JUDI DANIELSON
CHAIR
Idaho

Jim Kempton
Idaho

Gene Derfler
Oregon

Melinda S. Eden
Oregon

Steve Crow
Executive Director

Northwest Power and Conservation Council

TOM KARIER
VICE-CHAIR
Washington

Frank L. Cassidy Jr.
"Larry"
Washington

Ed Bartlett
Montana

John Hines
Montana

January 12, 2004

MEMORANDUM

TO: Council Members

FROM: Terry Morlan

SUBJECT: Another Draft Power Plan Component: Current Status and Future Assumptions

Attached you will find another building block for the 5th power plan; a draft Chapter 2. This draft has not yet been reviewed by the Power Committee and is subject to changes that may be requested by the Committee. This chapter is intended to set up the rest of the plan by summarizing the current conditions of the regional electricity system and our key assumptions looking forward. It notes that it has been 20 years since the Council's first power plan and compares developments in the last 20 years with the expectations and recommendations that were contained in the Council's first plan in 1983.

The draft chapter describes the current status of the region in terms of electricity demands and resources. The chapter includes a summary of our current view of the important components of a 20-year power plan. These include forecasts of electricity demand, fuel prices, conservation potential, demand side management and renewables. It also includes our benchmark forecast of electricity prices. The Council has already been briefed on these components individually. This chapter describes these in general terms and places them in the context of present and past trends.

The last section describes two other major considerations in developing a power plan besides the basic demand forecast and resource assessments. Those are the consideration of environmental effects, and addressing the risks posed by uncertainty and volatility.

The chapter also contains a brief section on the current status of electricity policies and energy issues. It provides a list of issues that need to be resolved by the region in the next several years.

851 S.W. Sixth Avenue, Suite 1100
Portland, Oregon 97204-1348

Telephone: 503-222-5161
Toll free: 800-452-5161

Fax: 503-820-2370
Web site: www.nwcouncil.org

Draft

Current Status and Future Assumptions

January 13, 2004

BUILDING BLOCKS for the Fifth Power Plan

Northwest Power and Conservation Council

Council Document 2004-

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 there 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 are important for the Council's power plan.

In this discussion, the Council takes a relatively long-run 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.

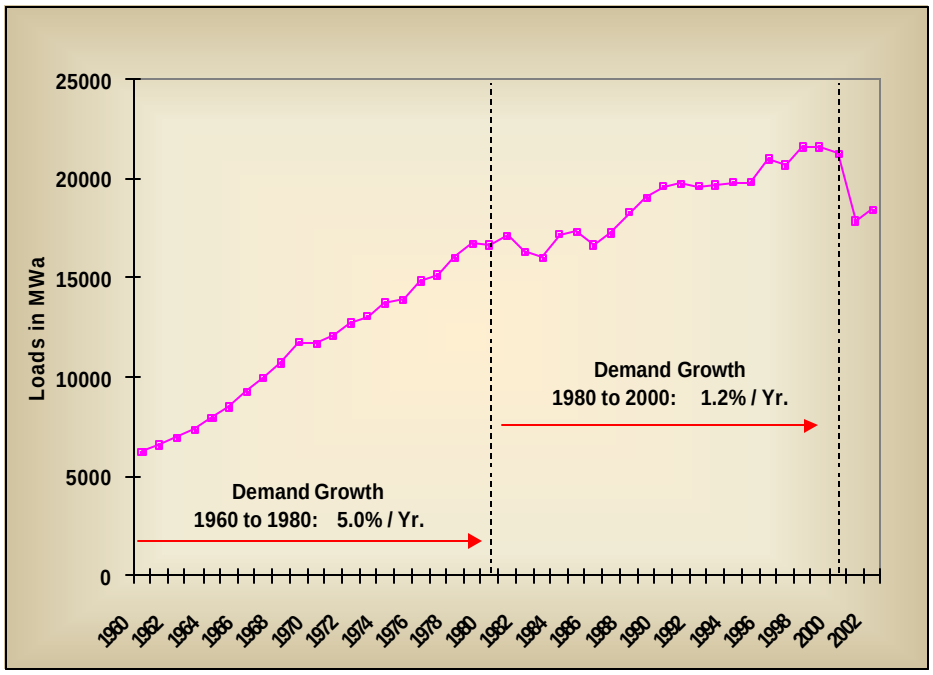
The key elements of the current and future electricity situation are the demand for electricity, the amount and cost of electricity generation capability in the region, transmission and exchange opportunities between the region and the rest of the West, potential and cost of conservation and demand management, 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 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 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 1
Forty-Three Years of Pacific Northwest Electricity Demand



tm/ex/histload.xls

Table 1
Changing Electric Intensity of the Regional Economy

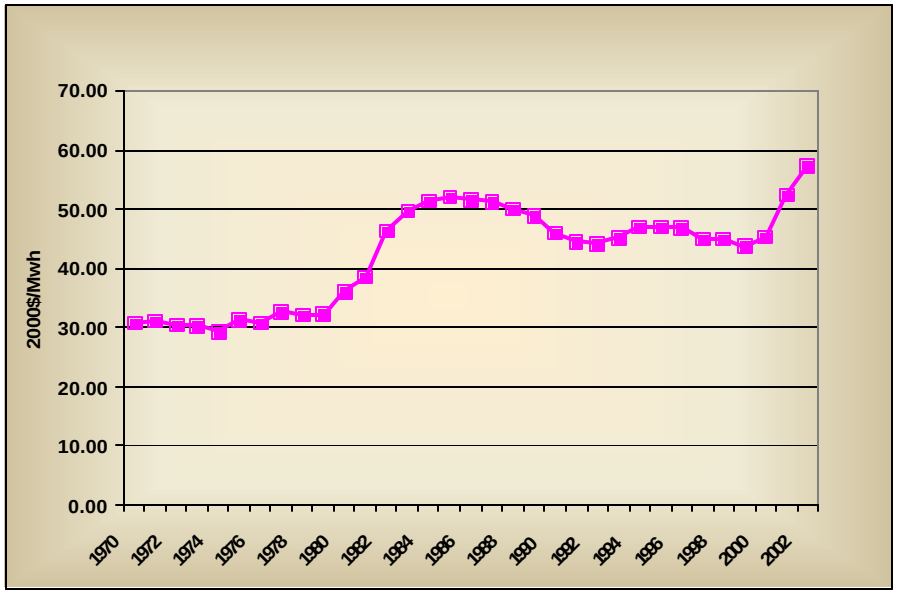
Year	Electricity Use Per Capita (MWa / Thousand Persons)	Electricity Use Per Employee (MWa / Thousand Employees)
1960	1.13	3.81
1980	2.07	5.10
2000	1.93	4.03

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. Actual 2000 electricity demand and conservation achievements correspond closely with what was anticipated in the 1983 power plan in amount if not in composition. 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 2,500 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 illustrates this price history. 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 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 1.

Figure 2
Historical Retail Electricity Prices in the Pacific Northwest



tm/eia data/PNW Energy Prices 70-02.xls

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 during 2003 does not indicate a significant increase 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 4th power plan. The forecast of total electricity consumption in 2015 (the last year in the 4th power plan) is 3,000

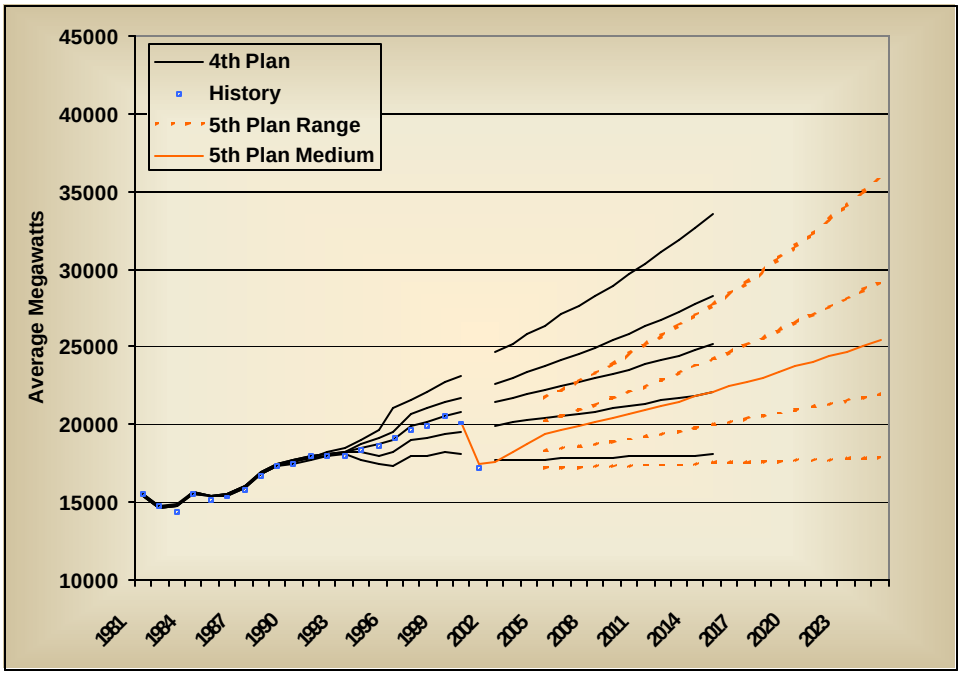
megawatts lower in the 5th power plan forecast. The demand forecast is described in detail in Appendix **??**. Table 2 summarizes the 5th power plan forecast. In the medium case, consumption is forecast to grow from 20,080 average megawatts in 2000 to 25,423 by 2025. However, current consumption levels are well below 2000 levels and it will be several years before those levels of consumption are reached again. The range of forecasts reflects significant uncertainty about the forecast and the entire range enters into the portfolio risk analysis.

Table 1
Demand Forecast Range

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

Figure 3 shows the range of forecasts compared to historical consumption and compared to the range of forecasts in the Council's 4th power plan. It shows that the medium demand forecast for 2015 is about equal to the medium-low forecast in the Council's 4th power plan.

Figure 3
Demand Forecast Range Compared to History and Council's 4th Power Plan



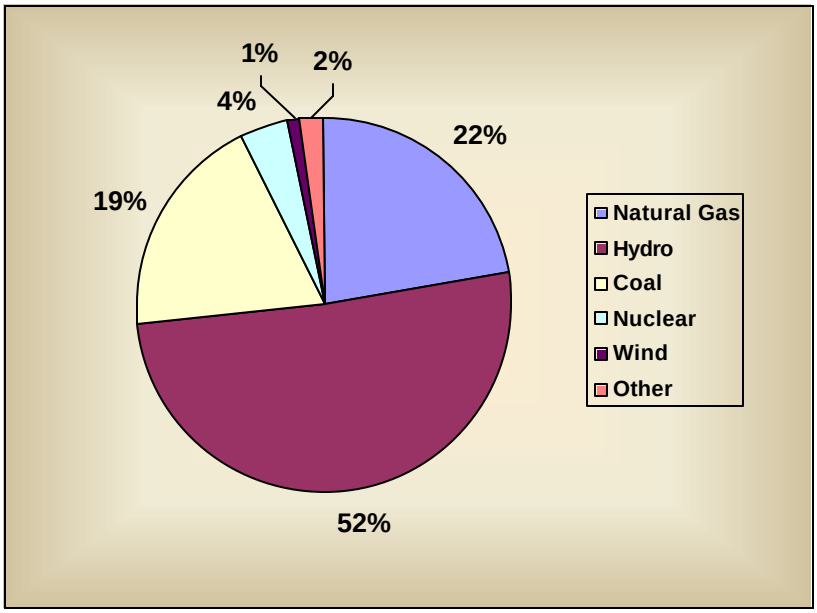
tm/ex/5th plan/TotalD2.xls

Regional Electricity Supply

The region's electricity supply is still dominated by hydroelectricity. The annual energy generating capability in the region, under critical water conditions, is estimated to be about

23,000 megawatts. Figure 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 4
Sources of Pacific Northwest Electrical Energy Generation



tm/ex/5th Plan/LR Bal 103003.xls

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[1] of the hydro system, for example, is 5,400 megawatts less than its nameplate capacity.

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 5 illustrates how the mix of regional electricity generation has changed over time.

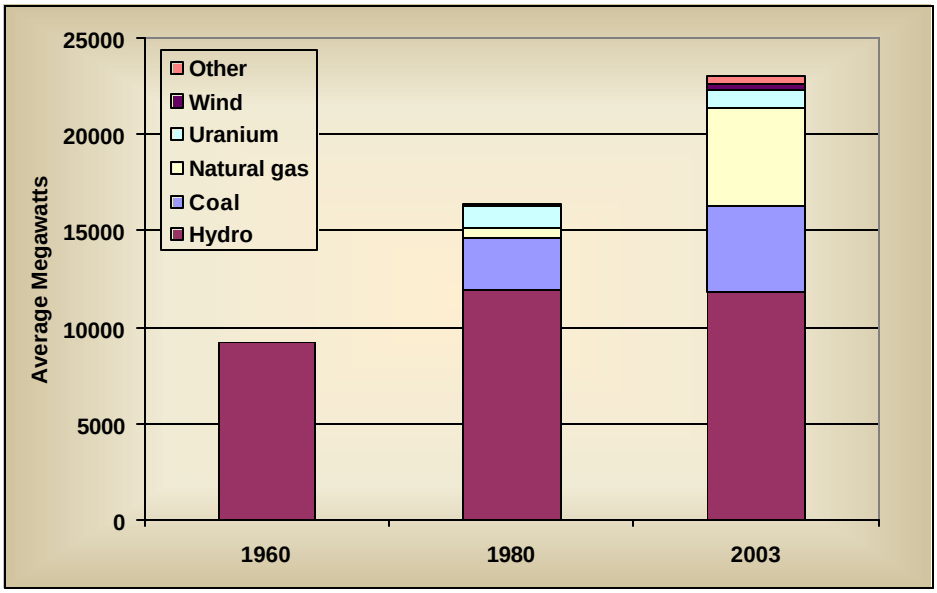
Conservation that has been achieved since the Northwest Power Act is also conceptually a part of the region's resource mix although it is not shown in Figures 4 or 5. The Council has estimated, as noted above, that the region has acquired 2,600 average megawatts of end-use

[1] 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).

conservation through 2002, the equivalent of about 2,800 average megawatts of electricity generation. 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 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.

Figure 5
Changing Pacific Northwest Sources Electricity Generation



tm/ex/Resource Mix 3_03.xls

The region's energy supplies have grown to meet growing electricity demand. 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 risks and uncertainties facing the region. Hydroelectricity still 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 shown in Figure 5, 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. In reality, the region has probably departed informally from critical water standards for a decade or more.

In addition to varying with water conditions, the 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 plants, 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.

Current Load-Resource Balance

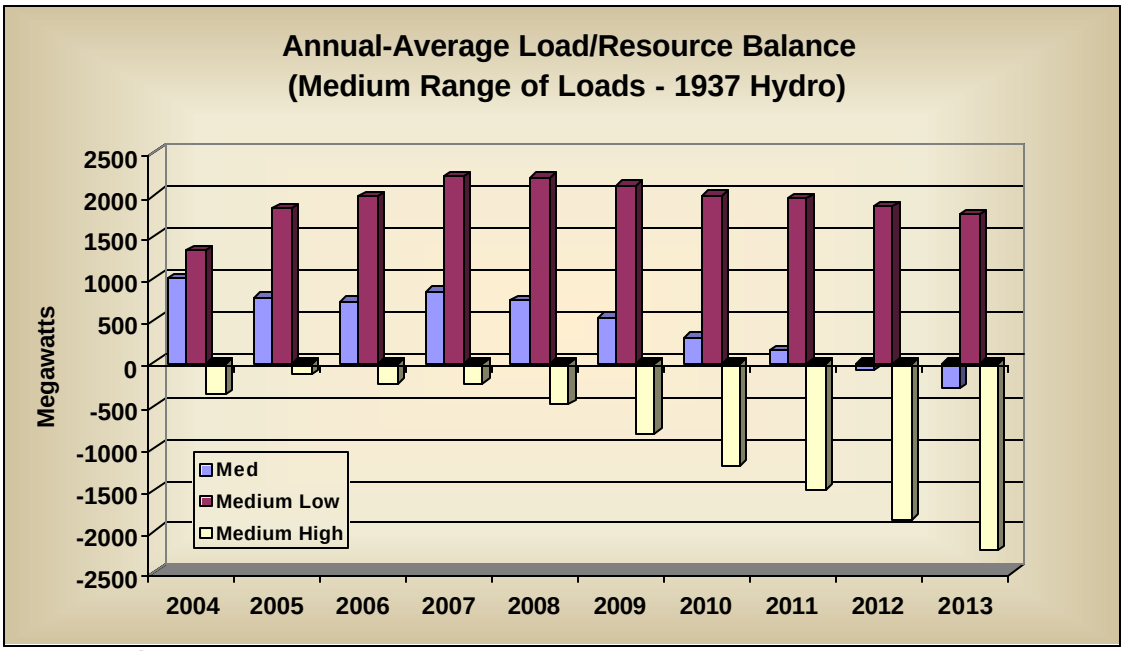
On the basis of generation installed in the region, the Pacific Northwest currently has more than enough electricity resources to meet demand. The expected load/resource balance for 2004 is a resource surplus of about 1000 average megawatts over demand. As recently as 2000, the region had a critical water deficit of about 4000 average megawatts. When the region experienced poor water conditions in 2000 and 2001, it triggered an electricity crisis affecting the entire West Coast. The crisis was 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 2003. At the same time new generating resources were added that increased energy capability by about 3,500 average megawatts.

Figure 6 shows average annual load resource balances in the region with critical water conditons under different demand forecast conditions. In the medium case, the surplus lasts until 2012. 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 2013 and beyond. However, with medium-high demand growth the region is somewhat deficit throughout the 2004 to 2013 period.

Not all the resources in the region are contractually committed to regional loads. Independent generators own many of these resources. We are assuming that under critical water conditions, these resources would be available to meet Northwest loads. This implies that sufficient resources exist outside the Northwest to offset any contractual export commitments that these generators may have. This has been a good assumption in most years as California and the Southwest are summer peaking systems that typically have excess capacity available in the winter when Northwest loads are highest. However, the problems experienced in the California market in 2000-2001 were an important exception.

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



tm/ex/5th plan/LR Bal 103003.xls

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.

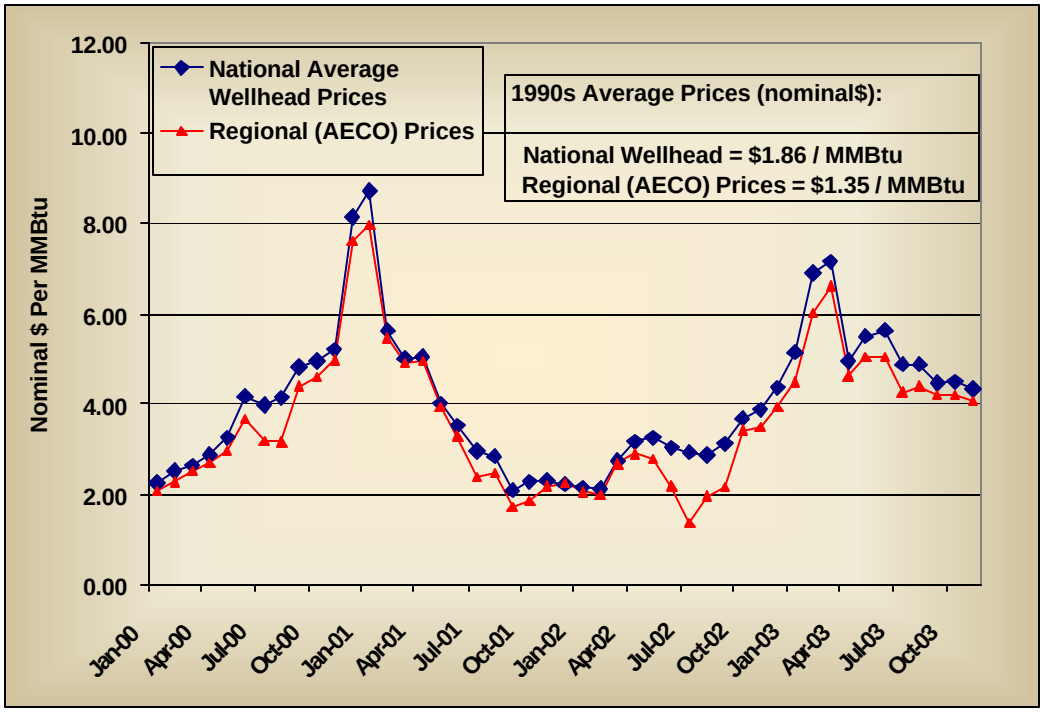
Natural Gas

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 source of most recent electricity generation additions. Recently, volatile and increasing natural gas prices have had a significant effect of energy costs in the region.

If natural gas prices are to 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 7 shows recent natural gas spot market prices at the national and regional level. National wellhead prices from 2000 to 2003 have 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 US Rocky Mountains. During the 1990s this differential averaged $.51; from 2000 to present it has averaged $.42.

Figure 7
Recent National and Regional Natural Gas Prices

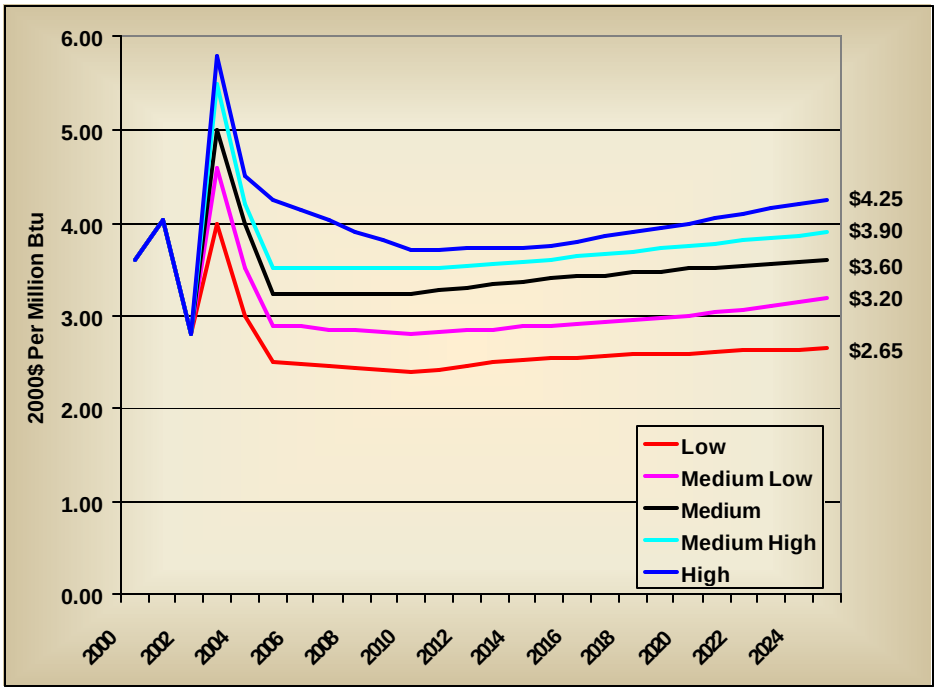


tm/fuel/gas price hist.xls

The Council forecasts a range of natural gas prices for use in this draft plan. The medium case assumes that national wellhead natural gas prices will average about $4.00 in 2004 (in year 2000 dollars) and drop to $3.25 in 2005. Prices are then assumed to grow gradually to $3.60 by 2025. The ending prices in 2025 vary from $2.65 in the low to $4.25 in the high. The recent prices and forecasts are shown in Figure 8.

The Council does not expect fuel prices to follow the smooth trends shown in Figure 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, 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.

Figure 8
Range of Future Natural Gas Price Forecasts



tm/fuel/modf/fuelmod03.xls

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 reflect 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 and, in all but the high case, are projected to decline slightly relative to general inflation although at a much slower rate than in the past. 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 appear in Appendix ??.

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.

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 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. As noted above, the region has succeeded in acquiring this conservation over the last 20 years. Does this mean there is no further 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 2,680 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 4th 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.

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 equilibrating supply and demand, this makes wholesales 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 most

timely 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.

Renewables and Other Resource Options

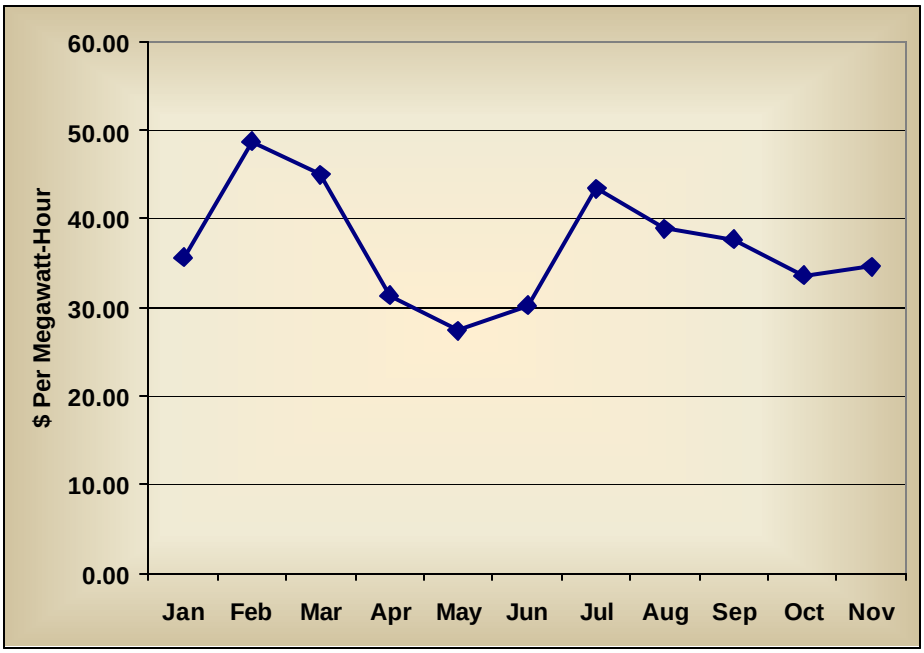
Renewable resources are also a priority resource in the Northwest Power Act. Like conservation, their potential and cost-effectiveness are sensitive to developing technology and the cost of more traditional generating alternatives. Many of these alternatives remain expensive relative to conservation 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 small-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.

Projected 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. However, prices dropped rapidly after May 2001 and have been more reflective of generating costs. Figure 9 shows average monthly prices from January through November 2003, which averaged $37 per megawatt-hour.

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



tm/ex/price study/EMR historic prices.xls

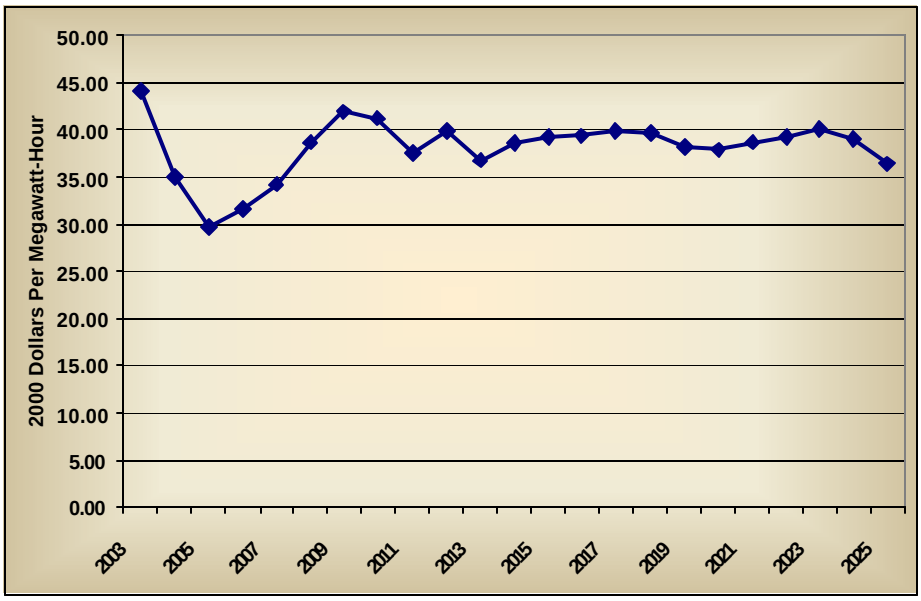
Forecasts of electricity demand and supply alternatives and their costs, including fuel costs as described above, are used to forecast future wholesale electricity prices at various pricing points in the West. These "benchmark" electricity price forecasts are used to help evaluate cost-effective levels of conservation and other resources and serve as the cost of reliance on the wholesale electricity market. The AURORA^{TM} Electric Market Model is used to estimate western electricity prices on an hourly basis at 16 load-resource areas. The model also provides an estimate of an optimal market-based portfolio of generating resources given the assumption of medium load growth and fuel prices. This portfolio provides a starting point and a benchmark for comparison as the Council evaluates alternative resource strategies under assumptions of uncertain and volatile energy market conditions.

The AURORA^{TM} forecast shows that if the medium load and natural gas price forecasts and average water conditions were to persist for the entire forecast period, total Western Electricity Coordinating Council (WECC) generating capacity would increase by about 100,000 megawatts, or by about 2 percent per year, between 2001 and 2025. Contrary to recent years, where new capacity was dominated by gas-fired combined cycle combustion turbines, the new WECC capacity is projected to be a mix of combined cycle combustion turbines (45%), wind (29%), coal (11%) and solar (11%) with small contributions from other resources. There are also some retirements of gas-fired steam plants, peaking turbines and internal combustion generators.

The forecast for the Pacific Northwest generating capacity is quite different. Capacity increases by a little over 10,000 megawatts, or by less than 1 percent per year. Wind accounts for a large share (71%) of the new generating capacity in the Pacific Northwest (the energy figure for wind would be approximately a third of the capacity), followed by combined cycle combustion turbines (19%), coal (7%), and solar (3%).

The forecast shows electricity prices decreasing in 2004 and 2005 as a result of the generating capacity surplus and decreases in natural gas prices. As the surplus is worked off electricity prices stabilize, on an average annual basis, to near $40 per megawatt-hour. The prices average $39 between 2010 and 2025, similar to electricity prices the region has experienced in 2003.

Figure 10
Benchmark Forecast of Mid-C Electricity Prices in Year 2000 Dollars



tm/R5B6 CCUBB Special.xls

The price forecasts include significant seasonal and hourly variation that is not reflected in the average annual price of Figure 10. The AURORA^{TM} model and its forecasts are described in more detail in Appendix ??.

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.

- 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 wholesales 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.

Other Considerations in Developing a Resource Portfolio

There are a number of considerations that enter into developing the power plan resource recommendations. The objective is to minimize the expected cost of providing electricity services, such as lighting, water heating, refrigeration, or space conditioning. The focus on electricity services, of course, brings efficiency changes into the mix. The term "expected cost" recognizes that the future is uncertain and that there is volatility in energy prices. A lowest expected cost resource plan must consider resources and strategies that are more robust in the face of changing or volatile conditions. The Northwest Power Act also requires that the Council include in its costs environmental costs associated with resource alternatives. So there are three major concerns in developing the power plan; the cost of alternative resources, the ability to address significant risks, and the effects on the environment, including fish and wildlife. The direct costs of resources were addressed above.

Environmental Effects

Environmental costs come into consideration in a number of ways as we look forward from the current situation. Of course the cost of currently required environmental controls on electric generating plants are included in the direct cost of each alternative generating technology. The plan must also consider, however, the remaining emissions from electricity generation. Quantifying the environmental effects and costs of these emissions is difficult, but the various models used by the Council to assess electricity generation explicitly estimate the amount of emissions. Environmental effects that are not addressed by current regulations may also carry the potential for future regulation. A primary example of this is CO2. Several states are implementing CO2 mitigation requirements. The plan assumes that other states will move forward with similar requirements, which increases the cost of building power plants that emit CO2. Although current U.S. policy stresses voluntary response to climate change, the growing consensus regarding the existence of climate change and its causal factors suggests the potential for federal regulations or CO2 taxes as global climate change policies evolve over time. Global

climate change may also have an impact on the amount and timing of hydroelectric generation in the region. These are risks that are assessed in the analysis.

The interactions between the power system and anadromous fish policy are a key issue for the Council to address in its power plan and fish and wildlife program. Changing fish and wildlife requirements have had a substantial effect on the capability of the hydroelectric system in the region. In 2001, the region saw that an inadequate supply of electricity could adversely affect the ability to carry out fish and wildlife operations. In addition, inadequate power supplies can have a significant adverse effect on electricity prices and reliability of service. An important issue for this power plan is what determines an adequate power supply and how that supply can be assured in a mixed electricity system. And, further, what is an equitable degree of reliability for both electricity and fish and wildlife operations.

Risk and Uncertainty

The Council's first power plan broke new ground in dealing with the uncertainties facing a twenty-year power plan. The plan acknowledged that future electricity demand, fuel prices and water conditions are highly uncertain and developed strategies to reduce the errors that could result from unexpected changes in future conditions. Over time, the Council has refined its approaches to evaluating the effects of such uncertainties. With this power plan, we have further refined the consideration of uncertainty to include an analysis of volatility of demand and of electricity and other fuel prices.

With the development of more competitive wholesale markets for natural gas and electricity, volatility has become an important issue. Unexpectedly large price increases and decreases in recent years have demonstrated the vulnerability of the region to price volatility. Better developed and structured energy markets can help reduce vulnerability to this volatility over time, but various types of electricity resources can also help mitigate these risks.

There are of course different types of risks that the region faces. Volatility risk of fuel prices is one. Resources based on wind, conservation, coal, or nuclear are less exposed to natural gas price volatility for example. However, these resources may carry more capital risk. Resources that have a large proportion of fixed costs carry more significant capital risk. This risk is a result of changing demand growth or just demand variations due to weather or business cycles. These resources' costs do not vary a great deal, even if they turn out not to be needed. The dramatic price increases the region experienced around 1980 were a good example of capital risk. Large amounts of money were invested in developing nuclear generating plants, most of which turned out not to be needed. Shorter lead times and modular, smaller unit size help reduce these risks. These types of risk issues were well addressed in the Council's previous plans.

However, an advantage of more capital-intensive resources lies in reducing exposure to price volatility. This power plan has been designed to better address this risk through the development of a new portfolio risk model, Olivia. This model helps quantify the value of resources that reduce exposure to volatile energy prices, along with longer-term uncertainty in demand and energy prices.

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 5th 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 loose some of their attractiveness. The relative cost-effectiveness of coal and renewables have increased and may offer a hedge against the effects of volatile of natural gas prices on electricity costs. Conservation potential has increased reflecting technological improvements and 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 resource 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.