Chapter 2: Key Drivers of Demand

SUMMARY OF KEY FINDINGS

The Pacific Northwest is expected to develop and expand over the next 20 years. Regional population is likely to increase from 12.7 million in 2007 to 16.3 million by 2030. This 3.6 million increase compares to a 3.8 million increase between 1985 and 2007. The population growth will be focused on older-age categories as the baby boom generation reaches retirement age. While the total regional population is projected to increase by 28 percent, the population over age 65 is expected to nearly double. Such a large shift in the age distribution of the population will change consumption patterns and electricity use. Some possible effects could include increased health care, more retirement and elder-care facilities, more leisure activities and travel, and smaller-sized homes.

The cost of energy (natural gas, oil, electricity) is expected to be significantly higher than during the 1980s and 1990s. Although prices have decreased significantly since the summer of 2008, current levels, especially for natural gas, are depressed by the effects of the recession. Nonconventional natural gas production has increased in the last few years, encouraged by higher prices. The technology to retrieve these supplies cost-effectively has only developed recently, making expectations for adequate future supplies more certain. Nevertheless, the cost of finding and producing it is higher than for conventional supplies, which increases the estimated future price trend for natural gas.

Carbon emission taxes or cap-and-trade policies are likely to further raise energy costs. Wholesale electricity prices are expected to increase from about $45 per megawatt-hour in 2010 to $85 by 2030 (2006$). These electricity prices reflect preliminary carbon costs that start at zero and increase to $47 per ton of CO_2 emissions by 2030. Residential consumer retail electricity prices are also expected to increase, growing 1.8 percent faster per year than general inflation for residential consumers, for example. Higher prices reduce demand, advance new sources of supply and efficiency, and make more efficiency measures cost-effective.

INTRODUCTION

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

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

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

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

ECONOMIC GROWTH

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

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

Population. Population in the Northwest states grew from about 8.9 million in 1985 to about 13 million in 2007, increasing at about 1.6 percent per year. The growth in population is projected to slow to about 1.3 percent annually, resulting in a total regional population of 16 million by 2030.

Homes. The number of homes is a key driver of demand in the residential sector. Residential units (single family, multifamily, and manufactured homes) are forecast to grow at 1.3 percent

annually from 2010-2030. The current (2008) stock of 5.7 million homes is expected to grow to 7.6 million by 2030, or approximately 83,000 new homes per year.

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

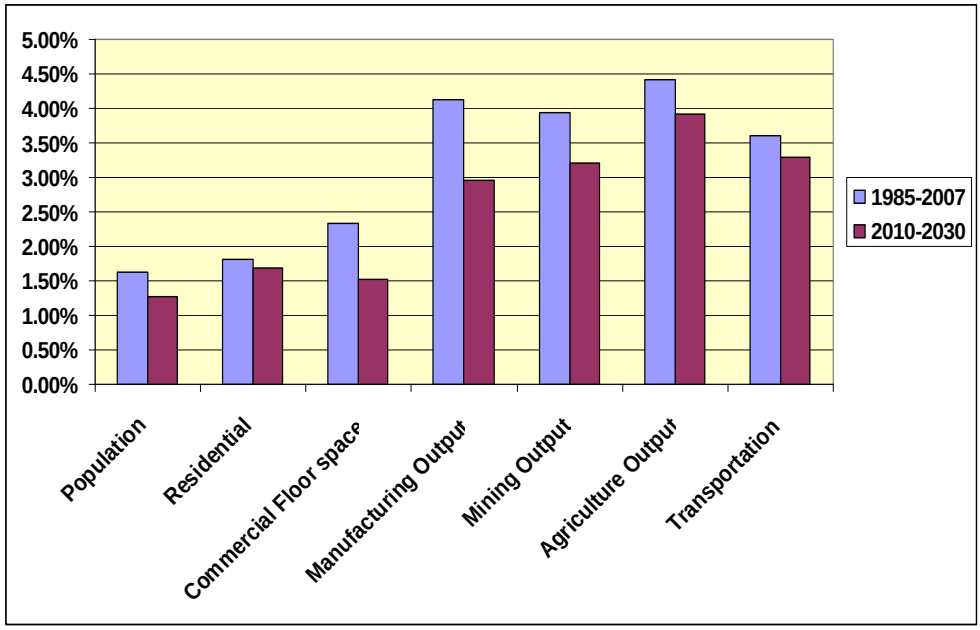
Commercial Square Footage. Demand for electricity in the commercial sector is driven by demand for commercial floor space that requires lighting, air conditioning, and services to make occupants comfortable and productive. The square footage of commercial buildings is forecast to grow at 1.5 percent annually from 2010-2030. The current 2007 commercial building stock of 2.9 billion square feet is expected to grow to 3.9 billion square feet by 2030, or at a rate of 40 million square feet per year. A growing portion of this commercial floor space is for elder-care facilities.

Industrial Output. The key driver of demand for the industrial and agricultural sectors is dollars of value added (a measure of output) in each industry. Industrial output is projected to grow at 3 percent per year, growing from $95 billion (2006 constant dollars) in 2007 to $193 billion by 2030. Agricultural output, which drives irrigation electricity use, is projected to grow at 3.2 percent per year, from $14 billion (2006 constant dollars) in 2007 to $29 billion by 2030.

Direct Service Industries. Demand for Bonneville's direct service industries (mainly aluminum smelting operations) is projected to be nearly constant, rising from 764 average megawatts in 2007 to 818 average megawatts in 2012, and then remaining constant from 2012 through 2030.

The main source of data for the economic drivers is HIS Global Insight's quarterly forecast of the national and regional economy and Global Insight's U.S. business demographic forecast. Second quarter 2008 data was used in developing the Council's draft Sixth Power Plan. The Council's financial assumptions, such as the inflation rate, are also drawn from the same economic forecast. Figure 2-1 shows both the historic and medium case growth rate assumed for the development of the draft Sixth Power Plan. In general, the medium forecast reflects a slowdown in key economic drivers compared to the last 20 years. The impact of the current recession was incorporated into the draft plan using Global Insight's short-term March 2009 forecast.

Figure 2-1: Comparison of Key Economic Drivers



Alternative Economic Scenarios

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

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

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

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

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

PRICE FORECASTS

Fuel Prices

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

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

Because natural gas is the primary energy source affecting both the demand and supply of electricity, forecasts of natural gas prices receive far more detailed attention than oil or coal prices. Fuel price forecasts start with global, national, or regional energy commodity prices, depending on the fuel. Oil is a global commodity, natural gas is still primarily a North American commodity (although this could change as liquefied natural gas imports grow), and coal prices tend to be regional in nature. All of these commodities have experienced periods of high and volatile prices since the Fifth Power Plan was developed in 2004. In most scenarios, fuel prices are assumed to decline from recent very high levels. This reduction in price is partly due to

natural supply and demand responses to a period of high prices, but also is greatly increased by the current recession and financial crisis.[1]

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

The high and low forecasts are intended to be extreme views of possible future prices from today's context. The high case wellhead natural gas price increases to $10 by 2025 and increases to nearly $12 by 2030. The Council's forecasts assume that rapid world economic growth will lead to higher energy prices, even though the short-term effects of a rapid price increase can adversely affect the economy. For the long-term trend analysis, the need to expand energy supplies, and its effect on prices, is considered the dominant factor. The high natural gas scenario assumes rapid world economic growth. This scenario might be consistent with very high oil prices, high environmental concerns that limit use of coal, limited development of world liquefied natural gas (LNG) capacity, and slower improvements in drilling and exploration technology, combined with the high cost of other commodities and labor necessary for natural gas development. It is a world where both alternative sources of energy and opportunities for reduced demand are very limited.

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

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

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

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

effects of what is becoming a severe recession. Longer-term trends in most of the cases show real fuel prices increasing gradually. All prices, even in the lowest cases, remain well above prices experienced during the 1990s.

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

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

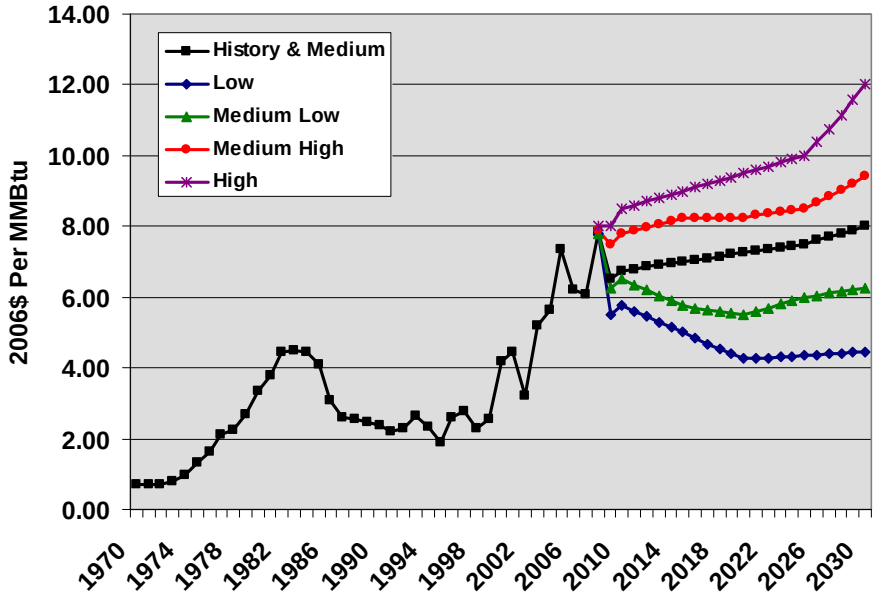


Table 2-2: U.S. Wellhead Natural Gas Price Forecast Range (2006$ per MMBtu)

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

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

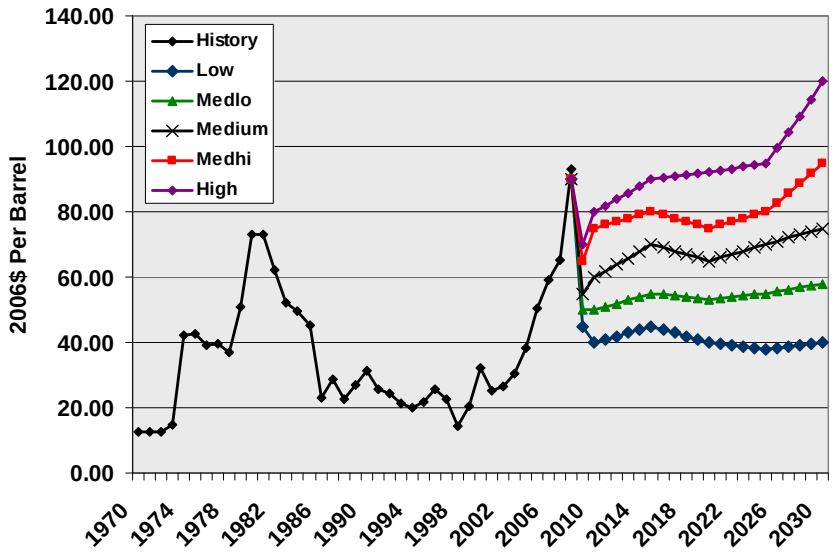


Table 2-3: World Oil Price Forecast Range (2006$ per Barrel)

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

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

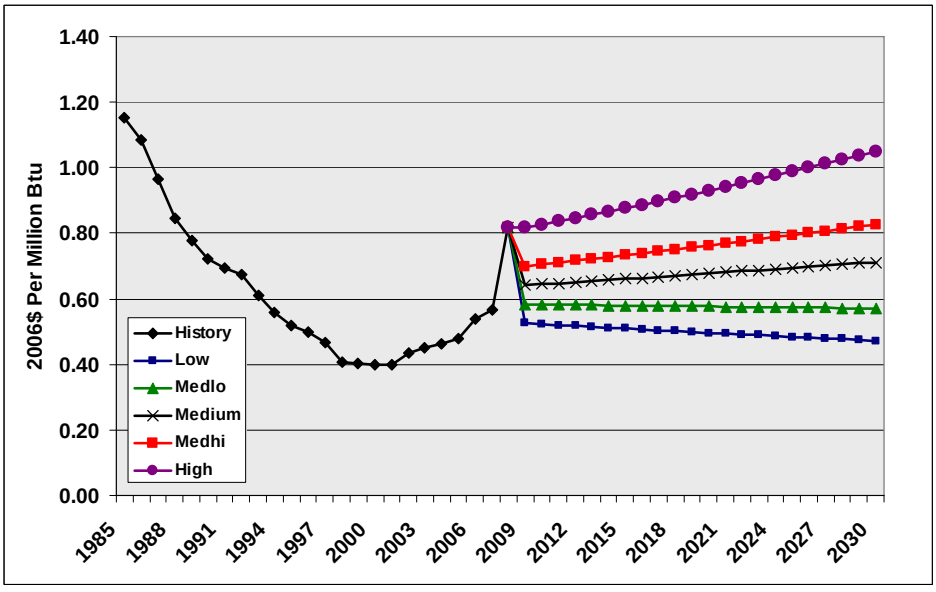


Table 2-4: Powder River Basin Minemouth Coal Price Forecasts (2006$ per MMBtu)

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

Wholesale Electricity Prices

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

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

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

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

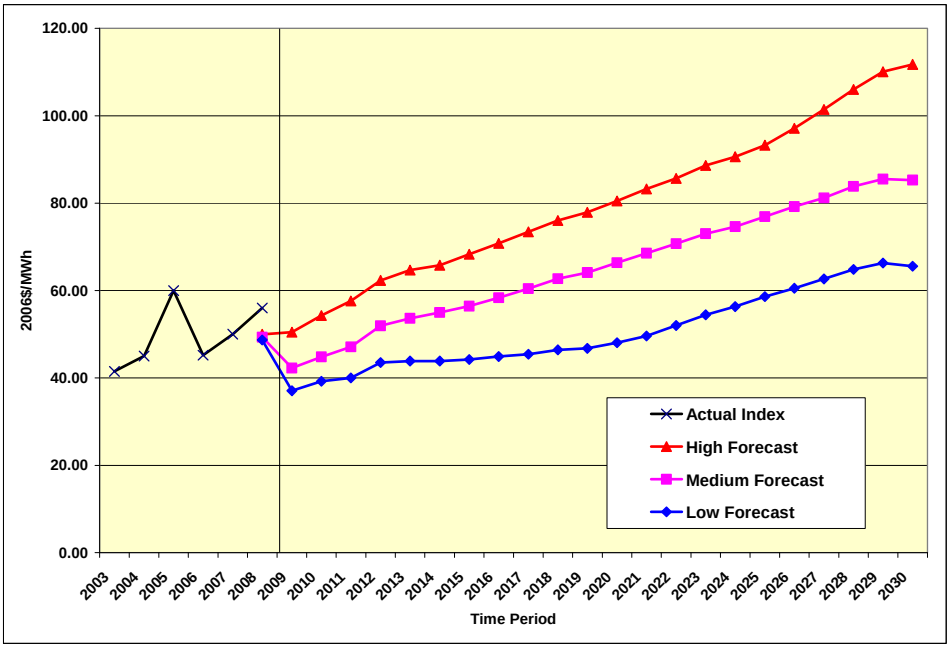
[2] These prices are not exactly the same as assumptions adopted later for the Regional Portfolio Model analysis. They will be revised when the Council's wholesale electricity prices, demand forecast, and other projections are revised in the process moving from the Draft Power Plan to the Final Plan.

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

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

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

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



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

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

selected years. Appendix D provides a detailed description of the wholesale power price forecasts.

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

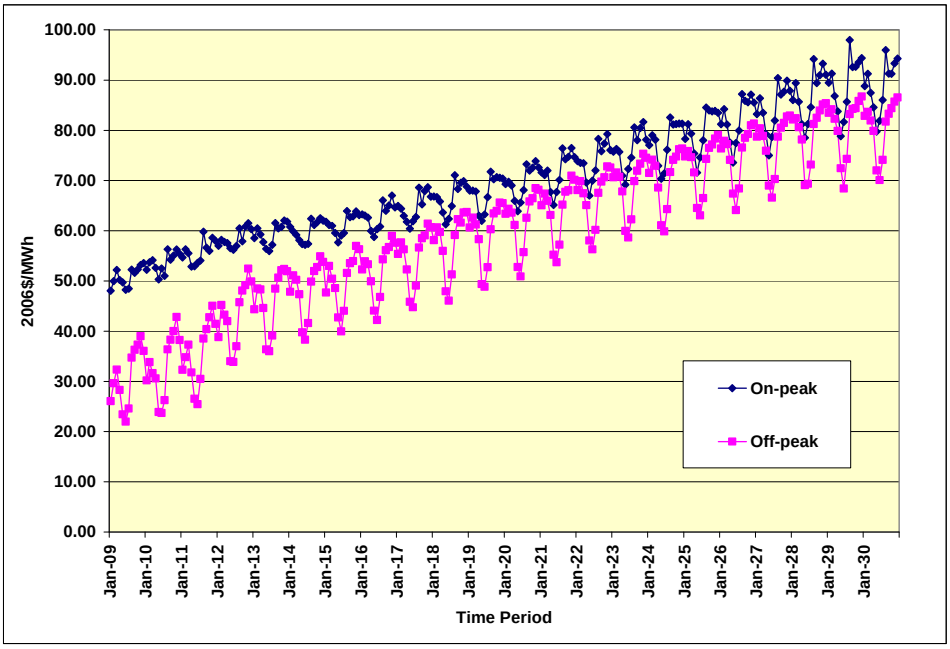


Table 2-5: Forecast of Mid-Columbia Wholesale Power Prices (2006$/MWh)

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

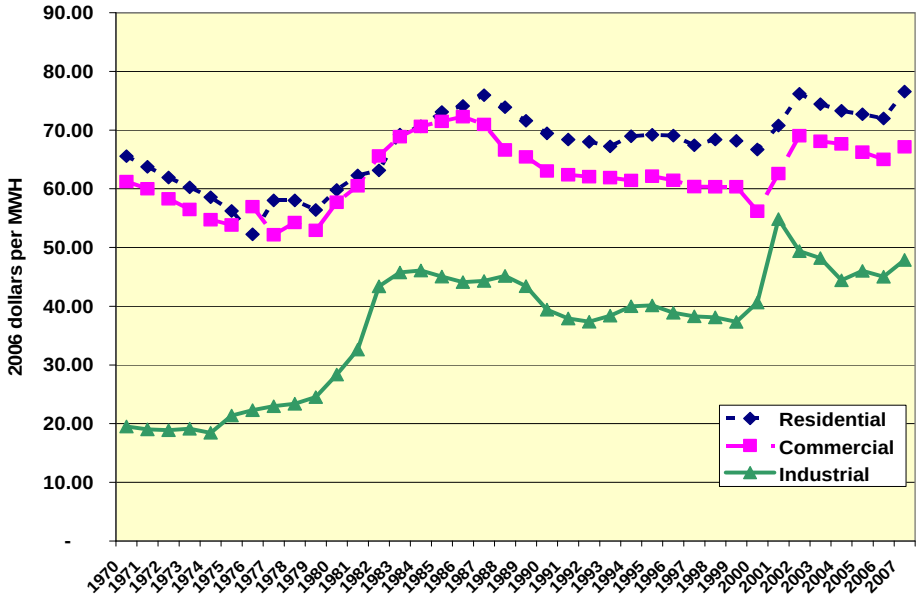
Retail Electricity Prices

History

In the first half of the 1970s, consumers in the Northwest experienced declining electricity prices. However, by mid-1970 and into the 1980s, the region experienced dramatic increases in the price of electricity, followed by an economic recession that hit the region particularly hard. In the latter half of the 1980s, electricity prices began a decade-long decline, in real terms. But in late 2000, the region again experienced large increases in the price of energy, accompanied by a moderate recession. Since the sharp increase in 2000, electricity prices have stabilized, and even declined in inflation-adjusted prices. However, since 2006, another round of more

moderate price increases has begun to be reflected in increases in fuel prices and other commodities. Figure 2-7 illustrates this price history.[3]

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



Forecast of Retail Electricity Prices

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

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

Sector Retail Prices

The estimated price of electricity by sector and state is presented in Tables 2-6 through 2-8. For the residential sector, the annual real growth rate of electricity prices is expected to be in the 1.5-1.9 percent per year range for the 2010-2030 period. It should be noted that these forecasts are at the state level, and within each state, individual electric utility rates may be higher or lower than

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

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

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

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

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

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

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

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