Chapter 10: Resource Strategy

KEY FINDINGS

The resource strategy for the Sixth Power Plan relies on conservation, renewable generation, and natural gas-fired generation. In addition, the region needs to better utilize, expand, and preserve its existing electric infrastructure and research and develop technologies for the long-term improvement of the region's electricity supply. Scenario analysis showed that the electric power sector of the region could meet its share of carbon emission-reduction targets similar to those adopted by some states and proposed in national legislative initiatives through three primary actions: achieving the conservation targets in the Council's plan, meeting existing renewable-energy portfolio standards, and reducing the use of the existing coal plants by about half.

A RESOURCE STRATEGY FOR THE REGION

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

Summary

The resource strategy is summarized below in six elements. The first three are high-priority actions that should be pursued immediately and aggressively. The longer-term actions must be more responsive to changing conditions in order to provide an array of solutions to meet the long-term needs of the regional power system. The last element recognizes the adaptive nature of the power plan and commits the Council to regular monitoring of the regional power system to identify and adjust to changing conditions.

- **Efficiency:** The region should aggressively develop conservation with a goal of acquiring 1,200 average megawatts by 2014, and 5,900 average megawatts by 2030. Conservation is by far the least-expensive resource available to the region and it avoids risks of volatile fuel prices, financial risks associated with large-scale resources, and it mitigates the risk of potential carbon pricing policies to address climate-change concerns.

- **Renewables:** Increasing development of renewable generation is necessary to meet existing renewable portfolio standards. On average, the renewable resources developed to fulfill state RPS mandates will contribute 1,450 average megawatts of energy, or 4,500 megawatts of installed capacity. Most of the recent renewable development has been wind, and that is assumed to be the primary source of renewable energy in the immediate future. However, power production from wind projects creates little dependable peak capacity and increases the need for within-hour balancing reserves. The resource strategy encourages the development of other renewable alternatives that may be available at the local, small-scale level and are cost-effective now. The strategy also encourages research on and demonstration of different sources of renewable energy for the future.

- **Natural Gas:** Natural gas-fired generation is likely to be needed to supplement efficiency and renewable resources depending on load growth and the possible need to displace coal use to meet carbon-reduction goals. Even if the region has adequate resources, individual utilities or areas may need additional supply for capacity or wind integration. In these instances, the strategy relies on natural gas-fired generation to provide energy, capacity, and ancillary services.

- **Infrastructure Operation and Investment:** Strong emphasis should be placed on improving wind scheduling and system operating procedures as cost-effective and achievable initial steps for the purpose of wind integration. In addition, the region needs to invest in its transmission grid to improve market access for utilities and to facilitate development of more diverse cost-effective renewable generation.

- **Future Resources:** In the long term, the Council encourages the region to expand its resource alternatives. The region should explore additional sources of renewable energy, improved regional transmission capability, new conservation technologies, new energy-storage techniques, carbon capture and sequestration, smart-grid technologies and demand-response resources, and new or advanced low-carbon generating technologies, including advanced nuclear energy. Research, development, and demonstration funding should be prioritized in areas where the Northwest has a comparative advantage or unique opportunities.

- **Adapting to Change:** The Council will regularly assess the adequacy of the regional power system to guard against power shortages, identify departures from planning assumptions that could require adjustments to the plan, and help ensure the successful implementation of the Council's Columbia River Basin Fish and Wildlife Program.

Planning Scenarios

The resource strategy is based on analysis of several scenarios. The discussion of the elements of the resource strategy draws on those scenarios so some introduction to the scenarios and their findings is needed. The bullets below summarize eight scenarios, or studies, that help determine the resource strategy.

Scenarios

- **Carbon Risk** - The carbon-risk scenario is intended to explore what resources result in the lowest expected cost and risk given current policy plus the risk that additional carbon reduction policies will be implemented. It includes a range of carbon prices from zero to $100 per ton, which average to $47 per ton by 2030. Specific numbers for average resource development in the resource strategy are taken from this scenario. It is designed to represent the current state of uncertainty about future carbon pricing policies and develop a responsive resource strategy.
- **Current Policy** - The current-policy scenario includes current policies such as renewable portfolio standards, new plants emissions standards, and renewable energy credits, but it does not assume any carbon pricing in the future. It helps identify the effect of carbon pricing risk when added to existing policies.
- **No Policy** - The no-policy scenario removes current policies from the analysis in addition to assuming no future carbon pricing risk. It does, however, assume that the renewable energy credit market will continue to operate. This scenario permits isolation of the effects of current policy.
- **No RPS** - This scenario includes future carbon-pricing risk, but the renewable portfolio standards are removed. Renewable energy credits are included. One can compare the cost-effectives of renewable generation to other responses to carbon emissions pricing risk by comparing this scenario to others.
- **$45 Carbon** - The $45-carbon price scenario is designed to achieve the carbon-emission reduction targets in proposed legislation. Instead of uncertain carbon prices from zero to $100, a fixed price of $45 is assumed starting in 2010.
- **Coal Retirement** - This scenario, like the $45-carbon scenario, is designed to achieve a particular carbon-emissions reduction target. About half of the existing coal-fired generation in the region is phased out between 2012 and 2019. This scenario is done with and without carbon-pricing risk. In the without-carbon-pricing version, fewer coal plants are retired.
- **No Conservation** - This scenario assumes that no conservation is available to meet future electricity needs or reduce carbon emissions. Carbon pricing risk is included, as are current policies. This scenario allows estimation of the role of conservation in reducing carbon emissions and the effect of conservation on cost and risk in the face of carbon-pricing uncertainty.
- **Lower Snake Dam Removal** - This scenario explores the cost and carbon impacts that would occur if the four lower Snake River dams were no longer available to meet regional power needs. Carbon pricing risk is included as well as current policies.

Results of these studies are compared in the discussion of the elements of the resource strategy, and more detailed comparison of their results appears in the later in the chapter.

Improved Efficiency

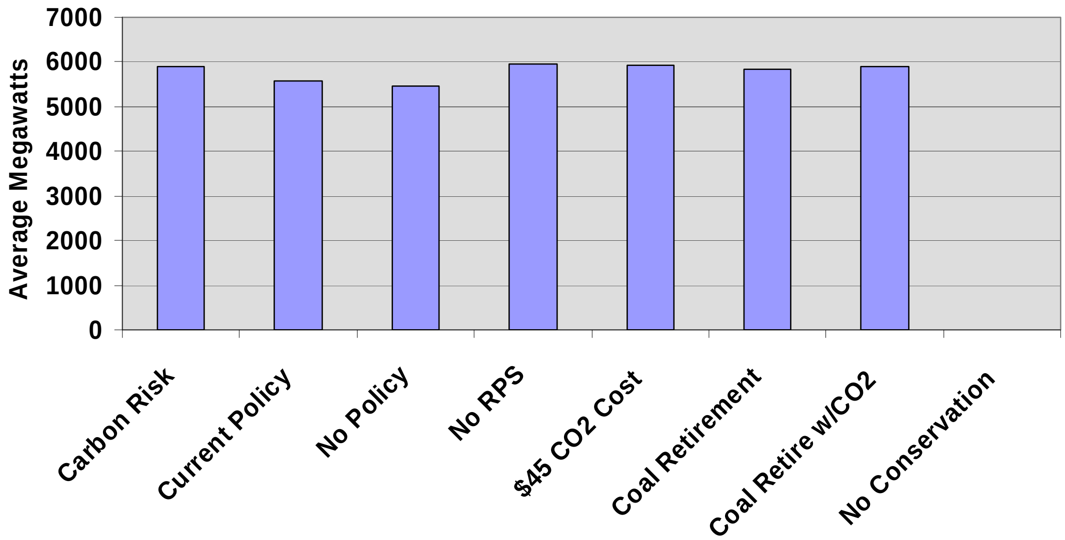
The dominant new resource in the Sixth Power Plan resource strategy is improved efficiency of electricity use, or conservation. The attractiveness of improved efficiency is due to its relatively low cost and the absence of major sources of risk. Conservation costs half of alternative generating resources and lacks the risk associated with volatile fuel prices and potential carbon policies. It also has short lead time and is available in small increments, both of which reduce risk. Therefore, improved efficiency reduces both the cost and risk of the resource strategy.

Energy efficiency has been important in all previous Council power plans. The region now has a long history of experience improving efficiency. Since the Northwest Power Act passed, the region has developed nearly 4,000 average megawatts. That makes efficiency the fourth-largest source of electricity in the region following hydroelectricity, natural gas, and coal.

The average levelized cost of the efficiency developed in the resource strategy is $36 per megawatt-hour. The comparable estimated cost of a natural gas-fired combined-cycle combustion turbine is $92 per megawatt-hour, and Columbia Basin wind costs $104 per megawatt-hour. Improved efficiency also costs less than the forecast market price of electricity. In the Council's analysis, extra resources are added to provide insurance against future uncertainties. Efficiency improvement provides attractive insurance for this purpose because of its low cost. In futures or time periods when the extra resources are not needed, the energy and capacity can be sold in the market and their cost more than recovered.

One result of these characteristics is that in all of the scenarios examined by the Council, both in the draft and the final power plan, similar amounts of improved efficiency are found to be cost-effective. Its role does not depend significantly on whether or not carbon policies are enacted. Figure 10-1 shows the amount of efficiency acquired in various scenarios considered by the Council in the power plan. In all scenarios except the no-conservation scenario, the amount of efficiency averages between 5,500 and 6,000 average megawatts. The amount of conservation developed varies in each future considered in the regional portfolio model. For example, in the carbon-risk scenario, while the average conservation development is 5,900 average megawatts, individual futures can vary from as low as 5,300 average megawatts to as high as 6,600 average megawatts.

Figure 10-1: Cost-Effective Conservation Resources

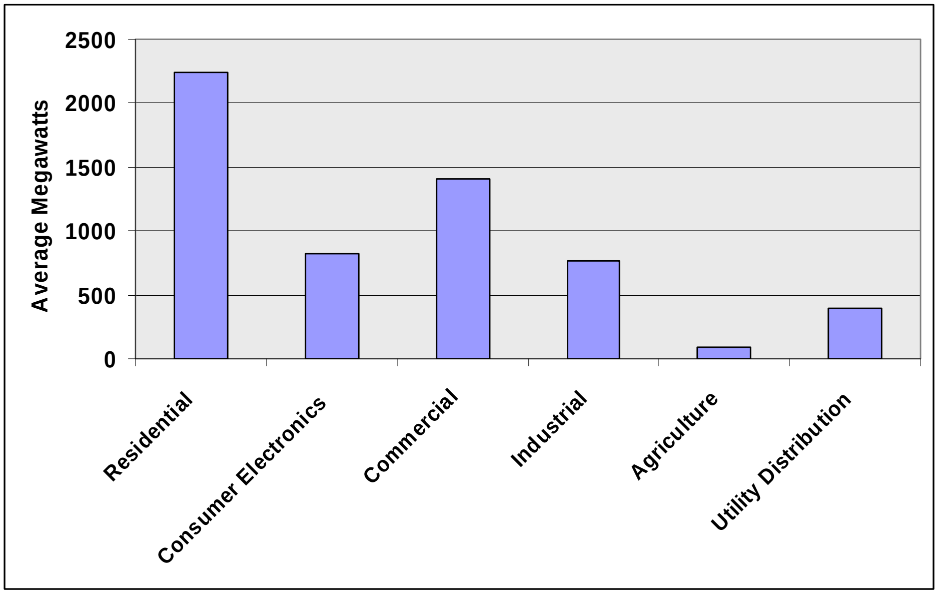


Developing the amount of efficiency included in the carbon-risk scenario is estimated to cost the regional power system $15 billion over 20 years[1]. The addition of a comparable amount of gas-fired generation would cost $62 billion. The nature of efficiency improvement is that the total cost is recovered over a smaller number of sales. Average cost per kilowatt-hour sold will increase, but because total consumption is reduced, average consumer electricity bills will be smaller. Consumers who choose not to improve their efficiency of use could see their bills increase. However, if the region does not capture the efficiency, the higher cost of new generating resources will increase everyone's bills.

The amount of efficiency included in the Sixth Power Plan is significantly higher than in previous Council plans. For example, in the Fifth Power Plan cost-effective efficiency was 2,500 average megawatts compared to 5,900 megawatts in the sixth plan. To a large extent, this increase is the result of changing technology that has created new efficiency opportunities and reduced costs. The Council has identified significant new efficiency opportunities in all consuming sectors. Also important are the increased cost of generating alternatives and the risk of increased carbon regulations. Figure 10-2 shows how efficiency improvements are located in various consuming sectors. Additional information on the sources and costs of efficiency improvements is provided in Chapter 4 and Appendix E of this plan.

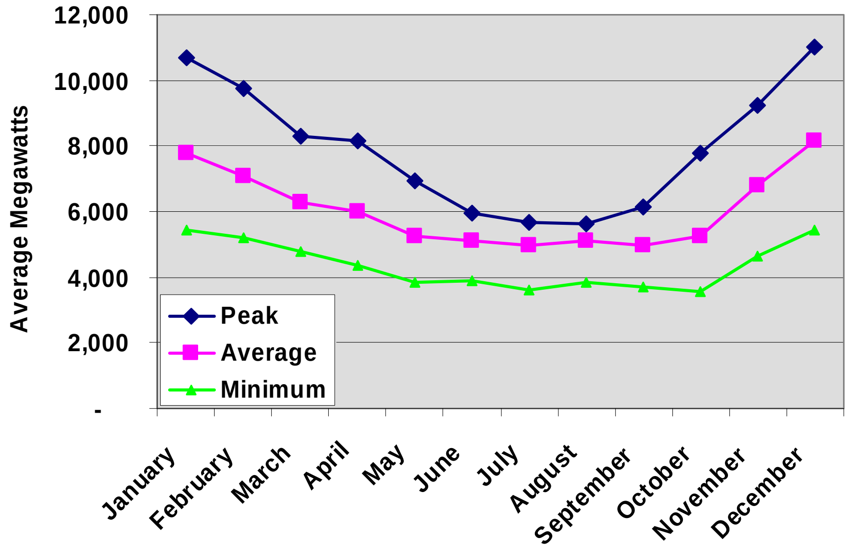
[1] About $6 billion of this amount is already in utility costs as currently expensed conservation. The additional cost to be recovered is therefore $9 billon over 20 years.

Figure 10-2: Cost-Effective Efficiency Potential by Sector



Improved efficiency contributes not only to meeting future energy requirements, but also provides capacity during peak load periods. The savings from conservation generally follow the hourly shape of energy use, saving more energy when more is being used. As a result, efficiency contributes more to load reduction during times of peak usage. Or in other words, efficiency improvements have capacity value, as well as energy value. The Council has built up the shape of efficiency savings from the hourly shape of individual end uses of electricity and the cost-effective efficiency improvements in those uses. Figure 10-3 shows the monthly savings of average energy, peak-hour capacity, and minimum-hour loads in 2030 based on 5,900 average annual megawatts of efficiency. The savings from efficiency actions in the Sixth Power Plan are highest in winter. For example, efficiency improvements that yield average annual savings of 5,900 average megawatts create 8,000 average megawatts of savings during December. The average capacity savings over the December 18-hour sustained peaking period is about 9,300 megawatts. Savings in the peak hour of December are 10,700 megawatts.

Figure 10-3: Monthly Shape of 2030 Efficiency Savings



As a comparison, the Council explored the effects of having no efficiency improvements available. A scenario was run based on the carbon-risk scenario but with no new efficiency improvements available. The resulting resource strategy was increased in cost, risk, and carbon emissions. Present value system cost increased 24 percent, from $63.9 billion (2006$) to $87.8 billion. In addition, increased carbon taxes would be collected. The tax increase is due to an increase of carbon emissions from 39.7 million tons per year to 57 million tons per year. The efficiency gains are replaced by a combination of increased use of existing natural gas and coal-fired generation, new gas-fired generation, reduced net exports of electricity, and a substantial increase in renewable generation due to increased electricity sales. Another way of describing the effects of no efficiency improvements on carbon emissions is that even with carbon taxes averaging $47 per ton by 2030 and current renewable portfolio standards, carbon emissions would not be reduced, on average, from 2005 levels. The efficiency improvements in the sixth plan resource strategy are a key to reducing carbon emissions.

Renewable Generation

Renewable generating resources are an important part of the resource strategy. Wind in particular has been a focus of recent generation development in the Pacific Northwest. Driven by financial incentives and renewable portfolio standards in three of the four states, the region has added over 3,400 megawatts of nameplate wind capacity since the Council's Fifth Power Plan. This existing wind is estimated to provide about 1,100 average megawatts of energy generation per year, but only provides about 170 megawatts of dependable peaking capability. Wind resources that have ready access to transmission are competitive with other generation alternatives.

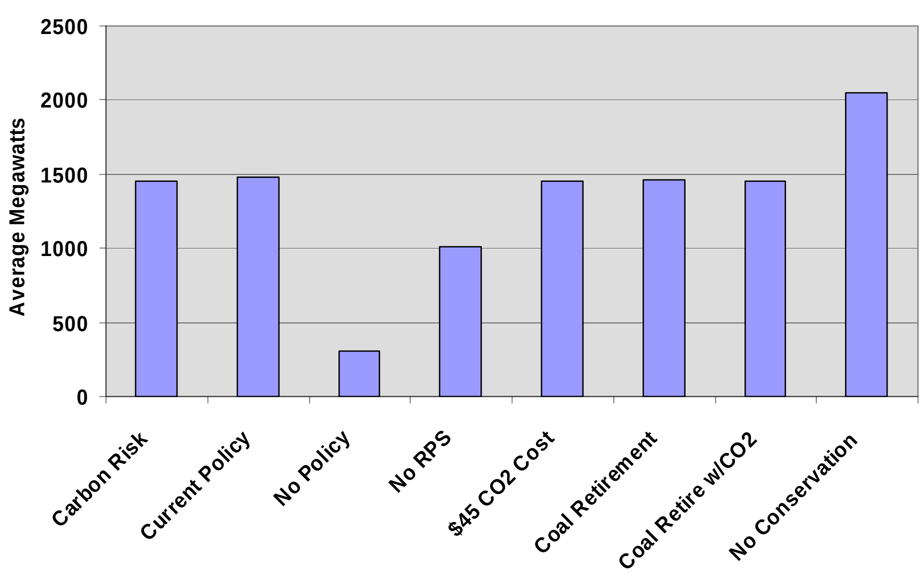
Renewable resources currently are modeled as wind or geothermal in the regional portfolio model. The Council recognizes that additional small-scale renewable resources are likely available and cost-effective and the plan encourages their development as an important element of the resource strategy. In addition, there are many potential renewable resources that are currently either too expensive or unproven technologies that may, with additional research and demonstration, prove to be valuable future resources.

Renewable generation development in the various scenarios is driven by state renewable portfolio standards. The amount of renewable energy acquired depends on the future demand for electricity because state requirements specify percentages of demand that have to be met with qualifying renewable sources of energy. Across the 750 futures of demand growth in the carbon-risk scenario, the amount of wind developed on average is 1,450 average megawatts. In terms of available capacity, that is 4,500 megawatts of installed wind capacity, but only about 225 megawatts of dependable peaking capacity.

Figure 10-4 shows the amount of additional renewable energy acquired on average in the various scenarios studied. The figure does not include the 1,100 average megawatts of existing and committed wind. In scenarios with renewable portfolio standards, the average development of additional wind is limited to 1,450 average megawatts, as required by the standards when the state's goals are combined. The only exception to this is when no efficiency improvements are assumed. In that scenario, an additional 600 average megawatts of wind is developed to satisfy RPS requirements for the higher electricity sales.

In the two scenarios without renewable portfolio standards, no policy and no RPS, the results are different. In the no-policy scenario, only 311 average megawatts of additional renewable generation is developed. In the no-RPS scenario, which includes the risk of carbon prices between $0 and $100 per ton, 1,008 average megawatts of additional renewable generation is developed; about 70 percent of the amount developed in scenarios that include renewable portfolio standards and carbon pricing risk.

Figure 10-4: Renewable Resource Development



Natural Gas-Fired Generation

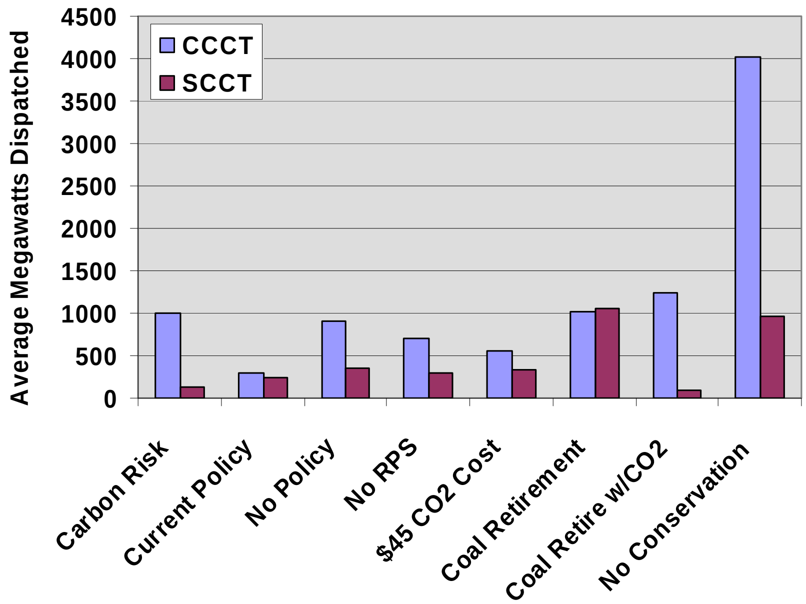
Natural gas is the third major resource in the Sixth Power Plan resource strategy. From an aggregate regional perspective, which is the plan's focus, the need for additional natural gas-fired generation is modest in the carbon-risk scenario. However, the role of natural gas may be larger than it appears in the Council's analysis for a number of reasons. The regional transmission system has not evolved as rapidly as the electricity market, resulting in limited access to market power for some utilities. In addition, some utilities have lost contract resources and have rapid load growth presenting them with significant near-term resource challenges. New gas-fired generation may be required in such instances even if the utilities meet their renewable portfolio requirements and develop conservation as rapidly as called for in the plan.

There are two types of natural gas-fired generation considered in the model: simple-cycle turbines (SCCT) that are most suitable for providing peaking capacity, and combined-cycle turbines (CCCT) that can provide base-load energy as well as peaking capacity. The gas-fired plants are optioned (sited and licensed) in the model so that they are available to develop if needed in each future. The resource strategy includes optioning 3,400 megawatts of CCCTs, and 650 megawatts of SCCTs. These options are developed in only a relatively small number of futures. The average build-out of natural-gas fired CCCTs over the 750 futures is 1,000 megawatts. For SCCTs the comparable number is 120 megawatts. In the carbon-risk scenario, the amount of energy actually generated from new CCCTs, when averaged across all 750 futures examined, is 400 average megawatts. For SCCTs the average energy provided is only 20 average megawatts. The contribution of these gas-fired resources would be largest during heavy- and peak-load hours, or in poor water years.

While the amounts of efficiency and renewables were fairly consistent across most scenarios examined, the future role of natural gas-fired generation is more variable and specific to the scenarios studied. Figure 10-5 shows the average amounts of SCCT and CCCT built among the 750 futures considered in each scenario. The actual amount of natural-gas fired generation constructed varies in each future.

The optioning of CCCTs is largest when there is a need for energy. This occurs, for example, in scenarios that feature energy lost from other resources as in the retirement, or decreased use, of existing coal plants or reduced conservation achievements. Among these scenarios not only does the amount of gas-fired resources optioned vary, but the likelihood of completing the plants also varies. The role of SCCT is greater when capacity needs to be replaced. This is prominent in the coal-retirement scenario where capacity from the retired coal plants is lost and in the no-conservation scenario where the capacity value of new conservation is eliminated.

Figure 10-5: Natural Gas-Fired Resource Options



The particular type of natural gas-fired generation built in the future depends significantly on anticipated future conditions. Specific utility needs drive resource choices. For example, individual utilities may find their circumstances include need for within-hour balancing reserves, a system with differing capacity requirements, or limited access to market resources. All of these factors limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas fired resources, or for the types of natural gas-fired generation.

Nevertheless, it is clear that after efficiency and renewables, natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Other resource alternatives may become available over time, and the Sixth Power Plan recommends actions to encourage expansion of the diversity of resources available.

Improving, Expanding, and Preserving the Existing Power System

The existing Northwest power system is a significant asset for the region. The FCRPS (Federal Columbia River Power System) provides low-cost and carbon-free energy, capacity, and flexibility. The network of transmission constructed by Bonneville and the region's utilities has supported an integrated regional power system. However, this regional infrastructure is in need of protection and expansion. In addition, the operation of the regional power system needs to evolve to better facilitate an efficient electricity market and help provide improved capacity and flexibility.

A key part of the Council's resource strategy is to improve the operation of the power system to better integrate variable wind generation and support growing capacity requirements. Improved wind forecasting, within-hour scheduling of resources, and increased use of dynamic scheduling among balancing authorities are likely to provide cost-effective and near-term solutions to capacity and flexibility needs. The region has recently made significant progress through a joint initiative of Columbia Grid, Northern Tier Transmission Group, and WestConnect.

For many years the region has failed to make significant investments in its transmission infrastructure. As a result, transmission constraints have become significant, limiting access to regional electricity resources and reducing the efficiency of the power system. Recently, transmission investments have gained attention and important investments have been proposed or are underway. One area where added transmission may have value is in improving access to more diverse and cost-effective wind and other renewable resources. Investing in the regional transmission system is important to preserving an efficient and low-cost power system for the region.

Finally, preserving the capability of the existing hydroelectric system has significant value for the region. Mitigating damage to anadromous fish from development of the FCRPS has changed the operation of the hydroelectric system, reducing its energy capability and its flexibility. It is important to mitigate this damage, but also to do it in a way that best preserves the value of a low-cost and low-carbon electricity source. The Council attempts to ensure that its fish and wildlife program uses cost-effective strategies to improve salmon and steelhead survival. An analysis of the effects of a loss of hydropower capability was done to illustrate the value of the system. The example analyzed was the loss of the four lower Snake River dams. This example is provided to illustrate the significant economic and carbon-emission changes that resulted from the scenario. The last section of this chapter describes the results of this analysis.

Develop Long-Term Resource Alternatives

The fifth element of the Council's resource strategy recognizes that technologies will evolve significantly over the 20 years of the Sixth Power Plan. When the Council next develops a power plan, the cost-effective, available and reliable resources will be different from those considered in the Sixth Power Plan. But the Sixth Power Plan indentifies areas where progress is likely to be valuable and includes actions to explore and develop such resources and technologies. In many instances the region can influence the development of technology and the pace of adoption.

Areas of focus in the long-term resource strategy include additional efficiency opportunities and the ability to acquire them, energy-storage technologies to provide capacity and flexibility, development of smart-grid technologies, expansion of demand response capability, and tracking the status and cost of potential no-carbon or low-carbon generation. The latter potentially includes renewable technologies, carbon sequestration, and advanced nuclear generation.

Research, development, and demonstration of these technologies is an important part of the Council's resource strategy. Tracking these developments, as well as plan implementation and changing assumptions, will indentify needed changes in the power plan and near-term actions to implement it. These elements of the resource strategy are addressed primarily in the action plan.

VALUE OF THE RESOURCE STRATEGY

The resource strategy of the Sixth Power Plan is designed to provide a low-cost electricity supply to meet future load growth. But it is also designed to provide a low-risk electricity future for the region. The Council choose to make risk reduction an important part of the resource strategy. Therefore the amount and type of resources included in the strategy are designed to meet loads, reduce costs, and help reduce the risks posed by uncertain future events.

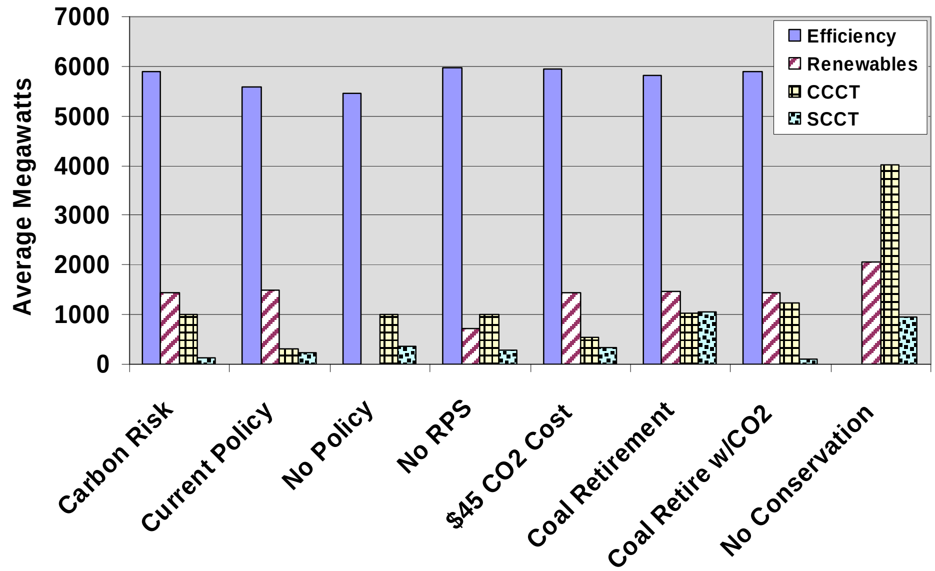
All of the scenarios evaluated for the plan include the same uncertainty regarding fuel prices, hydropower conditions, electricity market prices, capital costs, and load growth. In addition, several scenarios include the risk of carbon pricing. The zero-to-$100-per-ton carbon price risk is included in the carbon-risk, no-RPS, coal-retirement with CO2 pricing, no-conservation, and Snake River Dam scenarios. Carbon prices are not included in the no-policy or current-policy scenarios, nor are they included in the coal-retirement scenario without carbon price risk. The $45-carbon scenario assumes a fixed carbon price, instead of uncertain carbon prices. By comparing the results of these various scenarios, the effect of this significant uncertain future carbon-pricing policy on the resource strategy can be illustrated.

Figure 10-6 shows the resource development by resource type for each scenario. The resources are shown as average resource additions over 750 future scenarios. The high and consistent role of efficiency stands out. This is because of both its low cost and its role in mitigating risk from fuel price uncertainty and volatility. Efficiency acquisition is higher in scenarios with carbon prices reflecting its additional value for mitigating carbon price risk. Without conservation, renewable and gas-fired generation development is much greater. In the no-conservation scenario the net present value of future power system costs increases by $24 billion, or 37 percent even without considering the additional carbon penalties that would have to be paid because carbon emissions increase from 40 million tons to 57 million tons per year. Without efficiency improvements, regional power costs would also increase by 37 percent excluding the cost of carbon and 47 percent including the cost of carbon

The role of renewable generation is driven by renewable portfolio standards and renewable energy credits. In the absence of both, little addition renewable development would take place. Assuming renewable energy credits continue, but without renewable portfolio standards, the amount of renewable generation developed is about 70 percent of what is required by the standards, even in the face of carbon price risk. The higher renewable generation in the no-conservation scenario reflects higher electricity consumption, which increases the amount of renewable energy needed to meet the standards.

The role of natural gas varies among the scenarios. It is greatest by far in the absence of efficiency. In scenarios with carbon prices or coal retirement it is similar because it is providing energy to reduce the use of coal. Because the coal-retirement and carbon-pricing scenarios have been designed to reduce carbon emissions to similar targets, the need for coal replacement is about the same in these scenarios. In the coal-retirement scenario without carbon pricing, simple-cycle combustion turbines play a larger role to replace the capacity of retired coal plants. If the plants aren’t retired they continue to provide capacity under some future conditions.

Figure 10-6: Average Resource Development by Type in Alternative Studies



One of the key issues identified for the Sixth Power Plan was climate-change policy and the potential effects of proposed carbon-pricing policies. In addition, the Council was asked to address what changes would need to be made to the power system to reach a specific carbon reduction goal and what those changes would cost. The next section focuses on meeting carbon-reduction targets, but some more general carbon-emission results are addressed here. In providing analysis of carbon emissions and specific pricing or carbon-reduction targets, the Council is not taking a position on future climate-change policy. The Council's analysis is intended to provide useful information to policy-makers.

Figure 10-7 shows the costs and carbon emissions from all of the scenarios in the plan. The role of renewable portfolio standards in providing carbon reductions is one issue. This can be addressed by comparing results between two pairs of scenarios. The primary difference between the no-policy scenario and the current-policy scenario is renewable portfolio standards. In this comparison renewable portfolio standards reduce carbon emissions by 4 million tons per year, from 60.3 to 56.3 million tons per year. Conservation in the no-policy scenario slows the growth of carbon emissions, but emissions still increase above 2005 levels. The addition of renewable standards in the current-policy scenario reduces carbon emissions to 2005 levels by 2030. The renewable standards were estimated to increase the average cost of the power system by about 8 percent while reducing carbon emissions by about the same percentage.

The second comparison that shows the potential effects of renewable portfolio standards on carbon emission is the no-RPS scenario compared to the carbon-risk scenario. In these scenarios, which both include carbon-pricing risk, the presence of the standards reduced carbon emissions by 0.6 million tons per year, from 40.3 to 39.7 million tons per year. These results do not include, of course, the value of renewable portfolio standards in encouraging development of new carbon-free technologies for the future as encouraged in the Council's resource strategy.

The effects of carbon pricing risk on emissions can be seen by comparing the carbon-risk scenario to the current-policy scenario. The carbon-risk scenario adds to the expected cost of the power system and reduces carbon emissions compared to the current-policy scenario. Expected power system cost increases about 14 percent, from $56.1 billion (2006$) to $63.9 billion. Average carbon emissions decrease by 29 percent in 2030 reaching levels about 30 percent lower than 2005. By comparing emission levels and cost between the carbon-risk and the no-conservation scenarios, it becomes clear how important efficiency improvement is for reducing carbon at the least cost. Carbon emissions are not reduced from 2005 levels in the no-conservation scenario, but power system cost increases by $24 billion, or 30 percent. If the carbon penalty is included in cost, the increase is even larger.

Figure 10-7: Costs and Carbon Emissions by Scenario in 2030

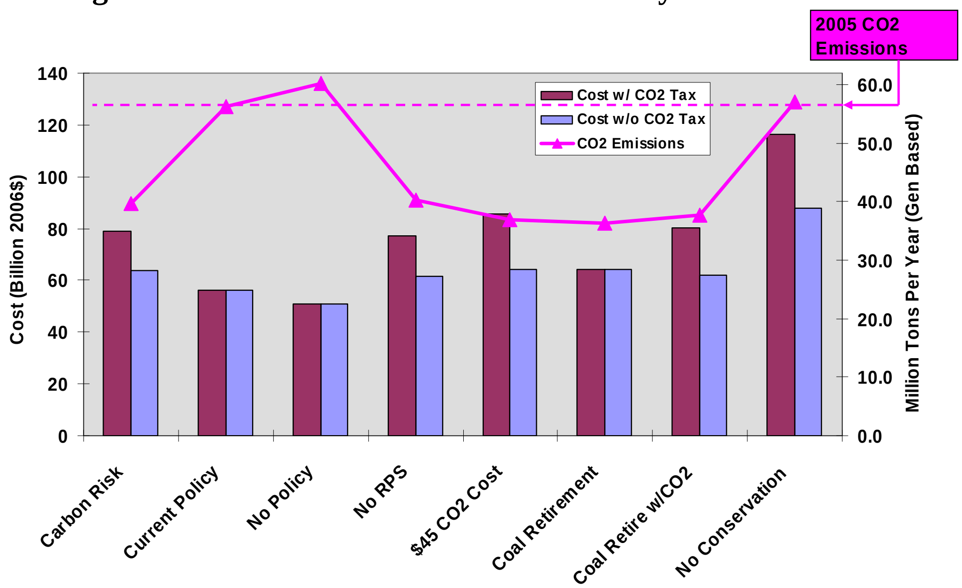
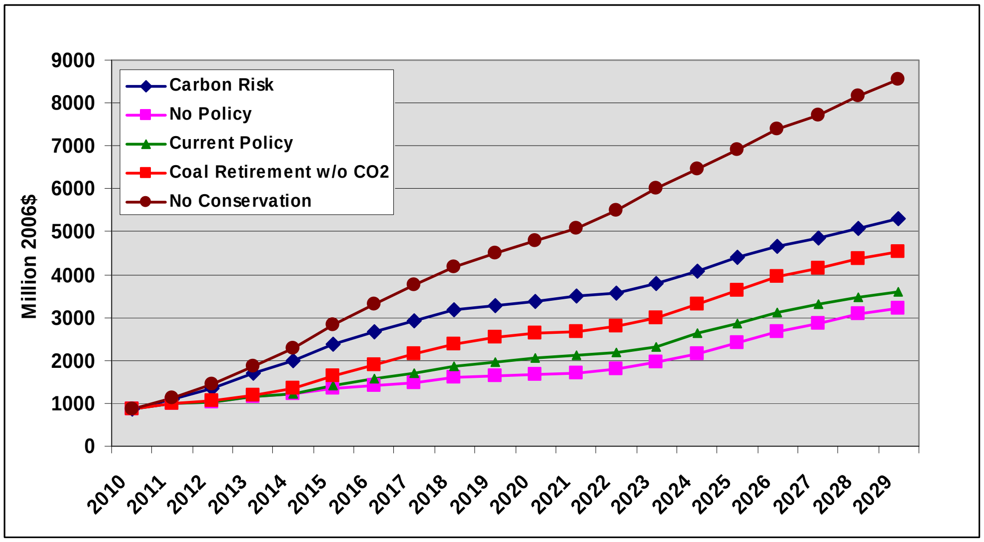


Figure 10-7 shows costs as the net present value of system costs, which is the measure of cost used for planning. It includes only the forward-going costs of the power system; that is, costs that can be affected by future conditions and resource decisions. Some have noted that reporting costs as net present values does not show patterns over time and obscures differences among individual utilities. The latter is unavoidable in regional planning and the Council has noted throughout the plan that different utilities will be affected differently by alternative policies. It is possible, however, to display the temporal patterns of costs among scenarios. Figure 10-8 shows forward-going power system costs for selected scenarios on an annual basis. Forward-going costs include only the future operating costs of existing resources and the capital and operating costs of new resources. The 2010 value in Figure 10-8 therefore includes mainly operating costs of the current power system, but not the sunk capital costs of the existing generation, transmission, and distribution system.

Figure 10-8: Annual Forward-Going Power System Costs

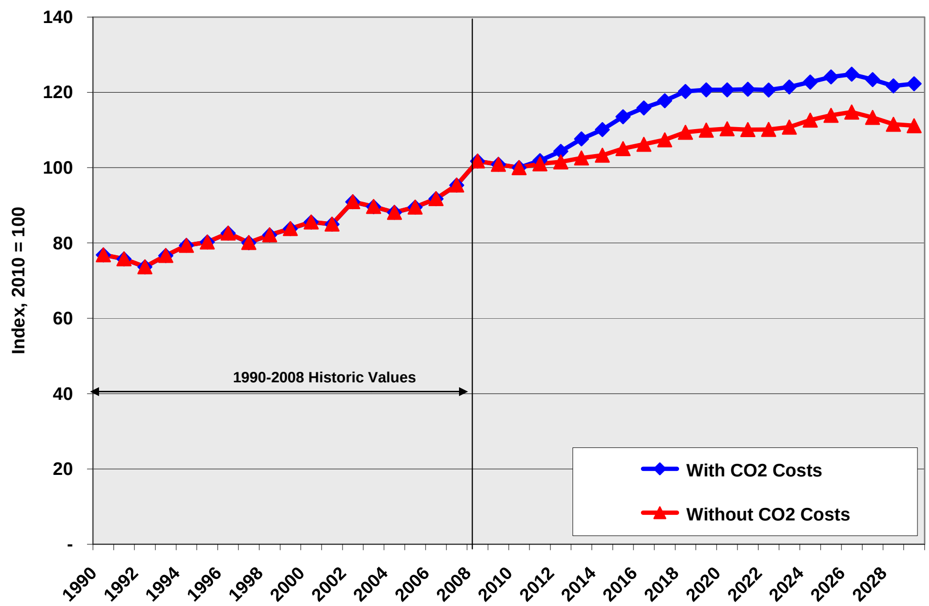


Power system costs increase over the forecast period even in the no-policy scenario. Renewable portfolio standards increase cost slightly in the current-policy scenario. The carbon-risk scenario, which best represents the resource strategy of the Sixth Power Plan, increases costs significantly, but not having conservation available in the future increases costs dramatically. The costs in Figure 10-8 all include the CO2 penalty that would occur on average if carbon pricing were implemented, but three of the scenarios include no carbon-pricing policy: no policy, current policy, and coal retirement without carbon pricing. If carbon penalties were excluded from these costs, the cost of the carbon-risk and no-conservation scenarios would appear lower. The other scenarios analyzed in the plan all would appear about the same as the carbon-risk scenario if included in Figure 10-8.

To translate these planning costs to the changes that would likely be experienced by consumers in their rates and bills, existing power system costs need to be included and some costs that are not recovered through utility electric revenues need to be excluded. Figure 10-9 shows an index of forecast total utility revenue requirements for the carbon-risk scenario in the context of historical levels. The higher line of forecasts includes average carbon penalties as if they were entirely recovered through electricity revenues. Below, these revenue requirements are translated into electric rates and typical residential customer monthly electricity bills. The addition of existing system costs makes these impacts on consumers appear smaller than looking only at forward-going costs. The rate and bill effects are further dampened by the fact that conservation costs are not all recovered through utility rates. In fact, it becomes difficult to graphically distinguish among the effects some of the scenarios.

If the Council had developed a resource strategy based on current policies only, it would be lower cost as long as carbon pricing were not implemented in the future. It would be a strategy with fewer new resources and slightly lower rates and bills. However, if that resource strategy was followed and the future turned out to have significant carbon-pricing policy, costs could turn out to be substantially higher. Existing coal plants would have to be used to meet load and the carbon costs required by their emissions would be substantial. The extra cost of the resource strategy that considers carbon-pricing risk helps insure the region against future situations that could be expensive.

Figure 10-9: Index of Historical and Forecast Utility Revenue Requirements



The effects of the different scenarios on costs are translated into possible effects on electricity rates and residential consumer monthly electricity bills. The rate estimates are average revenue requirements per megawatt-hour. The residential bills are typical monthly bills. Both are expressed in constant 2006 dollars and have been levelized over the forecasting period. As can be seen in Figure 10-10, levelized rates and bills generally move in the same direction as the net present value of system cost that is reported as power system cost in this plan. The only exception to this relationship is in the no-conservation scenario. There, bills increase with system cost without conservation, but rates decrease because costs are spread over a larger number of megawatt-hours sold without conservation. Figure 10-11 illustrates how efficiency improvements lower electricity bills.

Figure 10-10: System Costs, Rates, and Monthly Bills

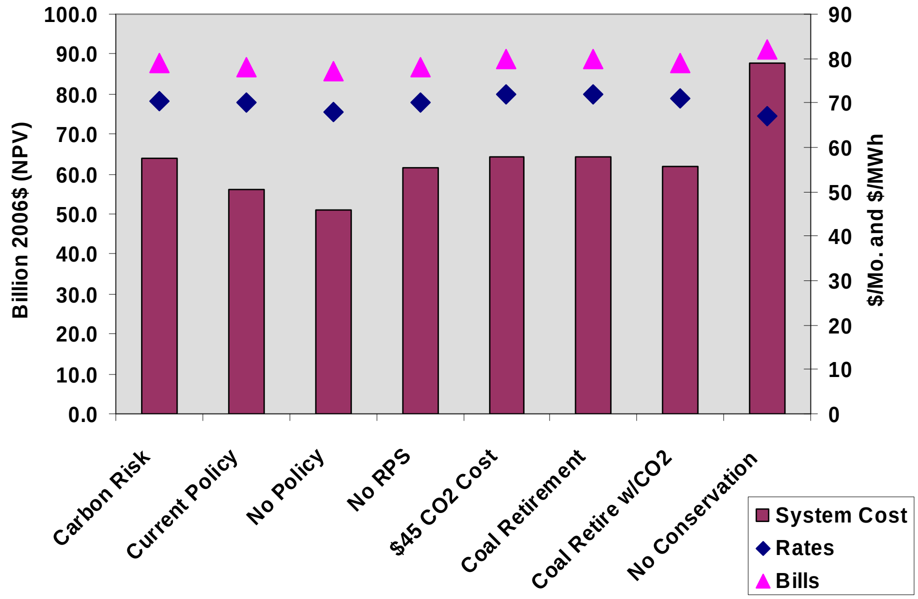
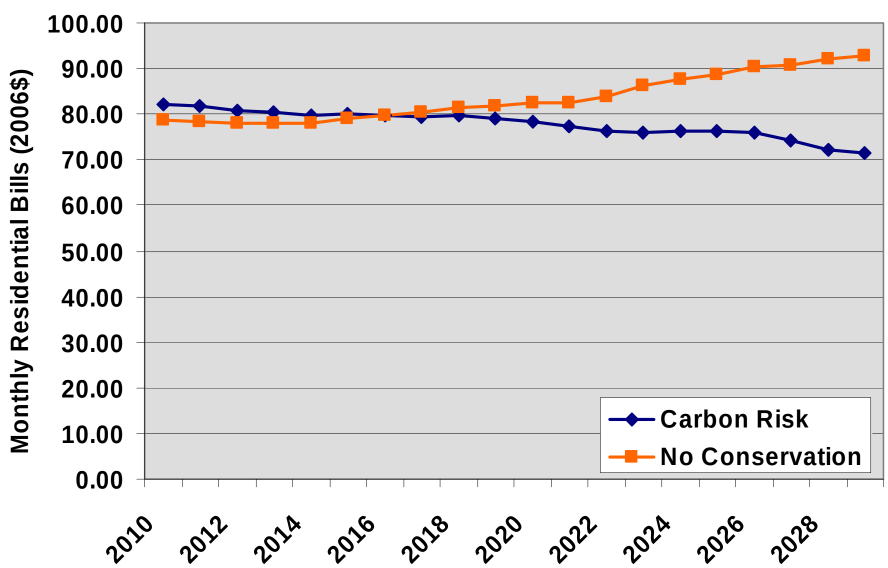


Figure 10-11: Residential Electricity Bills With and Without Conservation



The changes in rates and bills are small relative to system-cost changes. The primary reason is that revenue requirements contain a substantial amount of existing costs that do not change among the scenarios. The system costs used in planning exclude existing, or sunk costs and instead include only forward-going costs that could be affected by resource decisions. The effects of carbon reduction on rates and bills are smaller than some participants in the Council's planning process expected. One reason is that conservation addresses much of the problem and it is cheap. A second reason is that the region is fortunate to have a low-carbon power system. Most of the carbon emissions come from a relatively small share of the generation that is fired by coal. This makes achieving substantial carbon reductions less costly than in many regions.

Figure 10-12 shows monthly residential bills in the current-policy, carbon-risk, and coal-retirement scenarios. Figure 10-13 shows electricity rates for the same scenarios. Neither figure includes carbon penalties in rates or bills. The coal-retirement scenario does not include carbon pricing policy, nor does the current-policy scenario. Therefore, the bills and rates of those scenarios do not change if carbon costs are included. The effects of including carbon costs in bills and rates are illustrated in Figures 10-12a and 10-13a, respectively. Including carbon cost in revenue requirements raises the bills and rates of the three scenarios that include carbon risk. If the carbon penalty is counted as a net cost to consumers, the carbon-risk scenario results in higher bills than the coal-retirement scenario. Coal retirement results in the highest rates if carbon costs are excluded, but when carbon costs are included rates in the carbon-risk and no-conservation scenarios are higher than in the coal-retirement scenario.

Figure 10-12: Monthly Residential Bills Excluding the Cost of Carbon Penalties

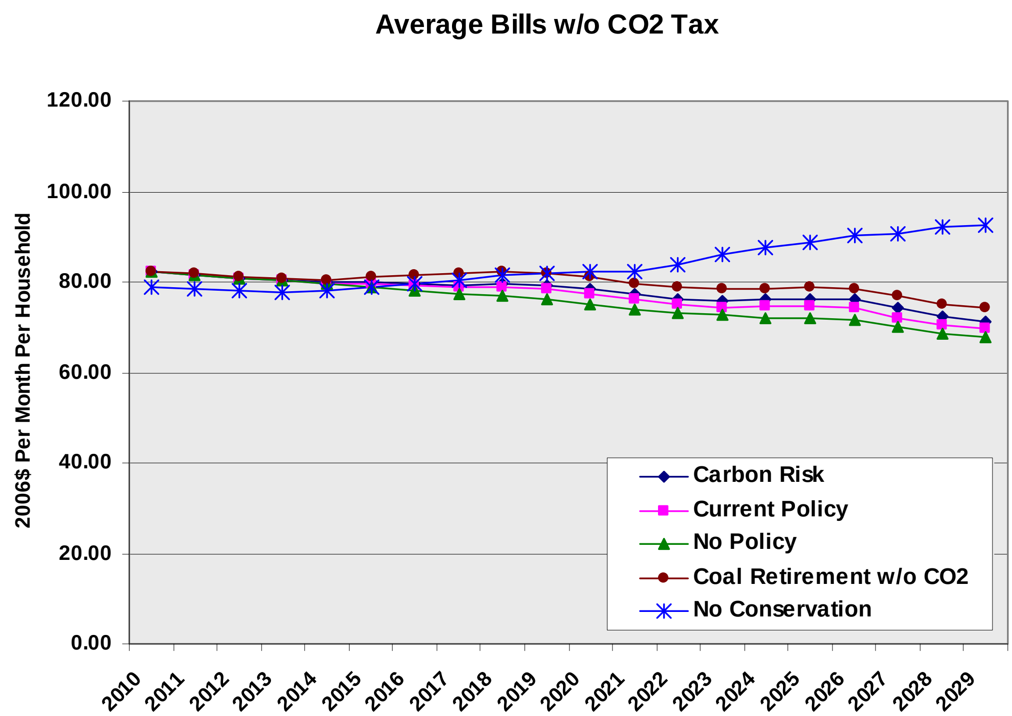


Figure 10-12a: Monthly Residential Bills Including the Cost of Carbon Penalties

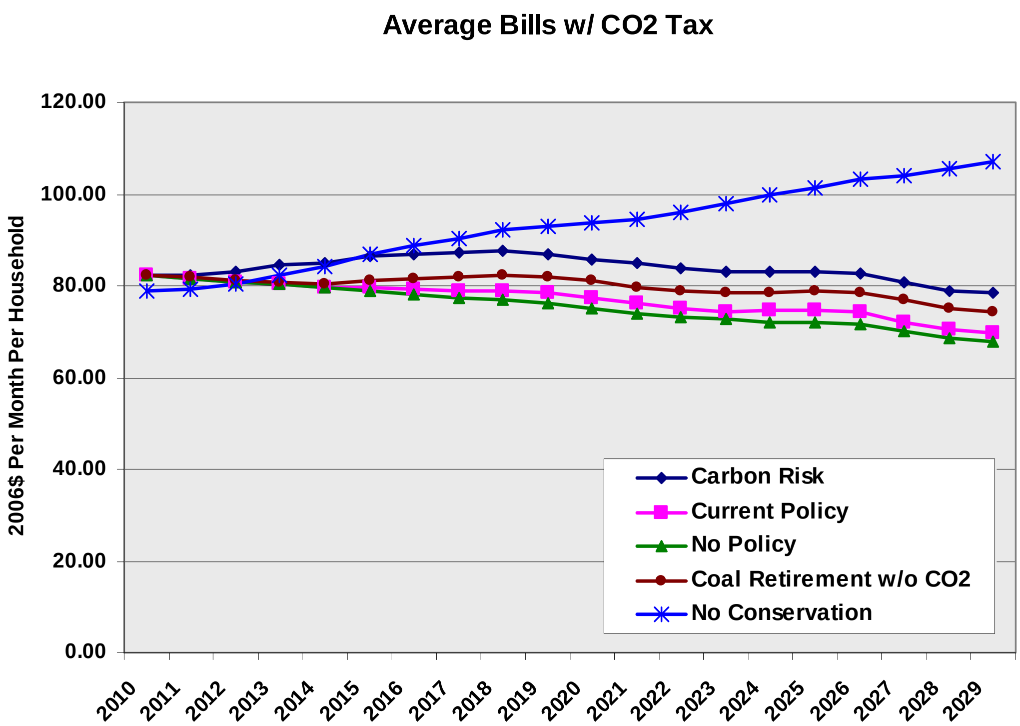


Figure 10-13: Electricity Rates Excluding the Cost of Carbon Penalties

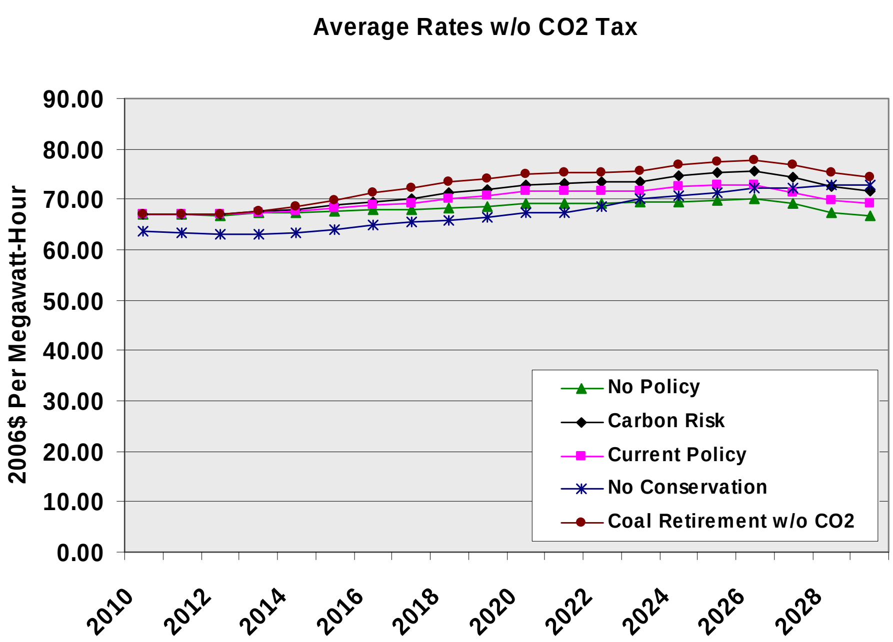
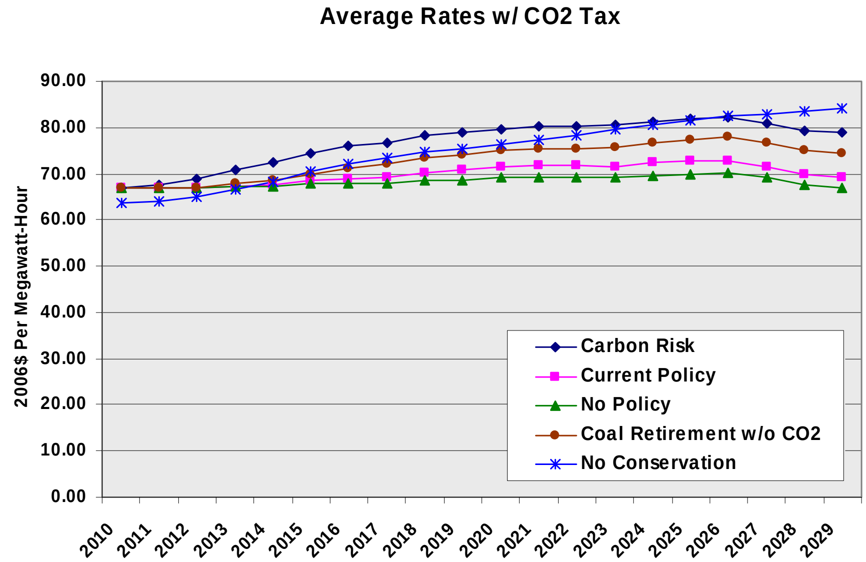


Figure 10-13a: Electricity Rates Including the Cost of Carbon Penalties



The pattern of change of rates and bills in other scenarios does not vary greatly from those shown in Figures 10-12 and 10-13. The trends in rates show a gradual increase, while the trends in bills show a gradual decrease. The one scenario that does have a significant effect on bills is the no-conservation scenario. Without the conservation available, the region, faced with carbon-price risk, would experience significantly higher electricity bills. This is apparent in Figures 10-11 and 10-12 compared to the carbon-risk Scenario. The no-conservation scenario results in about $5 per megawatt-hour lower rates until near the end of the planning period when the two scenarios' rates converge (see Figure 10-13).

CARBON EMISSIONS

Response to Risk

One of the most important issues identified for this power plan is climate change and the possible effects that policies to reduce carbon emissions might have on the Northwest's power system. Current policies include renewable portfolio standards in three of the four Northwest states, limits on carbon emissions from new power plants, announced carbon-reduction goals, and numerous initiatives to reduce greenhouse-gas emissions from energy use. Additional policy discussions at the state, regional, and national levels have focused on some form of carbon pricing with most proposals focusing on a cap-and-trade system for carbon.

The uncertainty of future policies has been treated as one of the key risks facing the power system in the regional portfolio model. The carbon-risk scenario assumes that some form of price could be placed on carbon emissions, but the timing and level of the price are treated as uncertain. The intent of this scenario is to examine what actions should be taken by the power system in the face of likely but uncertain carbon-control policy. In this scenario, carbon pricing can be enacted at different times in the future, and when it is, the prices can be anywhere between $0 and $100 per ton of carbon dioxide emissions. One of the problems of unresolved policy direction is that utilities and business cannot anticipate what actions are going to be required. Any decisions made today may turn out to be costly when policy is enacted some time in the future. This uncertainty can result in delayed decisions about additional resource investments. The carbon-risk scenario provides some guidance for current decisions, when future conditions are unknown.

The results of the carbon-risk scenario can be compared to a current-policy scenario that assumes current policies will continue into the future; that is, it includes no risk of carbon-pricing policy in the future. A comparison of these two scenarios is shown in Table 10-1. Analysis of the carbon-risk scenario indicates that the most cost-effective response to carbon-pricing risk is more efficiency and more natural gas-fired generation. The actual natural gas-fired generation built is much lower than the option amounts shown in Table 10-1, but the increased natural gas options indicates the strategy that makes sense in the face of significant carbon-pricing risk. The role of the increased natural gas-fired generation is to provide energy replacement for existing coal plants that would be used less when high carbon taxes are encountered.

Table 10-1: The Carbon-Risk Scenario versus the Current-Policy Scenario

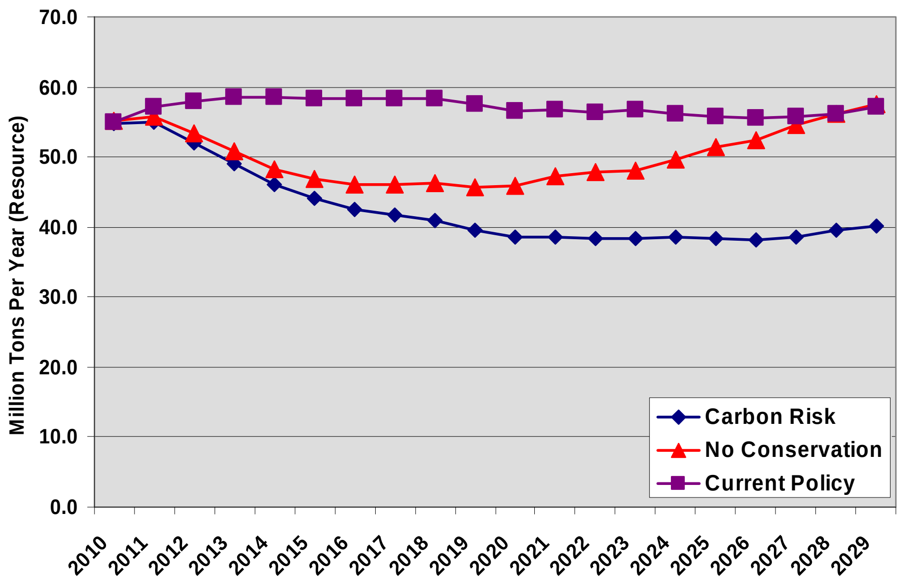
	Current Policy	Carbon Risk
Cost (billion 2006$ NPV)		
With Carbon Penalty	$56.10	$123.5
Without Carbon Penalty	$56.10	$63.9
Change in Retail Rates from Current Policy (levelized 2006$)		
Including Carbon Penalty		+ 8.6%
Without Carbon Penalty		+ 1.4%
Carbon Emissions (Gen) (Million Tons/Year in 2030)	56.3	39.7
Resources 2030		
Conservation (MWa)	5,572	5,895
Renewables (MWa)	1,480	1,453
CCCT Options 2030 (MWa)	1,512	3,402
SCCT Options 2030 (MWa)	1,620	648

Current (2005) carbon emissions from the Northwest power system are estimated to be 57 million tons per year (MMtpy) when adjusted to normal hydropower conditions. The comparable number for 1990 is estimated at 44 MMtpy. These are important numbers because proposed carbon-reduction targets usually are stated in terms of future emissions levels relative to either 2005 or 1990 levels. Based on simulations of the regional portfolio model , carbon emissions in the current-policy scenario are held fairly constant at 2005 levels through 2030. The commitment to aggressive efficiency improvement is largely responsible for limiting the growth of carbon emissions from the power system in the current-policy scenario. Actions taken in the carbon-risk scenario reduce carbon emissions by 30 percent from 2005 levels and by 10 percent from 1990 levels. The carbon reductions targeted by most stated or implied policy initiatives for 2020 are met in the carbon-risk scenario.[2] Continued reductions in carbon emissions would be required to meet long-term carbon reduction targets. Interpolation from 2020 targets to 2050 targets would place 2030 emissions targets between 35 and 40 MMtpy assuming the power sector is required to achieve carbon reductions in proportion to its share of total emissions.

[2] See description of policies in Chapter 11.

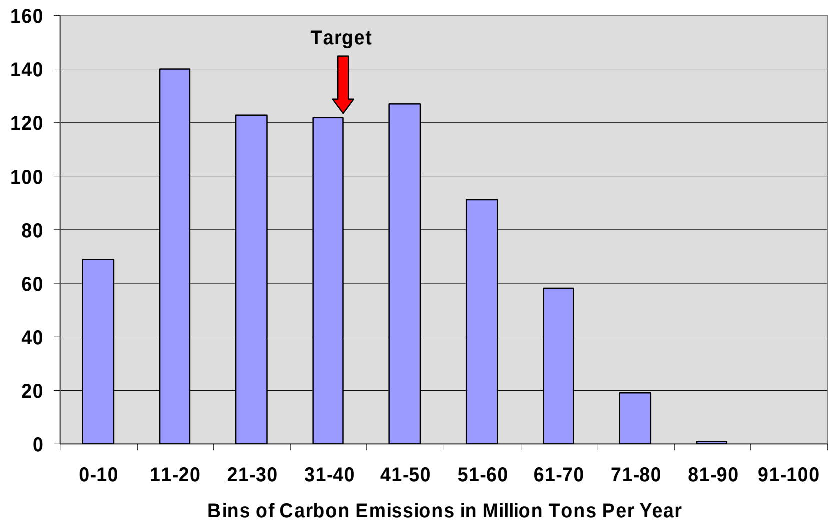
Figure 10-14 shows the average annual carbon emissions for the carbon-risk scenario compared to the current-policy scenario and another scenario that includes carbon price risk but does not include conservation as a resource (the no-conservation scenario). The figure illustrates the importance of the two key actions that will be required to meet carbon reduction goals: reduced coal use and increased efficiency.

Figure 10-14: Average Annual Carbon Emissions for Current-Policy, Carbon-Risk, and No-Conservation Scenarios



It is important to recognize, however, that the average carbon emissions shown in Figure 10-14 hide a great variety of possible future carbon emissions over the 750 futures simulated by the regional portfolio model. To illustrate this, Figure 10-15 shows the frequency distribution of 2030 carbon emissions for all 750 futures. Across the simulated futures, which vary in loads, carbon prices, natural gas prices, electricity market prices, and other conditions, carbon emissions range from less than 10 MMtpy to over 80 MMtpy. This sensitivity of carbon emissions to hydroelectric and other conditions makes verification of emissions levels difficult. Further, there are many different approaches to measuring and counting a region's carbon emissions. The measure that is shown in this plan is based on generation within, or committed on a long-term basis to, the region. An alternative approach is to base the carbon-emissions estimate on electricity consumption within the region. The Council calculates this concept as well, and because in most of the scenarios examined the Northwest is a net exporter of electricity, this measure of regional carbon emissions is lower. Because of all these factors, it would be inappropriate to make any definitive conclusions regarding carbon-emissions reduction targets and whether emission targets are achieved.

Figure 10-15: Frequency Distribution of Carbon Emissions in the Carbon-Risk Scenario



Reducing carbon emissions in the carbon-risk scenario is not free. The expected net present value of power system costs increases by $7.8 billion, or 14 percent, if only changes in the cost of electricity generation are included. The cost is $22.8 billion, or 40 percent greater, if the carbon price itself is included. The carbon price, perhaps a carbon tax, for example, may or may not be a net cost to the region depending on how the revenues from the tax are treated. Even for utilities the tax burden may be mitigated by other changes in taxation or credits. The structure of carbon-pricing policy is unknown at this time so both cost extremes are included in the plan.

Achieving Carbon-Reduction Targets

The carbon-risk scenario develops a resource strategy that addresses risk of future carbon costs. Another approach suggested in comments on the draft power plan is to design scenarios that are intended to achieve particular carbon-emission targets. As discussed above, 2030 carbon emissions targets fall into the 35-to-40-MMtpy range. Two scenarios examined alternative means to achieve carbon emissions levels that meet this target on average over the 750 futures simulated in the regional portfolio model.

The first scenario seeks a fixed carbon-emissions penalty that achieves the carbon-emissions target. Because the lowest penalty that achieves the target is $45 per ton, it is called the $45-carbon scenario. The tax is assumed to be implemented immediately in 2010. The level of this tax is similar to the average carbon tax in 2030 for the carbon-risk scenario, which assumed uncertain carbon taxes that, on average, increase over time.

Because it is clear that any significant carbon reduction requires reduced use of existing regional coal plants, the second scenario examined the retirement of enough coal-fired generation to meet the average emissions target. This is labeled the coal-retirement scenario. In the coal-retirement scenario, approximately half (54 percent or 2,700 average megawatts after planned and forced outages) of the region’s coal-fired generation capability is phased out between 2012 and 2019. Because coal retirement is viewed as an alternative to carbon pricing in this scenario, there is no carbon penalty in this study. An analysis of coal retirement with carbon pricing uncertainty has also been done and is discussed below.

Both of these scenarios meet the carbon emissions target of between 35 and 40 MMtpy by 2030, as did the carbon-risk scenario. However, the levels of carbon emissions, costs, and certainty of carbon reductions vary among them. Table 10-2 compares the results of the three scenarios. If the carbon penalties themselves are not included, the present value system costs of the three scenarios are very similar. If the carbon penalties are included (first row of Table 10-2) scenarios with carbon pricing are more costly. Because the carbon risk scenario includes many futures with prices well above the $45-per-ton-level, its cost is even higher than the $45 scenario.

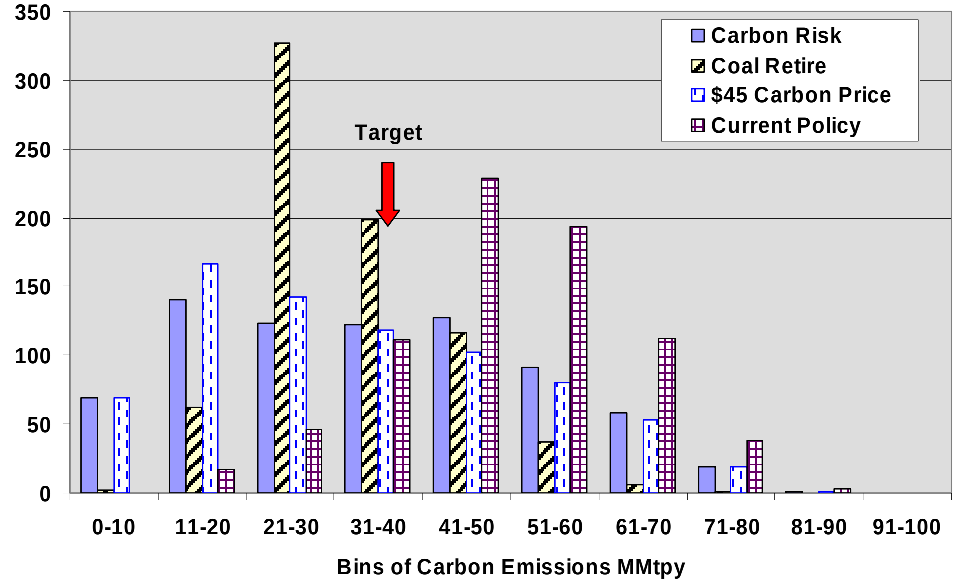
Table 10-2: The Carbon-Risk Scenario versus Current Policy

	Carbon Risk	$45 Carbon	Coal Retirement
Cost (billion 2006$ NPV)			
With Carbon Penalty	$123.5	$85.7	$64.3
Without Carbon Penalty	$63.9	$64.2	$64.3
Change in Retail Rates from Current Policy (levelized 2006$)			
Including Carbon Penalty	+ 8.6%	+ 12.9%	+ 2.9%
Without Carbon Penalty	+ 1.4%	+ 2.9%	+ 2.9%
Carbon Emissions (Gen) (Million Tons/Year)	39.7	37.0	36.3
Resources 2030			
Conservation (MWa)	5,895	5,933	5,825
Renewables (MWa)	1,453	1,450	1,459
CCCT Options 2030 (MWa)	3,402	1,890	3,024
SCCT Options 2030 (MWa)	648	1,620	3,240

The role of conservation and the amount of renewables needed to meet renewable portfolio standards are very similar among the scenarios. The amount of natural gas-fired generation, however, does change. The role of natural gas-fired generation depends on how much energy and capacity needs to be replaced and how much risk needs to be insured against. In the $45-carbon scenario, the cost of carbon is known as is the viability of existing coal plants. There is still variability based on uncertain natural gas prices, but on average less coal energy needs to be replaced than in the coal-retirement or carbon-risk scenarios. The coal-retirement scenario requires more natural gas-fired generation than the $45-carbon scenario to replace the energy and capacity of retired coal plants. The carbon-risk scenario requires more natural gas-fired generation than the $45-carbon scenario because of the risk of higher carbon penalties and the reduced cost-effective coal and inefficient gas-fired generation that ensues.

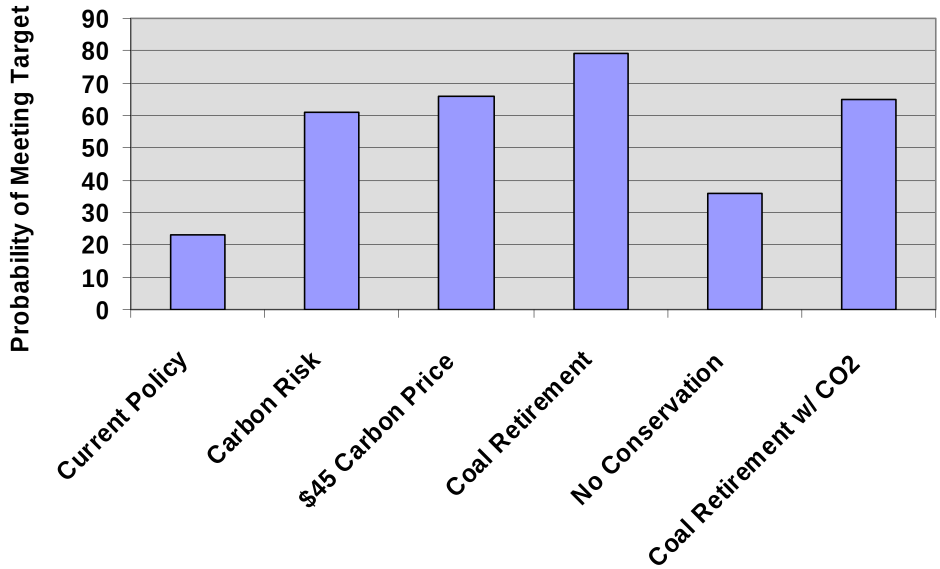
These three scenarios vary in their certainty of carbon reduction across the 750 futures that the regional portfolio model examines. Figure 10-16 shows a frequency distribution of carbon emissions, similar to Figure 10-15, for each of the three scenarios that, on average, meet the carbon-emissions target compared to the current-policy scenario. The carbon-risk frequency distribution is the same as shown in Figure 10-15. All of the three carbon scenarios shift the distribution of carbon emissions to the left. The distribution of the $45-carbon and carbon-risk scenarios are generally similar to one another. The coal-retirement scenario, however, focuses the emissions much more into the 20- to 40-MMtpy area.

Figure 10-16: Carbon Emissions Frequency Distribution in Four Scenarios



Another way to summarize the differences among the carbon scenarios and the current-policy scenario is to calculate the probability that each scenario will result in carbon emissions below 40 MMtpy. Figure 10-17 shows these probabilities. With current policies, the likelihood of emissions falling below 40 MMtpy in 2030 is only 23 percent. Coal retirement is the most certain of the policies to achieve the target under the variety of future conditions examined by the model. It achieves less than 40 MMtpy in 79 percent of the 750 futures. Pursuing actions to mitigate the risk of uncertain carbon pricing, as in the carbon-risk scenario, will achieve success in 61 percent of the futures, while a fixed carbon tax of $45 would achieve success in about 66 percent of the futures. Figure 10-17 includes the coal-retirement scenario combined with carbon pricing (coal retirement w/ CO2). In this scenario carbon prices do most of the carbon-reduction work. Only about 13 percent of the existing coal-fired generation is retired in this scenario. Its certainty of carbon emissions below 40 million tons per year is only slightly higher than the carbon-risk scenario, and slightly lower than the $45-carbon scenario.

Figure 10-17: Probability of Meeting Carbon Emissions Targets



The analysis of these scenarios indicates that in order to reduce carbon emissions from the Northwest power system to meet a pro-rata share of the current targets adopted by some Northwest states or being proposed in federal legislation, the region would have to acquire about 5,900 average megawatts of efficiency and significantly reduce the use of existing coal-fired power plants. If conservation were not available to the region in the face of carbon-pricing risk, the probability of meeting carbon reduction targets would only be 36 percent. Phasing out about half of the existing coal plants would provide a more assured reduction of carbon emissions at a comparable expected cost without the carbon penalty included. There is no guarantee that coal retirement would be a substitute for carbon pricing, however. Fewer coal plants would need to be retired if the region also faced the risk of carbon penalties. But relying on response to carbon risk does not provide the same assurance of carbon reductions.

The actual use of coal-fired generation, when averaged over the 750 futures in the three carbon scenarios, is fairly consistent. In 2030, the average dispatch of existing coal plants is 2,441 average megawatts in the carbon-risk scenario. The comparable numbers for the $45-carbon and coal-retirement scenarios are 2,276 and 2,136, respectively. With current policy the average dispatch of coal is about double these levels at 4,157. When the frequency distribution of coal plant dispatch over the 750 futures is examined, patterns similar to the carbon emissions patterns in Figure 10-16 result. The conclusion is that whether through retirement or less dispatch, existing coal would only provide about half as much energy and capacity to the power system as is now the case. Coal retirement provides increased certainty of carbon emission reduction and also increased certainty about actions that need to be taken and their costs over time. In addition, it may be that dispatch of coal plants at half their current levels would be an uneconomic operation for these plants. If that is the case, the carbon-pricing scenarios would imply that coal plants likely would be retired based on economic considerations.

VALUE OF THE HYDROELECTRIC SYSTEM

The Pacific Northwest power system emits about half the carbon dioxide per kilowatt-hour of the nation or the rest of the western states. This is due to the large role played by the hydroelectric system of the region. To illustrate the value of the hydroelectric system, a scenario was run to examine the effects of removing the lower Snake River dams on power system costs and carbon emissions. The results of the scenario, however, could apply to other changes that reduce the capability of the hydroelectric system for any reason.

The lower Snake River dams provide 1,110 average megawatts of energy under average water conditions, about 5 percent of regional annual electric energy needs. In addition, the dams provide 3,500 megawatts of short-term capacity, a little more than 10 percent of the total hydroelectric system capacity, and as part of the Automated Generation Control (AGC) System, they provide system reserves to maintain the reliability of the power supply. They also provide reactive support for the stability of the transmission system.

The effects of removing the capability of the lower Snake River dams are mainly determined by the replacement resources that would be required for the power system to duplicate the energy, capacity, real-time load following, stability reserves and reactive support currently provided by the dams. To examine the effects on energy and capacity, the generating capability of the dams was removed from the carbon-risk scenario of the Sixth Power Plan. For this scenario, it was assumed that the power produced by the dams was removed in 2020 and the energy and capacity were replaced by other resources selected by the regional portfolio model. That is, given the reduced energy and capacity of the hydroelectric system a low-cost and low-risk portfolio of new and replacement resources is developed. The changes in cost, carbon emissions, risk, and average retail electricity rates are shown in Table 10-3. The effects analyzed include the replacement resources for the assumed loss to the power system of only the energy and capacity of the Snake River dams. No estimate was made of the cost of replacing the other services provided by the dams. There are many other implications and costs of dam removal including the cost of removing the dams, future operating cost and replacement savings, substitution of other transportation modes for barge transportation (including fish transportation), changes in irrigation sources, and other factors. These were addressed most completely in the Corps of Engineers EIS on the *Lower Snake River Juvenile Salmon Migration Feasibility Study*,[3] and have not been included in this analysis.

[3] U.S. Army Corps of Engineers. *Lower Snake River Juvenile Salmon Migration Feasibility Study* 2000. http://www.nww.usace.army.mil/lsr/

Table 10-3: The Effect of the Dam Removal Scenario

	Carbon Risk	Dam Removal	Change
Cost (billion 2006$ NPV)			
With Carbon Penalty	78.9	85.8	+ $6.9 (+8.7 %)
Without Carbon Penalty	63.9	68.1	+ $4.2 (+6.5 %)
Risk (TailVar90 Billion 2006$ NPV)			
With Carbon Penalty	123.5	135.6	+ $12.1 (+ 9.8 %)
Retail Rates (levelized 2006$ Per MWh)			
With Carbon Penalty	75.6	77.0	+ 1.4 (1.9%)
Without Carbon Penalty	70.5	71.3	+ 0.8 (1.1%)
Carbon Emissions (Gen) (Million Tons/Year)	39.7	42.7	+ 3.0 (+7.6 %)

Dam removal increases the carbon emissions, cost, and risk of the power system. The projected changes to the power system to accommodate the loss of hydroelectric capability are not a simple energy and capacity replacement. Small increases in conservation and renewable resources occur in this scenario, but the primary replacement of the dams is provided by changes in the construction of new gas-fired generating plants, changes in the operation of existing and new generating plants, and changes in net exports. Existing natural gas-fired and coal-fired generation is used more intensively. In addition, the region exports less energy and imports more. The combination of these changes makes up for the lost 1,100 average megawatts of energy. Table 10-4 summarizes the average replacement resources; however, the average hides a wide variation in responses depending on the future that is encountered.

Replacement of the lower Snake River dam energy and capacity results in increased carbon emissions of 3.0 million tons year, a 7.6 percent increase compared to emissions in the carbon-risk scenario. To place this number in context, it is an amount five times greater than the amount of carbon saved by renewable portfolio standards between the carbon-risk and the no-RPS scenarios. Increased carbon emissions result because without the dams the resource strategy includes more options of additional new gas-fired generation and builds the options more frequently. In addition, existing carbon-producing resources are dispatched more often. In total, Table 10-4 shows that 1,103 average megawatts would be required to replace the dams with 437 average megawatts coming from carbon-producing resources, not including increased imports that would also most likely come from carbon-producing resources

Table 10-4: Replacement of Lower Snake Dam Energy

Replacement Resource	Average Change in Energy
Existing Natural Gas	+ 91
Existing Coal	+ 149
New Natural Gas	+ 197
Conservation	+ 145
Renewables and Other	- 10
Net Imports (reduced exports and increased imports)	+ 531
Total Energy Replaced on Average	= 1,103

The changes in net present value system cost shown in Table 10-3, while appropriate for regional electricity planning comparisons, hide significant changes in costs and their allocation over time and among utilities and consumers in the region. Figure 10-18 shows the annual pattern of cost changes for the dam-removal scenario. Annual cost of the power system increases in 2020 by over $530 million and remains higher. Further, because the lower Snake River dams serve Bonneville public-utility customers, those utilities and their consumers would bear the cost increases. Using a rate-making rule of thumb that a $65 million to $80 million cost increase translates into a $1 per megawatt-hour increase in Bonneville rates, a $530 million increase in Bonneville costs would raise rates by between $6.60 and $8.15 per megawatt-hour. Based on Bonneville's priority firm rate of $28 per megawatt-hour, dam removal causes an increase of 24 percent to 29 percent.

Figure 10-18: Annual Cost Changes for the Dam-Removal Scenario

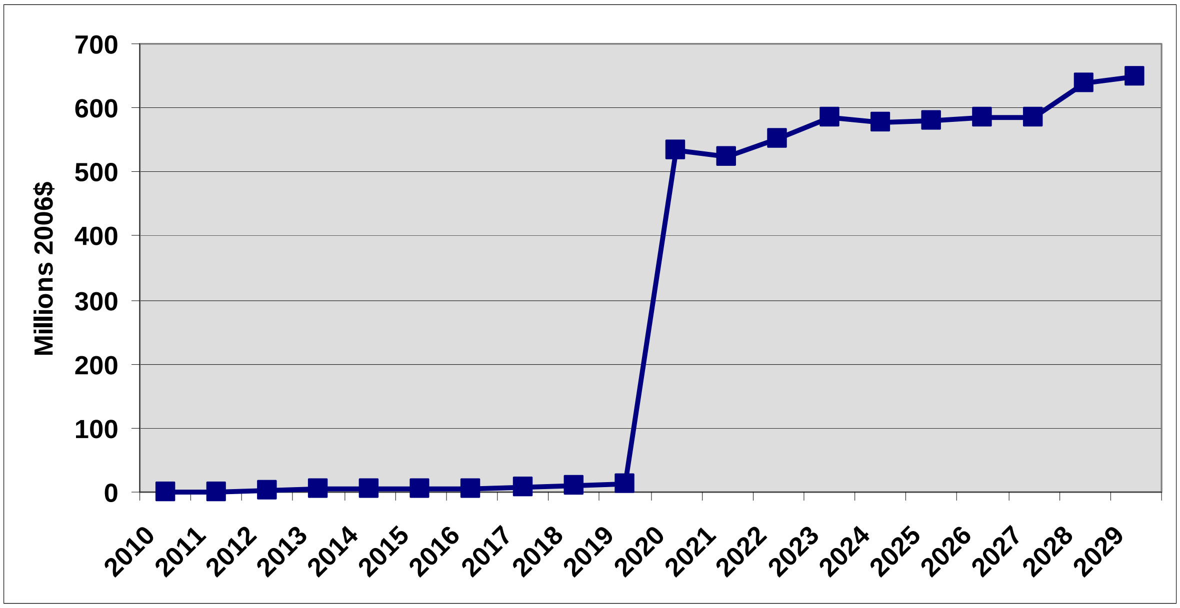


Figure 10-19: Summary of Scenario Results

Least Risk →

Scenario	Carbon Risk Least Risk L813LR	Current Policy Least Risk L813g	No Policy Least Risk L813i2	No RPS Least Risk L813h2	$45 CO2 Cost Least Risk L813d	Coal Retirement Least Risk L813b	Coal Retire w/CO2 Least Risk L813j	No Conservation Least Risk L813a	Dam Removal Least Risk L813k
COST & RISK									
NPV Cost (Bil. 2006$) (w/ carbon penalty)	78.9	56.1	51	77	85.7	64.3	80.3	116.2	85.8
NPV Risk (Bil. 2006$)	123.5	83.4	82.6	123.3	121.1	96.4	125	185.7	135.6
NPV Cost (Bil. 2006$) (w/o carbon penalty)	63.9	56.1	51	61.6	64.2	64.3	61.9	87.8	68.1
RATES (levelized 2006$/Mwh)	**Least Risk**	**Current Policy**	**No Policy**	**No RPS**	**$45 CO2 Cost**	**Coal Retirement**	**Coal Retire w/CO2**	**No Conservation**	**Dam Removal**
Retail Rates (w/o carbon penalty)	71	70	68	70	72	72	71	67	71
Retail Rates (w/ carbon penalty)	76	69	68	75	79	72	76	73	77
2010-29 Growth rate of rates (w/o carbon penalty	0.4%	0.2%	0.0%	0.2%	0.2%	0.6%	0.4%	0.7%	0.5%
% change levelized from Carbon Risk scenario (w/o)		-1.0%	-3.0%	-1.0%	2.0%	2.0%	1.0%	-6.0%	1.0%
MONTHLY RESIDENTIAL BILLS (2006$)	**Least Risk**	**Current Policy**		**No RPS**	**$45 CO2 Cost**	**Coal Retirement**	**Coal Retire w/CO2**	**No Conservation**	
Monthly Residential Bills (w/o carbon penalty)	79	78	77	78	80	80	79	82	79.00
Monthly Residential Bills (w/ carbon penalty)	84	78	77	84	88	80	84	91	85.00
2010-29 Growth rate of bills (w/o carbon penalty	-0.70%	-0.9%	-1.0%	-0.9%	-0.9%	-0.5%	-0.7%	0.9%	-0.6%
% change levelized from Carbon Risk scenario (w/o)		-1.0%	-3.0%	-1.0%	2.0%	2.0%	-1.0%	5.0%	1.0%
CARBON									
2030 Emissions (Generation Based, MMtpy) adjusted	39.7	56.3	60.3	40.3	37.0	36.3	37.7	57.0	42.7
2030 Emissions (Use Based, MMtpy) adjusted	29.0	42.0	50.0	31.0	28.0	28.0	27.3	60.0	35.0
RESOURCES									
Total Conservation (Average Development)	5895	5572	5452	5966	5933	5825	5903	0	6040
Renewable Resources (Forced in if RPS)	1453	1480	311	1008	1450	1459	1452	2049	1443
CCCT (Amount Optioned)									
Earliest Option	3402	1512	3780	2268	1890	756	378	3780	378
Earliest Construction Date	2019	2019	2019	2019	2019	2015	2013	2013	2017
Maximum Optioned	3402	1512	3780	2268	1890	3024	4158	10962	4536
Average Built	991	299	909	704	551	1027	1243	4024	619
SCCT (Amount Optioned)									
Earliest Option	162	648	648	648	162	162	162	162	0
Earliest Construction Date	2015	2015	2017	2017	2017	2015	2021	2009	
Maximum Optioned	648	1620	1620	1458	1620	3240	489	2916	
Average Built	122	236	355	288	329	1062	93	961	
Demand Response	4	4	4	4	4	4	4	9	4
Average Market Purchases	-1977	-2751	-1990	-1784	-1772	-1648	-1893	344	-1446
Total New Energy	8465	7591	7031	7970	8267	9377	8695	7043	8106