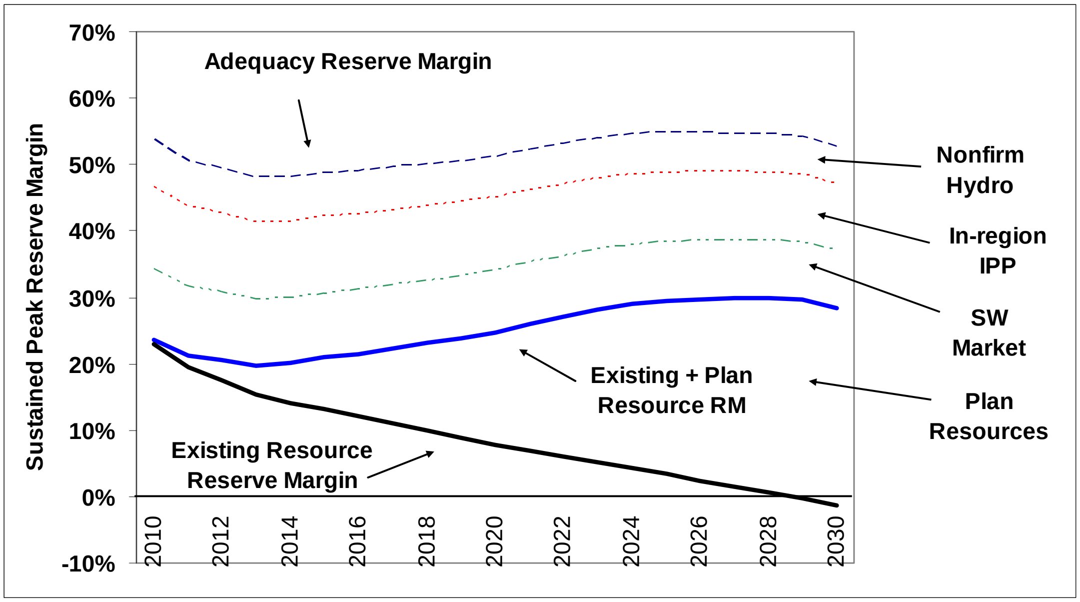
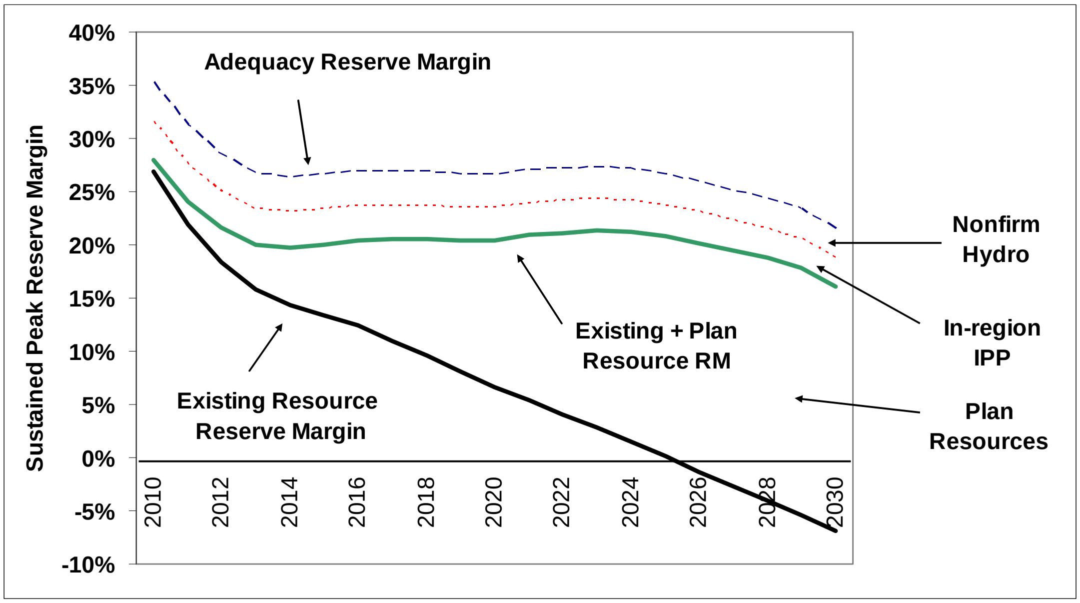


Figure 13-6: July Sustained Peaking Reserve Margin



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 8, 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

[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

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 “hydro flexibility,” that is, the ability to draft reservoirs below normal drafting limits during emergencies. Hydro 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.

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 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).

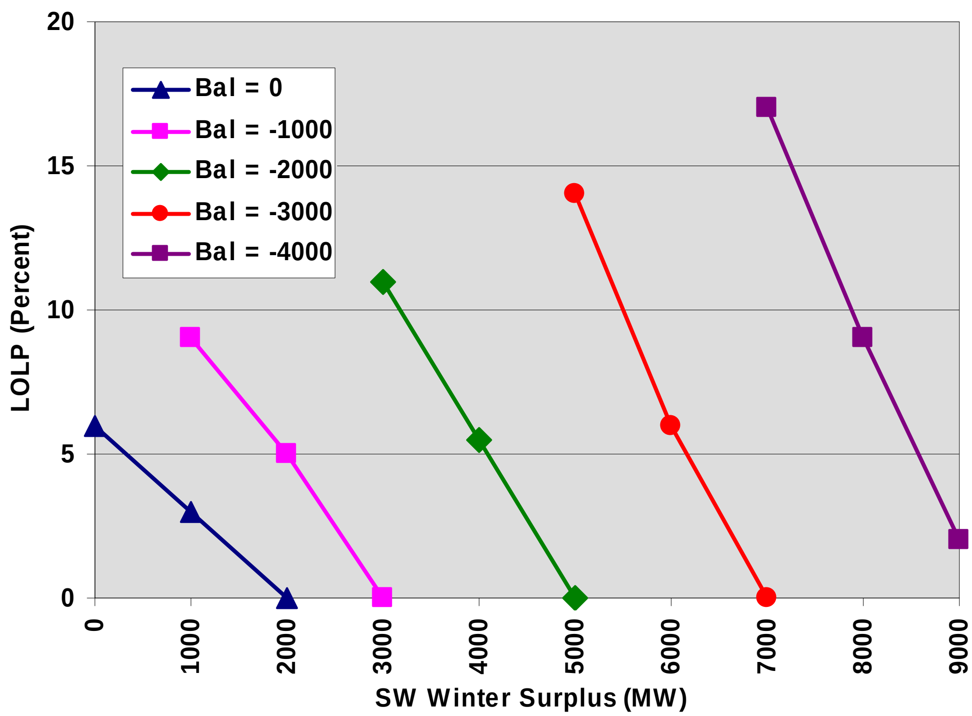
But what constitutes a significant curtailment event? Since the GENESYS model cannot possibly simulate all potentially varying parameters or know precisely every single resource that is available, a threshold is used to screen out inconsequential curtailment events. This threshold is commonly referred 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, price volatility from year-to-year could be extreme. Therefore, some level in between, calculated with the tradeoff between risk and cost in mind, is more appropriate for planning purposes.

Figure 13-1 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 13-1). 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 circular points), the LOLP would be over 5 percent with no available market supply.

Figure 13-1: Illustrative Example: LOLP as a Function of Available SW Capacity for Different Load/Resource Balance Conditions

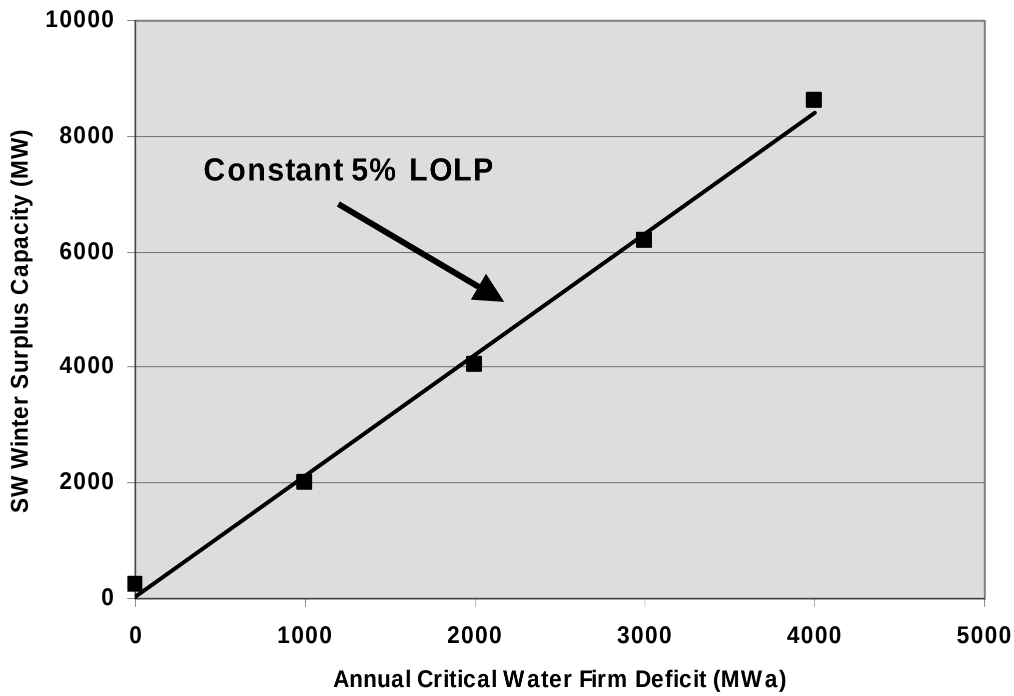


Translating the Adequacy Standard into a Simpler Measure

To make the relationship between the LOLP and market supply a little easier to see, the values in Figure 13-1 for all the points that cross the 5 percent LOLP level are plotted in Figure 13-2. 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 SW 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 13-2: 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 sell their output to the highest bidder, whether inside or outside the region. Current estimates show about 3,550 megawatts of such resources in the Northwest. During winter months, assuming that the Southwest region 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, 3,550 megawatts of IPP generation is assumed for winter and 1,000 megawatts are assumed for summer. For energy assessments, 2,200 average megawatts of IPP annual average generation is assumed.

By using the relationship in Figure 13-2 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.