Chapter 2: Key Assumptions

SUMMARY OF KEY FINDINGS

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

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

Carbon-emission taxes or cap-and-trade policies are likely to raise energy costs further. Wholesale electricity prices are expected to increase from about $30 per megawatt-hour in 2010 to $74 per megawatt-hour by 2030 (2006$). These electricity prices reflect carbon costs that start at zero and increase to $47 per ton of CO_2 emissions by 2030. Higher electricity prices reduce demand, advance new sources of supply and efficiency, and make cost-effective more efficiency measures.

INTRODUCTION

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

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

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

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

ECONOMIC GROWTH

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

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

Population. Population in the Northwest states grew from about 8.9 million in 1985 to about 13 million in 2007, increasing at about 1.6 percent per year. The growth in population is projected to slow to about 1.2 percent annually, resulting in a total regional population of 16.7 million by 2030.

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

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

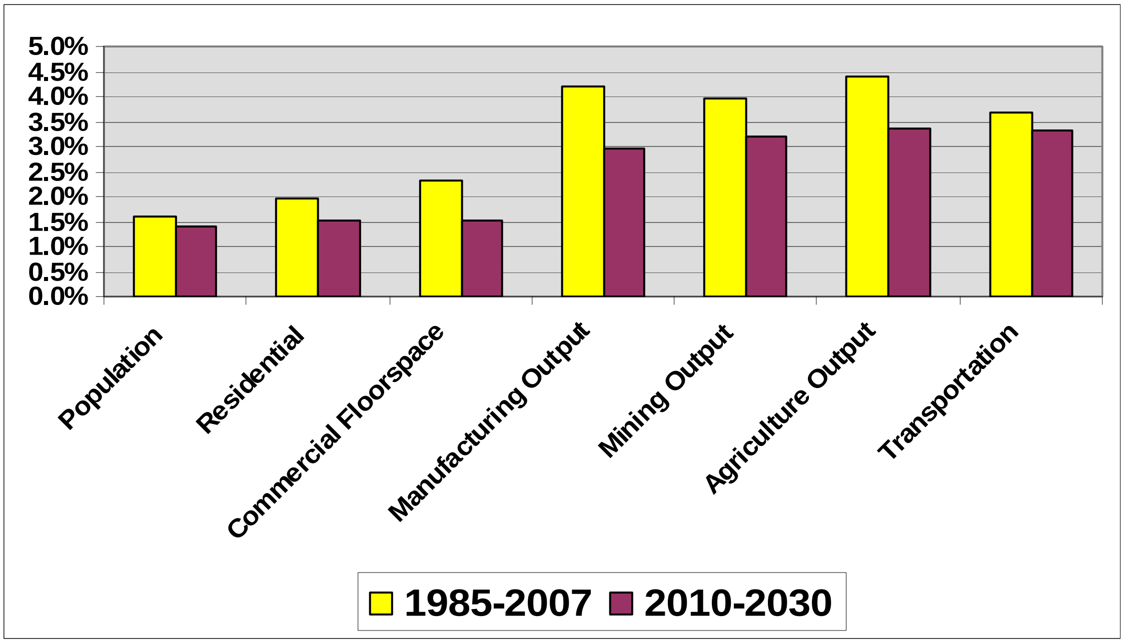
Commercial Square Footage. Demand for electricity in the commercial sector is driven by demand for commercial floor space that requires lighting, air conditioning, and services to make occupants comfortable and productive. The square footage of commercial buildings is forecast to grow at 1.2 percent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

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

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

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

Figure 2-1: Comparison of Key Economic Drivers



Alternative Economic Scenarios

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

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

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

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

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

FUEL PRICES

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

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

Because natural gas is the primary energy source affecting both the demand and supply of electricity, forecasts of natural gas prices receive far more detailed attention than oil or coal prices. Fuel price forecasts start with global, national, or regional energy commodity prices, depending on the fuel. Oil is a global commodity, natural gas is still primarily a North American commodity (although this could change as liquefied natural gas imports grow), and coal prices tend to be regional in nature. All of these commodities have experienced periods of high and volatile prices since the Fifth Power Plan was issued in 2004. Natural gas prices have collapsed since the summer of 2008. This reduction in price is partly due to natural supply-and-demand responses to a period of high prices, but also to a great extent is a result of the current recession and financial crisis.[1] The Council's forecast of natural gas prices assumes prices will rebound from recent recession-induced lows.

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

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

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

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

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

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

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

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

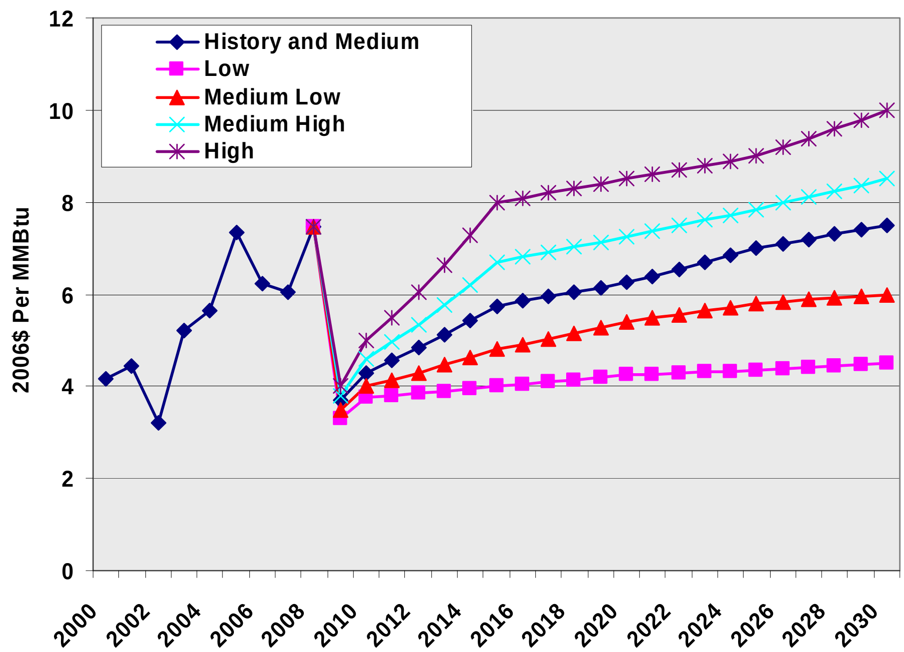


Table 2-2: U.S. Wellhead Natural Gas Price Forecast Range (2006$ per MMBtu)

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

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

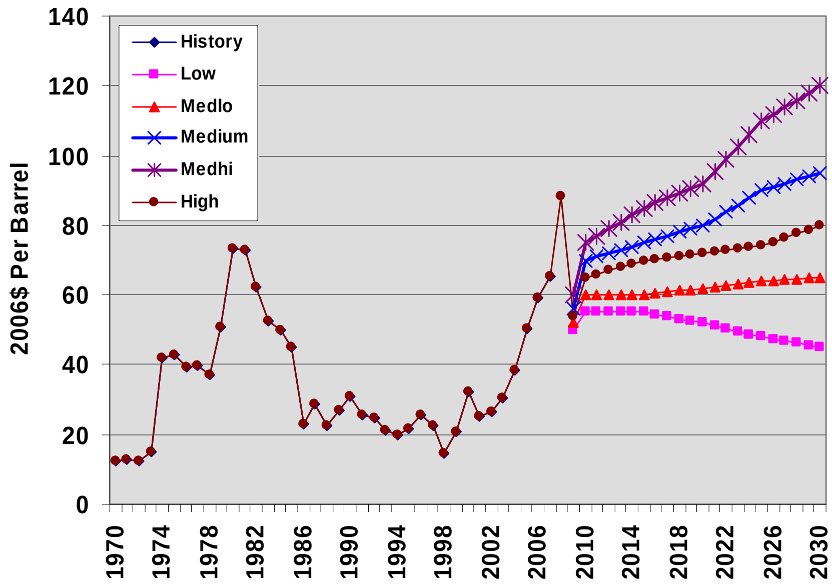


Table 2-3: World Oil Price Forecast Range (2006$ per Barrel)

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

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

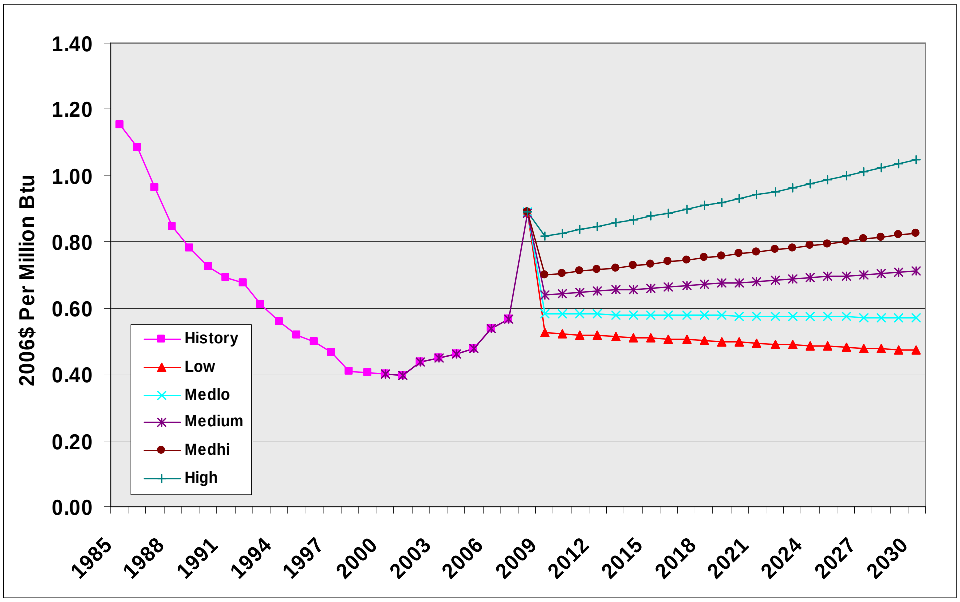


Table 2-4: Powder River Basin Minemouth Coal Price Forecasts (2006$ per MMBtu)

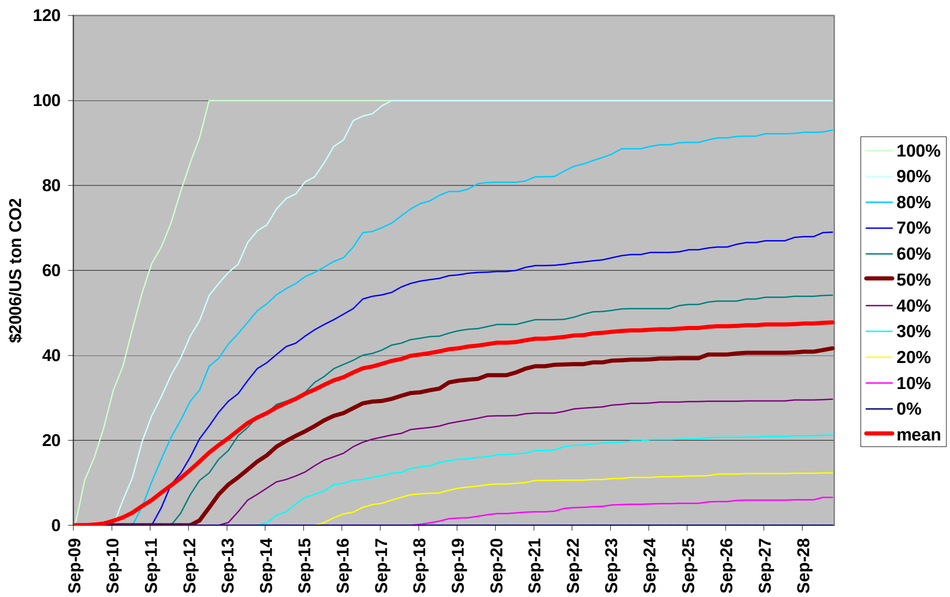
	Low	Medium Low	Medium	Medium High	High
2007	-	-	0.56	-	-
2010	0.52	0.58	0.64	0.70	0.83
2015	0.51	0.58	0.66	0.73	0.88
2020	0.50	0.58	0.68	0.76	0.93
2025	0.48	0.57	0.69	0.79	0.99
2030	0.47	0.57	0.71	0.83	1.05
Growth Rates					
2007-2015	-1.29%	0.32%	1.98%	3.33%	5.65%
2007-2030	-0.78%	0.05%	1.01%	1.67%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

CARBON DIOXIDE PRICES

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

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

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



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

The choice of the range of carbon prices to be considered was informed by research and review of the results of studies done by various organizations on the likely cost of carbon allowances that would result under various cap-and-trade policies. The Council commissioned a study by EcoSecurities Consulting Limited to review the literature on carbon-pricing studies and develop a range of likely prices under different policy scenarios. The range of estimates is very wide. Results depend on the study methodology, the carbon-reduction targets assumed, and the assumed scope and role of carbon-credit trading. However, the bulk of the estimates fell between $10 and $100 per ton of CO_2. Understanding that there is some chance that no carbon pricing policy will be agreed on, the Council used a range from $0 to $100 for its carbon-risk analysis.

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

RENEWABLE PORTFOLIO STANDARD RESOURCE DEVELOPMENT

Renewable resource portfolio standards (RPS) mandating the development of certain types and amounts of resources have been adopted by eight states within the Western Electricity Coordinating Council region: Arizona, California, Colorado, Montana, New Mexico, Nevada, Oregon, and Washington[2]. In addition, British Columbia has adopted an energy plan with

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

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

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

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

	AZ	BC	CA (33%)	CO	MT	NM	NV	OR	WA
Committed	87	366	3954	454	65	111	273	465	520
Cumulative new (100% achievement of standards)									
2010	32	0	425	0	0	0	21	0	0
2011	77	0	1,068	0	0	0	63	0	0
2012	115	0	1,774	0	19	0	137	0	0
2013	157	0	2,416	0	24	112	277	0	0
2014	196	17	2,863	280	31	147	339	0	218
2015	240	85	3,329	368	37	184	452	0	367
2016	313	136	3,401	450	37	214	463	0	511
2017	390	185	3,477	537	37	243	496	0	662
2018	471	239	3,551	626	37	273	508	0	812
2019	555	296	3,602	718	37	304	524	0	958
2020	642	351	3,674	813	37	335	537	0	953
2021	733	406	3,745	836	37	341	551	0	941
2022	826	462	3,816	860	37	346	566	478	939
2023	925	520	3,885	885	37	353	580	538	939
2024	1,027	579	3,954	910	37	359	595	599	941
2025	1,134	638	4,026	935	38	366	610	662	944
2026	1,163	698	4,099	961	38	372	626	670	950
2027	1,192	758	4,171	987	39	379	641	677	956
2028	1,223	819	4,244	1,014	39	385	657	685	965
2029	1,254	882	4,318	1,041	40	392	672	697	977
Total	**1,341**	**1248**	**8,272**	**1,495**	**105**	**503**	**945**	**1,162**	**1,497**

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

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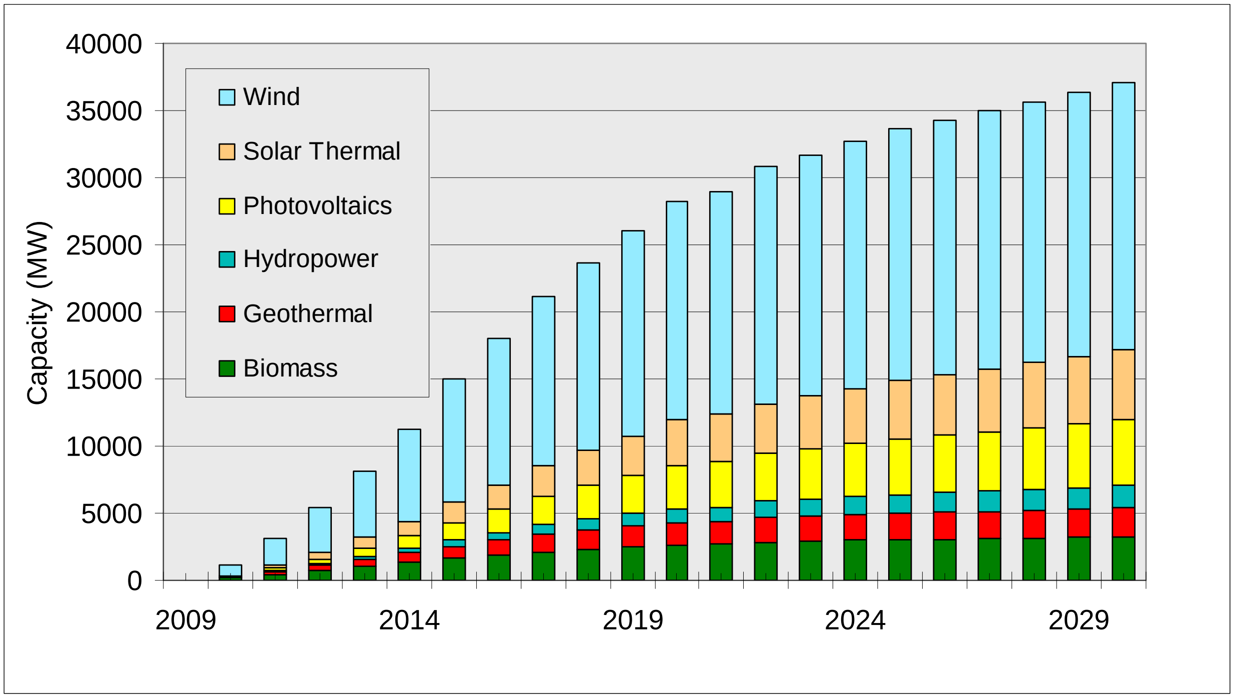
resource acquisitions based on cost-effectiveness are simulated by the capacity expansion logic of the AURORA$^{xmp®}$ Electricity Market Model used for the wholesale power price forecast, it was not necessary to separately forecast renewable resource development for Utah.

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

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

Figure 2-6: Forecast RPS capacity by resource type



WHOLESALE ELECTRICITY PRICES

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

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

The Council uses the AURORA$^{xmp®}$ Electricity Market Model[3] to forecast wholesale power prices. Electricity prices are based on the variable cost of the most expensive generating plant or

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

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

Three factors are expected to significantly influence the future wholesale power market: the future price of natural gas; the future cost of carbon dioxide (CO_2) production; and renewable resource development associated with state renewable portfolio standards (RPS). These factors will affect the variable cost of the hourly marginal resource and hence the wholesale power price.

Because natural gas is a relatively expensive fuel, natural gas-fired plants are often the marginal generating unit, and therefore determine the wholesale price of electricity during most hours of the year. CO_2 allowance prices or taxes will raise the variable cost of coal-fired units more than that of gas-fired units because of the greater carbon content of coal. Lower CO_2 costs will raise the variable cost of both gas and coal units, but not enough to push coal above gas to the margin. High CO_2 costs will move coal to the margin, above gas. In either case, the variable cost of the marginal unit will increase. As described earlier in this chapter, state renewable portfolio standards are expected to force the development of large amounts of wind, solar, and other resources with low-variable costs, in excess of the growth in demand. This will force fossil-fueled generators with lower variable costs to the margin, tending to reduce market prices.

A base case forecast, four sensitivity studies, and two bounding-scenario cases were run. The base forecast assumes medium-case fuel prices and mean CO_2 prices. All forecast cases assume 95-percent achievement of state renewable portfolio standards, average hydropower conditions, medium load growth and achievement of all cost-effective conservation. The changing case assumptions are shown in Table 2-6.

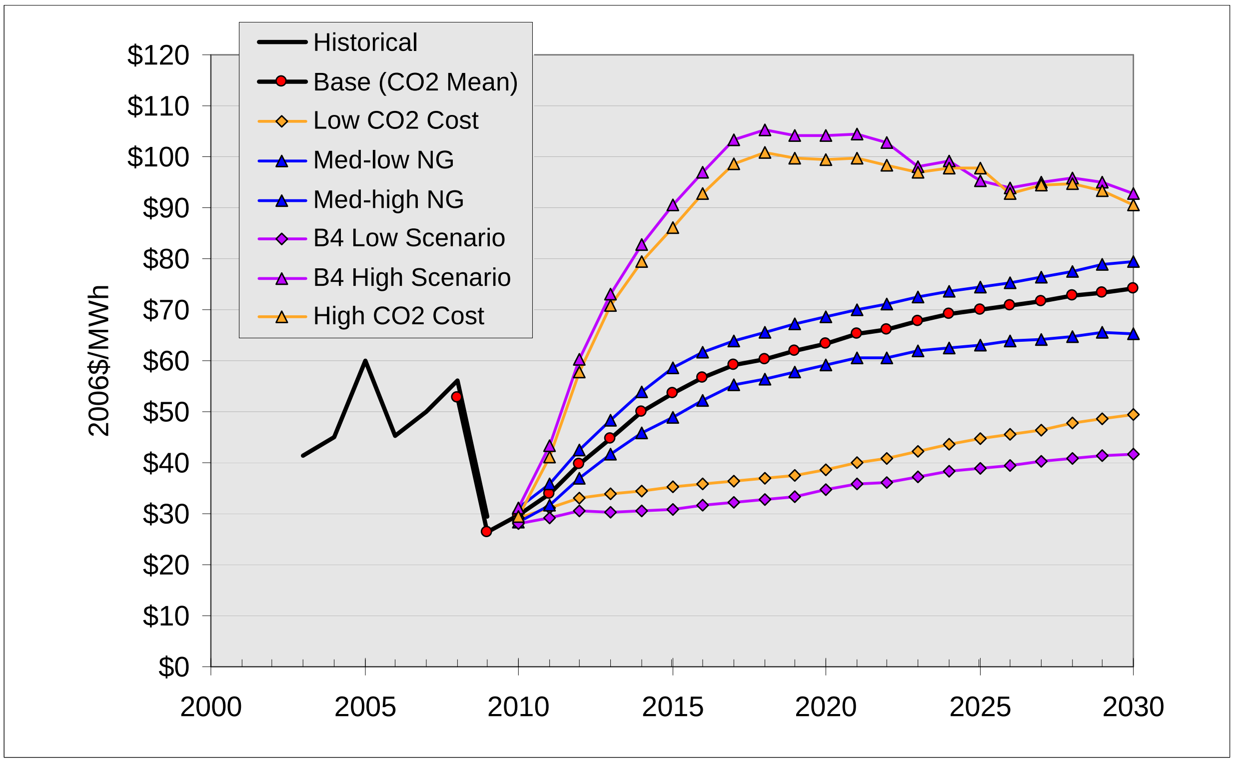
Table 2-6: Price Forecast Case Changing Assumptions

Case	Fuel Prices	CO_2 Cost
Base (mean CO_2)	Medium Case	Mean
Low CO_2 Cost	Medium Case	90% prob. of exceedance decile
High CO_2 Cost	Medium Case	10% prob. of exceedance decile
Medium-Low Natural Gas	Medium-low NG	Mean of RPM cases
Medium-High Natural Gas	Medium-high NG	Mean of RPM cases
Low Scenario	Medium-low NG	90% prob. of exceedance decile
High Scenario	Medium-high NG	10% prob. of exceedance decile

For the base forecast, wholesale power prices at the Mid-Columbia trading hub are projected to increase from $30 per megawatt-hour in 2010 to $74 per megawatt-hour in 2030 (in real 2006 dollar values). For comparison, Mid-Columbia wholesale power prices averaged $56 per megawatt-hour in 2008 (in real 2006 dollars), dropping abruptly to $29 in 2009 with the collapse of natural gas prices and reduction of demand due to the economic downturn. The levelized present value of the 2010-29 base case forecast is $56 per megawatt-hour.

Figure 2-7 illustrates recent and forecast wholesale power prices for the various cases. Comparing the shape of the power price forecasts with the mean CO_2 price forecast of Figure 2-5 clearly demonstrates the significant effect of CO_2 costs on prices. This is particularly evident in the high CO_2 and high-scenario cases. In these cases, prices rise rapidly early in the planning period as CO_2 prices increase, then stabilize and decline as CO_2 prices reach a steady-state of $100/ton of CO_2 and additional low-carbon resources are deployed.

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



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

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

Figure 2-8: Monthly Average Base Case (Mean CO_2) Forecast of Mid-Columbia Wholesale Power Prices

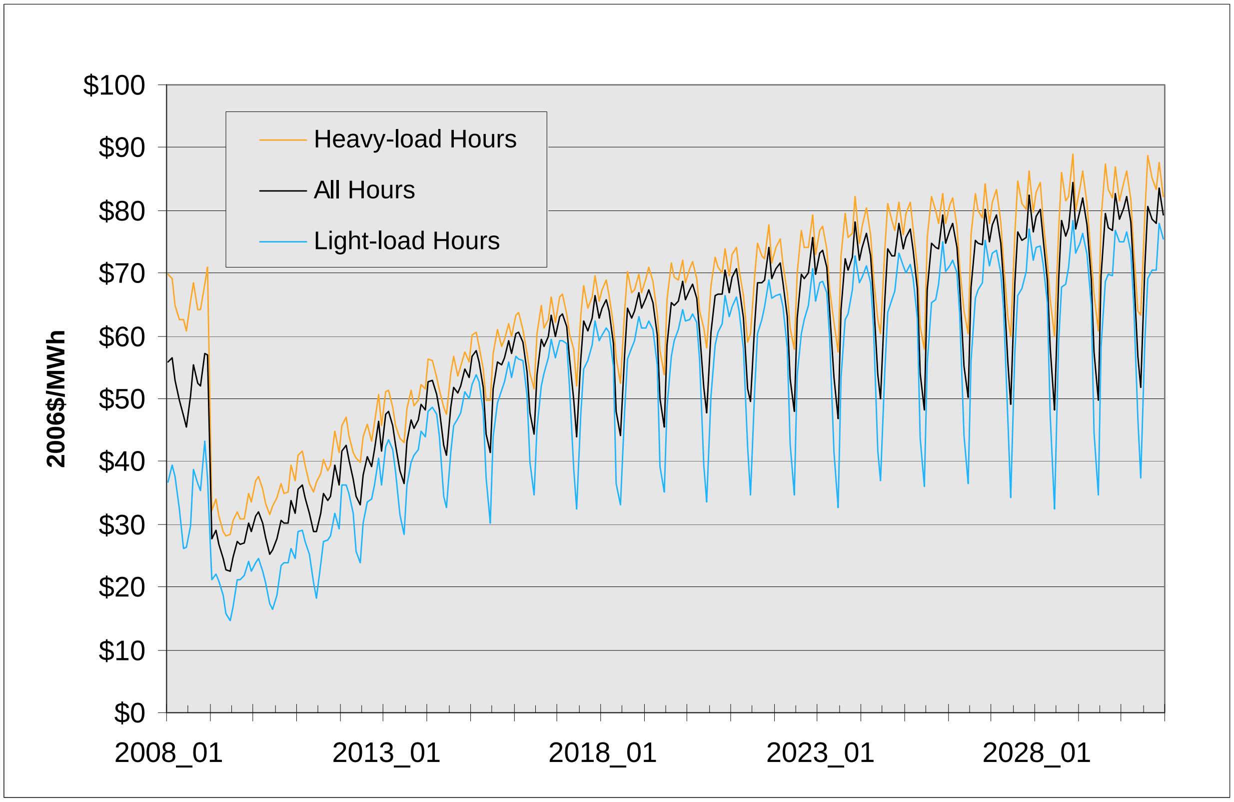


Table 2-7: Forecast of Mid-Columbia Wholesale Power Prices (2006$/MWh)

	Base	Low-CO_2	High CO_2	Med-Low NG	Med-High NG	Low Scenario	High Scenario
2010	$30	$29	$29	$28	$31	$28	$31
2015	$54	$35	$86	$49	$59	$31	$90
2020	$63	$39	$99	$59	$69	$35	$104
2025	$70	$45	$98	$63	$74	$39	$95
2030	$74	$49	$91	$65	$79	$42	$93
Levelized (2010-29)	**$56**	**$38**	**$82**	**$51**	**$60**	**$34**	**$85**
Growth Rates							
2010-2029	4.4%	4.6%	2.6%	5.9%	4.3%	4.7%	2.0%

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

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

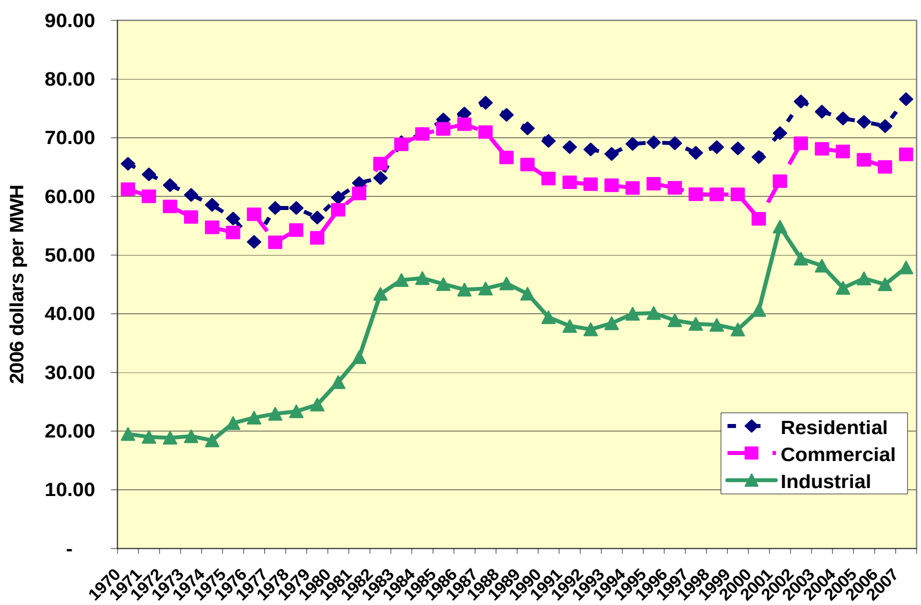
surplus, and remains so throughout the planning period because of the addition of resources to meet renewable-resource-portfolio requirements. Because of this continuing surplus, no discretionary (non-RPS) resources are added by the model and therefore the resulting energy prices do not reflect the avoided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

RETAIL ELECTRICITY PRICES

History

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

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



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

Forecast of Retail Electricity Prices

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

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

Sector Retail Prices

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

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

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

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

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

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

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