Draft Forecast of Electricity Demand for the 5th Pacific Northwest Conservation and Electric Power Plan

August 2, 2002

Background

A twenty-year forecast of electricity demand is a required component of the Council's Northwest Regional Conservation and Electric Power Plan. Understanding growth in electricity demand is, of course, crucial to determining the need for new electricity generation or new conservation opportunities. The Council has also had a tradition of acknowledging the uncertainty of any forecast of electricity demand and developing ways to address the risks of planning errors that could arise from this and other uncertainties in the planning process.

At the time the Council was formed, growth in electricity demand was the key issue for planning. The region was beginning to see some slowing of the historically rapid growth of electricity use, and the future of several proposed nuclear and coal generating plants was thereby put in question. It was important for the Council's Demand Forecasting System (DFS) to be able to determine the causes of changing demand growth and the extent and composition of future demand trends. Simple historical trends were no longer reliable. In addition, the requirement of the Northwest Power Act for a balanced consideration of both conservation and new generation placed another requirement on the Demand Forecasting System; it needed to support the detailed evaluation of improved efficiency opportunities and their effects on electricity demand.

These analytical requirements necessitated an extremely detailed approach to demand forecasting. Rather than identifying trends in aggregate or sectoral electricity consumption and their determinants, the Council developed a forecasting system that builds demand forecasts up from the end-use details of each consuming sector (residential, commercial, industrial). Forecasting with these models required detailed economic forecasts for all of the sectors that are represented separately in the demand models. The models also require forecasts of demographic trends, electricity prices and fuel prices.

Before the last power plan update a significant new component was added to the demand forecasting system. As Western electricity systems became more integrated through deregulated wholesale markets, and as capacity issues began to arise in the region, it became clear that we needed to understand the patterns of electricity demand over seasons, months and hours of the day. Therefore the Load Shape Forecasting System (LSFS) was developed. This model builds up the hourly shape of demand based on the underlying hourly shapes of electricity use by the different types of end-use equipment. It contains about the same detail as the Demand Forecasting System, but when multiplied by 8,760 hours per year, a one year forecast can contain 400 million values.

The detailed approaches of the DFS and LSFS are expensive and time consuming. Major efforts are involved in collecting detailed end-use data, building the models, and maintaining and operating the systems. Neither the current planning issues, nor the available data and resources seem to support the continued use of the old demand forecasting approach. The Council developed an issue paper on forecasting methods in

May 2001 to explore alternative approaches.[1] It was agreed that it was not possible for the Council to employ the forecasting models for the 5th power plan. However, there was little consensus among commenters in the region about what changes should be made to the forecasting system for future Council planning.

The basic priorities for a demand forecast have changed. Although the Northwest Power Act still requires a 20-year forecast of demand, there are few decisions that need to be made today to meet growing electricity demands beyond the next five years. The lead-time required to put new generating resources in place has been reduced substantially from the large scale nuclear and coal plants that appeared to be desirable in the early 1980s. In addition, the restructuring of the wholesale electricity markets to rely more on competitively developed supplies means that there is less role for the Council's planning of the type and timing of new resources to be acquired.

The focus of the Council's power activity has shifted to the evaluation of the performance of more competitive power markets and how to acquire conservation in the new market. The Council has been concerned about the likelihood of competitive wholesale power markets providing adequate and reliable power supplies, which has three implications for demand forecasting. First, the focus is much shorter term. Adequacy and reliability depend generating resources, including water conditions and their effects of hydroelectric generation, compared to loads. The question that has faced the region recently has been whether there is adequate capacity and energy to meet the coming winter demand. Second, the region is no longer independent of the entire Western U.S. electricity market. Electricity prices and adequacy of supply are now determined by West-wide electricity conditions. The Aurora electricity market model that the Council is using requires assumptions about demand growth for all areas of the western integrated electricity grid. Third, the temporal patterns of demand and peak demands matter more. The region is becoming more likely to be constrained by sustained peaking capability than average annual energy supplies, as it was in the past. Further, the rest of the West has always been capacity constrained and thus peak prices throughout the West can be expected during peak demand periods.

Thus, for purposes of demand forecasting, the requirements of the forecast are shifting to shorter term, temporal patterns, and expanded geographic areas. This implies that a different type of demand forecasting system may be useful for future Council planning. However, there remains the question of estimated potential efficiency gains in the use of electricity. To assess cost-effective conservation potential the end-use detail of the old forecasting models would still be useful. But even if the Council still had the resources to use the old forecasting models, the detailed data necessary to update the models does not exist. Finding new ways of assessing conservation potential, or of encouraging its adoption without explicit estimates of the amount likely to be saved is a significant issue for regional planning.

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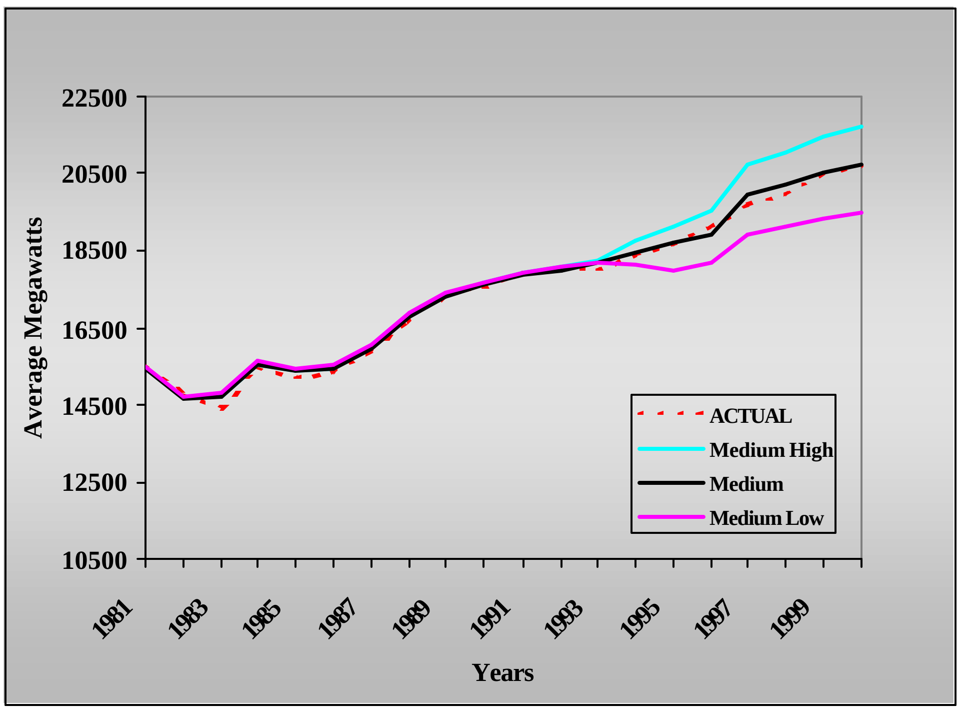
[1] Northwest Power Planning Council. "Council Demand Forecasting Issues". May 2001, Council document number 2001-13. [http://www.nwcouncil.org/library/2001/2001-13.htm]

Forecasting Methods

For this plan, the Council has not used its Demand Forecasting System. Instead, we have relied on the forecasts from the 4th power plan for the long-term demand trends. The long-term trends have been adjusted slightly for actual demand patterns observed since the beginning of the 4th plan forecast in 1994. A short-term forecast has been developed judgmentally to return from the current depressed levels of demand to near the long-term trend demand by 2005.

The decision to use the 4th power plan forecast trends was based partly on an assessment of the accuracy of those forecasts over the five or six years since they were done.[2] The total demand forecasts have tracked actual loads very closely since 1995. The average percentage error in the forecast of electricity consumption since 1995 has been less than one half of a percent. Figure 1 illustrates actual consumption compared to the medium, medium-low and medium-high forecasts. Figure 1 also illustrates the ability of the model to simulate the period before 1995 when actual values of the main forecast drivers are used.

Figure 1
Demand Forecast Versus Actual Consumption of Electricity



The forecasts for the major consuming sectors have also been quite accurate since the 1995 forecasts were done. The level of residential consumption was overforecast by an average of 0.6 percent. Commercial consumption was underforecast by an average of 0.9

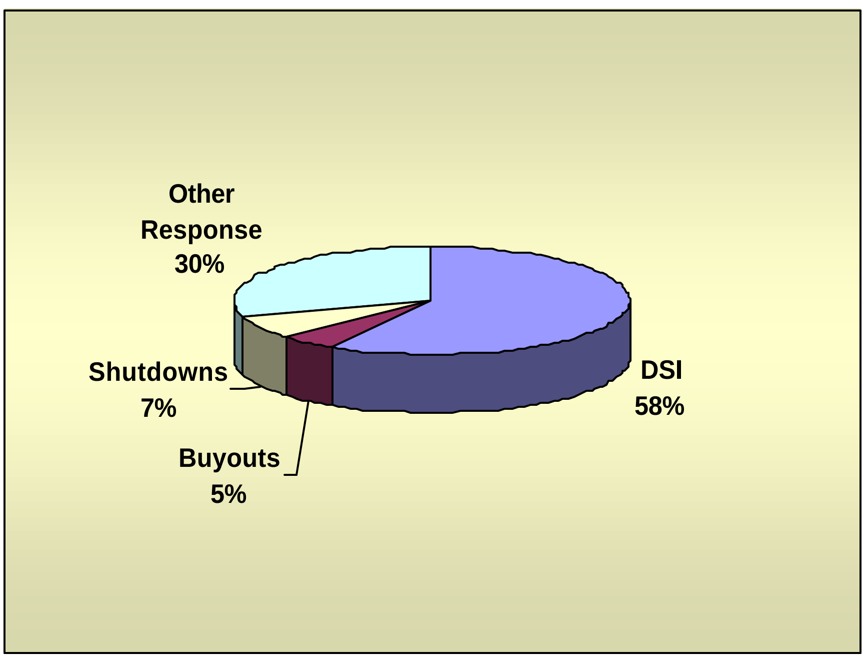
[2] Northwest Power Planning Council. "Economic and Electricity Demand Analysis and Comparison of the Council's 1995 Forecast to Current Data." September 2001, Council Document 2001-23. http://www.nwcouncil.org/library/2001/2001-23.htm

percent, and industrial consumption, excluding DSIs, was overforecast by an average of 3.6 percent. Since there was little evidence that the long-term forecasts were departing seriously from actual electricity consumption, the Council decided to continue to rely on its earlier forecasts.

However, during late 2000 and 2001 electricity demand decreased dramatically in the region due to concerns surrounding the electricity crisis, large increases in retail electricity rates, and an economic slowdown. The near-term forecasts to 2005 address the recovery from this starting condition. These near-term forecasts are done on a monthly basis and are more a basis for tracking demand recovery than an expectation of actual future demands.

The Council analyzed the components and cause of the 2000-2001 load decline in its assessment of the outlook for winter 2001-2002 electricity adequacy and reliability.[3] As illustrated in Figure 2, nearly 60 percent of the reduction was due to closing down aluminum smelters, which make up the bulk of the DSI category. Therefore, a large part of the near-term forecast load pattern depends on assumptions about aluminum smelter operations. The assumptions for aluminum plants' recovery to 2005 are very optimistic to ensure consideration of the greatest potential need for reliably meeting loads in the region. For the draft forecast, the summer 2001 near-term forecast has been retained. Tracking the recovery will provide a basis for adjustment of the forecast over time.

Figure 2
Components of a 20 Percent Load Reduction from July 2000 to July 2001



[3] Northwest Power Planning Council. "Analysis of Winter 2001-2002 Power Supply Adequacy". November 2001. Council Report 2001-28. http://www.nwcouncil.org/library/2001/2001-28.pdf

The near-term forecasts rely on specific assumptions about the return to operation of aluminum and other large industrial loads that were either bought out or shut down during 2001. The remaining load recovery depends on assumptions about recovery from the current economic slowdown and the effects of recent retail electricity price increases, although these effects are not modeled in any formal way. In general, the effects of higher retail electricity prices are assumed to dampen the effect of economic recovery on electricity use and slow the recovery of electricity demand. By 2004 electricity demands are assumed to have nearly returned to the longer-term trend of the 4^{th} plan forecast.

A range of long-term demand forecasts is developed for the years following 2005. The starting point for these ranges is estimated by applying 4^{th} plan low to high case growth rates to estimates of actual electricity demand in a recent year. Starting after 2005, low to high case growth rates from the 4^{th} plan are applied to the respective range of cases. The forecasts are adjusted to remove the effects of programmatic conservation estimates in the 4^{th} power plan.

The long-term forecasts should be viewed as estimates of future demand, unreduced for conservation savings beyond what would be induced by consumer responses to price changes. The Council has referred to these forecasts as "price effects" forecasts in the past. The shift to the price effects forecast is made in 2001. In the medium case, the only sector with any significant programmatic conservation was the residential sector. Residential sector consumption has 191 average megawatts of programmatic conservation savings added. This makes the decrease in residential consumption smaller in the forecast than actual consumption decreases are likely to be for 2001.

Demand Forecast

Draft demand forecasts are presented in this section. The near-term monthly forecasts are presented in the form of monthly load forecasts. That is, the values include transmission and distribution losses. The long-term forecasts are presented as electricity sales, or electricity consumption at the end-use level, and therefore exclude transmission and distribution losses. The long-term forecasts are directly comparable to the demand forecasts presented in the 4^{th} power plan.

Near-Term Monthly Load Forecast

Figure 3 illustrates how the near-term forecasts are designed to track recovery back to the forecast trends from the Council's 4^{th} power plan. The upper line is the 4^{th} power plan trend forecast converted to electricity loads with a monthly pattern added. The lower line shows the near-term monthly forecast of loads. The area to the left of the dashed vertical line indicates the period where the lower line reflects actual load data available to the Council at the time the near-term forecast was developed.

Figure 4 shows the recovery assumed for Direct Service Industrial (DSI) plants and large customers whose load was bought out during 2001 or who shut down their plants due to high electricity prices and the economic slowdown. It was assumed that non-DSI shut down and bought out plants would return to operation completely by the Fall of 2002.

DSI loads begin to return in April 2002, but don't reach their maximum recovery until spring of 2004. It was assumed that 2 aluminum plants would remain closed in the near-term forecast and for the long-term medium case forecast. This should probably be considered an optimistic forecast of the ability of existing aluminum plants to operate in the region. Currently, only 2 aluminum smelters are operating on a commercial basis and they are both operating only partially.

Figure 3
4th Plan Forecast Compared to Near-Term Monthly Forecast

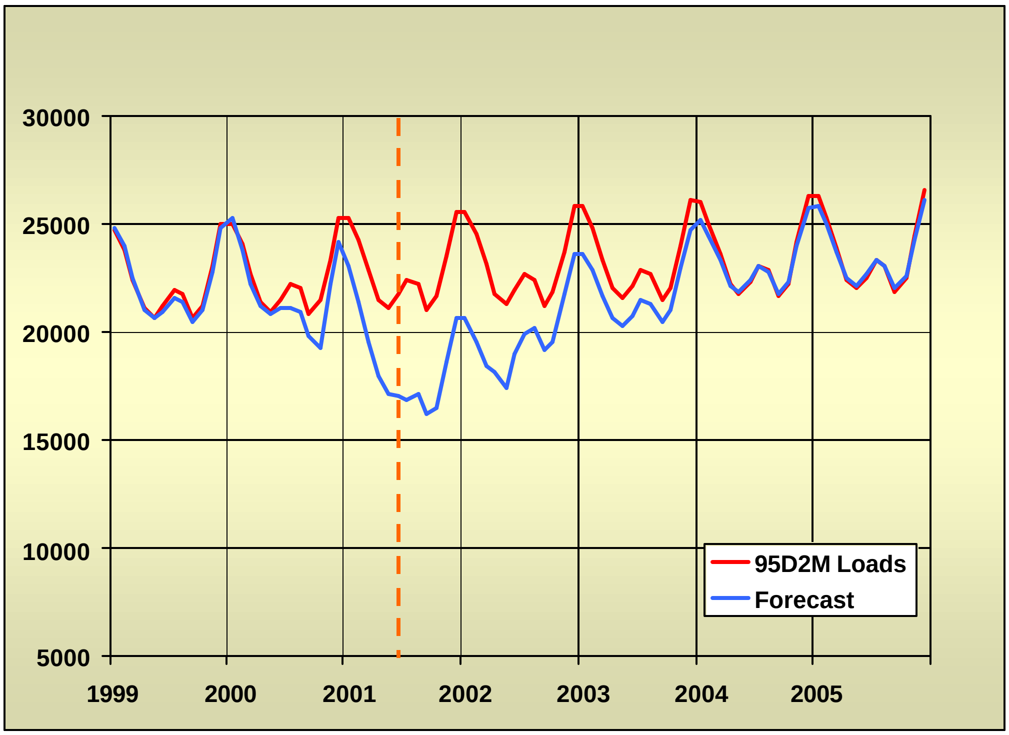


Figure 5 shows the near-term forecast compared to the 4th plan forecast through 2003. The near-term forecast and 4th plan forecast are the same information included in Figure3, but plotted differently. Actual loads have been added through April 2002 as diagonally striped bars. During the winter of 2001-02, actual loads were slightly higher than the near-term forecast. However, in April the forecast moved ahead of actual loads when it was assumed that three aluminum plants would begin to operate, at least partially. Until there is substantial recovery in aluminum plant operations, it can be expected that the near-term forecast will overestimate the actual load recovery unless there is an offsetting underforecast of the non-aluminum loads, as appears to be the case for May.

As of June, the near-term forecast of aluminum smelter loads is about 350 megawatts too high, 900 megawatts compared to actual of about 550 megawatts. An additional 100 megawatts of aluminum smelter loads is expected to start up in the next few months. However, until aluminum prices increase little increased operation is expected. Non-aluminum DSI loads are very close to the near-term assumptions at 58 megawatts.

Figure 4
Recovery of DSI Loads and Large Buyouts and Shutdowns

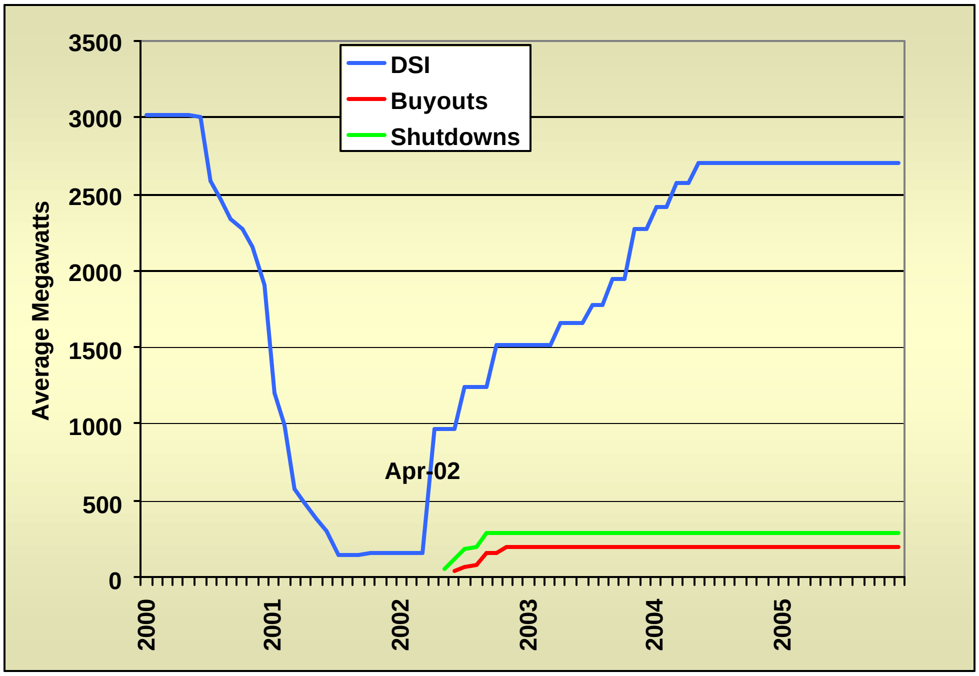
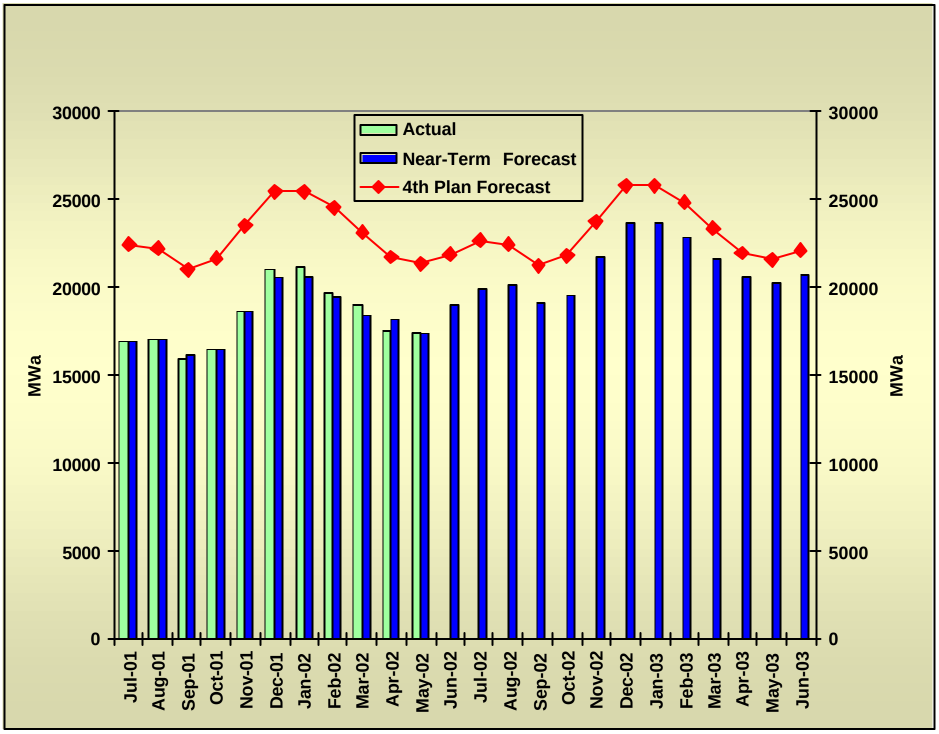


Figure 5
Tracking the Recovery of Loads Against the Near-Term Forecast

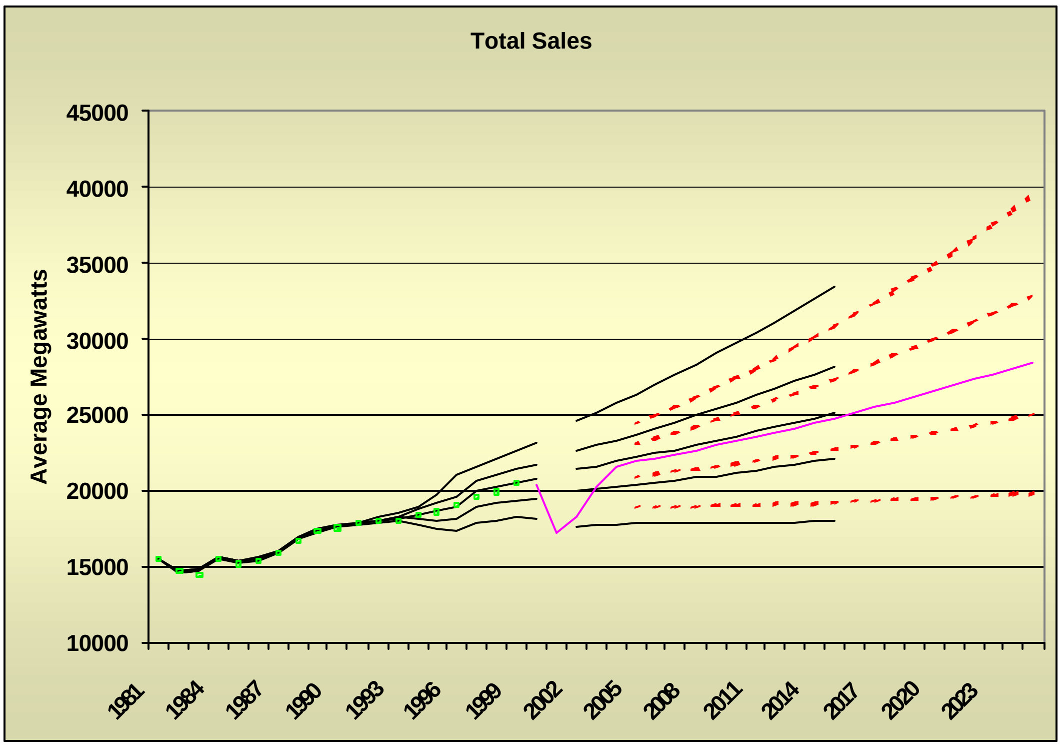


Long-Term Forecasts of Demand

Since the near-term demand forecast is intended to recover to the long-term forecast of demand from the 4th power plan by 2005, and then grow at the same rate as the 4th plan forecast thereafter, the 5th plan forecast medium case is about the same as the 4th plan forecast through 2015. The forecast is extended to 2025 using the same growth rates as in the last year of the 4th plan forecast.

Figure 6 illustrates how the 4th plan demand forecast and the draft near-term and long-term forecasts for the 5th power plan compare. The near-term forecast reflects the currently depressed electricity demand and then merges into the medium forecast. The other forecasts in the range appear as dashed lines that extend to 2025. The 4th plan forecasts appear as solid lines that extend to 2015. Historical actual weather adjusted sales appears as a dotted line through the year 1999.

Figure 6
Forecast Total Electricity Sales Compared to 4th Plan Forecasts



Maintaining growth rates from the previous plan's demand forecasts implicitly assumes that the underlying assumptions remain about the same in terms of their effects on growth in electricity demand. The main driving assumptions in the 4th power plan demand forecasts were economic growth, fuel price assumptions, and electricity price forecasts.

We have not attempted to develop a new economic forecast. However, the 4th plan economic forecasts were checked for obvious deviations from actual values since the forecasts were developed in 1995.[4] The most aggregate determinates of demand are, population, households, and total non-farm employment. The number of households is the key driver of residential electricity demand growth. Actual household growth has followed the medium household forecast from the 4th power plan. Population growth also tracked the medium forecast until 2000 Census data showed an upward revision in regional population. The new population count placed 2000 regional population between the medium and medium-high forecasts.

Employment forecasts are more sensitive to economic conditions than population and households. The period of sustained rapid growth in the national and regional economies during the late 1990s exceeded the forecast assumptions, which were representative of longer-term sustained growth possibilities. Non-manufacturing employment, which drives the commercial sector forecasts has been closer to the medium-high forecast through 2000, although state forecasts of non-manufacturing employment that were available when the assessment was done show its growth moderating and moving back toward the medium forecast. The current slowdown in economic activity will have moved non-manufacturing employment back to the medium or below.

The effects of robust economic growth in the late 1990s are even more apparent in manufacturing sector employment. Actual manufacturing employment moved well above the medium-high forecast in 1997 and 1998 when there was a boom in transportation equipment employment (i.e. Boeing). State forecasts available in mid-2001 expected manufacturing employment to return to medium forecast levels for 2001-2003. With the development of a recession in the fall of 2001 the manufacturing employment has probably fallen below medium forecast levels. There were some offsetting errors within the individual manufacturing sectors. In particular, electronic and other electrical equipment employment has been above the medium-high case, while paper and allied products has been below the medium-low.

Future natural gas prices are expected to be higher in this power plan than in the 4th plan. Table 1 below compares 4th plan gas price forecasts for 2015 to this plan's draft natural gas price forecasts. The medium natural gas price forecast for this plan in 2015 is about equal to the medium high case in the 4th plan, and the revised 2015 medium forecast is 28 percent higher than the 4th plan medium forecast. Based on the Council's Load Forecasting Models, this would imply that electricity demand might be increased by 2 to 3 percent over the 4th plan forecasts if nothing else changed.

[4] Council Document 2001-23, sited above.

Table 1
Natural Gas Price Forecasts for 2015
(2000 $ Per Million Btu)

	4th Plan Forecast	5th Plan Draft Forecast
Low	$ 1.85	$ 2.40
Medium Low	$ 2.16	$ 2.70
Medium	$ 2.47	$ 3.15
Medium High	$ 3.09	$ 3.35
High	$ 3.71	$ 3.60

However, the effects of higher gas prices may be offset by higher electricity prices. It is difficult to compare retail electricity prices between the two forecasts because the old price forecasting models are no longer appropriate for price forecasting in a partially restructured electricity market. The new price model addresses only wholesale electricity prices. Future retail prices will reflect both wholesale market prices and utility-owned resource costs if the system remains mixed, as it is currently. It is clear that higher natural gas prices will have an effect on electricity prices, both through the cost of utility owned natural gas-fired generation and through the wholesale market price of electricity. Higher electricity prices have a larger downward effect on electricity consumption than the upward effect that a comparable increase in natural gas prices would have. In the end, it isn't clear whether the changes in natural gas and electricity prices would cause a net increase or decrease in electricity consumption.

Sector Forecasts

Total consumption of electricity is forecast to grow from 20,442 average megawatts in 2000 to 28,464 average megawatts by 2025, an average yearly rate of growth of 1.33 percent. This implies an addition of 320 megawatts of consumption a year, requiring about 350 megawatts of additional electricity generation each year when transmission and distribution losses are accounted for. The year 2000 is used as the base year for the forecast and growth rate calculations for two reasons; it is the last year for which we have electricity sales data by sector, and it is a more representative year for examining long-term trends in demand than 2001 or 2002 would be.

Table 2
Medium Case Consumption Forecast
(Average Megawatts)

	2000	2005	2010	2015	2025	Growth Rates		
	(Actual)					2000-25	2000-15	2005-25
Total	20,442	21,890	23,234	24,785	28,464	1.33	1.29	1.32
Total Non-DSI	17,859	19,252	20,595	22,146	25,825	1.49	1.44	1.48
Residential	6,851	7,340	7,770	8,318	9,712	1.41	1.30	1.41
Commercial	4,951	5,252	5,558	5,919	6,698	1.22	1.20	1.22
Non-DSI Industrial	5,201	5,848	6,435	7,058	8,525	2.00	2.06	1.90
DSI Industrial	2,583	2,638	2,639	2,639	2,639	0.09	0.14	0.00
Irrigation	674	628	640	653	680	0.03	-0.21	0.40
Other	182	185	191	197	211	0.58	0.53	0.66

The range of forecasts based on the 4th power plan indicate that actual demands should fall within 15 percent of the forecast in Table 2 with fairly high probability. This is reflected in the medium-low to medium-high forecast range in Table 3. However, under more extreme variations in circumstances they could vary by 30 to 40 percent from the medium forecast, as shown by the low to high forecast range.

Table 3
Total Electricity Sales Forecast Range

	2000 (Actual)	2015	2025	2000-2015	2000-2025
Low	20442	19168	19769	-0.43	-0.13
Medium Low	20442	22674	24993	0.69	0.81
Medium	20442	24785	28464	1.29	1.33
Medium High	20442	27346	32842	1.96	1.91
High	20442	30790	39471	2.77	2.67

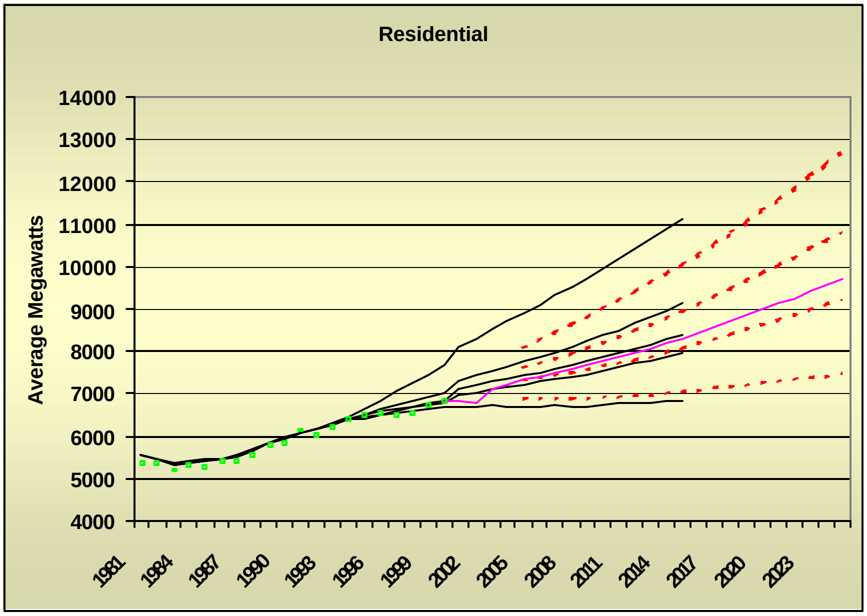
As in the last 20 years, the growth of total electricity consumption in the Pacific Northwest is dampened by the large electricity demands of the 10 aluminum smelters located in the region. These plants can account for 15 percent of electricity consumption, but have not increased their use in the past 20 years and are not expected to in the future. The future of these plants, which were all closed during the winter of 2001-02 can have a significant effect on future electricity demand in the region. The aluminum plants will be discussed further below, but here it should be pointed out that the forecast growth rate of electricity consumption excluding the aluminum plants and other directly served loads of Bonneville Power Administration (DSIs) is 1.49 percent per year instead of 1.33.

Residential Sector

Residential electricity consumption is forecast to grow by 1.41 percent per year between 2000 and 2025. Figure 7 illustrates the range of the residential consumption forecast, compared to historical data, and the forecasts from the Council's 4th power plan. The forecast growth of residential sector use of electricity is slightly less than the growth from 1986-1999 of 1.8 percent annually.

The medium residential forecast remains just below the 4th plan medium case. This adjustment reflects the fact that the 4th plan slightly overforecast actual residential sales between 1995 and 2000, and that there are expected to be some longer-term effects of utility and consumer efficiency investments in response to the electricity crisis and high prices of the last couple of years. In 2005 the difference is 83 megawatts, or a one percent reduction in the forecast consumption level.

Figure 7
Forecast Residential Electricity Sales Compared to 4th Plan Forecasts



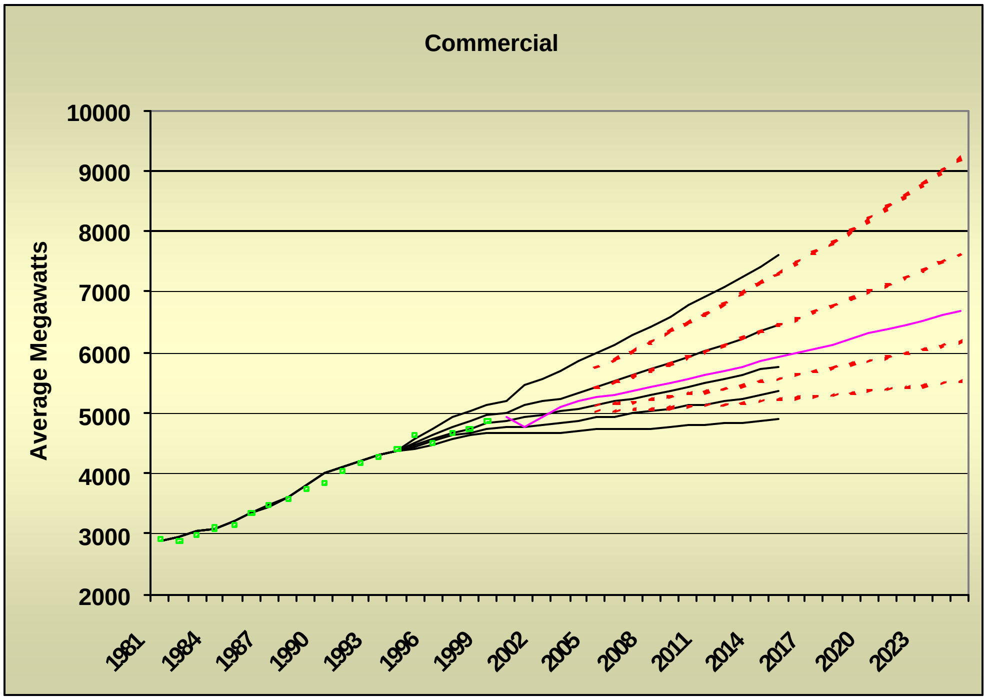
Although the near-term forecast shows a significant dip in residential consumption in 2001, the reduction in consumption is dampened significantly by making the adjustment to a "price effects" forecast in 2001. That is the forecasts are intended to reflect what demand for electricity would be if new conservation programs are not implemented. The consumption levels before 2001 include the effects of conservation programs on electricity use, thus reducing consumption. The residential sector sales forecast is the only one affected by programmatic conservation in 2001 in the medium case of the 4th power plan. The adjustment to eliminate the savings from conservation programs increased the residential electricity use forecast by 191 average megawatts in 2005.

It should be noted that the draft forecasts presented here have not been adjusted for the future effects of new building or appliance codes that have been put into effect since the 4th plan forecasts were done. These changes in minimum energy efficiency would reduce the future "price effects" forecast shown here. The analysis to make these adjustments has not been completed at this time.

Commercial Sector

Commercial sector electricity consumption is forecast to grow by 1.22 percent per year between 2000 and 2025, increasing from 4,950 to 6,698 average megawatts. Figure 8 illustrates the forecast. Compared to the 4th power plan forecast of commercial electricity use, the medium case has been adjusted upwards to reflect the fact that there has been a slight tendency to underforecast commercial demand since 1995. The draft forecast in 2005 is 124 average megawatts higher than the medium forecast in the Council's 4th power plan.

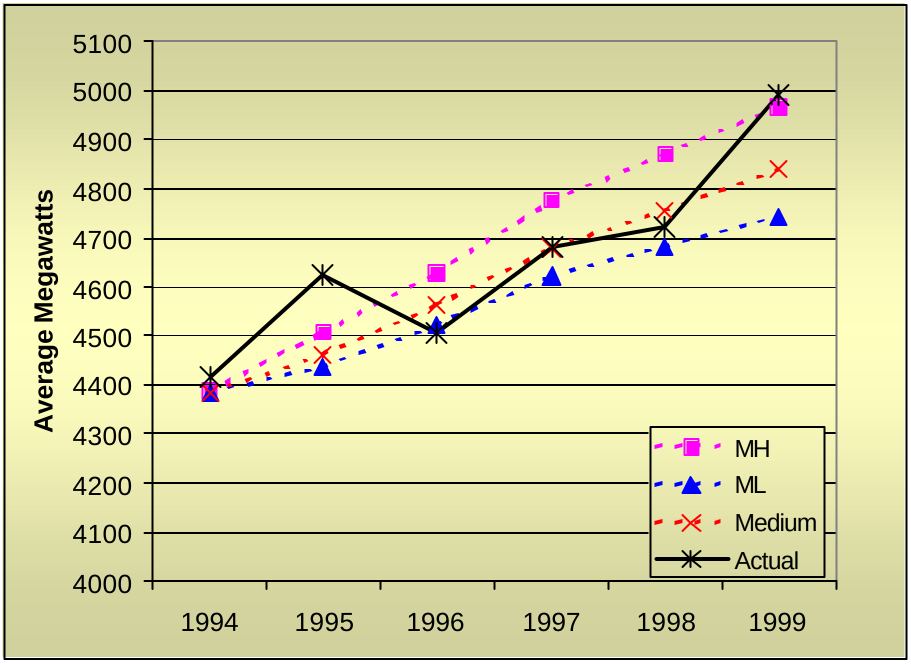
Figure 8
Forecast Commercial Electricity Sales Compared to 4th Plan Forecasts



Comments in the residential sector about the effects of new building and appliance efficiency codes apply to the commercial sector as well. In the medium commercial sector forecast there is no adjustment made for conservation programs in moving to the medium price effects forecast in 2001. The near-term forecast dip is the expected effect of recent price changes and economic slow-down. The conservation program adjustment does affect the starting point for the medium-high and high forecast in 2005. It also affects the 4th plan forecast shown in the graph. The transition from a "sales" forecast to a "price effects" forecast is apparent in the high case, the upper line in Figure 8.

The growth forecast for the commercial sector is for a significantly slower growth than in the past. Between 1986 and 1999 commercial electricity use grew at 3.1 percent per year. Therefore, the forecast growth rate of 1.2 percent represents a big slowdown in commercial growth. This slowdown was present in the 4th power plan forecasts as well. But there has been no obvious underforecasting trend since the 4th plan forecast of commercial demand was done even though the region has experienced a robust growth cycle during these years. Figure 9 shows the forecast compared to actual sales for 1994 through 1999. Although the actuals for 1995 and 1999 are above and at the medium-high, respectively, the other four years are at or below the medium case forecast.

Figure 9
4th Plan Commercial Forecast Performance



Several factors could help explain the slower growth of commercial electricity use. The underlying forecast of employment growth in the non-manufacturing sectors is significantly slower than historical growth. This alone could account for much of the decreased electricity demand growth forecast. In addition, the demand forecasting model accounts for building vintages and efficiency. As newer, more energy efficient, buildings that have been subject to building efficiency codes enter the stock and replace older buildings the electricity use per square foot of buildings will tend to decrease. Such factors may account for the decreased rate of growth of commercial electricity use, but the Council continues to evaluate the commercial forecasts to see if these forecasts might understate future commercial electricity needs. The Council would like to hear the views of utilities and the public on this issue.

Industrial Sector

Industrial electricity demand is difficult to forecast with much confidence. Unlike the residential and commercial sectors where energy use is predominately for buildings, and therefore reasonably uniform and easily related to household growth and employment, industrial electricity use is extremely varied. Further, the use tends to be concentrated in a relatively few very large users instead of spread among many relatively uniform users.

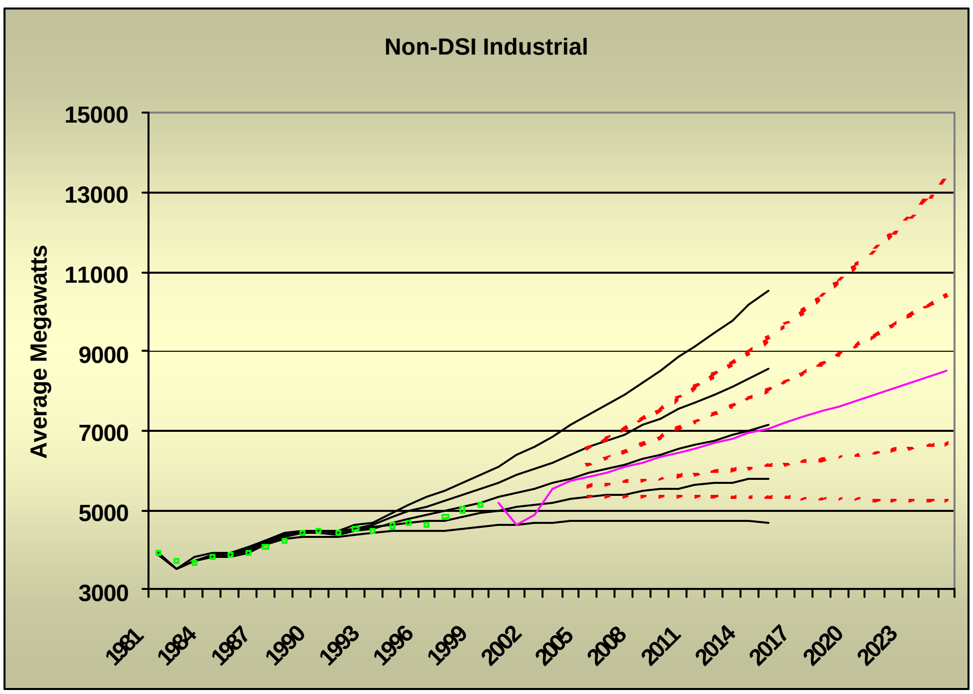
The direct service industries (DSIs) of Bonneville are treated separately in this discussion because this hand-full of plants (mainly aluminum smelters) accounts for nearly 40 percent of industrial electricity use. In addition, the future of these plants is highly uncertain. Large users in a few industrial sectors such as pulp and paper, food processing, chemicals, primary metals other than aluminum, and lumber and wood products dominate the remainder of the industrial sector's electricity use. Many of these sectors are declining or experiencing slower growth. These traditional resource based industries are becoming less important to the regional electricity demand and new industries, such as semiconductor manufacturing are growing faster.

Non-DSI Industrial Sector

Non-DSI industrial consumption is forecast to grow at 2.0 percent annually (see Figure 10). Electricity consumption grows from about 5,200 average megawatts in 2000 to 8,525 in 2025. The medium-high and medium-low forecasts are about 22 percent higher and lower than the medium forecast, respectively. This reflects the greater uncertainty in forecasting the industrial sector's electricity demand. In addition, the actual industrial consumption data is becoming more difficult to obtain as some consumers gain access to electricity supplies from independent marketers instead of their local distribution utility who must report on their electricity sales.

The near-term forecast reflects a severe reduction of consumption in 2001 and 2002. However, by 2004 demand has recovered from the current economic slowdown and high electricity prices to nearly equal the 4th plan forecast.

Figure 10
Forecast Non-DSI Industrial Electricity Sales Compared to 4th Plan Forecasts



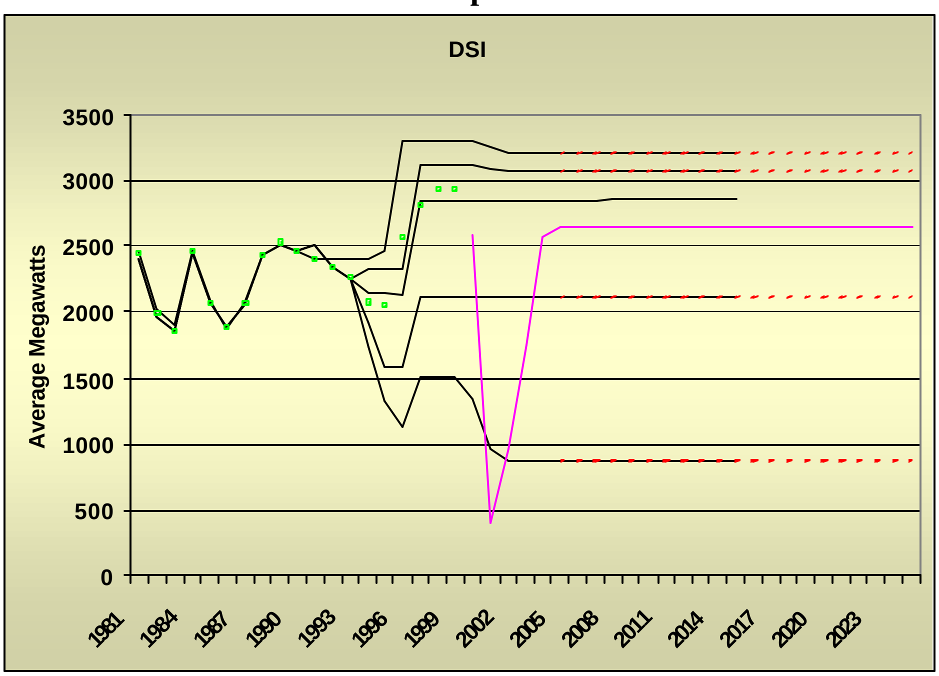
Aluminum Smelter Electricity Consumption

This section is titled aluminum smelter consumption, but it does include electricity use by a few other plants that are directly served by Bonneville. However, nearly all of the consumption is by aluminum smelters. There are no reliable models for forecasting aluminum plant survival and operation in the long term. The Council's 4th plan forecast, or any of its earlier forecasts, did not use models to forecast aluminum. Instead the forecasts relied on educated guesses and a wide range of uncertainty.

The total capability of each aluminum smelter in the region to produce aluminum and consume electricity is relatively well known. What is not known is their ability to operate profitably and survive in the region. The key factors are aluminum prices, electricity prices, and the strategies of global aluminum companies. In the past, Bonneville met the electricity needs of the aluminum plants at reasonably low and predictable prices. Now Bonneville meets less than half of the aluminum smelters' electricity demand and smelters' operations are increasingly exposed to the wholesale electricity market.

For this draft forecast the Council has not yet changed the 4th plan DSI forecast range except for the extension of the near-term forecast, which is below the medium forecast in the 4th power plan. The near-term forecast reflects the current shut down of aluminum smelters and its extension does not recover to level in the 4th power plan. The 4th plan forecasts, and the revised near-term outlook and its extension are illustrated in Figure 11. It is the Council's intent to work further on the aluminum plant issues with the industry and the Demand Forecasting Advisory Committee. An initial assessment of the industry, based on studies reviewed, would indicate that the draft near-term extension forecast is likely to be the highest reasonable forecast of aluminum plant operations. It assumes that all but two of the 10 smelters in the region could operate. The 4th plan high and medium-high forecasts assumed that essentially all plants would operate. The low forecast implies that only about 2 of the current plants would remain and operate in the region. As a point of discussion, it is proposed that the draft near-term extension and the 4th plan low case become the high and low draft forecasts, respectively, for the 5th power plan.

Figure 11
DSI Industrial Electricity Consumption:
Near-Term Extension Compared to 4th Plan Forecasts

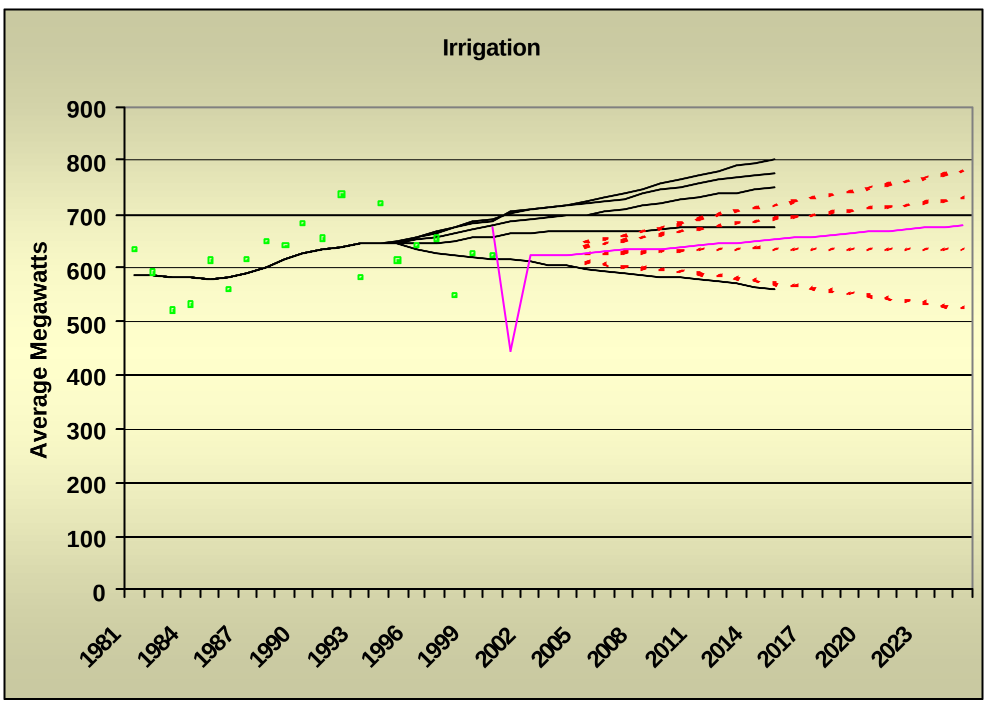


Irrigation and Other Uses

Irrigation and other uses are relatively small compared to the residential, commercial and industrial sectors. Irrigation has averaged about 640 average megawatts between 1986 and 1999 with little trend discernable among the wide fluctuations that reflect year-to-year weather and rainfall variations. Other includes streetlights and various federal agencies that are served by Bonneville. It is relatively stable and averaged about 180 megawatts a year between 1986 and 1999.

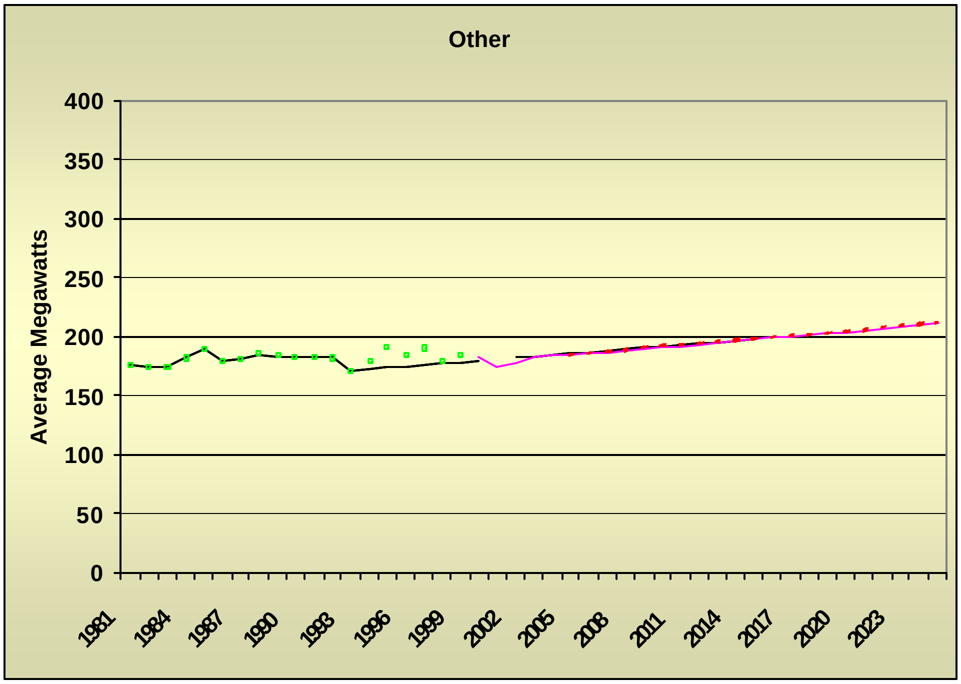
Unlike the other sectors in the draft forecast, the irrigation forecast range has been changed substantially, although due to its small size it has little effect on total demand. Analysis showed that the average irrigation use over the past 20 years was substantially lower than where the medium forecast in the 4th plan started. The 2005 consumption was lowered to 628 average megawatts in the draft forecast, compared to a 4th plan value of 700 average megawatts in that year. The forecast medium case includes very little growth, as has been the case for the last 10 or more years. The range considers a high case growth of 0.6 percent a year and the low case considers that irrigation electricity use could decline by 1.0 percent annually. Substantial expansion of irrigated agriculture seems unlikely given the completing uses of the oversubscribed water in the Pacific Northwest.

Figure 12
Forecast Irrigation Electricity Sales Compared to 4th Plan Forecasts



Other electricity use did not have a range associated with its forecast in the 4th power plan. The other forecast is unchanged from the 4th plan forecast, growing at just under one percent annually (See Figure 13).

Figure 13
Forecast Other Electricity Sales Compared to 4th Plan Forecasts



New Dimensions of Council Demand Forecasting

Changing electricity markets are changing the planning requirements for the region. Electricity prices in the Pacific Northwest are related directly to demand and supply conditions, not just in the region, but also in the entire interconnected western United States. In addition, electricity markets have been, and are expected to remain, volatile. Shortages and high prices will occur at specific times of the year and day depending on electricity demand, but can be prolonged in cases of poor hydroelectric conditions, such as occurred in 2001.

Evaluating electricity markets requires assumptions about demand growth in the entire west and some understanding of how the demand will vary across different seasons and across hours of the day. The sections below describe the very simple approaches to developing assumptions about future patterns of electricity consumption and predicted growth in demand throughout the rest of the west.

Patterns of Regional Electricity Consumption

In the 4th power plan, the Council used an extremely detailed hourly electricity demand forecasting model to estimate hourly demand patterns in the future. We have not run that model for this forecast, but the hourly patterns would remain similar. One approach to forecasting temporal patterns of demand is to use the monthly and hourly patterns from the 4th power plan. The other approach would be to use historical patterns of demand. In practice, these approaches would not result in significantly different monthly patterns of consumption. Whatever typical monthly shape is used, specific months can depart from the normal pattern depending on weather. Variability in consumption patterns due to weather events will be considered in the planning models that address mitigation of risk and uncertainty in electricity markets. Typical monthly patterns provide a starting point for that analysis. The same is true for the peak demand forecast and the typical hourly patterns of demand.

Monthly Patterns of Regional Demand

Figure 14 compares monthly patterns of regional demand in 1999 and 2000 with patterns from the Council's Load Shape Forecasting System (LSFS) from the 4th power plan simulation for 1995. The points on this graph indicate the monthly consumption of electricity compared to the annual average. The year 2000 reflects the disruptions in western power markets starting in June of that year. As a result the electricity consumption was higher in the first half of the year and lower in the second half. The year 2001 would have been even more atypical due to the absence of DSI demand and other industrial demand that is essentially flat over the months of the year.

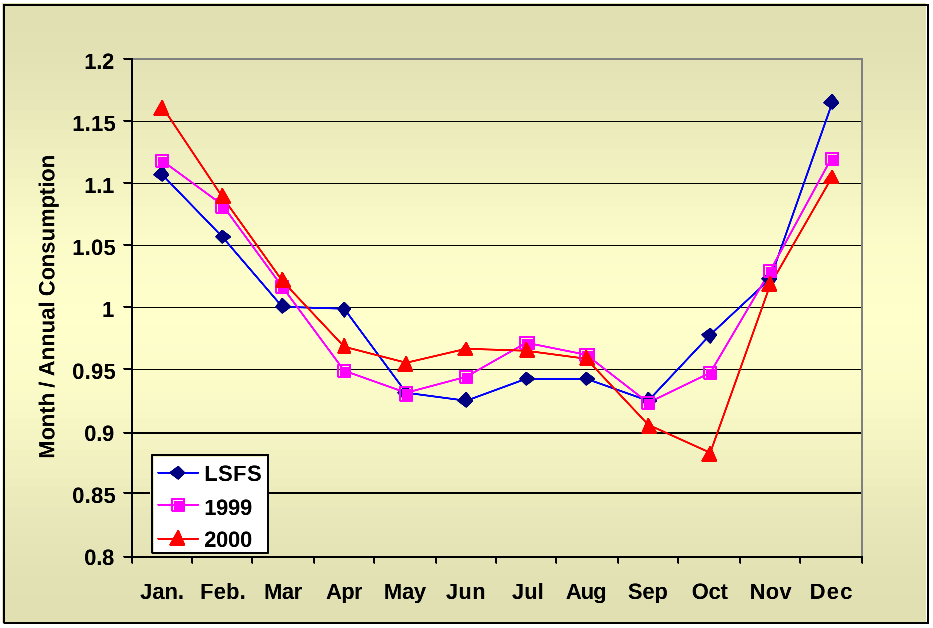
However, all three lines reflect the higher electricity consumption in the winter with a secondary and smaller increase during the summer. Within that general pattern, there appear variations in specific months. The LSFS was based on a year in which there was a severe cold event in December. A particular year was chosen to design the model rather than an average over several years to preserve the variability in the pattern. Averaging would have tended to flatten the hourly variation masking some of the potential volatility.

For purposes of the draft forecast, the LSFS pattern is used. Table 4 shows the monthly demand shape in numerical terms.

Table 4
Monthly Electricity Consumption Pattern

Month	Shape Factor
January	1.108
February	1.057
March	1.002
April	0.998
May	0.931
June	0.925
July	0.943
August	0.943
September	0.925
October	0.978
November	1.023
December	1.166

Figure 14
Monthly Patterns of Electricity Use



Based on discussions with the Council's Demand Forecasting Advisory Committee, the Council will develop monthly patterns of demand based on non-DSI consumption, and then treat the DSIs separately. The different levels of DSI consumption in the future would have a significant effect on the monthly patterns of total demand. This change will be implemented in a revised forecast.

Regional Peak Demand

Monthly regional peak demands are also taken from the Council's Load shape forecasting system. Figure 15 shows average monthly consumption compared to monthly peak hourly consumption. Peak demand is highest relative to average monthly demand in the winter months. For example estimated January peak demand is 45 percent higher than the average demand for the month, whereas the peak August demand is only 21 percent higher than average August demand. The summer and winter peak demands occur at different times of the day. In June, July and August peak demand hours are at 2:00 or 3:00 in the afternoon. The rest of the year peak demand occurs at 8:00 or 9:00 in the morning.

The ratio of average monthly demand to peak hour demand in a month is referred to as a "load factor". Over time the LSFS predicts that load factors will decline, especially during the winter months. That is, the peak hour demand will increase faster than the average monthly demand over time. Figure 16 shows predicted load factors for 1995, 2005 and 2015 from the LSFS analysis of the 4th power plan forecasts. The change in load factor is most pronounced in the winter months. Discussion with the Council's Demand Forecasting Advisory Committee indicated that utilities are experiencing increases in summer peak loads. The Council will investigate this trend further to see if the forecasted pattern needs to be modified to reflect a greater decrease in summer load factors.

Figure 15
Hourly Peak Demand Compared to Average Monthly Demand

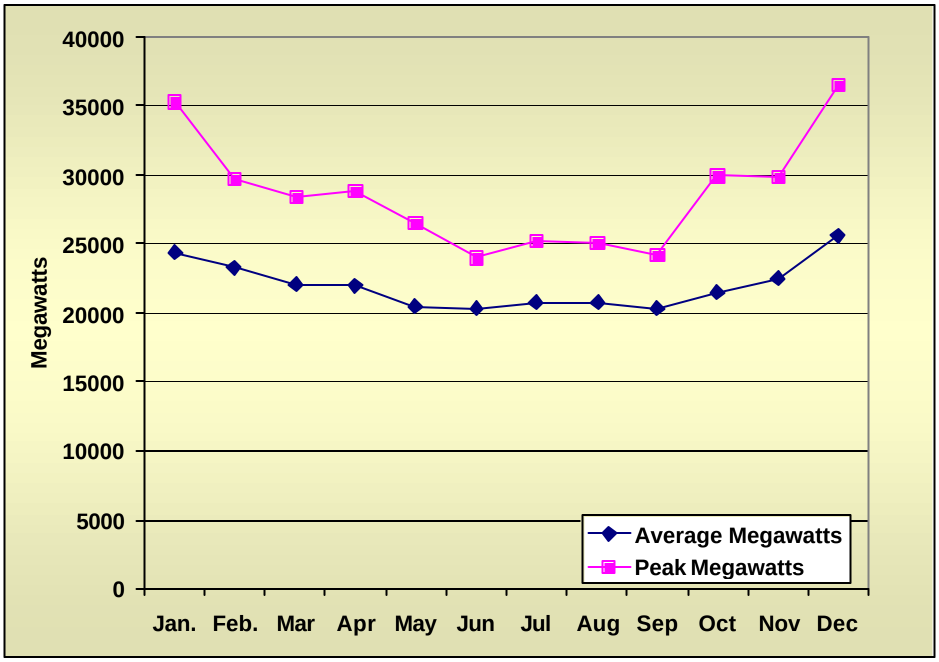
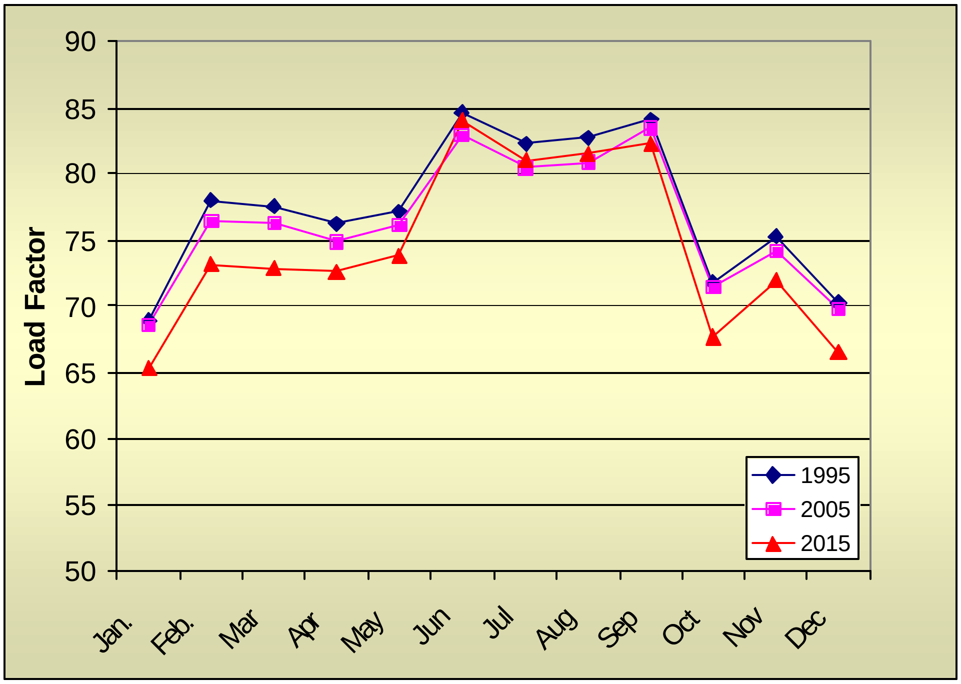


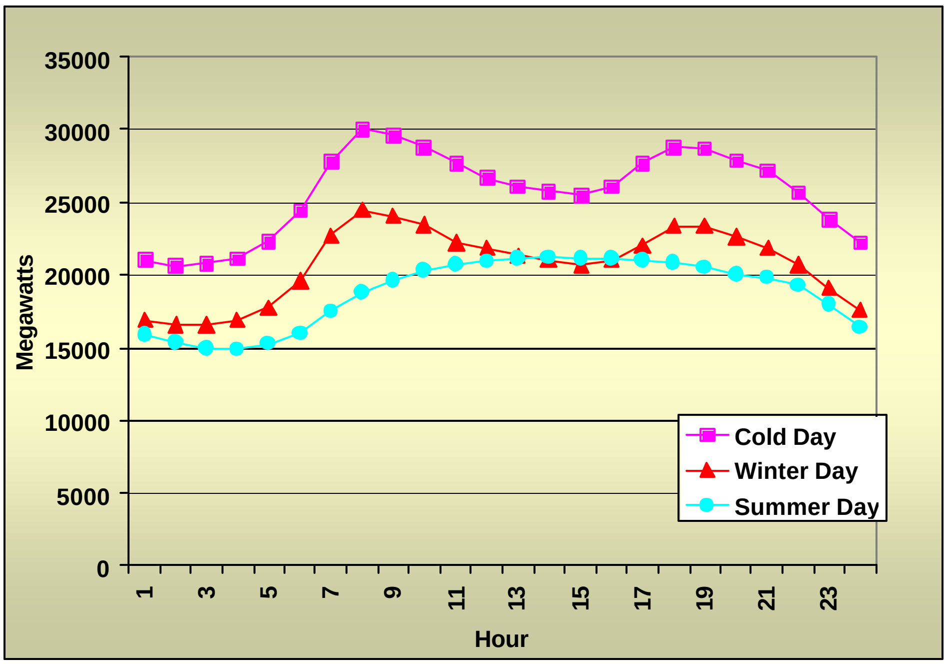
Figure 16
Forecast of Electricity Demand Load Factors



Regional Hourly Demand Patterns

The LSFS forecasts hourly demand for 8,760 hours in the year. It does this for individual end uses within the commercial and residential sectors, for specific manufacturing sectors, and for irrigation. These hourly patterns are aggregated to obtain total hourly demand in the region. Figure 17 illustrates hourly shapes for a typical winter weekday, a very cold winter weekday, and a summer weekday. Winter demand peaks in the morning and again in the evening. This pattern is driven largely by residential demand patterns, which are more variable across the hours of the day than the other sectors.

Figure 17
Illustrative Hourly Demand Patterns in a Day



These hourly patterns of demand may be used in various ways to address analytical requirements. In the 4th power plan, for example, they were aggregated into four distinct blocks of demand for a week. These included on-peak, shoulder, off-peak, and minimum load hours.[5] This was done to address sustained peaking requirements in the plan. By estimating an hourly pattern for 8,760 hours in a year, flexibility is provided to aggregate the demand patterns for different types of analysis.

Electricity Demand Growth in the Rest of the West

In previous power plans, the Council has not concerned itself with demand growth in other regions of the West. However, as noted above, this is now an important consideration for analysis of future electricity prices that will be faced in this region.

For this draft forecast, a simple approach was used to estimate electricity demand growth for other areas of the West. The areas used by the Aurora electricity market model

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[5] See "Draft Fourth Northwest Conservation and Electric Power Plan", Appendix D, p. D-36.

dictate the specific areas considered. The approach used varies for some areas. The general approach used for most areas is to calculate future growth in electricity demand as an historical growth rate of electricity use per capita times a forecast population growth rate for the area. The exception to this method is California where forecasts by the California Energy Commission were used. Population forecasts were taken from the U.S. Census Bureau web site. However, Nevada population forecasts were taken from the Nevada Department of Water Resources. There were two reasons for this. First, the Aurora model distinguishes between northern and southern Nevada and Census forecasts were only available at the state level. Second, the Census Bureau forecast showed Nevada population growing at only .85 percent a year, whereas Nevada has recently been the fastest growing state in the nation with population growth in the neighborhood of 5 percent a year. The approach used for Pacific Northwest areas will be discussed later.

Electricity consumption per capita varies substantially among the states in the West, as have their patterns of change over time. Figure 18 shows electricity use per capita for western states from 1960 to 1999. The most spectacular change is for Wyoming, which started out in 1960 with the lowest use per capita and grew to substantially higher than any other state. This may reflect significant heavy industrial growth in electricity intensive, but low employment, plants; for example, oil and natural gas production. The Pacific Northwest states are the highest per capita users of electricity reflecting a past of very low electricity prices and a heavy presence of aluminum smelters. California is the lowest user of electricity per capita, followed by New Mexico, Utah and Colorado, which are all very similar to one another. Nevada and Arizona fall between these three states and the Pacific Northwest states.

The general pattern is substantial growth in electricity use per capita until about 1980. After 1980, most states' electricity use per capita levels off or actually declines. Exceptions to this pattern are Colorado, New Mexico, Arizona, and Utah where use per capita has slowed, but continued growing.

A question to consider is what historical period to use for the trend in electricity use per capita. For this draft forecast, the growth from 1990 to 1999 was used. Use of a longer period, such as 1980 to 1999 would have increased the electricity demand growth forecast for most areas, some of them quite substantially. The Council will also examine some other sources of population forecasts.

In Aurora, the Pacific Northwest is divided into four areas; western Oregon and Washington (west of the Cascade Mountains), eastern Oregon and Washington combined with northern Idaho, Southern Idaho, and Montana. The sum of these area forecasts should be consistent with the 20-year regional forecast discussed earlier. One approach would have been to share the regional demand forecast to areas based on historical shares. However, in order to recognize that areas within the Pacific Northwest have not grown uniformly, the forecast area growth rates were modified to reflect historical relative population growth in the four areas.

Figure 18
State Electricity Use Per Capita: 1960 to 1999

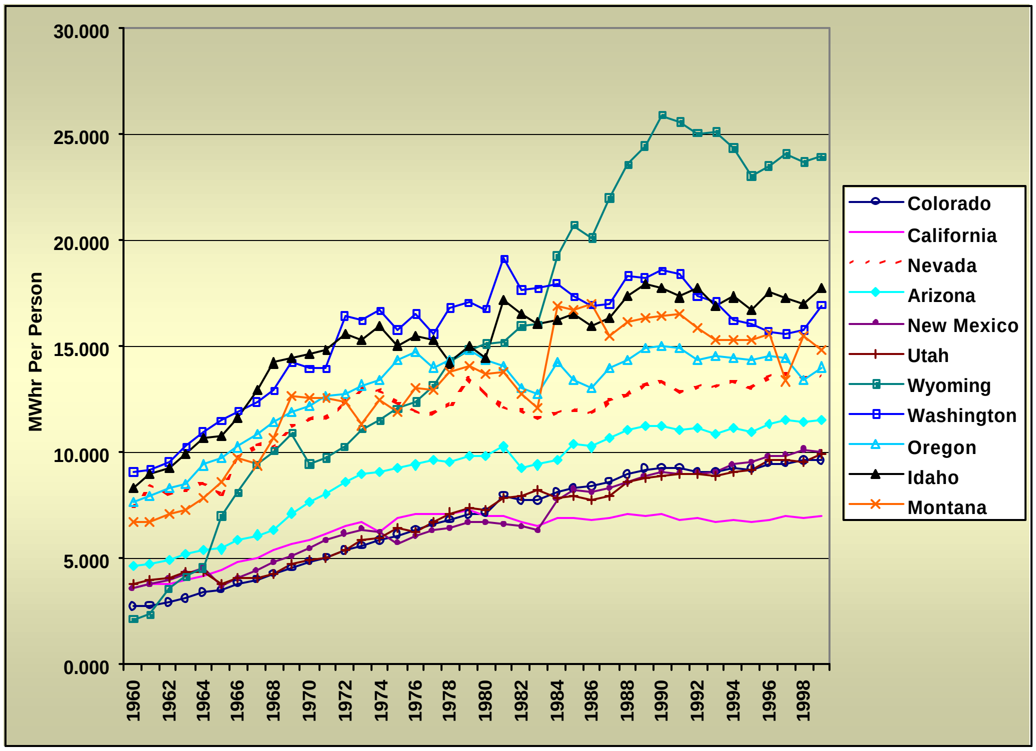

Table 5 shows the forecast growth rates for the Aurora demand areas. They are average annual growth rates from 2000 to 2025. Missing from Table 5, are forecasts for British Columbia and Alberta, which will be added later.

Table 5
Forecast Electricity Demand Growth Rates for Western Demand Areas

Area	Annual Growth Rate
PNW Western OR+WA	1.48
PNW Eastern OR+WA and Northern ID	1.52
PNW Southern ID	1.71
PNW MT	0.90
Northern CA	1.71
Southern CA	1.87
Northern NV	1.65
Southern NV	2.25
WY	0.23
UT	2.32
CO	1.22
NM	2.43
AZ	1.39

Future Forecasting Methods

The forecasts presented in this paper are based on an extension of the previous Council plan and relatively simple approaches to expanding the geographic and temporal dimensions of the forecast. The Council needs to invest in new forecasting approaches for future power plans. One of the action items for this plan is for the Council to develop a new forecasting system that is better oriented to the available Council resources, to the current planning issues, and to the available data regarding electricity consumption and its driving variables. The Council welcomes suggested approaches and advice in this area.

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