

# Current Status and Future Assumptions

## **INTRODUCTION**

This section describes the current status of the region's electricity system, some relevant historical trends leading to that status, and the Council's projections of how that status might change in the future. An understanding of our current situation and how we got here is important for the Council's power plan. As described in the introduction, there have been dramatic changes in the region's energy situation over the last few years. These changes are not limited to this region, however. We are increasingly linked to national and international energy markets and policies. Understanding these changes and the risks and opportunities they present is important for the Council's power plan.

In this discussion, the Council takes a relatively long-term perspective, as is necessary for a 20-year power plan. At the same time, an ongoing assessment and monitoring of the regional electricity situation requires some attention to current conditions and their implications. In the discussion that follows, the Council attempts to place our current situation in the context of historical trends and potential future changes and directions that underlie the analysis in this power plan. Any consideration of the future is necessarily uncertain. The forecasts discussed in this plan represent the Council's estimates of a range of possible futures. The power plan directly addresses the uncertainty of the future and appropriate strategies for minimizing the risks associated with unforeseen changes.

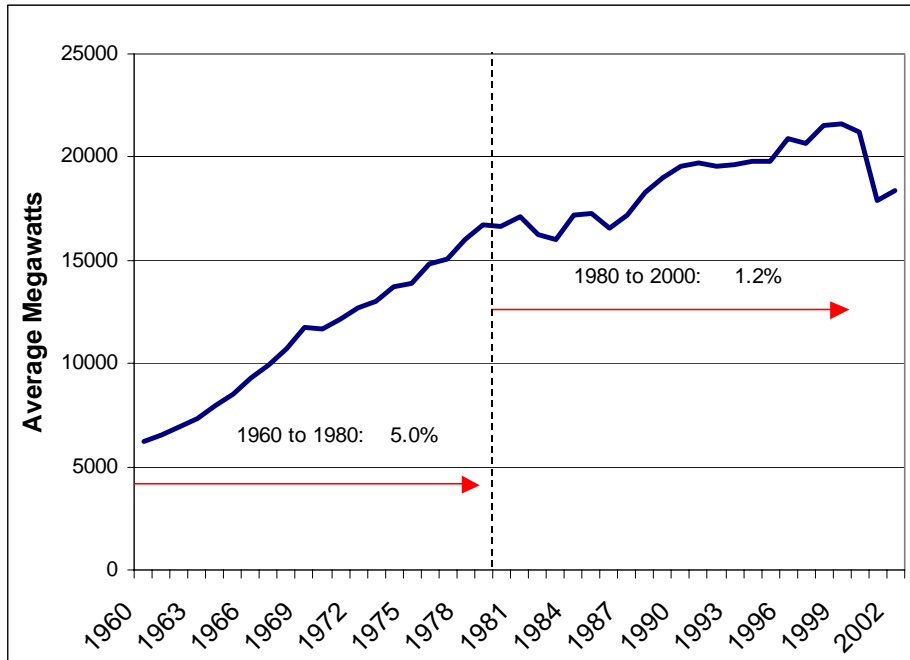
The key elements of the current and future electricity situation are the demand for electricity, the amount and cost of electricity generation capability in the region, transmission and exchange opportunities between the region and the rest of the West, the potential amount and cost of conservation and demand management, and regional and national energy and environmental policies. Demand defines the need for electricity while generation, demand management, and conservation are the means of meeting those needs. Transmission is the delivery mechanism and the chief means of operating the system. Policies shape the context and, to a large extent, the incentives that affect the adequacy and economy of the transmission system and the electricity supply. The types of electricity supply and efficiency investments that exist in the region, and additions that might be made in the future help define the nature of the risks inherent in the electricity system and its costs.

## **DEMAND FOR ELECTRICITY**

It has been 20 years since the Council's first power plan in 1983. In the 20 years prior to the Northwest Power Act, regional electrical loads were growing at 5 percent per year (Figure 2-1). Between 1960 and 1980 loads increased from 6,300 average megawatts to 16,600 average megawatts, an increase of over 10,000 average megawatts. In the 20 years since the Power Act (1980-2000), loads grew by 4,600 average megawatts, an average annual growth rate of only 1.2 percent.

The dramatic decrease in electricity demand growth after the Power Act was not due to a slowdown in economic growth in the region. The region added more population and more jobs between 1980 and

2000 than it did between 1960 and 1980. The cause of the change was decreased electric intensity of the regional economy. As shown in Table 2-1, electric intensity, both in terms of use per capita and use per employee, increased between 1960 and 1980, but decreased significantly after 1980. This shift reflected a changing industrial structure, higher electricity prices, and regional and national conservation efforts.



**Figure 2-1: Forty-Three Years of Pacific Northwest Electricity Demand**

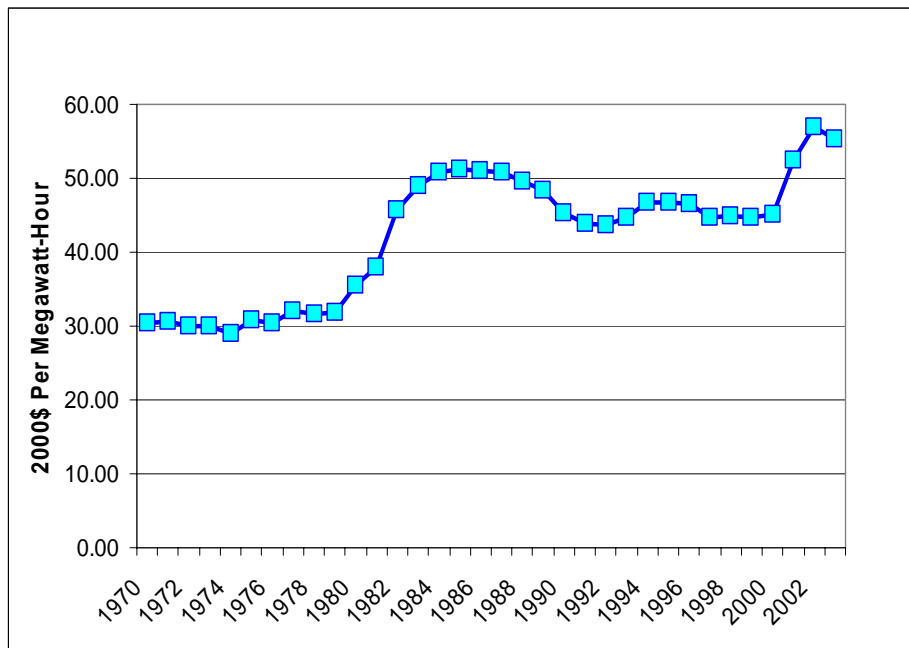
**Table 2-1: Changing Electric Intensity of the Regional Economy**

Year	Electricity Use Per Capita (MWa / Thousand Persons)	Electricity Use Per Employee (MWa / Thousand Employees)
1960	1.13	3.81
1980	2.07	5.10
2000	1.93	4.03

The Council’s first power plan was able to anticipate many of the effects of changing industrial structure and electricity prices on the demand for electricity. In addition, the first plan identified conservation opportunities and encouraged the region to achieve them. The plan predicted 2000 electricity loads of 23,400 average megawatts (average of medium-low and medium-high forecasts), which would be reduced by 2,500 average megawatts of conservation to 20,900 average megawatts. The Council estimates that the region had actually achieved 1,800 megawatts of conservation by 2000, and regional electricity loads in that year are estimated to have been 21,200.

The third decade following the Northwest Power Act has started out similar to the first decade. Around 1980, the region experienced dramatic increases in the price of electricity, followed by an economic recession that hit the region particularly hard. In late 2000, the region again experienced large increases in the price of energy, accompanied by a moderate recession. Figure 2-2 illustrates this

price history.<sup>1</sup> These price increases have decreased electricity demand and increased the implementation of conservation programs, but the largest effects were on energy intensive industries, especially the region's 10 aluminum plants. The electricity price increases of the early 1980s turned many of the region's aluminum plants into swing plants that tended to shut down during periods of low aluminum prices. The 2001 electricity price increase resulted in the closure of all of the aluminum plants and the demand forecast assumes that many of the plants will remain closed. When all were operating, the aluminum plants could account for 15 percent of regional electricity demand. Their closure accounts for much of the drop in electricity demand after 2000 shown in Figure 2-1.



**Figure 2-2: Historical Retail Electricity Prices in the Pacific Northwest**

Average annual electricity demand dropped by 2,800 average megawatts between 2000 and 2002. These recent demand changes were described in the introduction. Evidence available so far for 2003 and 2004 does not indicate a significant recovery in demand. This decrease in electricity demand has erased more than a decade of demand growth, leaving electricity loads at a level similar to 1989.

As a result of this demand reduction, and the expectation that aluminum loads will remain low, the medium demand forecast for this draft plan is significantly lower than in the Fourth Power Plan. The forecast of total electricity consumption in 2015 (the last year in the Fourth Power Plan) is 3,000 megawatts lower in the Fifth Power Plan forecast. The demand forecast is described in detail in Appendix A. Table 2-2 summarizes the Fifth Power Plan forecast. In the medium case, consumption is forecast to grow from 20,080 average megawatts in 2000 to 25,423 by 2025. However, current consumption levels are well below 2000 levels, and it will be several years before those levels of

<sup>1</sup> Prices in Figure 2-2 are expressed in constant year 2000 dollars as are many other tables and graphs throughout the plan. In the Executive Summary and Overview and in Chapters 6 and 7 constant dollar prices are expressed in year 2004 dollars. To convert from constant 2000-dollar prices to constant 2004 dollar prices multiply by 1.0776, which is a measure of the general inflation between 2000 and 2004.

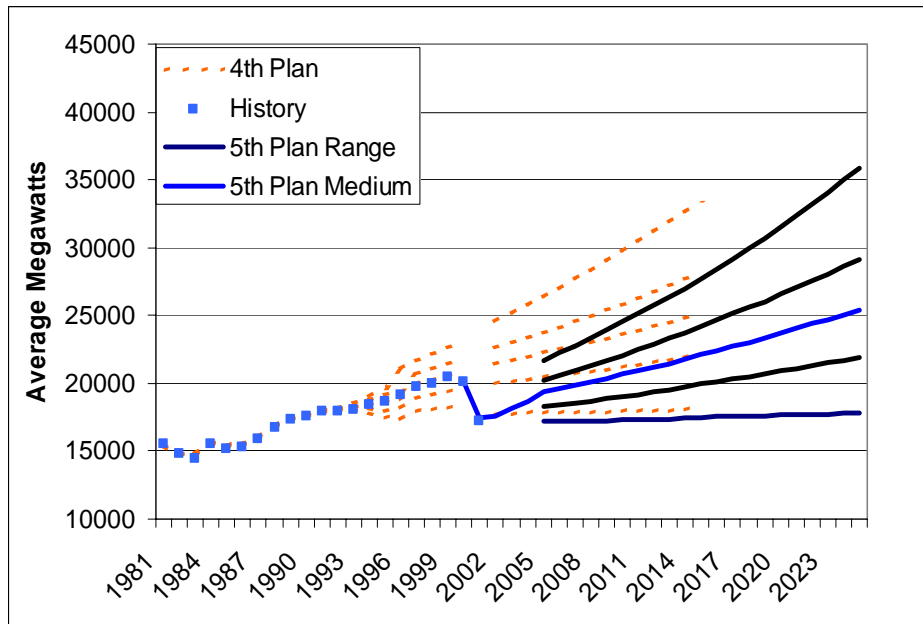
consumption are reached again. The range of forecasts reflects significant uncertainty about demand trends.

Uncertainty in long term demand trends, as shown in Figure 2-3, define only a part of the uncertainty in demand that is evaluated in the portfolio analysis. The portfolio model adds variations to reflect seasonal patterns, business cycles, and weather sensitivity. In addition, the demand of electricity for aluminum smelting is treated separately and is assumed to depend on variations in aluminum prices and electricity prices

**Table 2-2: Demand Forecast Range<sup>2</sup>**

	(Actual)			Growth Rates	
	2000	2015	2025	2000-2015	2000-2025
<b>Low</b>	20,080	17,489	17,822	-0.92	-0.48
<b>Medium Low</b>	20,080	19,942	21,934	-0.05	0.35
<b>Medium</b>	20,080	22,105	25,423	0.64	0.95
<b>Medium High</b>	20,080	24,200	29,138	1.25	1.50
<b>High</b>	20,080	27,687	35,897	2.16	2.35

Figure 2-3 shows the range of forecasts compared to historical consumption and compared to the range of forecasts in the Council’s Fourth Power Plan. It shows that the medium demand forecast for 2015 is about equal to the medium-low forecast in the Council’s Fourth Power Plan.



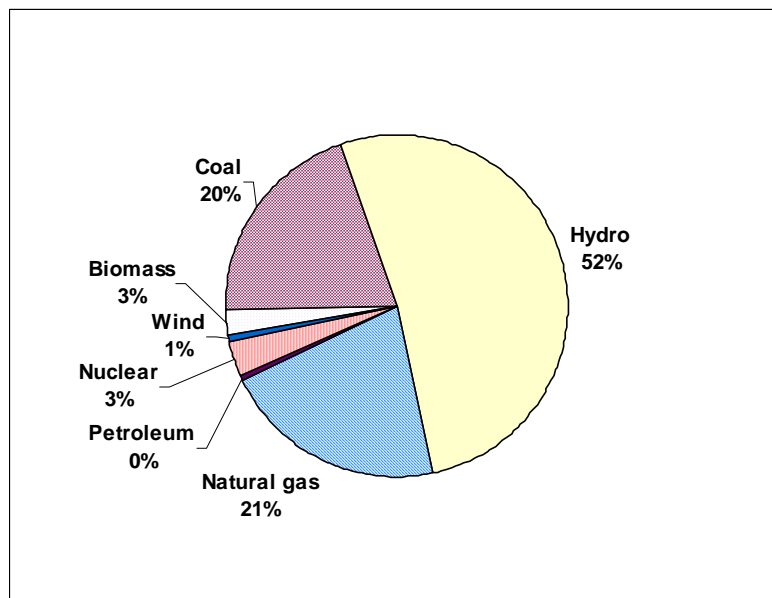
**Figure 2-3: Demand Forecast Range Compared to History and Council’s Fourth Power Plan**

<sup>2</sup> Figures are electricity use by consumers and exclude transmission and distribution on losses.

## **REGIONAL ELECTRICITY SUPPLY**

The region's electricity supply is still dominated by hydroelectric power. Hydroelectricity accounts for roughly half of the region's electrical energy supply, but its amount in any given year depends on water conditions. In an average water year, the hydroelectric system can provide about 16,000 average megawatts of electricity. For planning, the region has formally relied on only the 12,000 average megawatts, which is the amount of generation ability under the worst historical water conditions (critical water). In a good water year, the hydroelectric system might be able to generate 20,000 average megawatts of electricity. The total annual energy generating capability in the region under critical water conditions (including non-hydro resources), is estimated to be about 23,000 average megawatts. In reality, the region has probably departed informally from critical water standards for a decade or more.

Figure 2-4 shows that about half of the regional energy generation comes from hydropower. Coal and natural gas make up most of the remainder, with smaller contributions from nuclear, wind and other sources.



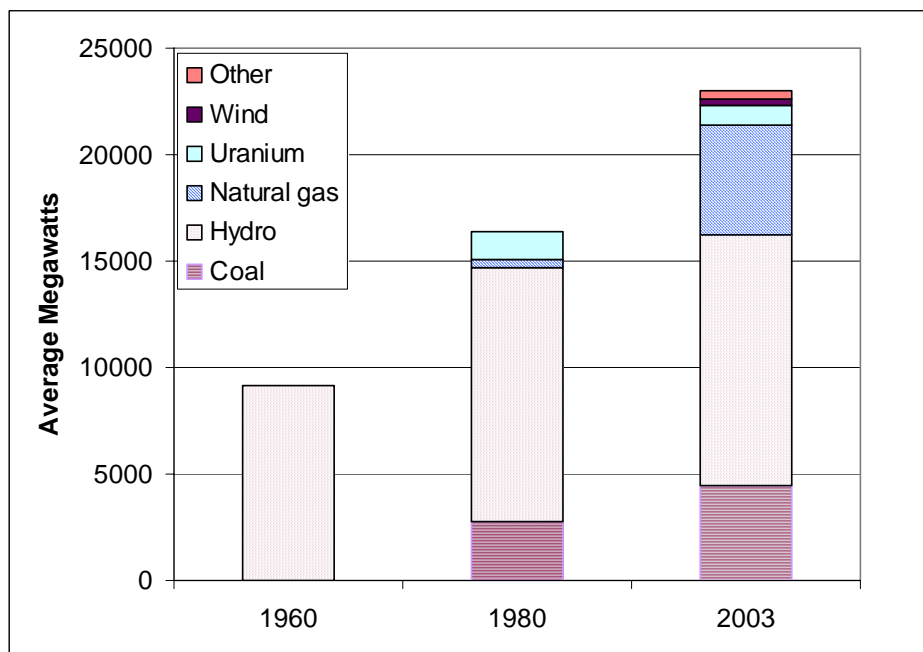
**Figure 2-4: Sources of Pacific Northwest Electrical Energy Generation**

Although the traditional indicator of resource needs has been average energy, increasing attention is being paid to the region's capacity to meet various types of peaking requirements. The regional generating capacity, the combined peak generation capability, is over 50,000 megawatts; much larger than current winter peak loads. However, two thirds of that capacity is in the hydroelectric system, and the ability of the hydro system to meet high cold weather loads over a sustained period is limited. The sustained peaking capacity<sup>3</sup> of the hydro system, for example, is 5,400 megawatts less than its nameplate capacity.

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<sup>3</sup> Sustained peaking capacity is typically defined as the maximum amount of energy the hydroelectric system can deliver (on average) over the 50 highest demand hours in the week (generally modeled as 10 hours per day over the weekdays).

The region's energy mix has been changing over time. Twenty years before the Northwest Power Act, the region's electrical energy came almost entirely from hydroelectricity. By the time the Act was passed, the region was outgrowing its hydroelectric capability and coal, nuclear, and natural gas generation accounted for a quarter of the electrical energy supply. Currently, these thermal resources account for 45 percent of the region's electrical energy supply. Figure 2-5 illustrates how the mix of regional electricity generation has changed over time. The region's electrical energy resources are more diverse now than they were historically. As the resource mix has changed, so has the nature of the uncertainties and risks facing the region.



**Figure 2-5: Changing Pacific Northwest Sources Electricity Generation**

In addition to varying with water conditions, hydroelectric generation has a distinct seasonal pattern that can only be partially managed by the use of reservoir storage. The ability to shape hydro generation to the seasonal load requirements has been reduced by growing fish and wildlife management requirements. The direct service industries, industrial customers served by the Bonneville Power Administration, also contributed to the ability to manage hydro uncertainty through interruption agreements on the top quarter of their electricity use. Most of the direct service industries were aluminum smelters, now closed, and they no longer provide that flexibility.

The new thermal generating resources are more predictable in the amounts of electricity they provide, but are more prone to cost uncertainty as their input fuel prices vary. This is especially true of the natural gas-fired generation that has made up most of the recent generation additions. Nuclear and coal plants carry a different kind of risk. Their costs consist primarily of capital costs that must be paid whether they are generating electricity or not, thus they carry a larger financial risk when they are not needed for meeting electricity demand.

Conservation that has been achieved since the Northwest Power Act is also conceptually a part of the region's resource mix although it is not shown in Figures 2-4 or 2-5. The Council has estimated that the region has acquired 2,200 average megawatts of end-use conservation through 2002, the

equivalent of about 2,500 average megawatts of electricity generation.<sup>4</sup> Approximately 25 percent of the resources added in the Northwest since 1980 have been conservation.

Another component of the region's electricity supply is the ability to import electricity from other regions. The region currently has the transmission capability to import up to 6,775 megawatts from the South and 3,150 megawatts from the North. This transmission capability is used to provide additional flexibility to electricity supply and mutually beneficial electricity trade with neighboring regions. Except for existing long-term firm contracts, however, the region has not explicitly relied on seasonal power availability in California and our ability to import it over existing transmission interties for resource planning. In actuality, however, some degree of reliance on imports had been part of normal operations for many years.

## **CURRENT LOAD-RESOURCE BALANCE**

On the basis of generation installed in the region, the Pacific Northwest currently has more than enough electricity resources to meet demand. The expected load/resource balance for 2004 is a resource surplus of about 1,500 average megawatts over demand. As recently as 2000, the region had a critical water deficit of about 4,000 average megawatts. When the region experienced poor water conditions in 2000 and 2001, it triggered an electricity crisis affecting the entire West Coast, as described in the introduction.

Two major factors erased the region's energy deficit: a reduction in demand and the addition of new generating capacity. Demand fell by about 2,800 average megawatts between 2000 and 2002. During the same time, new generating resources were added that increased energy capability by about 3,500 average megawatts.

Figure 2-6 shows average annual load resource balances in the region with critical water conditions under different demand forecast conditions. In the medium case, the surplus lasts until 2014. Given the ability to import energy from the Southwest, this does not necessarily indicate a need, even then, for new regional electricity generation. The picture is very different for the medium-low and medium-high forecasts. The region remains in surplus under medium-low demand growth to 2015 and beyond, but with medium-high demand growth the region is somewhat deficit after 2008.

However, not all the resources included in Figure 2-6 are contractually committed to regional loads. Independent power producers (IPPs) own most of the current surplus. For the period 2005 through 2008, only 950 out of 3600 megawatts of IPP capacity are contractually committed to regional loads. Beyond 2008, that figure drops to 430 megawatts.<sup>5</sup> The rest is available for short-term sales.

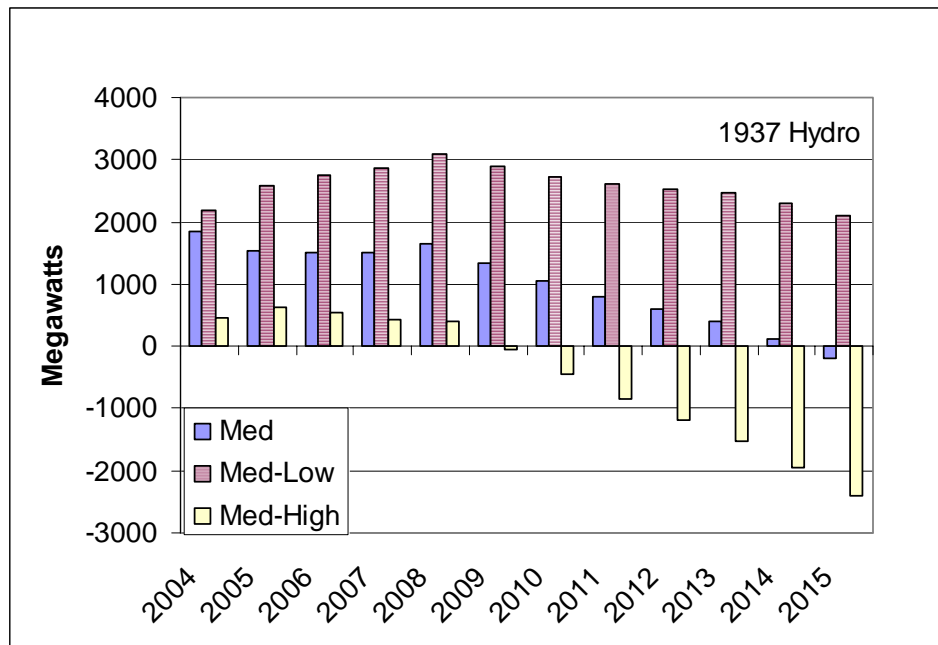
As of this writing, none of the IPP generation is committed on a firm basis to loads outside the region through 2008 and beyond. Making long-term firm sales out of the region would be difficult or impossible because of a lack of firm transmission access. Therefore, we assume that these resources would be available to meet Northwest loads. However, unless these resources are purchased or contracted for on a long-term basis, their power will be priced at the market.

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<sup>4</sup> The difference is attributable to transmission and distribution system losses that affect generation.

<sup>5</sup> Data from survey of membership of Northwest Independent Power Producers Coalition, June 8, 2004.

Because the IPP power is assumed to be purchased at market prices, it makes little difference in terms of the cost of power to the region whether or not these IPP plants are contracted out of the region. Because the amounts of generation and demand in the western electricity market would not change, the electricity market price would not change. Therefore, whether the region purchases energy from the market, or from the IPP plants, the price would be the same. The balance of loads and resources for the Pacific Northwest as compiled in Figure 2-6 does not include the possibility of purchases from the wholesale market. The sale of the IPP power outside the region would reduce regional resources and reduce the surplus shown in the graph. However, if the reduction in resources were replaced by purchases in the wholesale electricity market, the regional energy cost and reliability situation would be little changed in reality.



**Figure 2-6: Load Resource Balance with Existing Resources Under Medium-Low, Medium And Medium-High Demand Forecasts**

## **ASSESSING FUTURE SUPPLY ALTERNATIVES**

The essence of the power plan is a determination of how future electricity needs should be supplied. The plan relies on analysis and forecasts of alternative generating and conservation technologies and their costs. These analyses and forecasts necessarily reflect the current knowledge of alternative technologies and their costs, but also attempt to project a range of possible future trends.

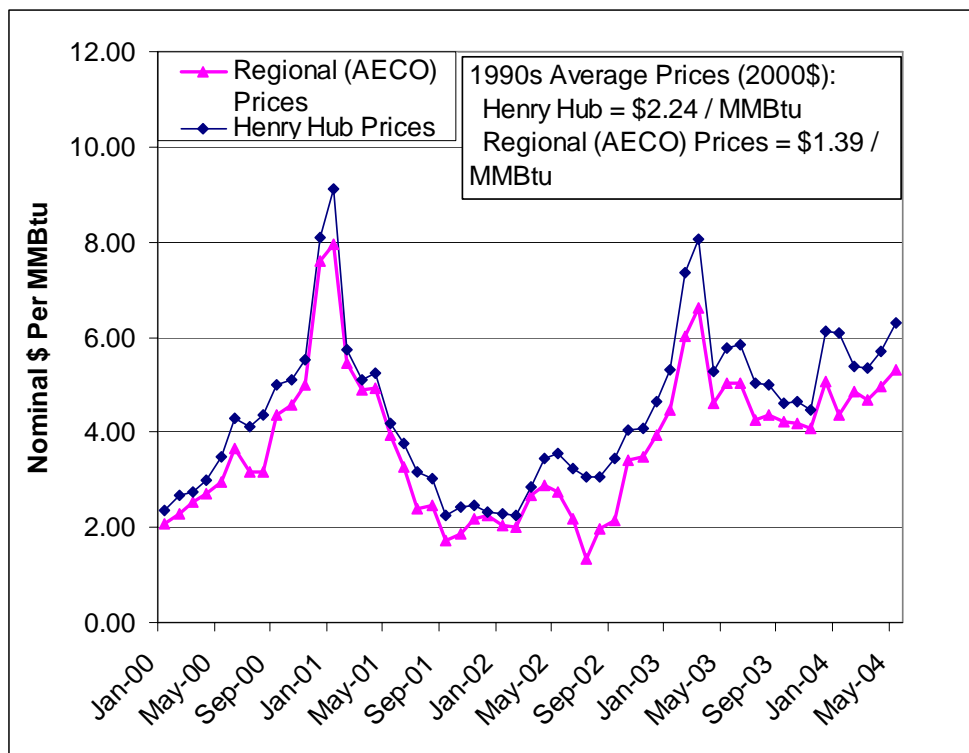
### **Natural Gas**

Conditions in other energy markets affect both the demand for electricity and the expected cost of electricity. Particularly important in the Pacific Northwest is the cost of natural gas. Natural gas is both the most active competitor to electricity for space and water heating and the fuel source for most recent electricity generation additions. Recently, volatile and increasing natural gas prices have had a significant effect on energy costs in the region.



If natural gas prices remain significantly higher than they were during the 1990s, as the Council's forecast suggests, then coal prices and the costs of renewable generation will become more significant for future electricity generation and its costs. There is still substantial ability among industrial users to switch between oil and natural gas use depending on their relative prices. With growing natural gas price volatility, fuel-switching capability may increase as a way of mitigating vulnerability to periods of high natural gas prices.

Figure 2-7 shows recent monthly natural gas spot market prices at the national and regional level. National wellhead prices from 2000 to 2003 averaged \$4.06 compared to \$1.86 during the 1990s. Natural gas prices in the Pacific Northwest are typically lower than national prices due to proximity to relatively low-cost natural gas supplies in the Western Canada Sedimentary Basin and the U.S. Rocky Mountains. During the 1990s this difference averaged \$.51; from 2000 to present it has averaged \$.42.

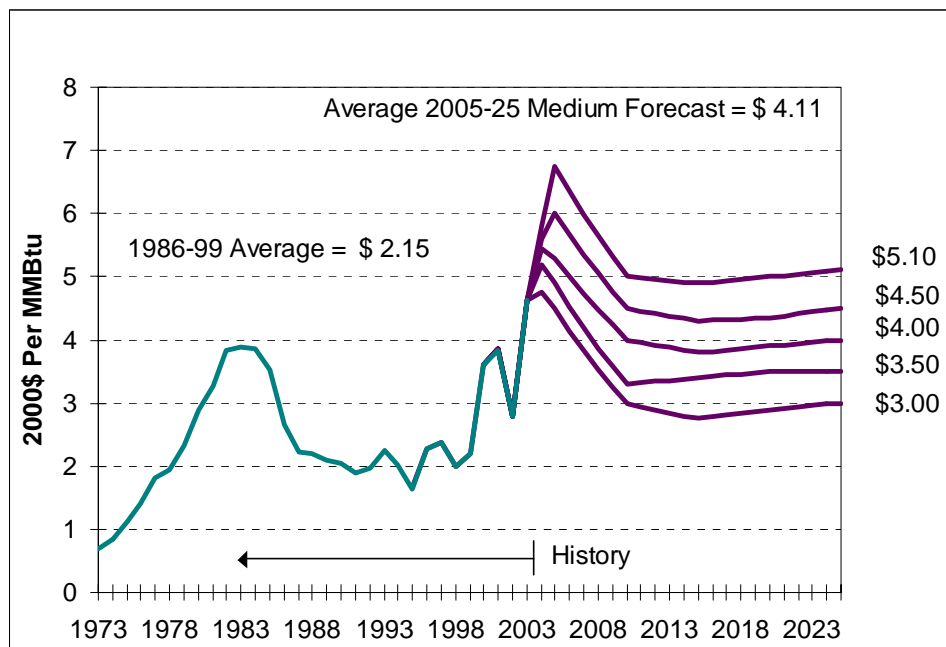


**Figure 2-7: Recent National and Regional Natural Gas Prices**

The Council forecasts a range of natural gas prices for use in this draft plan. The forecast reflects the assumption that future natural gas prices will be significantly higher than the 1986 to 2000 period. The medium case assumes that national wellhead natural gas prices will average about \$5.45 in 2004 (2000\$) and decrease to \$4.00 by 2010. Prices are then assumed to further decrease gradually to \$3.80 by 2015 and then grow back to \$4.00 by 2025. The ending prices in 2025 vary from \$3.00 in the low to \$5.10 in the high. The forecasts and historical prices are shown in Figure 2-8.

The Council does not expect fuel prices to follow the smooth trends shown in Figure 2-8. New sources of natural gas supply will need to be developed during the forecast period, including non-conventional supplies (coal bed methane, tight sands, oil shale), increased import capability through

liquefied natural gas terminals, and new pipelines to remote sources. As long as these new gas supplies have difficulty keeping up with demand, natural gas prices will be volatile and, on average, higher, reacting dramatically to changes in temperature, storage levels and other indicators of changing supply or demand. The draft plan captures the implications of such volatility, as well as the uncertainty in long-term trends represented by the range of natural gas price forecasts, through the portfolio model simulations.



**Figure 2-8: Range of Future Natural Gas Price Forecasts**

### Coal and Oil

The forecasts of coal and oil prices do not share the much higher price relative to recent historical levels that characterizes the natural gas price forecast. The medium-low to medium-high world oil price forecasts generally reflects OPEC’s stated price target range of \$22 to \$28 a barrel. The low and high forecasts reflect the possibility of price falling outside that range, but with smaller likelihood. As in the case of natural gas, oil prices are expected to exhibit significant volatility responding to world economic conditions and political developments in the Middle East.

Coal prices are expected to remain relatively stable. In the low and medium-low cases, coal is projected to decline slightly relative to general inflation although at a much slower rate than in the past. Small increases are assumed in the medium and medium-high cases. Combined with higher natural gas prices, this will tend to make coal relatively more attractive as a source of electricity generation. However, there remains significant uncertainty about future environmental regulations that might adversely affect coal use. More detail regarding fuel price forecasts appears in Appendix B. Assumptions regarding electricity generating technology using these fuel sources are described in Chapter 5 and Appendices I and J.

## **Conservation**

The Council considers improved efficiency of electricity use to be a resource for meeting future electricity demand. It is a priority resource in the Northwest Power Act. Conservation potential and cost are assessed by evaluating many individual efficiency improvements in each consuming sector. These individual improvements, or measures, are ordered by increasing cost into a supply curve for conservation. Potential savings from implementing each measure are assessed in terms of technical potential as well as actual expected savings when policies are put in place to implement the measures. Cost-effective conservation measures are determined by comparing their cost per expected megawatt of savings to the cost of avoided electricity generation as measured by the estimated market price of electricity. Conservation analysis and assumptions are described in Chapter 3 and Appendices D through G.

Looking back 20 years to the Council's first power plan, the estimated cost-effective conservation available averaged about 3,600 average megawatts, although the amount varied substantially depending on the specific demand forecast. It was expected that by 2000 about 1,200 megawatts of this potential would be accomplished through consumers' response to changing electricity prices, with 2,500 megawatts to be acquired through utility conservation programs, improved building codes and appliance efficiency standards. As noted above, the region succeeded in acquiring 1,800 megawatts of conservation by 2000 and has acquired additional conservation since.<sup>6</sup> However, the region did not capture all the conservation identified in that first power plan or in subsequent plans.

Do past achievements mean there is much less efficiency improvement that is cost effective? No, in fact, the amount of future cost-effective conservation has remained significant in each of the Council's power plan revisions. The current assessment of achievable cost-effective conservation potential in this draft plan, at 2,700 average megawatts, is not vastly different from the amount in the first power plan.

This is, however, greatly increased from the 1,500 megawatt potential in the Fourth Power Plan. There are two primary reasons for the additional conservation potential in this draft. Most important is the continuing improvement in technology leading to new conservation measures and declining cost for many measures. Especially significant in this plan are improvements in lighting technology for both residential and commercial applications. In addition, the Council has expanded its evaluation of conservation potential in the non-building commercial sector. Significant efficiency gains were found to be cost effective in sewage and water treatment, computer equipment, vending machines, and small AC to DC power converters to name a few. The residential and commercial sector account for about 85 percent of the potential conservation.

The second reason for increased conservation potential is that avoided generating costs are higher due to increased forecasts of natural gas prices. This enables some higher cost conservation measures to become cost effective.

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<sup>6</sup> The match of conservation achievement does not mean that the region's conservation programs followed the Council's recommendations. Rather, acquisitions of some conservation measures fell below the Council's recommendations, but these shortfalls were roughly balanced by acquisitions of efficiency in the form of newly-developed technology, technology not available or included in the Plan in 1983. If conservation programs had reached all of the 1983 Council recommendations the total acquisitions of cost-effective conservation by 2003 should have been significantly above 2500 MW.

## **Demand Response Resources**

Analysis of the 2000-2001 electricity crisis made it clear that without the ability of electricity use to respond to wholesale electricity market conditions, electricity prices can escalate almost without limit under tight market conditions. This is a condition that particularly characterizes the mixed electricity market that we currently have. Since consumers are not exposed to wholesale price changes in a timely manner, they cannot respond to shortages and wholesale price escalation. This eliminates from electricity markets the automatic stabilization that works in most commodity markets. Combined with the inability to store electricity and the necessity of continuously balancing supply and demand, this makes wholesale electricity markets highly unstable and volatile during tight market conditions.

“Demand response resources” refers to programs whereby consumers can be given an opportunity to reduce electricity consumption when the value of electricity becomes very high. The objective of these programs is to moderate the volatility of electricity prices and to help reduce the expense of providing generation capacity for the most extreme peaks of electricity demand. Such demand reductions in the Pacific Northwest, though not implemented in the timeliest manner, probably significantly reduced the length and impact of the 2000 and 2001 electricity shortage. Such programs need to be developed so that they can be implemented quickly, have predictable results, and reduce the negative economic impacts of such consumption reductions.

The Council sees demand response as a key policy for the mixed electricity market that is expected to continue for the foreseeable future. Demand response is different from conservation because it involves interruptions to electricity service as opposed to improved efficiency of use. However, the participation in such programs should be designed to be voluntary for energy consumers. The power plan estimates the value of such programs being in place in the regional power system. Demand response is discussed in Chapter 4 and Appendix H.

## **Renewables and Other Resource Options**

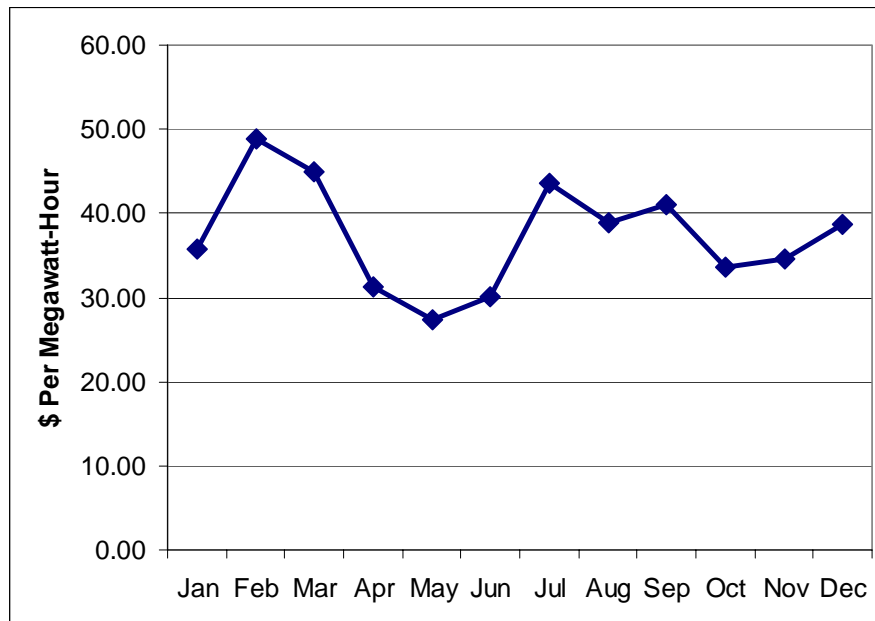
Renewable resources are also a priority resource in the Northwest Power Act. Like conservation, their potential and cost-effectiveness are sensitive to developing technology and the cost of more traditional generating alternatives. Many of these alternatives remain expensive relative to conservation or fossil fuel-fired generation. Wind energy, however, is becoming more competitive. Its attractiveness is aided by financial incentives, renewable portfolio standards, and green-tag credits. These are assumed to continue in the future, but wind technology improvements and falling cost are also assumed to continue in the future. Renewables have potential risk reduction benefits related to their ability to hedge risks of fuel price volatility and the risks of possible measures to mitigate greenhouse gas emissions.

Distributed generation is a potential future source of electricity. Distributed generation consists of electrical generating units, generally smaller-scale, located at or near loads. These can take advantage of cogeneration opportunities, offset transmission, distribution and end-use loads and improve reliability. Its cost-effectiveness is more difficult to assess because it depends partly on location-specific transmission and/or distribution system constraints and expansion costs. In addition, integration of distributed generation into the electricity grid is relatively new and the problems are not well understood. Nevertheless, like conservation, distributed generation may carry significant cost advantages in specific situations and locations. It may be most important to assure that the operation and management of the electrical generation and transmission system allows opportunities for such

resources, provides appropriate price information and does not impose barriers to their development where cost effective. Renewable resources and other generating technologies are described in Chapter 5 and Appendices I and J.

## **PROJECTED WHOLESALE ELECTRICITY PRICES**

Western electricity markets were in chaos between June 2000 and May 2001. Monthly Mid-Columbia heavy load hour spot prices averaged over \$238 per megawatt-hour during these 12 months. The prices during this electricity crisis were well described in the introduction to this plan. However, prices dropped rapidly after May 2001 and have been more reflective of generating costs recently. Figure 2-9 shows average monthly prices during 2003, which averaged \$37 per megawatt-hour.



**Figure 2-9: Wholesale Spot Market Electricity Prices at Mid-Columbia Pricing Point: Jan. - Dec. 2003**

Forecasts of electricity demand and supply alternatives and their costs, including fuel costs as described above, are used to forecast future wholesale electricity prices at various pricing points in the West. In this discussion, the focus is on wholesale, short-term (spot) market prices at the Mid-Columbia trading hub. These “benchmark” electricity price forecasts are used to help evaluate cost-effective levels of conservation and other resources and serve as the basis for estimating the cost of purchasing from, or selling into, the wholesale electricity market in the Council’s risk analysis.

As in the case of electricity demand and natural gas price forecasts, the electricity price forecast described in this section forms only the central tendency of future electricity prices that are assessed in the portfolio model. Electricity price volatility is a key issue addressed in this plan. The portfolio model reflects significant variations in electricity prices seasonally, regionally, and in response to a number of varying conditions. These conditions include hydro conditions, natural gas prices, demand variations, load-resource balance, transmission congestion, and a significant random element reflecting the effects of events in the rest of the western interconnection. This is discussed further in Chapter 6 on risk assessment and management.

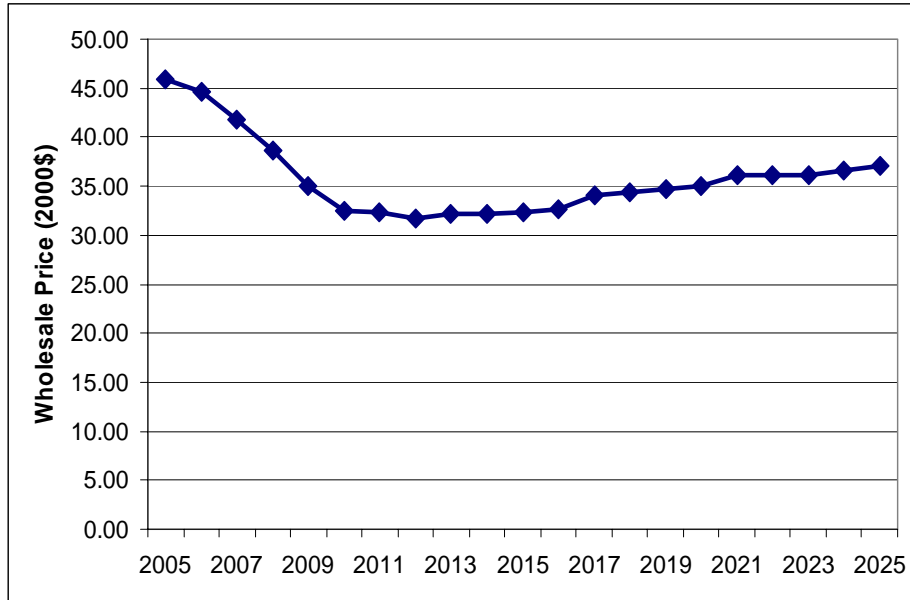
The AURORA® Electric Market Model is used to estimate Western electricity prices on an hourly basis.<sup>7</sup> Electricity price forecasts are based on the variable cost of the most expensive generating plant, or increment of load curtailment, needed to meet load for each hour of the forecast period. Preparing a forecast is a two-step process. First, a forecast of capacity additions and retirements beyond those currently scheduled is developed using long-term resource optimization logic. This is an iterative process, in which existing resources are retired if forecast market prices are insufficient to meet future maintenance and operation costs. New resources are added if forecast market prices are sufficient to cover the fully allocated costs of resource development, maintenance and operation. This step results in the future resource mix depicted in Figure 2-12. This resource mix is used as the base resource portfolio for the portfolio risk analyses. The second step is to forecast the dispatch of these resources to obtain an estimate of future power prices.

The market price forecast is based on the medium load and fuel price forecasts, average hydropower conditions, and current trends with respect to technological development, energy-related policies and other factors affecting the market price of electricity. These assumptions and the resulting forecast resource mix are not necessarily “the right things to do”, nor necessarily reflect the recommendations of this plan. Instead they represent the direction that the industry appears to be moving at the present time. The AURORA® model forecast is based on electricity generation choices and dispatch that make economic sense given a forecast of demand growth and expected costs of constructing and operating alternative generation technologies, including expected fuel costs. The AURORA® forecast of future resource development differs from the Council’s portfolio analysis in that it does not evaluate the effects of uncertainty and volatility in the key determinants of electricity price. AURORA, however, more explicitly models the hour-by-hour operation of the electricity supply system and the overall interconnected western grid. For these reasons, the future resource mix of the electricity price forecast differs somewhat from the Council’s resource development recommendations. The forecast of market electricity prices is described in detail in Appendix C.

The levelized annual average electricity price at the Mid-Columbia trading hub for 2005 through 2025 is forecast to be \$36.20 per megawatt-hour (2000\$). Figure 2-10 shows forecasted annual average prices for the Mid-Columbia trading hub. Prices decline between 2005 and 2010 reflecting declining natural gas prices. Prices increase gradually through the remainder of the planning period as slowly increasing natural gas prices are partially offset by improved combined-cycle efficiency and increasingly more cost-effective windpower. Because mean values of hydropower, fuel prices and other potentially volatile underlying assumptions are used in this forecast, possible episodes of price excursions resulting from volatility in the gas market or poor hydro conditions are not shown. Volatility is addressed in the portfolio model analysis.

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<sup>7</sup> The AURORA® Electricity Market Model was developed and is offered by EPIS, Inc. of West Linn, Oregon. EPIS may be contacted by phone at 503-722-2023 or by e-mail at [info@epis.com](mailto:info@epis.com). The EPIS website is [www.epis.com](http://www.epis.com).

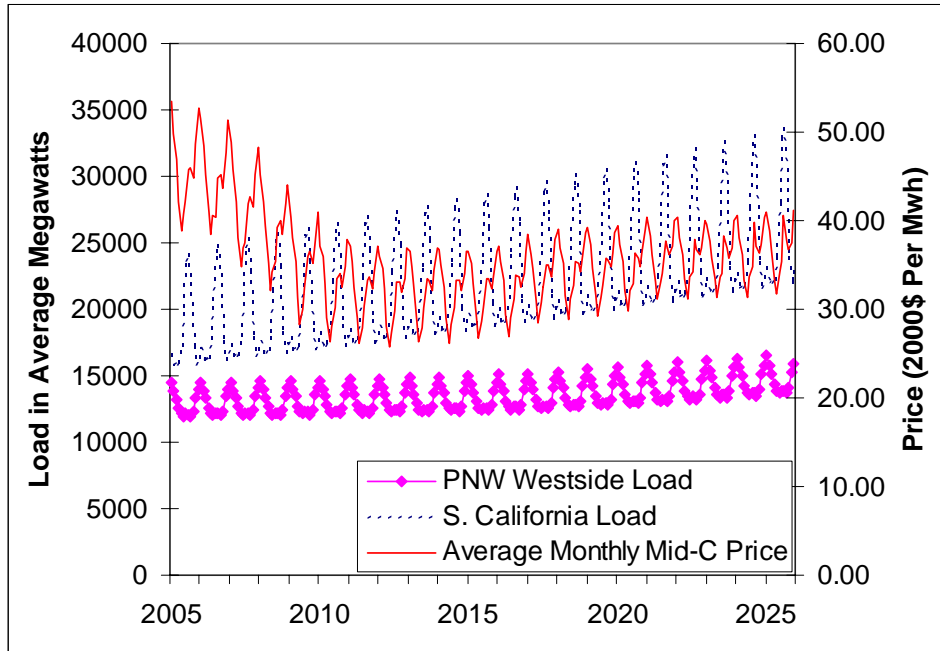


**Figure 2-10: Forecast of Average Annual Wholesale Power Prices at the Mid-Columbia Trading Hub**

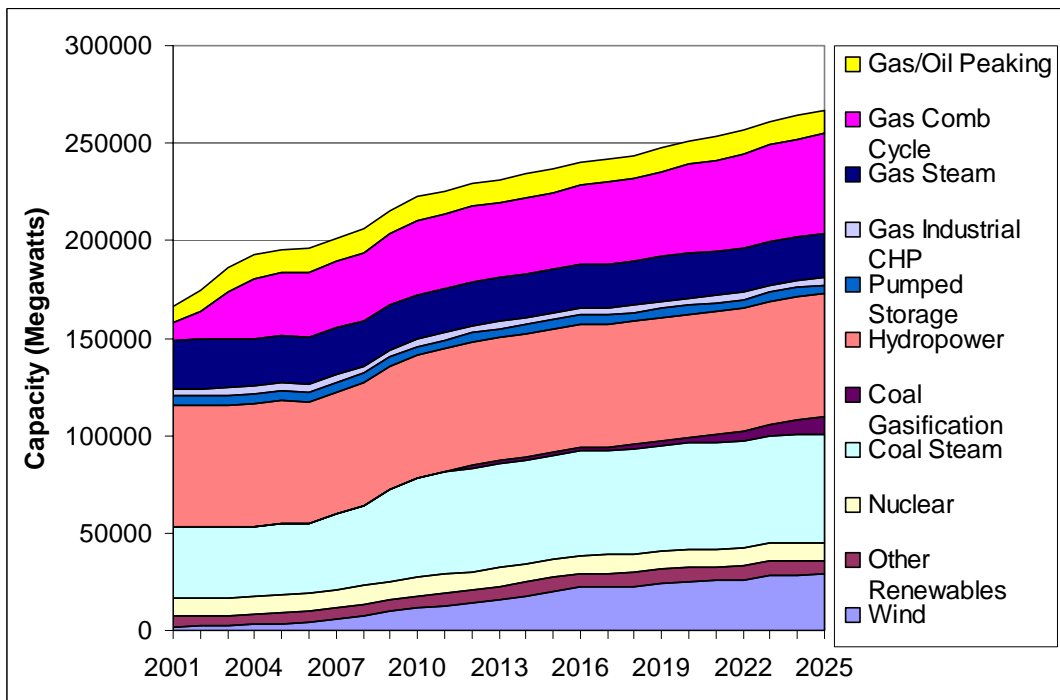
The Council did sensitivity tests to determine how changes in assumptions or policies would affect the model’s price forecasts. Prices were shown to increase in response to aggressive CO<sub>2</sub> control, higher reserve margin requirements and higher natural gas prices. Prices decreased in response to low natural gas prices, less aggressive CO<sub>2</sub> policy, and reduced electricity demand. These changes also affected the role of renewables, coal and natural gas-fired generation. The effects of these uncertainties are described in Appendix C.

The annual average prices of Figure 2-10 conceal significant seasonal and daily price variation. Seasonal variations are revealed in Figure 2-11 illustrating monthly average prices. Also shown in Figure 2-11 is the effect of southwestern load patterns on Northwest market prices. Northwest market prices track those in the Southwest whenever transfer capacity is available on the Pacific interties. Forecasted daily variation in price is significant as well, with implications for the cost-effectiveness of certain conservation measures. A table of forecasted annual average prices for the Mid-Columbia trading hub and other Northwest pricing points is provided in Appendix C.

The forecast WECC resource mix associated with the electricity price forecast is shown in Figure 2-12. Factors at work from 2005 to 2025 include load growth, increasing natural gas prices, technology improvements, renewable resource incentives and increasing efforts to offset carbon dioxide production. Over the period approximately 6,000 megawatts of renewable resources are added as the result of state renewable portfolio standards and system benefit charges. Market-driven resource additions include 42,000 megawatts of combined-cycle plant, 29,000 megawatts of coal capacity, 30 percent of which is gasified coal generation, 23,000 megawatts of wind capacity and 3,300 megawatts of gas peaking capacity. Not shown in Figure 2-12 is about 9,000 megawatts of short-term demand response capability assumed to be secured by 2025.



**Figure 2-11: Forecast Monthly Wholesale Mid-Columbia Electricity Prices Compared to Northwest and Southwest Loads**



**Figure 2-12: Base Case Forecast WECC Resource Mix**



## **INSTITUTIONAL AND POLICY STATUS**

Electricity policy and institutional conditions are as important for the achievement of the energy goals of the Northwest Power Act as the demand and supply of electricity. The electricity crisis of 2000 and 2001 was a result of both inadequate electricity supplies and poorly organized and regulated wholesale electricity markets. The shortage of electricity supplies has been addressed for the time being, but the wholesale electricity market structure remains uncertain and fragmented. Basic issues of transmission system operation and planning have not been resolved. Many basic responsibilities for resource adequacy and transmission system capacity expansion remain unclear. In addition, many participants in the independent power producer sector have been financially weakened, or bankrupt, by the electricity crisis and its fallout.

The development of a substantial electricity surplus has given the region a window of opportunity to address these issues. Currently, the state-regulated electricity distribution and sales sector, the federally regulated transmission system, and the competitive wholesale electricity market do not always operate smoothly together. Their individual limits and interactions are not well defined and are inconsistent among the states in the region and in the West. There are a number of issues that need to be worked out, including:

- The region needs to address growing problems in the management, operation, planning and expansion of the transmission system.
- A more transparent wholesale power market structure needs to be developed and operated in concert with the transmission system.
- Accountability for monitoring wholesale electricity and transmission markets is needed along with improved data for timely market assessment.
- It is important to facilitate demand that is responsive to wholesale market conditions, whether through retail access, electricity pricing schemes, or utility demand management programs.
- Bonneville's role in a modern electricity market needs to be defined, including a lasting settlement of the residential exchange and an agreement on Bonneville's role in meeting growing loads beyond its current Federal Base System resources.
- Changing demands and resource adequacy need to be monitored carefully until it is well established that the mixed regulated and competitive electricity system will result in enough capability to reliably meet loads.

The power plan contains actions that are intended to help the region make progress in resolving these policy problems.

## **SUMMARY**

When the Council developed its first power plan, the region had just experienced a large price increase and a significant electricity surplus was developing. These are conditions that again face the region as the Council develops its Fifth Power Plan. Demand has been reduced significantly in response to the most recent electricity price increases, and forecasts of future demand growth are lower. New generating resources added in response to the 2000-2001 electricity crisis are the other contributor to the current surplus.

The natural gas price forecasts are higher, and also more volatile than in the last power plan. As a result, natural gas-fired generation alternatives, which dominated new capacity for the last several years, are beginning to lose some of their attractiveness. The relative cost effectiveness of coal and renewables have increased and may offer a hedge against the effects of volatile natural gas prices on electricity costs. Conservation potential has increased reflecting technological improvements and the higher cost of electricity generation. In a mixed market, the ability to adjust electricity demand to changing conditions is needed to help reduce electric price volatility. Developing this demand response capability may be necessary for a well-functioning mixed electricity market.

The region faces the same uncertainties about the future that it has addressed in past power plans; economic and electricity demand growth, fuel and electricity prices, environmental policy, and hydroelectric conditions. However, electricity and fuel prices have also become more volatile at the wholesale level creating different risks that also need to be addressed in deciding on the most cost-effective resource plan.

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