APPENDIX D
ECONOMIC AND DEMAND FORECASTS

INTRODUCTION AND SUMMARY

Role of the Demand Forecast

A demand forecast of at least 20 years is one of the explicit requirements of the Northwest Power Act. A demand forecast is, of course, necessary to determine what resources will be required to meet regional load growth. In addition, the demand forecast in the Council's planning plays two other important roles in risk assessment and in conservation analysis.

Because the future is inherently uncertain, the Council forecasts a range of future demand levels. This forecast uncertainty, combined with uncertainty about fuel prices and water conditions, supports a strong analysis of uncertainty and risk in the regional power system that has characterized all of the Council's power plans. The forecast range consists of five forecasts (low, medium low, medium, medium high, and high) based on different assumptions about the key determinants of electricity demand. Much of the detailed discussion in this appendix will focus on the more likely forecast range between the medium-low and medium-high cases. The low and high forecasts are designed to be plausible but not likely futures. The details of the full forecast range are included in the tables at the end of this appendix.

The demand forecast and the detailed models that are used to derive the forecast are used extensively in the Council's conservation analysis. Demand forecasts have a twofold role in conservation planning. First, they determine the conservation potential associated with various levels of demand. For example, estimates of the number of energy-using buildings and equipment in the region, including their fuel type and efficiency characteristics, are needed to help determine how much additional efficiency can be achieved to offset the need for new electricity generation.

Second, the forecasting models aid in determining the reduction in demand that can be attributed to programs to acquire conservation resources. The effects of conservation programs can be quite complicated, and the demand models are designed to help assess those effects. For example, an energy-efficient building code can affect all three components of a building owner's energy choice: efficiency, fuel type and intensity of use. While the direct impact is on efficiency choice, there are also likely to be unintended effects on fuel choice and intensity of use. For example, a more stringent code for residential electrical efficiency will tend to increase the construction cost of electrically heated homes. This relative increase in the initial cost, if borne by homebuyers, may cause some increase in the number of homes heated by natural gas or oil, even though the operating cost of the electrically heated homes would be reduced.

Major Determinants and Forecasting Methods

Energy is a critical component of most human activity. It is an important ingredient in industrial production and provides essential services to support our standard of living. It should not be surprising, therefore, that the level of business and household activity in the regional economy is the dominant determinant of electricity demand both now and in the future.

The demand for electricity to support a given level of economic activity will also depend on the cost of electricity and the cost of alternative products and services. Therefore, the price of electricity and the price of alternative energy forms, such as natural gas, are also important determinants of electricity demand. Demand for electricity can also be affected by changes in technology, which can either increase or decrease electricity demand.

The Council has constructed a demand forecasting system designed to capture the effects of these key factors on the demand for electricity. It is driven by detailed forecasts of economic activity, demographic patterns, and alternative fuel prices. The system is composed of very detailed computer models of electricity use in each of four economic sectors; residential, commercial, industrial, and irrigation. These electricity use models are linked to an electricity price model that simulates the effects of growing electricity demand on the cost of electricity. Demand forecasts both determine, and are determined by, electricity prices. Therefore demand and price forecasts are produced simultaneously in the demand forecasting system.

This introduction and summary discusses only aggregate input assumptions and demand forecast results. More detailed sections on each forecast sector expand on the particular measures of economic activity that drive the results in those sectors. The forecasts of natural gas, oil, and coal prices were described in Appendix D. The final section of this appendix describes the forecasts of electricity prices.

Past Forecasts

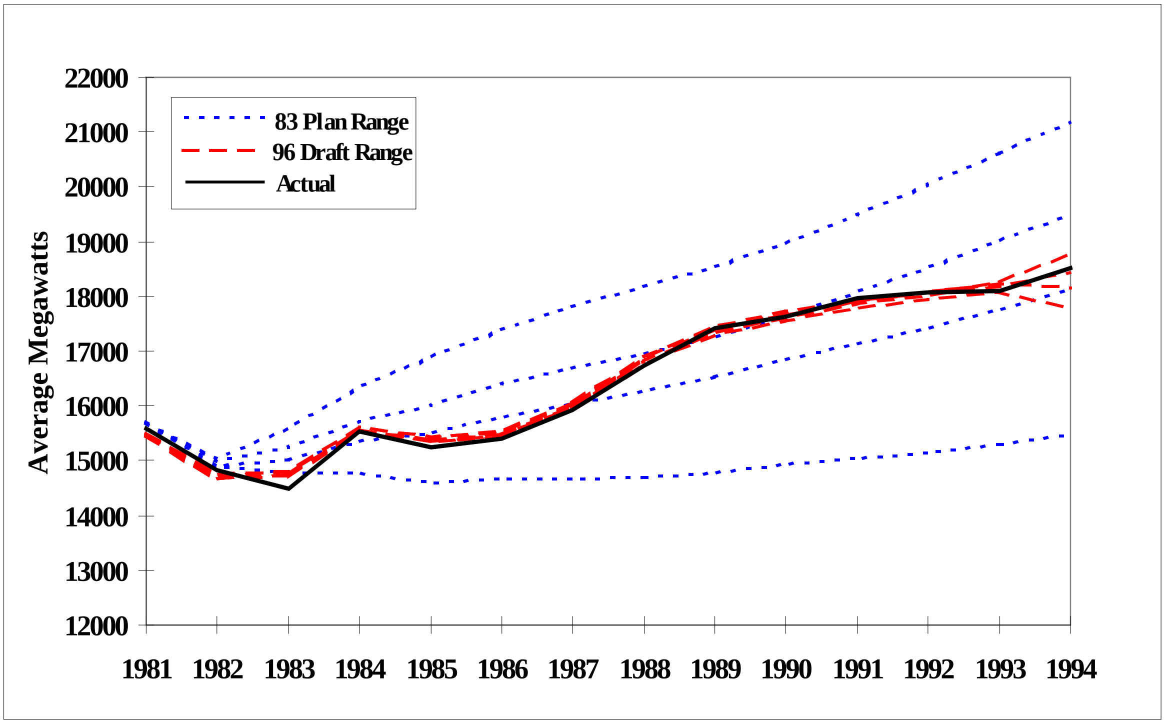
Before the mid-1970s, electricity demand forecasting was largely a matter of projecting past trends in demand. Those historical trends had been steady and rapid growth, and utilities saw little reason to expect significant changes to those trends. However, following the Arab oil embargo in 1973 energy matters rose to a more prominent position and new methods of forecasting were developed. Initially, these methods were econometric in nature, relating historical trends among electricity demand and other factors that were thought to be important determinants of demand, such as electricity price, income, and population. Soon, however, these methods were extended to more structural approaches to energy demand that were constructed around energy services and how those services are provided from energy-using equipment, and buildings. The Council adopted methods that combine the structural end-use approach and econometrics. These methods have been updated and modified since the Council's first forecasts in 1983, but remain unchanged in their general approach.

The Council's models are able to simulate aggregate historical electricity demand accurately when supplied with actual historical values for the economic and fuel price drivers. The average error for the historical period 1981 to 1994 is only 0.01 percent. The largest individual year error in a 1.6 percent over-estimate during the 1983 recession.

The Council's forecasts of future demand have been reasonably stable to date. After the Council's first plan in 1983, the forecast dropped some as the region's traditional forestry industry went into decline and rising electricity prices revealed vulnerability in the aluminum smelting sector. However, following the 1986 plan, the forecasts increased again as nontraditional regional industries showed stronger-than-anticipated growth, particularly the high technology sector, which had not appeared as promising when the 1986 plan was developed.

Figure D-1 illustrates both how the current draft forecast simulates history and how actual demand has evolved compared to the first Council forecast for the 1983 power plan. The actual sales line has been adjusted for variations from normal weather. The actual 1994 electricity sales fall well within the medium-low to medium-high forecast range of each of the historical Council forecasts except the 1986 plan forecast in which the medium-high forecast falls below the actual 1994 sales. Figure D-1 illustrates that electricity demand does not tend to grow smoothly, but rather reflects economic cycles and other random events. Such cycles are not generally built into the forecasts and they, therefore, appear as smooth lines in the future.

Figure D-1
Illustrated Historical Forecast Performance



Effects of Competitive Markets

The development of competitive power markets has fewer implications for demand forecasting than for the Council's resource planning. Regardless of the evolution of the power market, business and personal activities will continue in much the same way. Electricity will be an important requirement to support those activities, and it will be used in much the same manner as it is currently. Total demand forecasts have the same validity they had under a regulated market.

In a competitive wholesale power market, however, the distinction between which type of utility serves a particular demand becomes far less predictable and is not particularly relevant. Demand can be served by any number of different suppliers from utilities to marketers and aggregators. Accordingly, the demand forecast discussion in this appendix does not describe demand in publicly owned utility service areas separately from demand in investor-owned utility service areas. This distinction has also been largely eliminated from the resource analysis in the ISAAC model.

The other aspect of market restructuring that affects demand forecasts is the pricing of electricity. Under regulated markets, electricity prices have been set to recover utility costs. Thus, the electricity price forecasting model was designed to calculate prices that would be sufficient to recover all utility costs when applied to the forecast sales of electricity. In an increasingly competitive market, prices will tend toward marginal costs of the last generating unit that is dispatched to meet loads. The total revenue recovered at those prices may be above or below the utilities' total costs. Further, these prices would be set on a frequent basis, perhaps hourly or continuously, rather than being set for a year or more at a time. The forecasts also assume that electricity is sold and priced on a bundled basis whereas, in a competitive market, prices are likely to be unbundled into various component services in addition to the actual electricity commodity.

In developing these forecasts, the effects of competitive market pricing have only been approximated within the old modeling framework. This is discussed in the final section of this appendix. It is not expected that the resulting long run average patterns of electricity prices would be seriously in error. However, to the extent that unbundled pricing and time-of-day pricing might affect demand patterns, these effects are not reflected in the forecasts of demand.

Forecast Summary

Economic Forecast

The Council's forecasts are comprehensive long-term economic and demographic forecasts for the four-state Pacific Northwest region. The economic and demographic forecasts are the single most important means of estimating future electricity needs, although fuel and electricity prices have significant impacts as well.

The forecasts the Council develops consist of industrial output and employment projections for 27 manufacturing industries, employment projections for more than 22 categories in the commercial sector and forecasts of population, households, housing stock by type and personal income. The forecasts are extremely detailed. Changing demographic and social characteristics are reflected in the linkages between employment and population and between population and households.

Table D-1 compares the draft regional forecasts for total employment with recent periods of history and with growth projections for the United States. The Northwest is projected to grow faster than the nation in all but the lowest growth forecast. Employment growth is projected to slow nationally as population growth slows, reflecting the aging of the population as well as a slowing in the increase in women in the labor force. The regional outlook is affected by this overall trend as well, with employment increasing at a rate of 1.6 percent per year in the medium case. Employment increases from 4.4 million in 1994 to 6.1 million in 2015 in the medium case.

One of the primary demographic forces at work in this country is the aging of the population. Over the next 20 years, the population of the United States is projected to increase nearly 21 percent. This population growth will not be evenly distributed between age groups, however. The population aged 50-59 is projected to increase nearly 80 percent, while the population aged 30 to 39 will actually decline. The population over the age of 75 is projected to increase 46 percent, more than twice the rate of increase of the overall population.

This aging of the population is expected to affect consumption patterns, the labor force and labor productivity. Consumption patterns are expected to emphasize personal services, clothing, travel and health services, as the older population increases. Over the next 20 years, the number of young people entering the labor force will increase at a slower rate than historically. As a result lower employment growth is projected. The tightening labor supply will put upward pressure on wages. Producers will seek to substitute capital for labor, which tends to increase productivity or output per employee. In addition, the rapid pace of technological change and re-engineering efforts will stimulate increasing productivity.

The labor force has been changing as women's participation in the labor force has increased. Further increases are projected, although at a slower pace than in the past. In addition, the growth of ethnic minorities in the U.S. population is having a profound effect on the composition of the labor force. This trend will continue throughout the forecast period. Changing labor force needs will also lead to increased training and continuing education for workers to adapt to a world that is transforming at a rapid pace.

Table D-1
Total Employment (Average Annual Percent Growth)

	Pacific Northwest	United States
1960-1980	3.1	2.1
1980-1994	2.2	1.6
1994-2015:		
High	2.9	1.5
Medium High	2.1	na
Medium	1.6	1.4
Medium Low	1.2	na
Low	0.7	1.2

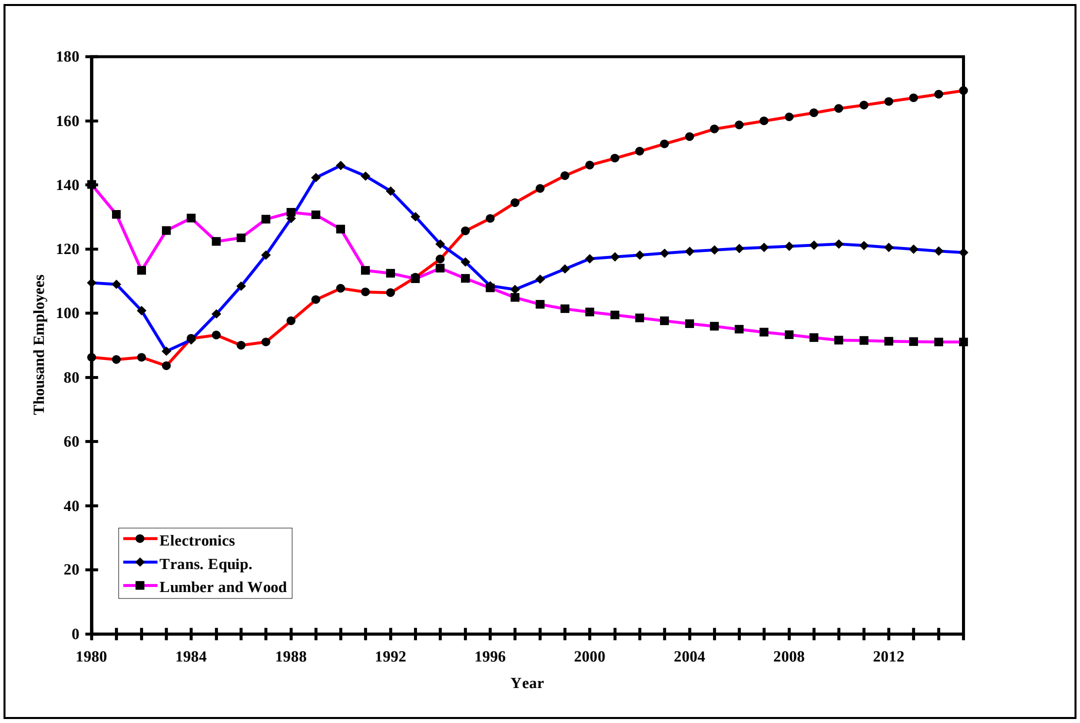
Although growth in total employment is important and uncertain as well, the total employment forecasts do not show the significant changes underway in the composition of employment in the region. Within the manufacturing sector, the Pacific Northwest has traditionally been dominated by resource-based industries, such as forest products and food products. Half the manufacturing employment in 1970 was in lumber and wood products, paper and paper products and food products. Although these industries are still significant, their importance is declining. In the early part of this decade, the largest manufacturing industry in the Northwest was transportation equipment -- primarily The Boeing Company in Washington. During 1995, electronics became the largest manufacturing industry. Lumber and wood products now makes up the third largest manufacturing industry in the region. Employment in the three largest manufacturing industries is shown in Figure D-2. In addition, a wide variety of other manufacturing industries have grown significantly, increasing the diversity of the manufacturing base in the Northwest.

The changes in industrial mix are critical to electricity use. Five industries currently account for 83 percent of the industrial electricity use in the Northwest: primary metals, pulp and paper, chemicals, food processing, and lumber and wood products. These industries are all projected to experience slow growth or decline over the forecast period. This will have a significant impact on electricity demand in the industrial sector.

The biggest change is the decline in the lumber and wood products industry. Lumber production is projected to decline in all of the forecasts, as reductions in federal timber harvest take effect. Most people are familiar with the reductions in harvest as a result of spotted owl protections, but there also could be reductions in harvest to protect other species, such as salmon.

A second major change in the composition of employment is in the balance between manufacturing and non-manufacturing jobs. Non-manufacturing industries now account for 85 percent of total regional employment. This growth has been aided by a number of factors. Manufacturing productivity has increased, decreasing employment relative to output. Out-sourcing, that is, service functions being performed by service firms instead of within manufacturing industries, has reduced manufacturing employment while increasing service employment. A larger proportion of manufactured goods is produced in other countries. The increase in women in the labor force has led to the purchase of services that were formerly carried out within the home, without a financial transaction (and therefore not counted in national income tallies).

Figure D-2
Major Manufacturing Industry Employment



In some cases, the distinctions between manufacturing and service industries are not clear, as both products and services evolve. Temporary employment companies, classified as services, sometimes provide temporary jobs for manufacturing companies. Portions of computer software development, which is considered a business service, may be reclassified into printing and publishing, a manufacturing category. Many services are packaged and sold in units similar to manufactured products, and manufactured items include a substantive service component. More and more, manufactured products are sold in conjunction with services or as part of a package that includes products and services.

Most people think of service industries as the *consumer* services: restaurants, housekeeping services, dry cleaners and beauty salons, for example. But another important category of the services industry is *producer* services: those services that are sold primarily to businesses. These include engineering and management services, computer software development, mailing services, marketing and public relations. Because about a third of these industries have sales outside their state or country, they bring in income from outside the region and provide for economic growth. In such cases, they play a role in the regional economy that is similar to the manufacturing sector.

Another significant and growing industry in the Pacific Northwest is tourism and travel. It is difficult to measure this industry by the usual employment categories because employment related to tourism is mixed with employment that serves the local population. Categories include food service, hotels, guide services, amusements, airports, gasoline stations, and so on. The tourism and travel industry is expected to benefit from the aging of the population because the middle-aged population spends more money on travel and leisure than the younger population.

The world is becoming more interconnected. The Pacific Northwest is already more dependent on international trade than other parts of the country. The region has benefited from its ties and proximity to the rapidly expanding Pacific Rim countries. This impact, as well as changes in technology and growing cultural ties, will result in economic growth in the region.

The Pacific Northwest is a desirable place to live. As the changes brought about by the information superhighway make it easier for people to work at home and "telecommute," the Northwest will attract those who have the ability to relocate for quality-of-life reasons. Advanced information technologies will also enable more profitable utilization of natural resources in the Northwest's traditional resource-based industries. In the lumber and wood products industry, firms have been able to utilize the latest computer and laser technology to maximize their profits. Current market information on prices for different products is combined with laser scanning that shows the most profitable cuts for each log. Similarly, in the agriculture sector, market price and sales information is available to facilitate profitable sales. Farmers can also use computerized, satellite-relayed weather and soil analysis to make their operations more water-, fertilizer- and energy-efficient. Changes such as these will help the resource-based industries remain competitive. Even though resource-based industries are projected to be less dominant in the future, they will still play a significant role in the regional economy.

Within each forecast, the projections for employment, population and households are linked together to form a coherent scenario. However, each category does not grow at the same rate. Table D-2 shows the forecast for summary variables. Manufacturing employment is projected to grow very slowly, as is most employment growth occurring in the nonmanufacturing industries. A primary reason is that productivity growth is much faster in manufacturing industries than in nonmanufacturing industries. Population grows slower than total employment because of continued (although slower) growth in the percentage of women in the labor force and shifts in the age structure of the population. Population increases from nearly 10 million in 1994 to 12.8 million in 2015 in the medium case, which represents a growth rate of 1.2 percent per year. Households grow faster than population because of the continued decrease in the average number of people per household, reflecting changes in the age structure of the population and social changes.

Table D-2

Northwest Economic and Demographic Forecasts

	1994 (in thousands)	2015 (in thousands)	Average Annual Rate of Growth (%) 1994-2015
Total Employment			
Medium High		6879.0	2.1
Medium	4418.7	6144.5	1.6
Medium Low		5653.0	1.2
Non-Manufacturing Employment			
Medium High		6072.4	2.3
Medium	3775.8	5439.5	1.8
Medium Low		5082.2	1.4
Manufacturing Employment			
Medium High		806.6	1.1
Medium	642.9	704.9	0.4
Medium Low		570.8	-0.6
Population			
Medium High		13951.6	1.7
Medium	9891.2	12766.3	1.2
Medium Low		11982.2	0.9
Households			
Medium High		5810.9	2.1
Medium	3783.2	5317.1	1.6
Medium Low		4990.0	1.3

Demand Forecast

Current Electricity Demand

In 1994, the region consumed 18,257 average megawatts of firm electricity. Expressed differently, this amounts to 160 billion kilowatt-hours. However, 1994 was warmer than normal. Adjusting the consumption to normal weather raises consumption to 18,509 average megawatts. In addition to this firm electricity consumption, 139 average megawatts of nonfirm electricity were consumed by industries served directly by the Bonneville Power Administration.

In order to sell 18,509 average megawatts of electricity, the region's utilities would have to generate a larger amount of power. The difference is caused by generation and transmission losses. Firm regional generation, often called load, was about 19,650 average megawatts. The demand forecasts are presented as consumption or sales, whereas resource analysis is done at the generator level. Demand forecasts are converted to load forecasts when they are passed to the resource analysis models by adding estimated transmission and distribution losses.

Electricity consumption occurs in four primary sectors. Electricity consumed in private homes is included in the residential sector and accounted for 35 percent of firm electricity use in 1994. The commercial sector includes electricity consumed in non-manufacturing business activities. This activity accounted for 24 percent of electricity sales in 1994. Electricity consumed in manufacturing business activities is included in the industrial sector and accounted for 36 percent of 1994 sales. About a third of this consumption takes place in industries that are directly served by Bonneville Power Administration. Irrigation electricity is a relatively small sector compared to the other three and only accounted for 4 percent of sales. The remaining one percent is in other activities including street lighting and federal agencies. Figure D-3 illustrates this sectoral breakdown of demand. A detailed discussion of each of these four sectors follows in later sections of this appendix.

Total Demand Forecast

In the most likely range of forecasts, firm demand is expected to increase from its current level of 18,509 average megawatts to between 21,584 and 27,407 average megawatts by 2015. The medium forecast is for 24,429 average megawatts. The medium forecast implies an average growth rate of 1.3 percent per year and the addition of 282 average megawatts a year of demand. The full range of demand forecasts and selected annual growth rates is shown in Table D-3. Table D-4 shows the forecasts as loads, with transmission and distribution losses added.

Figure D-3
1994 Electricity Sales by Sector

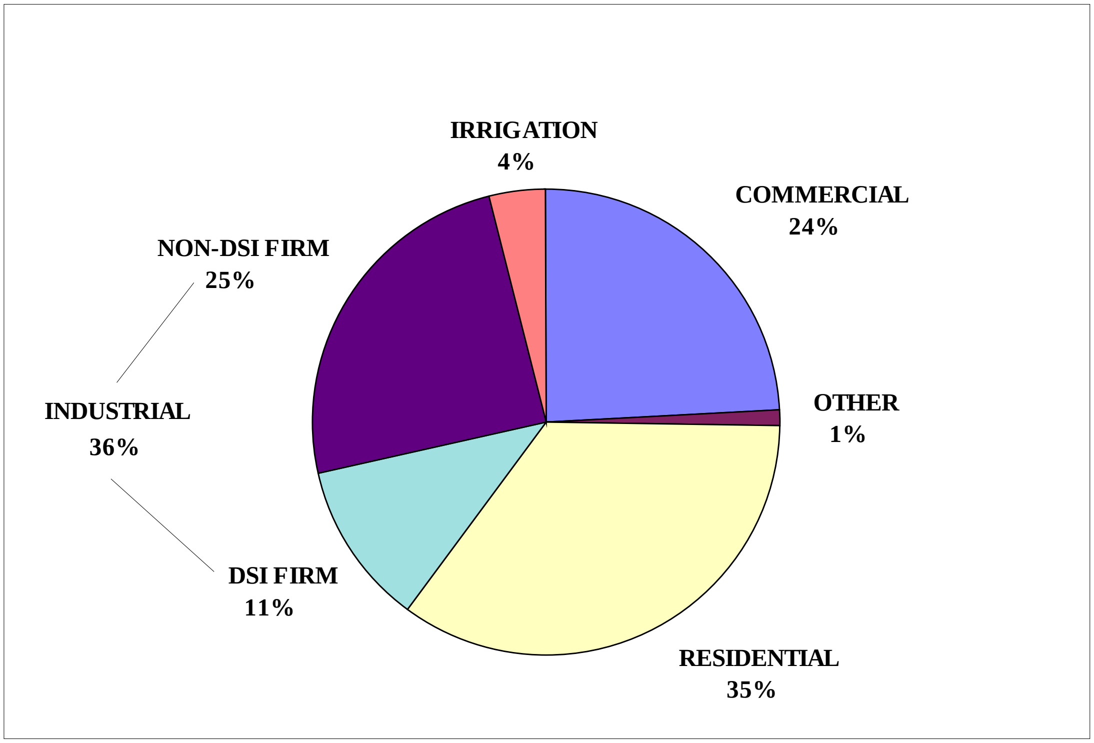


Table D-3
Total Firm Demand Forecasts

	Low	Medium Low	Medium	Medium High	High
Forecast (MWa)					
1994 (Actual)	18,509	18,509	18,509	18,509	18,509
2005	17,588	19,881	21,498	22,963	25,608
2015	17,865	21,584	24,429	27,407	32,646
Growth Rates (%)					
1994-2005	-0.5	0.7	1.4	2.0	3.0
1994-2015	-0.2	0.7	1.3	1.9	2.7

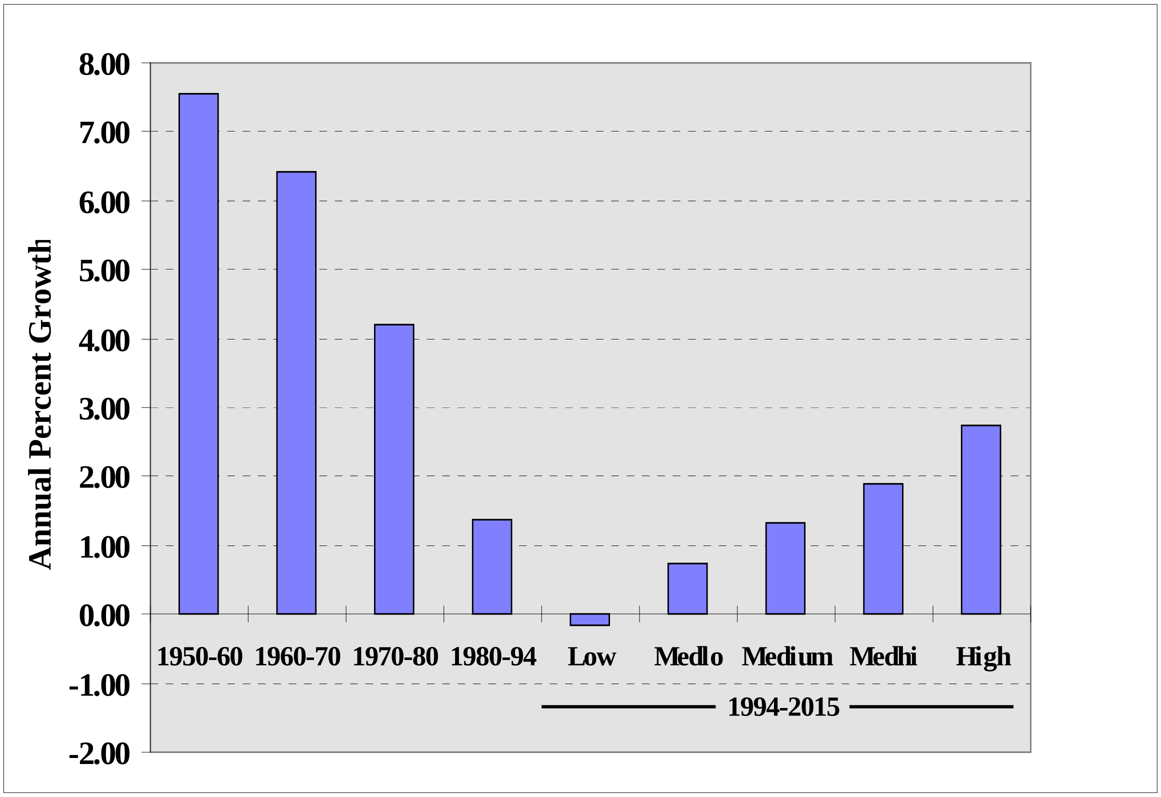
Table D-4
Total Firm Load Forecasts

	Low	Medium Low	Medium	Medium High	High
Forecast (MWa)					
1994 (Actual)	19,987	19,987	19,987	19,987	19,987
2005	19,155	21600	23330	24919	27803
2015	19457	23460	26533	29776	35498
Growth Rates (%)					
1994-2005	-0.4	0.7	1.4	2.0	3.1
1994-2015	-0.1	0.7	1.3	1.9	2.7

The forecasts are placed in a long-term historical perspective in Figure D-4. The very rapid growth in electricity demand during the 1950s and 1960s began to erode quickly during the 1970s with its energy crisis. The effect of the oil embargo was to reduce the rate of growth in demand for electricity. This reduction was largely unexpected by utility forecasters and large commitments were made to coal and nuclear projects during the 1970s. The Council's first forecast in 1983 showed a much lower expected demand growth reflecting escalating power plant costs and the changing composition of the region's economic activity.

Figure D-4

Forecast Demand Growth Compared to Long-term Historical Trends

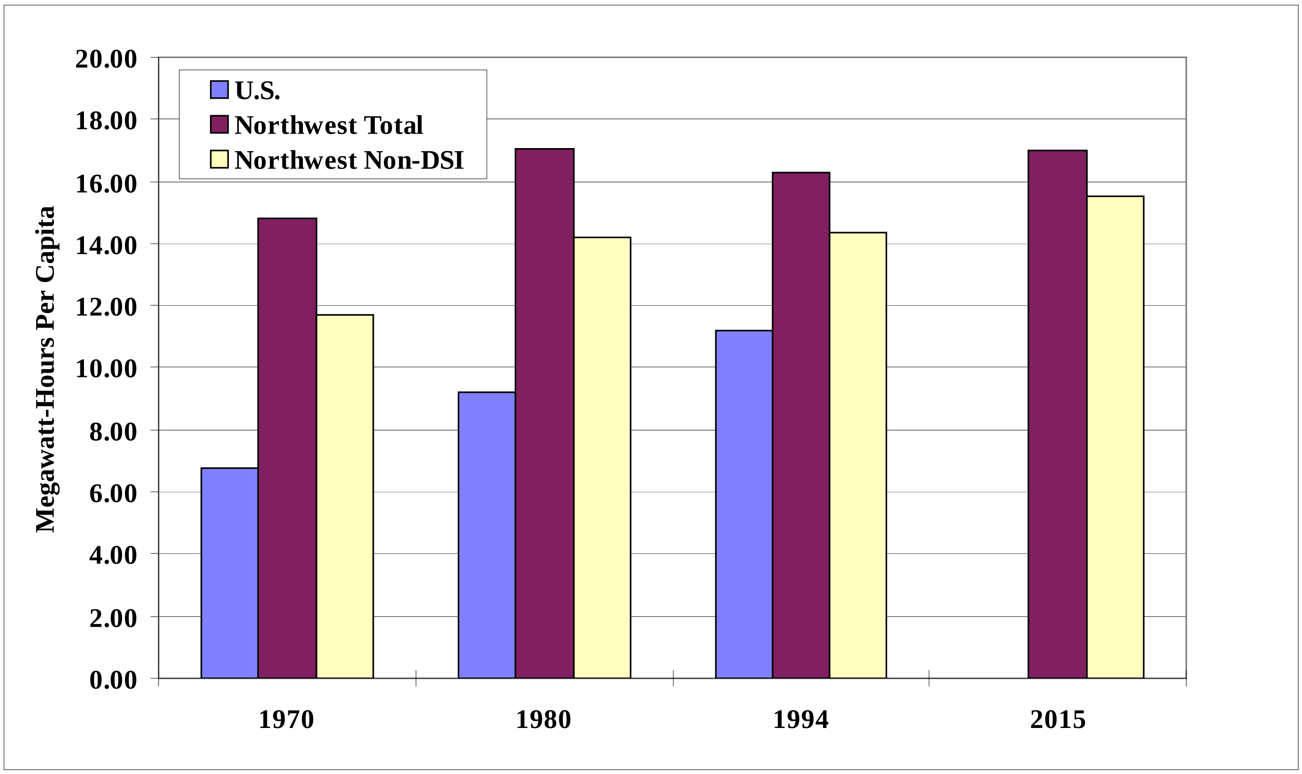


Regional electricity demand growth from 1980 to 1994 turned out quite similar to the Council's medium high forecast from the 1983 Power Plan when adjusted for the significant amount of efficiency improvements during that time. The adjustment is necessary because the forecast projected what demand would have been without energy efficiency programs.

The medium forecast in this draft plan is very similar in growth rate to the actual growth rate experienced since 1980. In terms of the average megawatts of demand added each year, however, the forecast represents an increase from 201 average megawatts per year since 1980 to 282 average megawatts per year during the forecast period. The medium-low to medium-high forecast range shows that it is very likely that growth could either continue to decrease slightly or it could experience a modest rebound. The high case shows that even with extremely robust assumptions about economic growth and continued strength of electricity intensive industries, it is unlikely that growth could return to even the levels experienced during the 1970s. This is due to several factors including; lower potential economic growth (both regionally and nationally), much higher electricity prices and lower alternative fuel prices than during the 1970s, and a regional industrial structure that is shifting away from highly energy intensive activities.

It is common knowledge within the electric power industry that the Pacific Northwest is more electricity intensive than the rest of the country. Due to the availability of low-cost electricity, the region has evolved to use more electricity relative to other fuels than most parts of the country. Figure D-5 illustrates that, in total, the region used roughly twice as much electricity per capita as the whole country in 1970 and 1980. Part of the region's electricity intensity has been a result of the location here of some highly electricity-intensive industries, particularly 10 aluminum smelters that are directly served by Bonneville Power Administration. The light bars in Figure D-5 show that, when the directly served industries are excluded, the region's electricity intensity decreases significantly but still remains higher than the national average. Since 1980, however, the regional electricity intensity per capita has stabilized while the national intensity has continued to grow. The long-term medium case regional forecast shows only a slight upward trend in the per capita use of electricity. This reflects little growth in electricity-intensive industries and increased competitiveness of natural gas for space and water heating.

Figure D-5
Northwest and U.S. Electricity Intensity Trends



Temporal Patterns of Electricity Demand

As discussed elsewhere in this plan, growing demand, increasing constraints on river operations, and development of a more competitive wholesale power market all tend to make the seasonal and hourly patterns of demand more important. The hydroelectric system is no longer able to accommodate all of the seasonal variation in demands that might occur under varying water conditions. For planning, this means that the Council has begun to incorporate capacity as well as energy considerations into its planning.

During the last few years the Council has added a model to its demand forecasting system to estimate the hourly patterns of demand throughout each forecast year. The model is called the Load Shape Forecasting System and has at its heart a model developed for the Electric Power Research Institute called the Hourly Electric Load Model (HELM).[1] HELM takes many specific end-use forecasts for each sector and applies an estimated hourly shape. For example, there is a specific hourly shape for single-family residential central electric space heating in pre-1978 vintage homes. There are hundreds of such end-use, fuel type, building

[1] ICF Resources Inc. and Barakat & Chamberlin Inc., Load Shape Forecasting System, Final Report to the Northwest Power Planning Council, March 14, 1995.

type, and vintage load shapes embedded in the model. The aggregate temporal pattern of demand therefore reflects growth in all of the end-use categories.

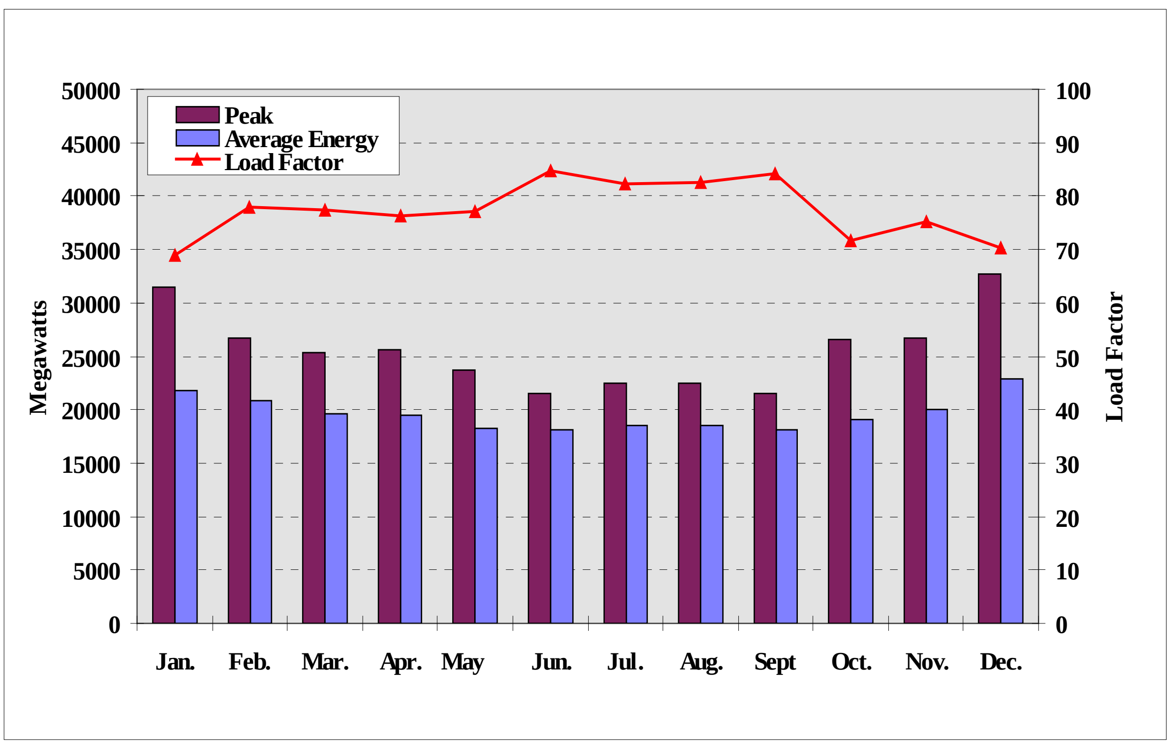
The new model theoretically allows the Council to estimate both the energy and capacity effects of improved end-use efficiency. To the extent, for example, that improved building codes reduce space heating requirements in buildings, the seasonal and hourly shape of electricity demand will be affected. In practice, however, the available data on the effects of various efficiency actions on load shapes is still weak in many cases.

The seasonal shape of loads in the Pacific Northwest shows higher average loads during the winter months. The hourly peak load also occurs during the winter. The relationship between average loads and hourly peak load is captured in the "load factor," which is the ratio of average load to peak load expressed as a percentage. On an annual basis, the region's capacity factor is about 60 percent. The fixed cost of capacity must be recovered through energy sales throughout the year. Therefore, the lower the capacity factor, the more energy sales prices are burdened by capacity costs.

Figure D-6 illustrates these patterns for 1995 on a monthly basis as calculated by the Load Shape Forecasting System. The average energy bars show that average loads are highest in the winter. December loads, for example, are about 30 percent higher than during June or September, the lightest load months. Peak hourly load each month is represented in the dark bars. The seasonal pattern of peak loads is more pronounced than for energy, with December peak load exceeding June peak load by over 50 percent. This difference is reflected in the monthly load factor, which is plotted as a line against the right vertical axis. It varies from about 70 percent in the winter months to 84 percent in June and September.

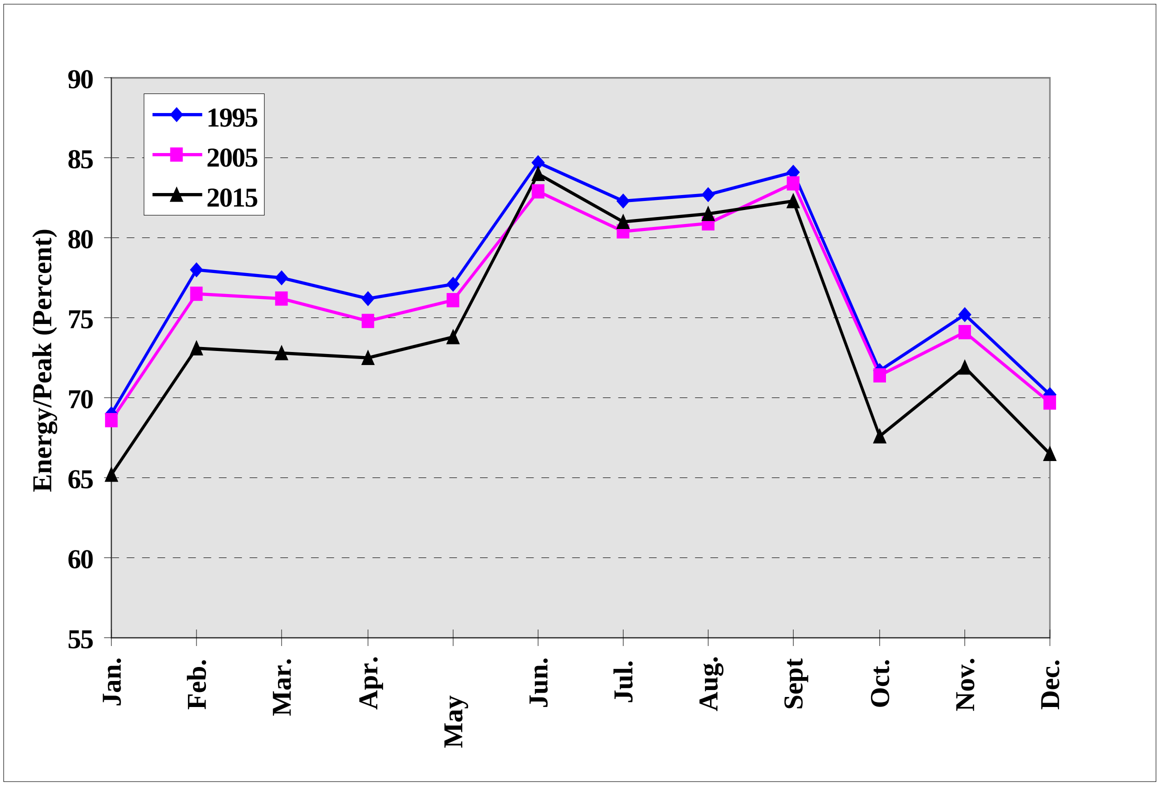
Figure D-6

Seasonal Load Patterns, 1995



The monthly pattern of demand is primarily due to electric space heating. Other end-uses show little seasonal pattern with the exception of lighting and water heating, which contribute in a minor way to the seasonal pattern. During the forecast period, annual load factors decline slightly, from 60 to 56 percent, as peak load grows faster than average energy loads. As illustrated in Figure D-7, the largest reduction in load factor occurs during the peak winter period.

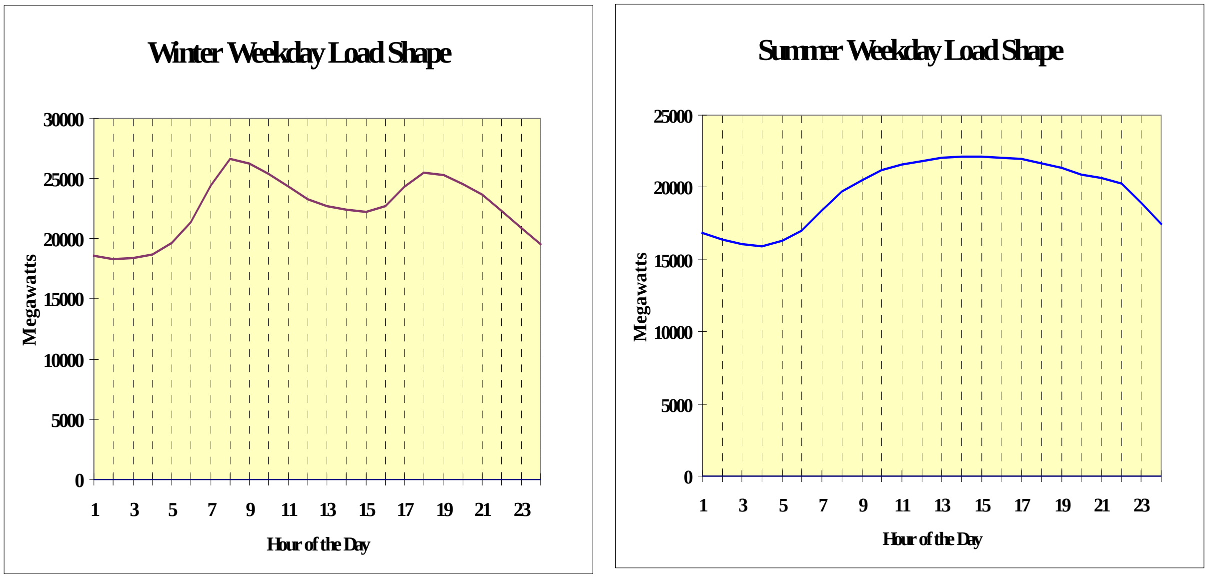
Figure D-7
Changing Monthly Load Factors.



Although the monthly load factors show a small change over time, the seasonal pattern of electricity loads is quite stable. For example, the share of annual loads that occur in the winter months of December through February is forecast to remain at 27 percent.

The Load Shape Forecasting System estimates loads for every hour in a year. These loads have typical daily patterns for each end use that vary at different time of the years, for different days in a week, and in some cases by weather conditions. When all of these patterns are aggregated over the hundreds of different end uses in the model, an aggregate load shape emerges. This shape, like its components, varies significantly depending on season, day of the week, and weather. During the winter, a typical daily load shape has a double peak, one at about 8:00 in the morning and a second slightly lower peak at between 6:00 and 7:00 in the evening. The summer load shape is a broad peak from about 8:00 AM to about 9:00 PM reaching its highest point during the middle of the day. These load shapes are illustrated in Figure D-8 for 1995.

Figure D-8
Typical Winter and Summer Weekday Load Shapes

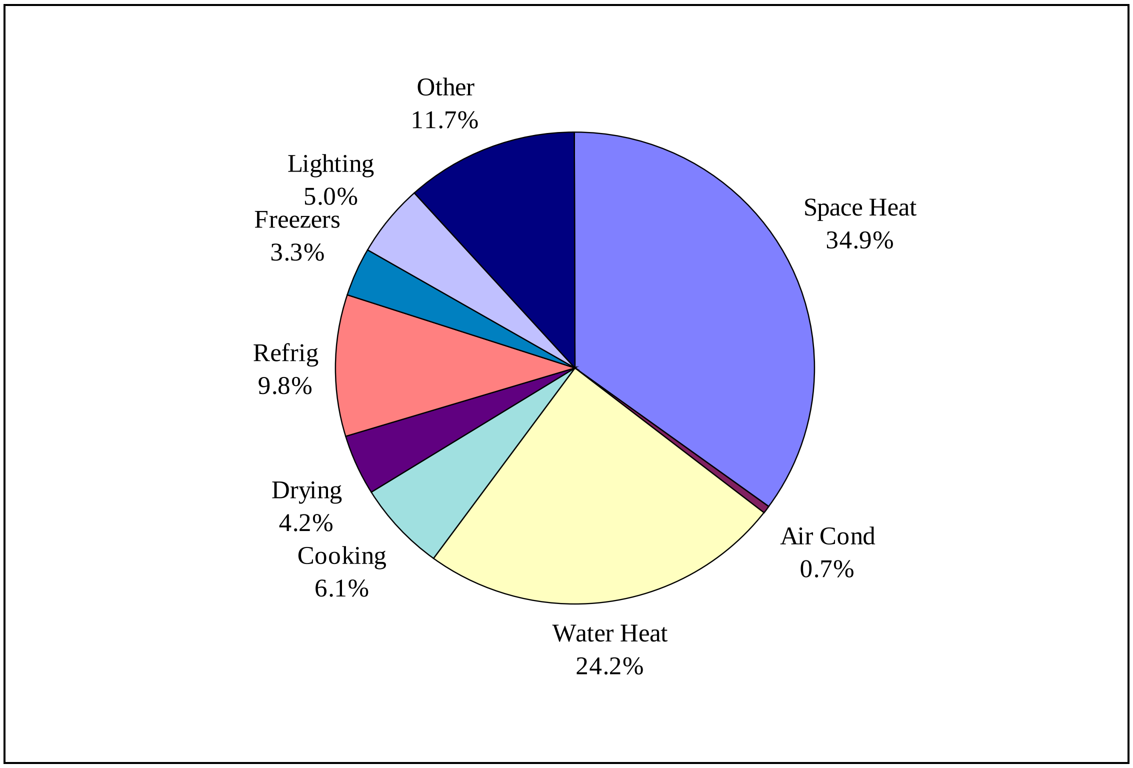


RESIDENTIAL DEMAND

The residential sector accounted for 35 percent of regional firm sales of electricity in 1994. Residential sector demand is influenced by many social and economic factors, including fuel prices, per capita income, and the choices of efficiency for energy-consuming equipment available to consumers (available technology). The most important factor, however, is the number of households.

The use of electricity is separated into nine use classifications. Figure D-9 shows estimated historical shares of these uses in 1994. Space heating and water heating are the two most important end-use categories, accounting for over 59 percent of all residential electricity use. The miscellaneous category also includes some back-up space heating in houses that are heated primarily by wood. Note that Figure D-9 shows end-use shares averaged over all houses, whether they use electricity for a given end use or not. Houses that use electricity for space and water heating will tend to use a larger share for those end uses than is shown in Figure D-9.

Figure D-9
1994 Residential Use By End Use



Forecasting Methods

The residential energy demand model is best described as a hybrid of engineering and econometric approaches. It is based on the fundamental idea that residential energy is used by equipment such as furnaces, refrigerators and water heaters to provide amenities to the occupants of residences. The model projects future demand for electricity, given future growth in households by housing type, by projecting: 1) the amount of electricity-using equipment the average household owns, 2) choices of fuel for space heating, water heating; and cooking, 3) the level of energy efficiency chosen, and 4) the energy-using behavior of the household. Residential energy use, as simulated by the model, is a function of the following factors.

1. Total number of residences and the number of new residences constructed. The projections for future years are taken from the economic and demographic projections.
2. Number of energy-using appliances in the average residence. Each year's appliance penetrations, or purchases of appliances per household, are simulated based on econometric analysis of historic sales patterns. Penetrations are influenced by equipment and energy costs and by per capita incomes.
3. Efficiencies of these appliances. Efficiency choice by consumers is simulated based on engineering analysis of costs of appliances of varying efficiencies and on econometric analysis of observed efficiency choices in the past. Efficiency choices are influenced by energy prices, the cost of more efficient appliances, and the inclination of consumers to invest in conservation (represented by their implicit discount rates). Efficiency choices can also be constrained (e.g., thermal integrity choices will be no worse than some specified level), which provides the means of representing such conservation programs as building codes and appliance efficiency standards.
4. Fuels used by these appliances. While some appliances such as air conditioners use electricity exclusively, others such as water heaters can use any of several fuels. Fuel choice is simulated based on the efficiency choices and econometric analysis of past fuel choice behavior. Fuel choices are

influenced by relative fuel prices, equipment prices, and relative efficiencies of the appliances using the various fuels.

5. Intensity of use of these appliances. Intensity of use is varied by such means as thermostat settings and reduced use of hot water for washing clothes. Variation in intensity of use is based on econometric analysis of observed short-run response to fuel prices. Intensity of use is determined in the model by fuel costs, appliance efficiencies and per capita incomes.

Economic Assumptions

Forecasts for population, households and the housing stock are the principal economic drivers for the residential sector. The population forecast is derived from the forecast of total employment by using an average employment-to-population ratio. Changes in the employment-to-population ratio reflect changes in labor force participation, unemployment rates and age composition of the population. The participation of women in the labor force increased rapidly in the last thirty years. The employment-to-population ratios in this forecast incorporate the impacts of continued increases in female labor-force participation, although at slower rates than in the past. The range of projections was based on national trends as forecast by the WEFA Group and the U.S. Bureau of Labor Statistics. Changes in employment-to-population ratios implied in the national forecasts were tracked in the state-level forecasts, maintaining historical differences between the state and national ratios.

The forecast for total households is obtained from the forecast of population after dividing by average household size. Changes in average household size reflect changes in the age composition of the population and householder rates by age group. The projections are based on national trends as forecast by the U.S. Bureau of the Census. The high and all three medium cases assume that householder rates will continue to increase, but at much slower rates than in the past. This results in part because of increases in the relative cost of housing and in a slowing of increases in the divorce rate. The low case assumes that householder rates do not increase, but average household size decreases slightly because of changes in age composition.

The forecasts of households that result from the assumptions described are shown in Table D-5. The residential model uses forecasts of occupied housing stock as its major input. Change in the housing stock is the result of change in total households plus replacement of existing units. The proportion of new housing units by type is projected for each scenario and each state. The resulting forecast of occupied housing stock is shown in Table D-5.

Residential Demand Forecasts

The projections of residential demand for electricity cover a wide range. This range results mostly from variations in projections of the number of households, per capita income and fuel prices in the economic and demographic growth assumptions. Projected demand also varies because of different assumptions regarding use of wood for space heating. In the absence of new conservation programs, projected residential electricity use in the year 2015 ranges from 9,122 average megawatts in the medium-high case to 7,969 average megawatts in the medium-low case. As shown in Table D-5, the average annual rate of growth, based on the 1994 weather-adjusted actual of 6,443 average megawatts, varies from 1.7 percent for the medium-high case to 1.0 percent for the medium-low case.

Table D-5 provides a summary of historical and projected values of some of the components that determine total demand for electricity.

Table D-5

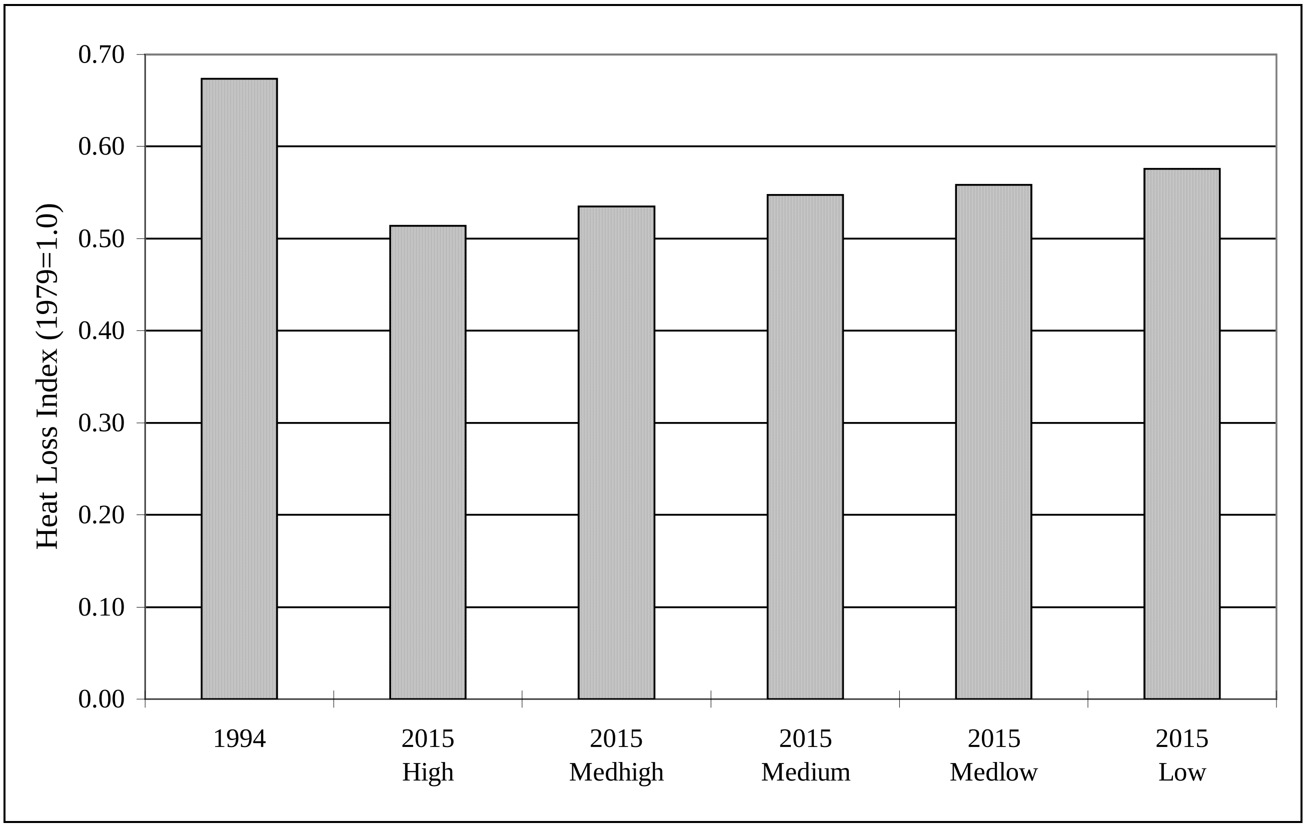
Residential Sector Summary Indicators

	1994	2015	2015	2015	2015	2015
	(Estimate)	Low	Medium	Medium	Medium	High
			Low		High	
Households (millions)	3.783	4.251	4.990	5.317	5.811	7.238
Share by Type						
Single Family	0.729	0.662	0.675	0.692	0.717	0.766
Multifamily	0.155	0.198	0.183	0.178	0.160	0.134
Manufactured Home	0.117	0.140	0.142	0.130	0.123	0.099
Electricity Prices	4.9	4.5	4.6	4.8	5.1	5.6
(1995 cents/kwh)						
Natural gas prices	51.7	50.1	52.8	55.6	61.1	66.7
(1995 cents/therm)						
Heat Loss Index (Electrically heated	0.67	0.58	0.56	0.55	0.53	0.51
Homes, Relative to 1979 stock = 1.0)						
Appliance Use (kwh/unit)						
Water Heat	4,233	3,972	3,991	4,004	4,031	4,076
Refrigerators	1,242	785	794	801	816	833
House Size (Electrically heated, Relative						
to 1979 stock = 1.0)						
Single Family	1.02	1.06	1.05	1.05	1.04	1.04
Multifamily	1.08	1.17	1.16	1.16	1.16	1.16
Manufactured Home	1.27	1.47	1.47	1.48	1.48	1.48
Saturations						
Electric Space Heat (% of all Homes)	59	58	61	62	63	65
Electric Water Heat (% of all Homes)	81	84	82	81	80	77
Total use per Household (kwh)	14,918	14,146	13,989	13,861	13,752	13,456
(All Homes)						
Space Heat Use Per Household	8,806	8,495	8,	8,230	8,139	7,949
(Electrically heated Homes)						
Non-space Heat Use Per Household	9,705	8,645	8,722	8,743	8,785	8,812
(All Homes)						
Space Heat Sales (MWa)	2,251	2,669	3,000	3,107	3,295	3,837
Total Sales (MWa)	6,443	6,864	7,969	8,413	9,122	11,118
Projected Annual Growth 1994-2015		0.30%	1.02%	1.28%	1.67%	2.63%

Thermal Integrity

The forecasts show improving thermal integrity by homes in the region. This is reflected in the heat loss index of electrically heated houses (shown in Table D-5 and Figure D-10), which improves from 1979 levels. The tighter construction of new houses lowers the average heat loss by 2015. The higher growth scenarios have a higher proportion of new houses, so the average heat loss index of the total stock is lower.

Figure D-10
Heat Loss Index of Housing Stock



Thermal integrity improvements reflect residential weatherization programs throughout the 1980s and early 1990s and more stringent building codes that took effect in Washington and Oregon in 1986, 1989 and 1992. In addition to the standards adopted in Washington and Oregon, a building code that obtains 50 to 60 percent of the savings of the model conservation standards has been adopted in Idaho and several local jurisdictions have adopted codes similar to the model conservation standards. Taking these developments into account reduces projected energy use from what it would be otherwise. The Council's estimate of conservation supply still available was reduced accordingly.

Appliance Efficiency

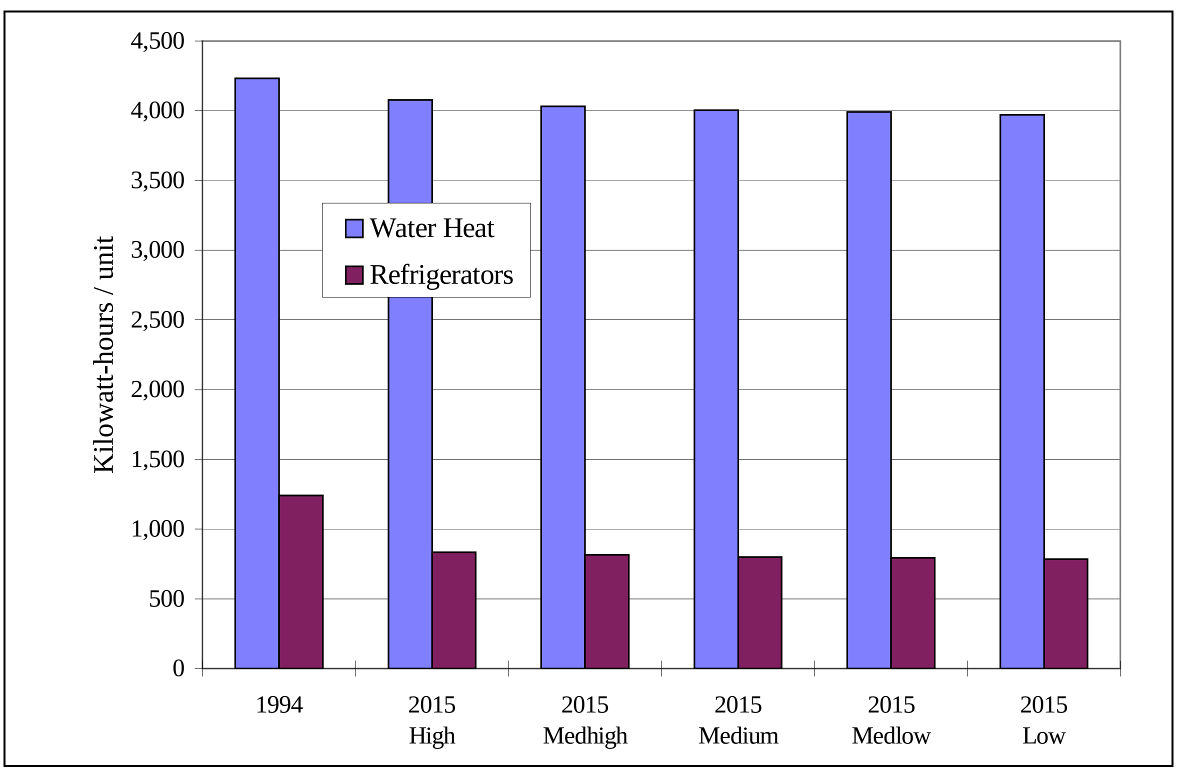
Appliance efficiencies have also improved significantly during the 1980s and early 1990s. For example, in 1972, the average new refrigerator (17 cubic feet, automatic defrost, top-mounted freezer compartment) was estimated to use about 1,600 kilowatt-hours per year. By the early 1980s a comparable new refrigerator was estimated to use about 1,100 kilowatt-hours. The 1990 federal efficiency standard for this average refrigerator is about 900 kilowatt-hours, and the 1993 federal efficiency standard is about 700 kilowatt-hours. Conservation potential still available has been reduced by corresponding amounts.

As time passes and older, less efficient refrigerators wear out and are replaced, the models that meet the 1990 and 1993 federal standards will make up a bigger share of the population of refrigerators. The average efficiency of refrigerators will therefore improve so that, by the end of the forecast period, it will approach the 1993 efficiency standard. This is an example of the long-term adjustment processes that can be expected in response to changes in energy prices and policy decisions that have already occurred. This forecast includes the improvements through 1993. Further cost-effective improvements in appliance efficiencies, described in Appendix A on conservation, are not included in the forecast; instead they are treated as supply-side resources.

Projected improvements in refrigerator and water heat use per unit are shown in Table D-5 and Figure D-11. As in the case of the heat loss index of the housing stock shown above, the appliance stock improves from 1994 to 2015 in all forecast scenarios. However, while the heat loss index varies significantly among forecast scenarios, use per unit of water heaters and refrigerators varies hardly at all from one forecast scenario to another. The main reason for this contrast is the difference in the lifetimes of houses, compared to the lifetimes of appliances. Houses have long expected lifetimes (for example, that of single family houses is 80 years), so that the housing stock in 2015 is a mixture of houses built before the building codes of the late 1980s and early 1990s, and the more thermally efficient houses built since the codes were adopted. The housing stock in the higher growth forecasts have a greater proportion of recently built, thermally efficient houses, and lower average heat loss, than the lower growth forecasts.

By contrast, water heaters have shorter (13-year) expected lifetimes, so that by 2015 all water heaters in the stock will reflect the 1993 federal efficiency standard, in all growth scenarios.   The 2015 stock of refrigerators, with 22-year expected lifetimes, will likewise be made up entirely of purchases since the 1993 federal efficiency standard took effect, in all growth scenarios. The remaining slight differences in use per unit from one forecast scenario to the next is due to differing projected shares of each house type; for example, projected electricity use of refrigerators in multifamily units is less than that of refrigerators in single family houses.

Figure D-11
Appliance Use Per Unit



Fuel Choice

Fuel choice projections have moderate effects on energy use per household. As shown in Table D-5, the shares of households with electric water heating are projected to decrease in higher growth forecasts and increase in lower growth forecasts. Electric space heating shares are projected to be higher in higher growth forecasts and lower in lower growth forecasts. Space and water heating saturations are influenced by electricity prices, per capita incomes and the share of recently constructed houses in the stock. In addition, they are influenced heavily by the relationship of electricity prices to those of competing fuels such as natural gas and oil. The higher growth scenarios have higher electricity prices, but relatively lower prices of electricity compared to competing fuels. This pattern helps explain the higher saturation of electrical space heating in the higher growth scenarios. Fairly stable price projections for both electricity and natural gas contribute to the moderation of fuel choice changes over time and among growth forecasts.

Housing Type

Housing type also influences energy use per household. Table D-5 shows the 1994 estimated shares of the three building types, along with the projected 2015 shares for each of the forecasts. For all but the high forecast, a reduction in the total share of homes that are single-family houses, and increases in the shares of multifamily units and manufactured homes, are projected. This trend has mixed effects on average use per household. For example, multifamily and manufactured housing are more likely to use electricity for space and water heating than are single-family homes. All else equal, a higher share of electric space and water heating raises electricity use per household. However, multifamily and manufactured homes are smaller than single-family homes; so they tend to require less energy to heat and cool.

Use per Household

Electricity use per household is the net result of changes in efficiency, housing type, housing size, utilization levels, fuel choice and interaction between end uses (e.g., lower appliance use can increase space heating requirements). The changes in some of these individual components are substantial, but there is a tendency for them to offset one another in their effects on use per household. For example, efficiencies generally improve, tending to reduce use per household, while the sizes of multifamily units and manufactured homes are projected to increase, thereby increasing the per-household energy requirements for space conditioning. The net effect of several conflicting influences is the projected overall reduction in use per household, greatest in the high forecast, shown in Table D-5.

Summary

When all the influences just described are combined over all house types, end uses and rate pools, the net effect is the observed pattern of relatively small changes in per-household use between scenarios. This means that the variation in total residential demand across the range is due largely to variation in the projected number of households.

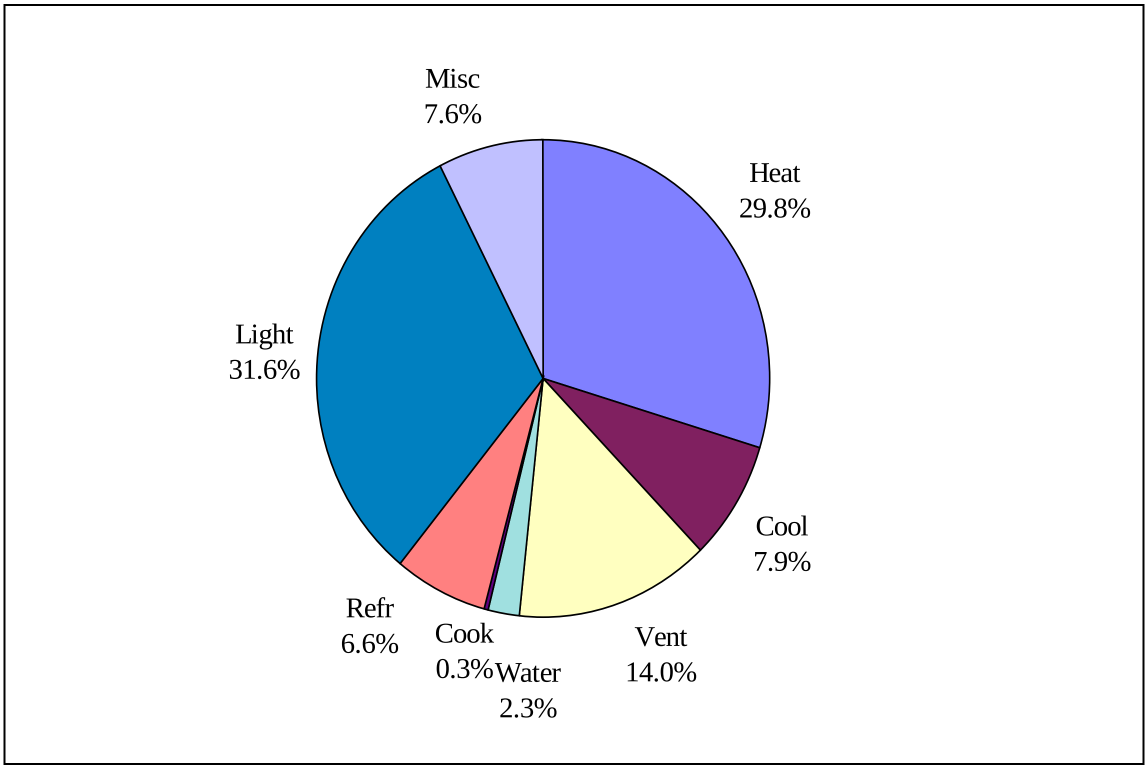
The projection of demand for electricity does not take into account any efforts to achieve cost-effective conservation beyond that projected to occur due to market incentives. The effects of such efforts would cause sales of electricity to grow at slower rates. In addition, the use of electricity per household would decline because of the increased thermal efficiency of buildings and improved appliance efficiencies. The effects of these efficiency increases would be somewhat diminished, however, by the greater use of energy services due to cost savings from improved efficiency. These effects are reflected in the “sales” forecasts that are the basis of the electricity prices used for the “price effects” forecasts.

COMMERCIAL DEMAND

Although currently the smallest of the three major consuming sectors, the commercial sector is the fastest growing, averaging 3.3 percent growth per year since 1980. This rate of growth is more than twice that of total demand by all sectors. The commercial sector has steadily increased its share of regional sales from 16 percent in 1970 to 24 percent in 1994.

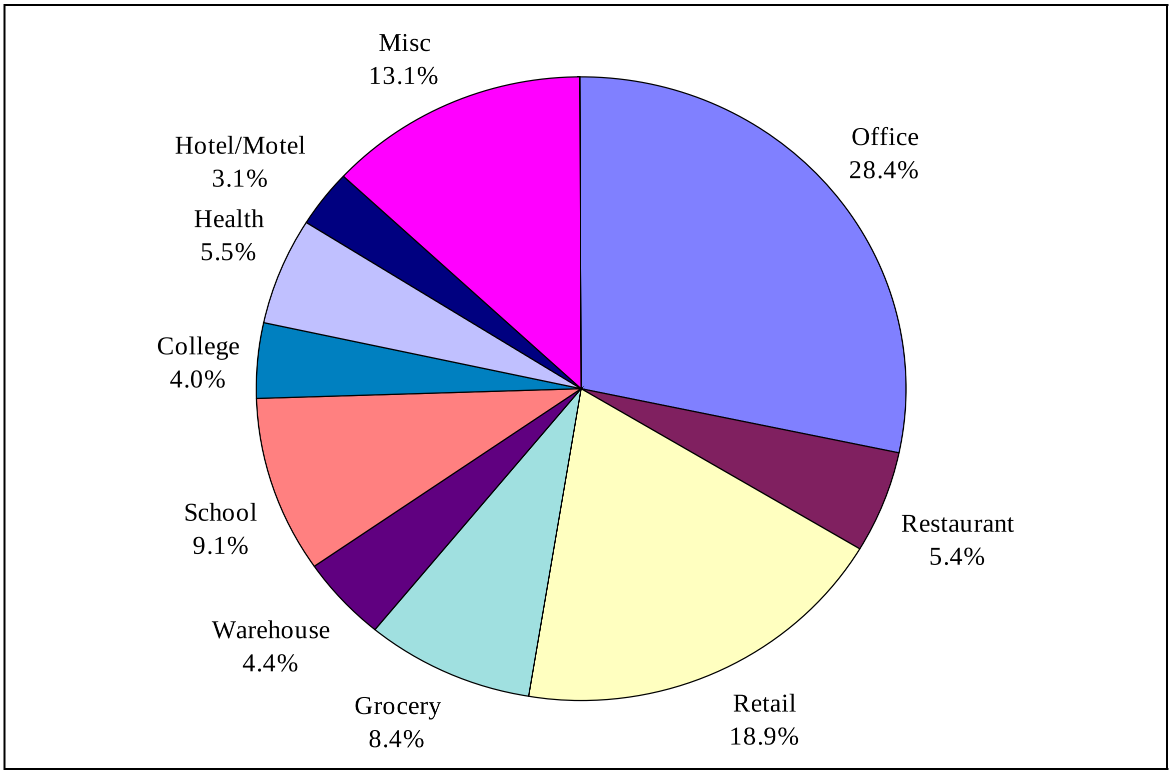
Shares of historical commercial sector demand for electricity for various applications are shown in Figure D-12. Space heating and lighting make up the largest shares of commercial electricity use. If space heating, ventilation and air conditioning are combined, as they commonly are, into an HVAC category, HVAC and lighting account for more than 80 percent of electricity use in the commercial sector.

Figure D-12
Commercial Use by End Use



Commercial sector electricity use is estimated separately for 10 different building types. The consumption shares of these building types are shown in Figure D-13. Offices account for more than one-fourth of electricity use by the sector. Retail buildings are the next largest category, followed by miscellaneous buildings and groceries. More than two-thirds of the sector's electricity use is attributed to these four building types.

Figure D-13
Commercial Use by Building Type



Forecasting Methods

Commercial sector electricity demand, like that of the residential sector, is influenced by many factors, such as fuel prices and available technology. In particular, one fundamentally important factor used as a basis for energy use projections is the total floor space of the buildings in the commercial sector. The commercial sector demand model projects the amount of commercial floor space and then predicts fuel choice, efficiency choice, and the use of the energy-consuming equipment necessary to service this floor space. These choices are based on investment factors, fuel prices and available technology. Energy-use projections are made separately for different building types, applications and fuel types.

Economic Assumptions

The primary economic driver for the commercial sector forecast is employment growth in non-manufacturing industries. Employment forecasts by industry are grouped into categories that reflect the building types used in the commercial sector model. An index of employment growth by building type is multiplied by the initial square footage by building type to produce the forecast.

Table D-6 demonstrates the growth rate assumptions for the various categories of non-manufacturing employment. The largest category of non-manufacturing employment in the region is wholesale and retail trade, followed by services (which includes such industries as health care, business services and personal services). The third largest non-manufacturing industry is government. Since 1980, the fastest growing components of these industries have included social services, engineering and technical services, business services, legal services, food stores, private educational services and health care. It is projected that growth in non-manufacturing will make up most of the growth in employment over the forecast period, as shown in Table D-2.

Table D-6
Non-manufacturing Employment Projections--Average Annual Rate of Growth (%)

	1980-1994		1994-2015	
		Medium Low	Medium	Medium High
Total Non-Manufacturing	2.5	1.4	1.8	2.3
Construction	2.2	1.0	1.3	2.2
Transportation, Communications, and Public Utilities	1.3	0.8	1.0	1.2
Trade	2.6	1.4	1.8	2.4
Wholesale Trade	2.0	0.8	1.2	1.8
Retail Trade	2.8	1.6	1.9	2.5
Food Stores	3.7	1.0	1.4	2.1
Eating and Drinking Places	2.9	2.6	3.0	3.5
Finance, Insurance and Real Estate	1.8	0.9	1.4	2.2
Services	4.6	2.3	2.6	2.9
Hotels and Lodging Places	2.5	1.4	1.9	2.5
Business Services	5.4	3.5	3.8	4.2
Health Services	3.8	2.9	3.1	3.5
Government	1.7	1.0	1.3	1.9
Federal Government	0.2	0.3	0.7	1.3
State and Local Government	2.0	1.1	1.4	2.0

Commercial Demand Forecasts

The resulting projections of commercial demand for electricity vary widely. In the medium-low growth forecast, commercial demand for electricity increases from 4,384 megawatts in 1994 to 5,350 megawatts by 2015. In the medium-high growth forecast, it reaches 6,462 megawatts. As shown in Table D-7, the average rate of growth of demand ranges from 1.0 percent per year in the medium-low forecast to 1.9 percent per year in the medium-high forecast.

Table D-7 shows some of the components underlying these totals. Floor space increases in all forecasts, as a result of increased employment in the commercial sector, and is the major driver of growth in demand for electricity.

Use per Square Foot

Use of electricity per square foot of floor space of all buildings decreases in all growth forecasts. The change in use per square foot from 1994 to 2015 is modest for all forecasts, ranging from a decrease of 7 percent in the medium and medium-high growth forecasts to a decrease of 9 percent in the other growth forecasts. Use of electricity per square foot of office floor space is higher than the average for all buildings together. The projected changes over time of use per square foot are larger for offices than for all buildings together, as well. All forecasts project a decrease in use per square foot over time, ranging from 16 percent in the medium-low forecast to 8 percent in the low forecast.

Table D-7
Commercial Sector Summary Indicators

	1994 Estimate	2015 Low	2015 Medium Low	2015 Medium	2015 Medium High	2015 High
Floor Space (million square feet)	2350.8	2885.5	3145.6	3351.4	3712.3	4462.9
Fuel prices						
Electricity (1995 cents/kwh)	5.0	4.4	4.6	4.8	5.1	5.5
Natural Gas (1995 cents/therm)	52.6	51.2	54.1	57.0	62.7	68.5
Electric Space Heat Saturations						
Office (% of floor space)	76.3	56.2	58.1	61.7	66.5	71.1
All Buildings (% of floor space)	56.6	38.4	41.4	45.4	49.5	52.0
Use per square foot						
Office						
Space Heat (kwh/square foot)	6.6	6.0	5.8	5.8	5.8	5.7
Light (kwh/square foot)	8.1	7.2	7.4	7.3	7.2	7.0
Total (kwh/square foot)	25.6	23.5	21.4	23.4	23.4	22.9
All Buildings						
Space Heat (kwh/square foot)	8.6	9.2	8.6	8.4	8.1	7.7
Light (kwh/square foot)	5.2	4.8	4.9	4.8	4.8	4.7
Total (kwh/square foot)	16.3	14.9	14.9	15.1	15.2	14.9
Total Sales (MWa)						
Heating, Ventilating and Air Conditioning	2,264	2,309	2,496	2,732	3,087	3,639
Light	1,384	1,574	1,745	1,847	2,028	2,379
Total	4,384	4,899	5,350	5,780	6,462	7,605
Projected Annual Growth 1994-2015		0.53%	0.95%	1.32%	1.86%	2.66%

Prices

The pattern of projected electricity prices is lower and more stable than in previous Council plans. The pattern is described in more detail later. A summary for the commercial sector is that higher growth still brings somewhat higher electricity prices, but the increase is quite modest. Electricity prices rise 10 percent from 1994 to 2015 in the high growth forecast. In the medium and lower growth forecasts, electricity prices are projected to decline in real terms; the largest reduction in electricity price is 15 percent in the low forecast by 2015.

The ratio of the price of natural gas to the price of electricity, both prices expressed in dollars per million Btus, is shown in Figure D-14 for actual prices in 1994 and projected prices in 2015. For historical perspective, the average ratio for the decade of the 1980s is also shown. The net effect of the projections of the prices of the competing fuels is that natural gas is relatively more attractive in the lower growth forecasts. All forecasts project the relative price of natural gas in 2015 to be higher than it was in 1994.

Space Heat Saturation

The share of floor space heated by electricity is projected to decrease in all forecasts, in both office buildings and all building types taken together. The decrease is most pronounced in the lower growth forecasts, influenced by prices for natural gas in those forecasts. The general pattern of reduction in electric space heating saturations is different from the forecasts in previous Council plans, in which some of the growth scenarios included increasing electric space heat saturations.

The reduction in electric space heating saturations seem inconsistent with the forecasts' projected increases in the relative price of natural gas from 1994 to 2015. After all, it seems that building owners' fuel choice should move toward the fuel that is becoming less expensive, that is, electricity and electric space heat saturation should increase from 1994 to 2015. But the 1994 electric space heat saturation in commercial buildings is not the final result of a complete adjustment to 1994 fuel prices. Instead, the 1994 saturation is a snapshot taken part way through an adjustment in response to a substantial change in relative prices in the late 1980s and early 1990s.

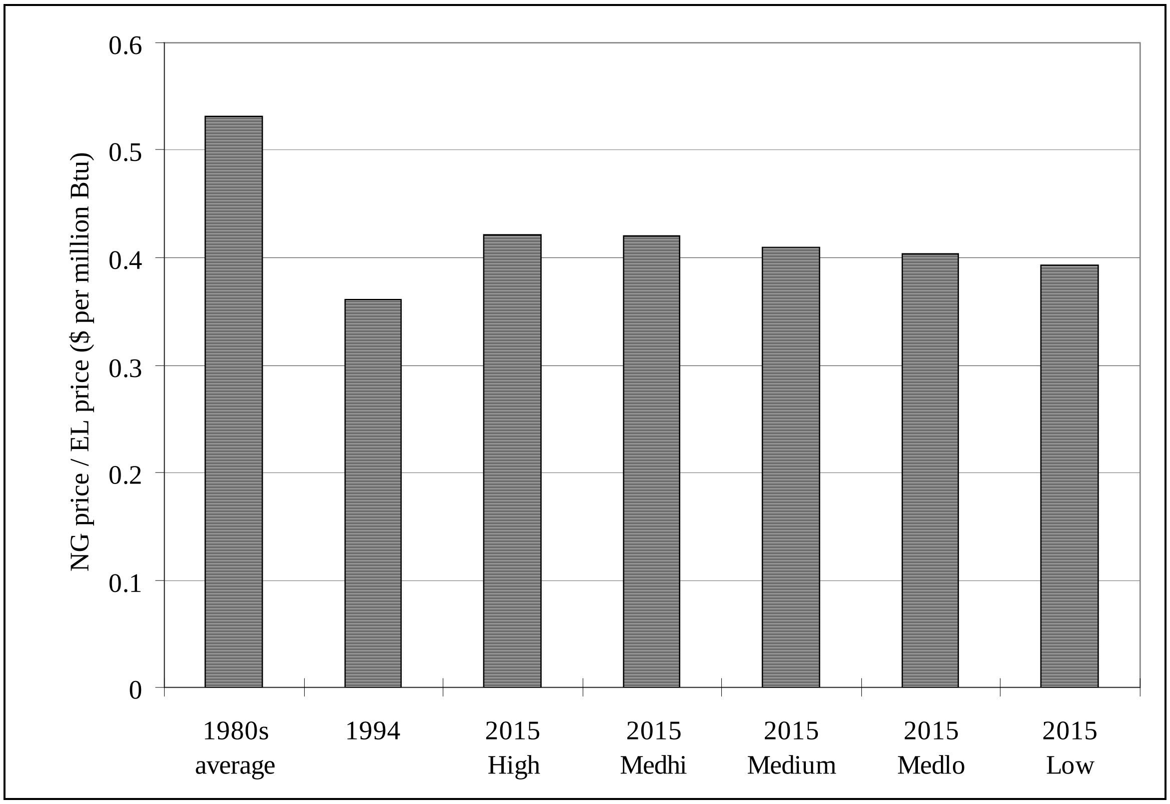
The heating fuel of much of our current stock of commercial buildings was chosen in the 1980s, when natural gas was relatively less attractive than now, as shown in Figure D-14. By 1994, changes in fuel prices had made natural gas much more attractive, and changes in fuel choice in response to the new relative prices had begun. Changes in fuel choice take place most naturally at the time of replacement of heating equipment, which follows the equipment's life cycle,[2] so that a full adjustment takes a number of years. Unless prices have been stable for a long time, changes in heating fuel saturations may appear to be unreasonable until adjustment lags are taken into account. Taking these lags into account, even though we project the attractiveness of natural gas to diminish from its 1994 level, buildings are likely to be moving from electricity to natural gas as a heating fuel for some years to come.

As pointed out earlier, the electricity price projections reflected in our commercial forecasts are based on traditional rate-making conventions, most importantly, kilowatt-hour prices that reflect average costs. Electricity is quite likely to be priced differently in the future, which could change the relative attractiveness of electricity and natural gas. As changes in pricing occur and are incorporated into the Council's pricing model, the demand forecasts will change as well.

As in the case of the residential sector forecasts, these projections of demand for electricity do not take into account additional efforts to achieve cost-effective conservation, beyond existing codes and standards and efficiency improvements that are projected to occur due to market incentives. The effects of such efforts would cause sales of electricity to grow at slower rates. The effects of such additional efficiency increases would be somewhat diminished, however, by the greater use of energy services due to cost savings from improved efficiency. These effects are reflected in the "sales" forecasts.

[2] The Council's commercial sector forecasting model simulates 18 years to replace the existing stock of heating equipment. As a result, the model takes 18 years to simulate a complete adjustment of the building stock's fuel choice, in response to a change in fuel prices.

Figure D-14
Relative Commercial Sector Price of Natural Gas to Electricity



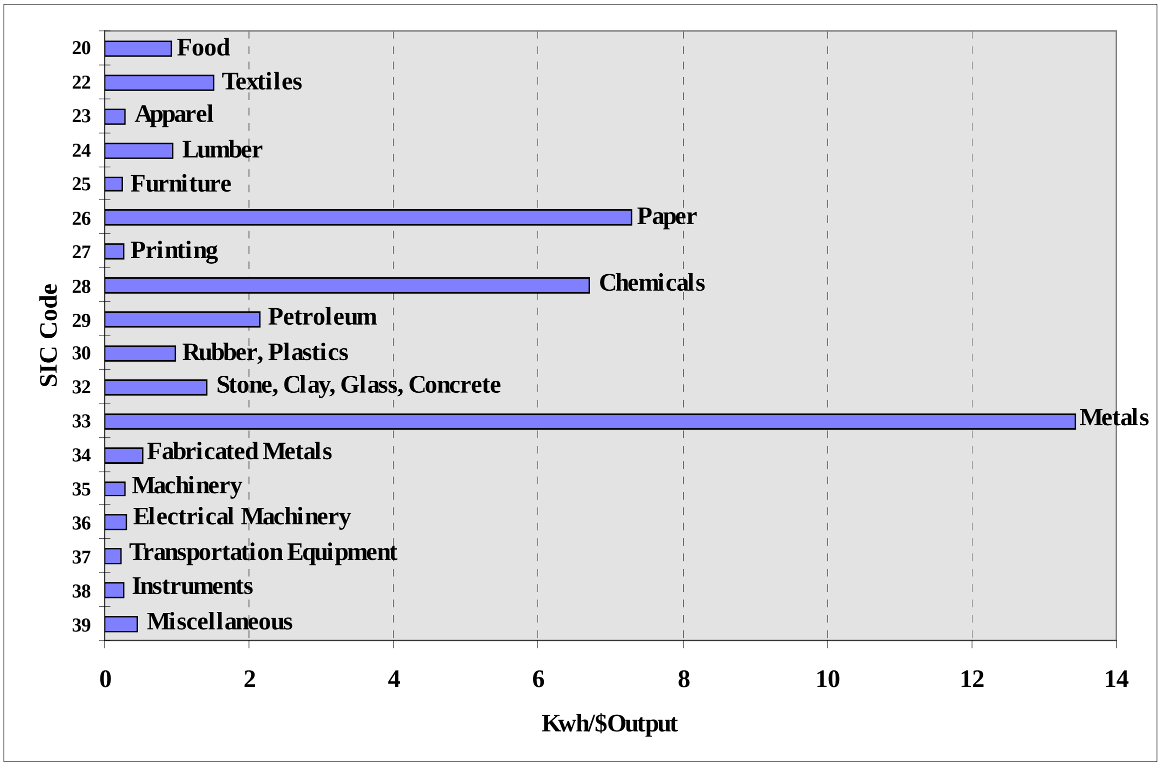
INDUSTRY

Introduction

The industrial sector is the largest of the four consuming sectors. In 1994, the industrial sector consumed 6,674 average megawatts of firm power, accounting for 36 percent of total firm demand in the region. In addition to the firm power, the industrial sector consumes varying amounts of interruptible, or nonfirm, power depending on economic and hydroelectric conditions. In 1994, industry consumed 139 average megawatts of interruptible, or nonfirm, electricity, which is well below typical levels because of restricted sales due to poor hydroelectric conditions in 1994.

Unlike the residential and commercial sectors, where the uses of electricity are similar in different houses or buildings, the industrial uses of electricity are extremely diverse. It is very difficult to generalize about the end uses of energy or the amounts of energy used in a "typical" industrial plant. For example, the primary metals industry uses about 60 times as much electricity per dollar of value-added (a measure of output) as the transportation equipment industry. Even within these broad industry categories, plant configurations and processes can be radically different. To further complicate matters, there is very little reliable information on production and energy use for industrial subsectors on a regional basis. After the early 1980s, availability of data was further reduced by Census Bureau budget cuts. Figure D-15 shows the electric intensity of manufacturing industries in the Pacific Northwest in 1980, one of the last years that reasonable amounts of data were available and the year in which the forecasting models are based.

Figure D-15
Electricity Intensity of Manufacturing Sectors, 1980



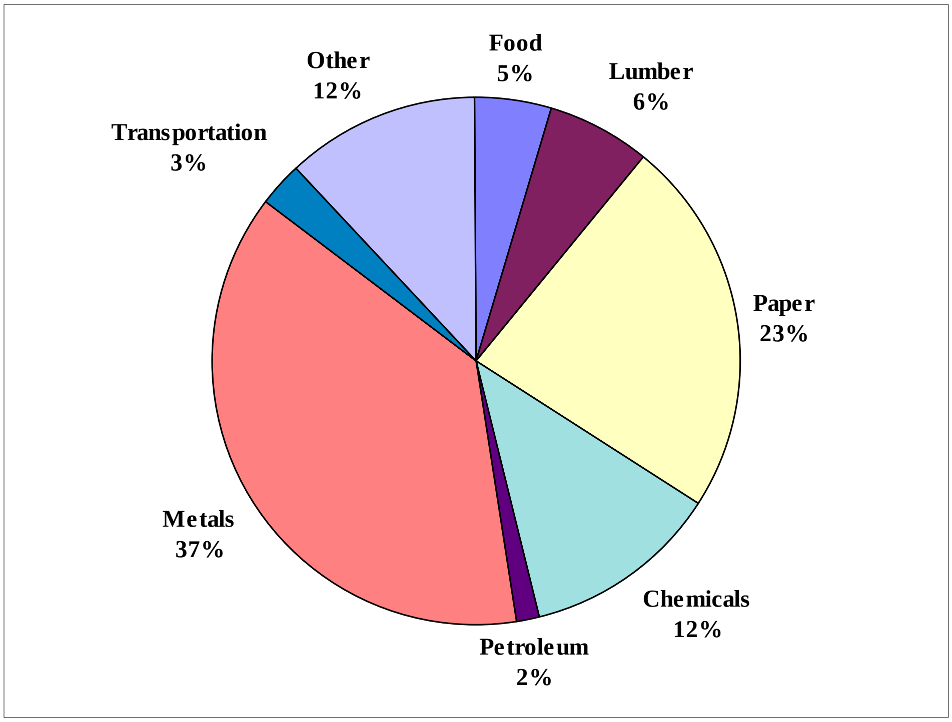
The significant variations in energy intensity are evident in Figure D-15. Primary metals, paper, and chemicals use far more electricity per dollar of value-added than other industries. Six other industries use between 1 and 2 kilowatt-hours of electricity per dollar of value-added. These include food, textiles, lumber, petroleum refining, rubber and plastics, and stone, clay, glass, and concrete.

The total industrial use of electricity in the Northwest is highly concentrated in a few subsectors. Five industries -- food, chemicals, paper, lumber and metals -- account for over 80 percent of industrial use of electricity. Figure D-16 illustrates the composition of firm industrial demand for electricity based on the forecast for 1995. Metals production alone accounted for a third of firm industrial electricity use, and the paper industry accounted for nearly a quarter. Although, as shown in Figure D-15, food and lumber are not particularly electricity intensive, they account for significant amounts of electricity consumption because of the size of the industries. The same is true of transportation equipment, dominated by Boeing, which is one of the least electricity intensive sectors in terms of kilowatt-hours per dollar of value-added. The “other” category includes 12 other 2-digit-SIC (standard industrial classification) industries.

Over 80 percent of firm electricity use in the metals industry is by Bonneville’s direct service industry customers, primarily the region’s 9 operating aluminum smelters. These aluminum smelters dominate the direct service industry sales, accounting for about 95 percent of that total. Bonneville’s direct service industrial customers accounted for about a third of total industrial demand for electricity in 1995, or about 12 percent of firm regional sales to all sectors. One-fourth of the direct service industry demand is considered nonfirm demand, or interruptible demand. If Bonneville were to have a shortage of energy, for example, due to poor water conditions, it could withhold service for one-fourth of the direct service industry demand. Only the firm portion of direct service industry demands are included in the Council’s forecasts of energy requirements. However, the interruptible portion of direct service industry demand is considered in system operation and electricity pricing analyses.

Figure D-16

Composition of Firm Industrial Electricity Demand by Standard Industrial Classification Code, 1995



Economic Drivers

Forecasts of industrial demand for electricity are based on production forecasts for the various manufacturing sectors combined with the effects of electricity and other fuel prices. For the large electricity-using sectors of lumber and wood products, pulp and paper products and chemicals, physical measures of production are forecast. For the other manufacturing industries, production is in value-added terms.

In overall terms, manufacturing output is projected to increase at a rate of 3.9 percent per year in the medium case. This compares to a rate of 4.2 percent per year over the period 1980 to 1994. While the overall rate of growth is fairly strong, the outlook for individual industries varies quite significantly. This has an important impact on electricity use, since a few industries account for most of the electricity use in the industrial sector.

The forecast for lumber and plywood production is based on the U.S. Forest Service forecasts for producing regions using the Timber Assessment Market Model. The forecast takes into account current plans for federal lands in the northwest states. The Northwest is a primary producing region for lumber and plywood in the U.S. accounting for nearly 40 percent of U.S. softwood lumber production and 25 percent of U.S. structural panel production. By 1994, lumber production levels had dropped more than 20 percent from the high levels of the late 1980s. Between 1994 and the end of the forecast period, medium case production is expected to drop further, then recover slightly, so that by the year 2015, lumber production in the region is forecast to be nearly 30 percent below the level of the late 1980s. By 1994, structural panel production had dropped by nearly 40 percent below the level of the 1980s. Further cuts are incorporated in the forecast but most of the reduction has already occurred. For both lumber and plywood, even the high case does not include production levels as high as those experienced in the late 1980s. Forecasts of production for the medium high, medium and medium low cases are shown in Table D-8.

The forecast for pulp and paper production is derived from older forecasts developed by Ekono, Inc. for the Bonneville Power Administration. The forecasts have been reduced somewhat because of changes in the availability of raw materials and issues related to water effluence from the plants. In contrast to the forecasts for the lumber and plywood industries, the forecasts of pulp and paper products include increases in output for all cases. This is because of the use of increasing amounts of recycled content, new wood and other raw material sources, as well as the strong growth in demand for paper products worldwide. Forecasts of production for the medium high, medium and medium low cases are shown in Table D-8.

Two primary components of the chemicals industry forecasts are the outlook for chlorine and caustic soda and for elemental phosphorous. Chlorine and caustic soda is used in a variety of production processes, but the primary use in the Pacific Northwest is for the bleaching of pulp and paper products. The forecast is based on the outlook for paper products. Elemental phosphorus is used primarily in detergents and cleansers, food and beverages, metal treating and other chemicals. The outlook for these markets is mature, and environmental considerations have put a damper on growth in demand. Forecasts of production for the medium high, medium and medium low cases are shown in Table D-8.

Table D-8

Forecasts of Production for Large Electricity-Using Industries, 1994 - 2015

Industry	**Medium High**	**Medium**	**Medium Low**
Lumber	-0.5	-0.9	-1.4
Plywood	-0.1	-0.8	-1.3
Pulp	1.3	0.8	0.4
Paper	2.4	1.6	1.1
Paperboard	2.0	1.4	0.9
Chlorine and Caustic Soda	2.3	1.6	1.0
Elemental Phosphorus	0.8	0.3	-0.2

The forecasts for two other manufacturing industries should be mentioned. These are electronics, which includes Machinery (SIC 35), Electrical Equipment (SIC 36) and Professional Instruments (SIC 38), and Transportation Equipment, which is dominated by Boeing. These industries are not large electricity-using industries, but they are significant in terms of employment in the industrial sector.

Electronics is the region’s largest manufacturing employer, followed by transportation equipment. The electronics industry has been experiencing a boom over the last two years, with numerous announcements of new plant locations and expansions in the Northwest. This will give a short-term boost to employment in this sector, and growth is projected to be strong in the long term as well. Commercial aircraft production dominates transportation equipment employment in the region. This industry has been highly cyclical over the past 30 years. Currently, employment levels are low because of low profits in the airlines industry. The outlook is projected to be strong, although it will probably continue to be highly cyclical. Table D-9 shows employment forecasts for these industries.

Table D-9
Employment Forecasts for Major Manufacturing Industries

Industry	Medium High	Medium	Medium Low
Transportation Equipment	0.8	-0.1	-1.7
Electronics	2.5	1.8	0.8

Forecasting Methods

The methods used to translate industrial production, electricity and fuel price forecasts into future industrial demands for electricity vary substantially among the industry subsectors. These approaches were documented in the 1991 and earlier power plans and are only described in general terms here.[3] There are several different methods applied to the industrial demand forecasts. More detailed methods are used for the larger electricity-consuming industries, and simpler less-detailed methods are used for smaller consuming sectors. All of these methods, however, rely primarily on the predicted growth of production in the sector. The exception is the direct service industries. The DSI forecasts were based on work done by Bonneville for the 1991 Power Plan and have not been updated since the 1991 plan.

Industrial Demand Forecasts

Table D-10 summarizes the industrial demand forecasts for the most likely range. Total industrial electricity use is forecast to grow between 0.5 and 2.3 percent per year. The growth of the non-DSI sector is significantly faster, reflecting the fact that there is expected to be little growth in DSI demand in the future. In the medium case forecast, industrial demand by 2015 increases by 2,614 average megawatts from the 1994 level. This increase, averaging about 125 average megawatts a year, accounts for 44 percent of the average annual growth in firm electricity demand for all sectors in the medium forecast.

Table D-10
Industrial Demand Forecast Summary (Average Megawatts)

	Actual	Forecast	Forecast	Growth Rate
	1994	**2005**	**2015**	**1994-2015**
Non-DSI				
Medium Low		5317	5810	1.1
Medium	4599	5925	7152	2.1
Medium High		6568	8547	3.0
Total Firm				
Medium Low		6898	7391	0.5
Medium	6674	8061	9288	1.6
Medium High		8868	10848	2.3

The direct service industry forecasts can be characterized as assumptions about the percent of DSI contract capability that remains in operation during the forecast period. The way that Bonneville arrived at these assumptions involved several approaches and was described in the 1991 Power Plan. The electrical use capability of the DSIs is about 3,300 average megawatts. If the DSIs were operating at this capacity three

[3] Northwest Power Planning Council, 1991 Northwest Conservation and Electric Power Plan, Vol. 2, Part 1, pp. 228-232.

fourths of the demand, or 2, 475 average megawatts, would be considered firm demand. The medium forecast is for DSI firm demand to be about 2,135 average megawatts per year. This is close to the experience since the 1991 Power Plan. The medium high forecast, at 2,300 average megawatts, is just a little higher than the medium case, but the medium low forecast is significantly lower at 1,580 average megawatts. The high case explores the case where DSI loads remain in the region at near full utilization while the low case assumes only a quarter of the DSI load remains competitive.

The treatment of the DSI loads in resource planning does not follow the low to high pattern described for the demand forecasts. The ISAAC model includes a random choice for DSI load levels for any given demand forecast path. As a result, DSI loads are uncorrelated with the other demand cases. For example, a high DSI forecast could be combined with a low forecast for non-DSI loads or vice versa.

The forecasts reflect a continued decline in the overall electricity intensity of the manufacturing sector. Since 1980 total regional industrial electricity use per real dollar of value added has declined at 3.8 percent a year. Similar trends have been observed at the national level. Analysis of the national level trends show that a significant amount of the decline results from changing industry mix rather than decreases in the electricity intensities of individual industry subsectors. For example, the primary metals industry, which is not only the largest electricity using industry nationally but also the most electricity intensive, actually experienced a decline in output since 1980. In addition, primary metals was one of a few industries that experienced declining intensities. Generally, the national experience reflected slow growth of large and intensive electricity-using industries and growing shares for less electricity intensive industries. Although a few industries, like primary metals, experienced declining intensities individually, most have not shown significant trends in intensity.

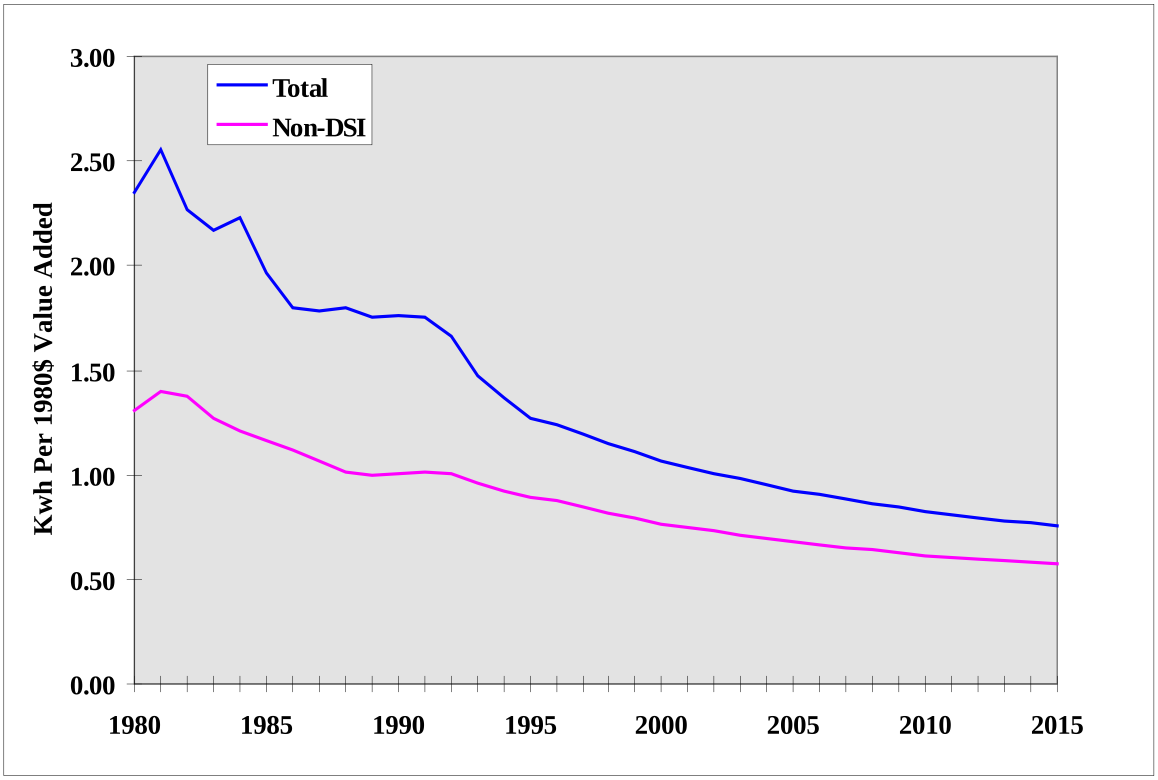
Tracking changes is a little more difficult at the regional level due to poor-quality data. It is clear that the highly electricity-intensive aluminum industry has played a role in the rate of decrease in regional energy intensity. The rate of decline in non-DSI industrial electricity intensity was only 2.4 percent a year compared to the 3.8 percent rate of decline for the total industrial sector including DSIs. The growth of other electricity-intensive sectors has also been modest compared to the growth of some of the less electricity-intensive sectors.

The region’s declining industrial electricity intensity since 1980 was accelerated by the very dramatic increases in electricity prices that occurred around 1980. While the price levels are forecast to be relatively stable, the shifts away from the most electricity-intensive sectors is forecast to continue. As a result, the forecasts exhibit continued, although less steep, decreases in industrial sector electricity use per dollar of value added. Total electricity intensity in the medium case decreases an average of 2.7 percent a year and non-DSI intensity decreases at 2.3 percent annually. Figure D-17 illustrates these trends.

It is clear from Figure D-17 that the DSI load volatility has had an effect on the patterns of energy intensity historically. The smooth forecast assumption of DSI demands eliminates this volatility in the forecast period, but, in reality, volatility is likely to continue to characterize DSI demands in the future.

The sectors forecast to increase most rapidly in their electricity use include electrical machinery, machinery other than electrical, rubber and plastics, and miscellaneous manufacturing. Particular attention was paid to the forecast for the electrical machinery industry (SIC 36). This industry includes, among other activities, semiconductors and related devices. The region, and particularly Oregon, has been very successful in attracting several large plants to produce computer chips, silicon wafers, and microprocessors. Eighteen such plants have been confirmed, 12 in Oregon and three each in Washington and Idaho. These plants are highly electricity intensive, using from 2 to 4 kilowatt-hours per dollar of value added compared to the existing average SIC 36 intensity of only 0.3 kilowatt-hours per dollar of value added. The forecasts had to be modified to add about 230 average megawatts of demand to account for this growth.

Figure D-17
Electricity Intensity Continues to Decline in the Industrial Sector. (Medium FC)



The fastest growing industries are not among the highly electricity-intensive sectors. The large and intensive electricity consumers, primary metals, paper, and chemicals, are the three slowest growing sectors after lumber. Lumber has also been a large consumer of electricity historically although it is not electricity intensive. These changing growth patterns play a significant role in reducing aggregate industrial electricity intensity over the forecast period.

IRRIGATION

In 1994, 722 average megawatts of electricity were used for irrigation, less than 4 percent of total regional firm electricity sales. For several decades, Pacific Northwest irrigation sales climbed rapidly and steadily. However, after 1977 they became more erratic and leveled off. The average annual rate of growth of on-farm and Bureau of Reclamation irrigation electricity use from 1970 to 1977 was a robust 13 percent per year. From 1977 to 1987 there was no net growth, reflecting increased electricity and water conservation and a slowing down in the development of new irrigated land. Since 1987 irrigation sales have increased, but this is at least partially due to a series of dry years.

The historical pattern of irrigation electricity demand is shown in Figure D-18 and compared to the medium-low to medium-high forecast range. The numbers for 1994 and selected forecast years are shown in Table D-11. The forecast growth rates are shown from a 1994 base to be consistent with other tables in this appendix. However, since 1994 was a high irrigation demand year, the growth rates are understated compared to what would be a normal weather forecast. For example, the medium forecast growth rate from the forecasted 1995 base would be 0.7 percent a year compared to 0.2 on the actual 1994 base.

Figure D-18
Electricity Use for Irrigation, History and Forecast

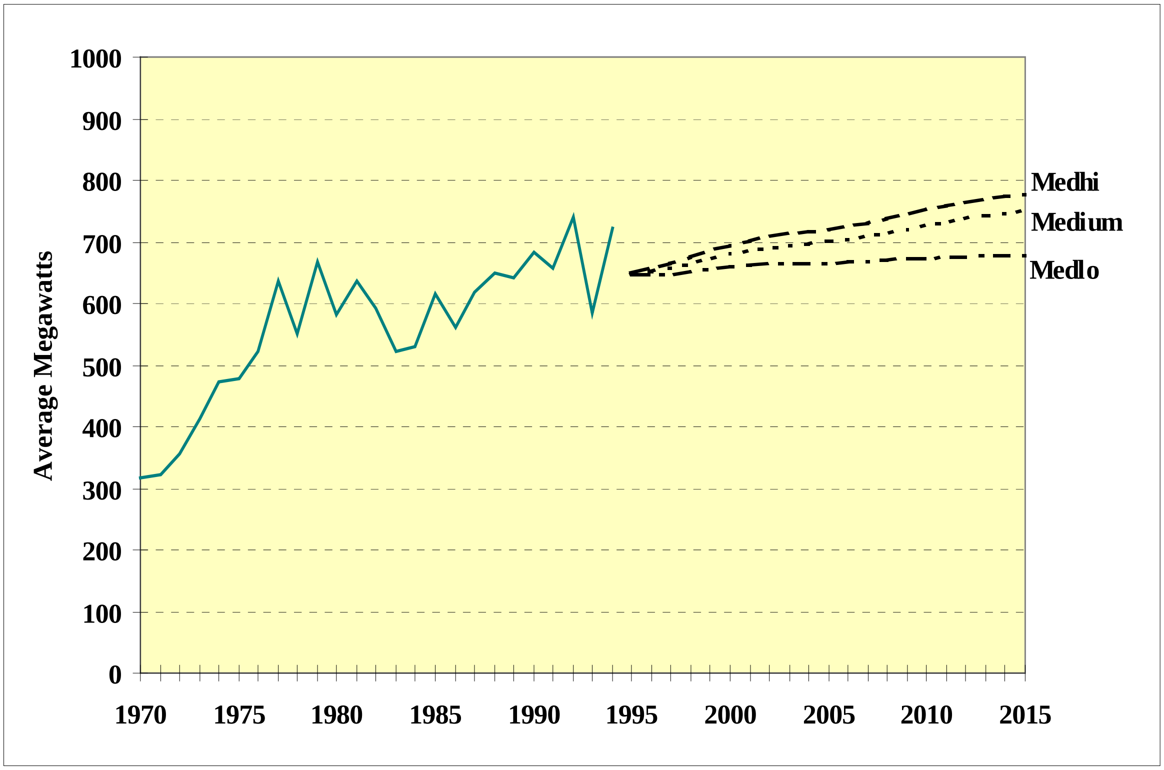


Table D-11
Irrigation Demand Forecasts

	Actual	Forecast	Forecast	Growth Rate
	1994	**2005**	**2015**	**1994-2015**
Medium Low		666	677	-0.3
Medium	722	700	750	0.2
Medium High		720	778	0.4

Forecast Concepts

Treating conservation as a resource creates interactions among demand forecasts and resource choices that complicate analysis. For example, conservation actions that planners think are available resource choices may also be taken by consumers in response to increasing electricity prices. Double counting of this conservation must be avoided in planning. In order to avoid such problems, some innovative analytical methods have been developed.

For example, three different demand forecast concepts are used in resource planning. Most presentations and publications, including this chapter, describe "price effects" forecasts. Price-effects forecasts show what the demand for electricity would be if customers were to respond to price, but no new conservation programs were implemented. Price-effects forecasts reflect current state building codes as of 1995 and federal appliance efficiency standards, but do not assume further adoption of the Council's model conservation standards.

An important factor affecting price-effects forecasts is what resource mix is assumed in developing the electricity price that is provided to the demand models. The electricity prices that determine the price-effects forecast are based on a second concept of demand--a “sales” forecast. A “sales” forecast is a forecast of the demand for electricity after the effects of the model conservation standards and other conservation programs have been taken into account. This is the amount of electricity that would actually be sold by utilities if conservation programs were implemented and savings realized.

The third demand concept, the “frozen-efficiency” forecast, attempts to eliminate double counting of conservation actions that are taken by consumers in response to price, but which could also be achieved through the proposed conservation programs. Frozen-efficiency forecasts, as the name implies, hold the technical efficiency of energy use constant at current levels for uses where conservation programs are proposed. This eliminates the part of consumer price response that could potentially be double-counted as conservation program savings.

The three forecasts for the high scenario are illustrated in Figure D-19. Table D-12 shows the growth rates for the three forecast concepts for each of the forecast scenarios. The price-effects growth rates are the same as those shown in Table D-12 and Figure D-19. The frozen-efficiency growth rates are slightly higher because part of the demand decreases due to price response have been eliminated. The differences between price-effects and frozen-efficiency forecasts are relatively small because prices are not forecast to increase much in most forecast scenarios. Demand growth is significantly lower for the sales forecasts than for the other two forecasts, reflecting potential conservation savings from the Council’s programs. The differences between the frozen-efficiency and sales forecasts are smallest in the low case because only new building standards savings are acquired and relatively few new buildings are constructed.

Figure D-19
Comparison of Medium-High Forecast Concepts

The difference between the highest forecast (the frozen-efficiency forecast) and the lowest (the sales forecast) is the total effect on electricity demand of conservation resources. The price-effects forecast divides that total effect into two parts, that which would result from price response and the incremental effect of conservation programs. The difference between the frozen-efficiency and price-effects forecasts represents the price response portion. The difference between the price-effects and the sales forecasts represents the incremental program impacts. The results of the forecast indicate that very little of the cost-effective conservation would be achieved, under current regional electricity pricing practices, without a strong conservation program effort.

Table D-12

Growth Rates Different Forecast Concepts

(Average Annual Rate of Growth, 1994-2015)

	Sales	Price Effects	Frozen Efficiency
Low	-0.2	-0.2	-0.2
Medium Low	0.5	0.7	0.8
Medium	1.1	1.3	1.4
Medium High	1.6	1.9	1.9
High	2.4	2.7	2.8

Electrical Loads for Resource Planning

Demand forecasts serve as the basis for resource portfolio analysis. This section describes what forecast concepts are used and how they are modified for resource planning analysis.

For resource portfolio analysis, the decision analysis model (ISAAC) uses frozen-efficiency forecasts of demand in order to avoid counting conservation potential twice. However, several adjustments are made to these forecasts before they are used for resource planning.

First, demand forecasts are converted to load forecasts by adding transmission and distribution losses. The demand forecasts are for consumption of electricity at the point of use, while loads are the amount of electricity that needs to be generated. More electricity has to be generated than is actually consumed by utility customers, because some electricity is used or lost in the transmission and distribution of power. The demand forecasts are converted to loads based on historical average losses. These losses are about 8 percent.

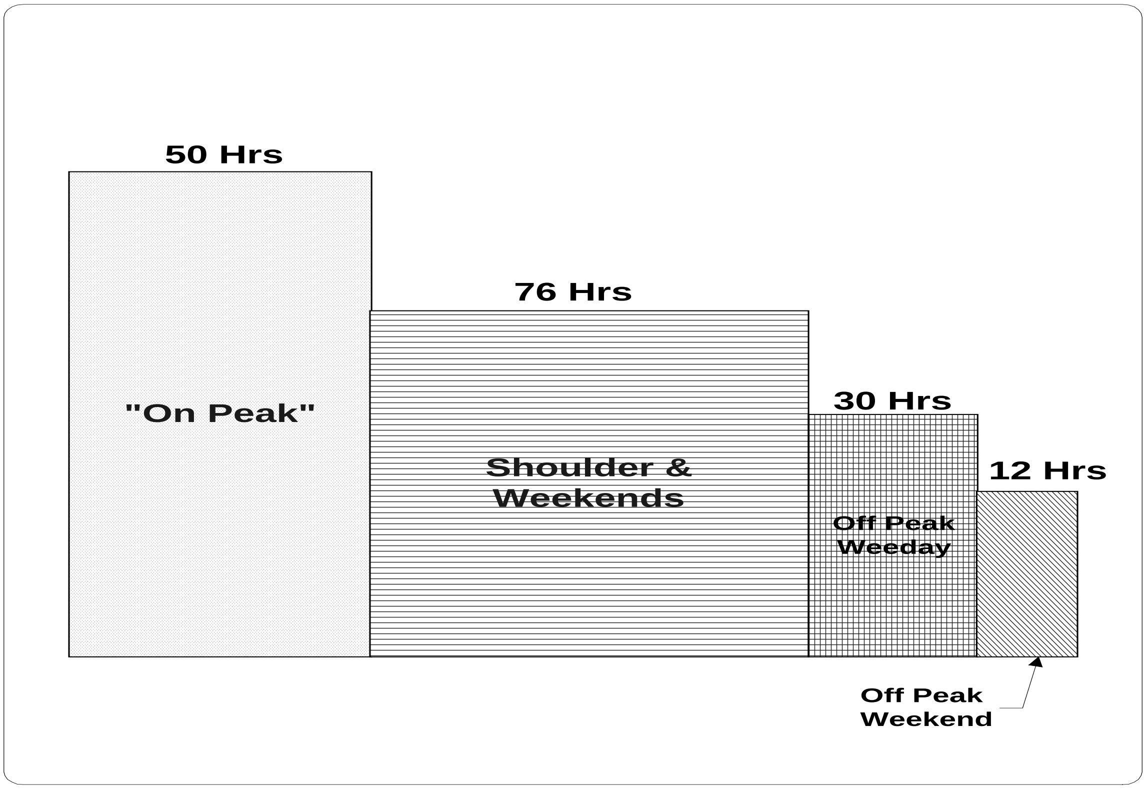
Second, resource analysis is done on an operating year basis. Since the demand forecasts are done on a calendar year basis, the demands must be converted from a year that begins in January to a year that begins the previous September. This is done by calculating a weighted average of the previous and current calendar years. The previous year receives a one-third weight, and the current year a two-thirds weight. In addition, for resource planning, the forecasts were set to actual values for operating year 1994.

In the demand-forecast range, the forecasts of direct service industry demand for electricity are shown as a range of demand levels associated with specific forecast scenarios. The direct service industry loads are treated differently, however, for resource planning. The decision analysis model (ISAAC) embodies an aluminum forecasting submodel. This model forecasts levels of aluminum demand that depend on a randomly selected level of aluminum prices, as well as electricity prices and other costs of production. Aluminum prices are not assumed to be correlated to general economic conditions. As a result, levels of aluminum demand, instead of being associated with particular demand scenarios as they are in the demand forecast ranges described here, are independent of demand scenarios. The aluminum model was calibrated to result in the same range of aluminum loads as those in the demand forecasts, but they are not associated with particular demand conditions. This better reflects the various counterbalancing influences that are likely to affect the aluminum industry under specific scenarios.

Finally, Federal agency and non-aluminum direct service industry loads are entered into the decision model separately from other loads, and do not vary by scenario. Most of these adjustments have been automated in the Load Forecasting System.

Hourly load shape information also is used differently in the resource decision model. For resource planning in the Pacific Northwest, sustained peaking requirements are more important than the hourly peak. To capture the sustained peaking needs, ISAAC groups the hours in a typical week into four categories; on peak, shoulder, off-peak, and minimum load. Peak hours are defined as weekday loads between 8:00 AM and 6:00 PM. Shoulder hours include weekdays from 4:00 AM to 8:00 AM and from 6:00 PM to 10:00 PM. Shoulder hours also include daytime weekends from 4:00 AM to 10:00 PM and midday holidays from 8:00 AM to 6:00 PM. Off-peak hours are defined to include weekday nights from 10:00 PM to 4:00 AM and holidays between 5:00 AM and 8:00 AM and between 6:00 PM and 9:00 PM. Minimum load hours include weekend nights from 10:00 PM to 4:00 AM and holiday nights from 9:00 PM to 5:00 AM. Sorting hourly loads into these categories permits estimation of a weekly block load duration curve as conceptually illustrated in Figure D-20.

Figure D-20
Block Load Duration Curve



ELECTRICITY PRICE

Introduction

Electricity prices are an important determinant of electricity demand growth, but electricity prices are also affected by demand growth. As new demands are placed on utilities or other generators, new sources of power must be added through conservation, new generation, or imports of power from outside the region. These additional sources of electricity have costs that affect the price of electricity. Price forecasts are based on a model that simulates the addition of new sources of electricity to the existing system and calculates new estimates of future electricity prices.

The resources added to the system generally match the resource strategy in the draft plan. However, since the demand forecasts must be completed before the resource analysis, the resources are not an exact match. Because electricity prices are not sensitive to small variations in resource type, the approximation is a good one.

Methods and Assumptions

Retail electricity price forecasts are produced by an electricity pricing model that is part of the Council's demand forecasting system. The model develops forecasts of retail prices by sector for investor-owned and public utilities. The prices are forecast through a detailed consideration of power system costs, secondary power sales, forecast assumptions, and the provisions of the Pacific Northwest Electric Power Planning and Conservation Act (the Act).

The Council's electricity pricing model contains capacity and cost information on both generating and conservation resources. Cost and capacity of the federal base hydroelectric resources are included as a total. However, most other resources are treated on an individual basis. Capability of each resource is specified for critical water conditions and for peak capacity. Capital cost and operating costs are specified for each generation resource. For conservation resources, only those costs that are to be paid through electric rates are included. The effects of conservation programs are generally predicted directly in the various demand models, although in some cases the savings are included as a resource within the pricing model and subtracted from demand there.

The costs of generation and conservation are added up and allocated to the various owners (Bonneville and investor-owned and public utilities). The costs of resources used to provide power to customers of Bonneville, public utilities and investor-owned utilities are combined to reflect contractual agreements among utilities and the exchange and other provisions of the Act. The model develops forecasts of wholesale power costs for three Bonneville rate pools--priority firm, direct service industries and new resources. Similarly, costs are developed for investor-owned and public utilities. Retail markups are added to these costs to obtain estimates of retail rates for each consuming sector of each type of utility.

As demand grows, resources are added to meet demand, and the new resource costs are melded with existing resource costs. The pricing model balances resources and demand based on critical water capacities. However, the effects of different water conditions on secondary energy and electric rates are simulated by the pricing model. The operation of the hydroelectric system on a monthly basis over 40 historical water years is the basis of this simulation. When there is surplus hydroelectric power in any month for a specific water year, the model allocates that secondary power to various uses according to a set of priorities specified in the model assumptions. These uses in the assumed order of priority are, 1) serve the top quartile of direct service industry demand, 2) shut down combustion turbines, 3) sell outside the region, and 4) shut down other thermal generation.

For purposes of the pricing model, firm surpluses are added to secondary power and allocated using the same priorities. If the region is in a deficit situation, instead of surplus, the model will use secondary power and, if necessary, import power at a pre-specified price until additional resources can be added to meet demand.

The revenues from sales of secondary power and firm surplus power, or the costs of importing to cover deficits, are averaged over months and water years to obtain estimates of expected prices of power given uncertain water conditions.

The methodology of the electricity pricing model was designed for a regulated price world. It is essentially a cost recovery model. Although the general structure of the model could not be changed, several significant changes were made to the model to better reflect current power markets.

The National Marine Fisheries Service 1995 Biological Opinion significantly changed operation of the river toward more priority on fish and less on power value. These changes in operation affect the availability of firm power and the patterns of secondary energy availability. A revised secondary energy table was included in the pricing model to reflect the 1995 Biological Opinion. As the Council has observed in its analysis of fish and wildlife programs, more stringent river operations tend to create problems in meeting firm load at specific times of the year and under specific water conditions. These show up as negative secondary energy availability. The pricing model had to be modified to deal with these shortfalls on a monthly basis. Previously, firm surpluses or deficits were dealt with on an annual basis. Now, when the power system is in balance on an annual basis, it may still need to import power during specific months and water conditions.

Another modification was to phase out the residential exchange between 1995 and 1999. The availability of low cost replacement power to Bonneville will result in a phasing out of the exchange. Recently Congress has directed Bonneville and its customers to work out an agreement to phase out the exchange by 2001.

Anticipating that imported power from the southwest U.S. would be an attractive long-term energy source, the pricing model was balanced to about a 3,000-average-megawatt deficit. The model will then import power when sufficient secondary is not available to cover this deficit. This, combined with the monthly balancing of power supplies described above, makes the representation of the import market price more important. The staff's analysis of the Southwest power market was used to develop a supply curve for imported electricity and a demand curve for exported electricity.[4] This allows the price of the imported power to vary depending on market conditions. Essentially, the more power the region sells to California, the lower the price. Similarly, the more power the region buys from California, the higher the price. The import price of electricity also has a real escalation rate designed to reflect the decreasing surplus in the Southwest and the increasing environmental requirements to be phased in there.

A final change to the price model was one to allow changes to retail markups over time. Retail markups are the difference between wholesale costs, as estimated by the model, and retail rates. Historically, the markups are used to calibrate the model to actual retail prices. In previous plans there was only one markup per sector and utility type that stayed constant in real prices over time. Expecting that restructuring of the electricity market would result in changes to utility costs and allocations among customer classes, the model was modified to allow annual markups. The forecasts reflect a reduced retail markup in the industrial sector over time but relatively little change in residential and commercial markups. The assumption is that utilities will be able to achieve increased efficiencies over time and that industrial customers are most likely to benefit in the early stages of competition.

[4] An Analysis of Western Power Markets, Northwest Power Planning Council Issue Paper 95-19, November 2 1995.

Price Forecast

Lower natural gas prices and improved gas turbine technology and costs have had a significant effect on electricity prices. The forecasts are, of course, lower, but they are also less sensitive to regional growth. In past Council plans, electricity price forecasts were very sensitive to growing demands. This resulted in a wide range of forecasts depending on the demand case being evaluated. The forecasts in this draft plan no longer reflect a large degree of sensitivity to the rate of demand growth. In essence, the new resources available to meet growing demands are no longer dramatically higher in cost than the existing power system resources. Lower electricity price forecasts are also related to reliance on 3,000 average megawatts of imported power at low prices and an assumption that utilities will not be able to support as large a share of conservation costs as in the past.

The forecasts are essentially for stable electricity prices. Table D-13 and Figure D-21 show average retail prices for the region. The low, medium-low, and medium forecasts are very similar, declining slowly in real terms. The medium-high case declines some in the early years but increases after 2000 leaving it at about its current level by 2015. Only the high case shows some real escalation throughout the forecast, but its growth rate is only 0.5 percent a year.

Table D-13
Retail Electricity Price Forecasts

	Low	**Medium Low**	**Medium**	**Medium High**	**High**
Forecast (Mills/Kwh, 95$)					
1994 (Estimated)	41.7	41.7	41.7	41.7	41.7
2005	39.2	38.7	38.9	40.5	43.0
2015	37.6	38.0	39.1	41.9	46.5
Growth Rates (%)					
1994-2005	-0.5	-0.6	-0.6	-0.3	0.3
1994-2015	-0.5	-0.4	-0.3	0.0	0.5

Figure D-21
Retail Electricity Prices

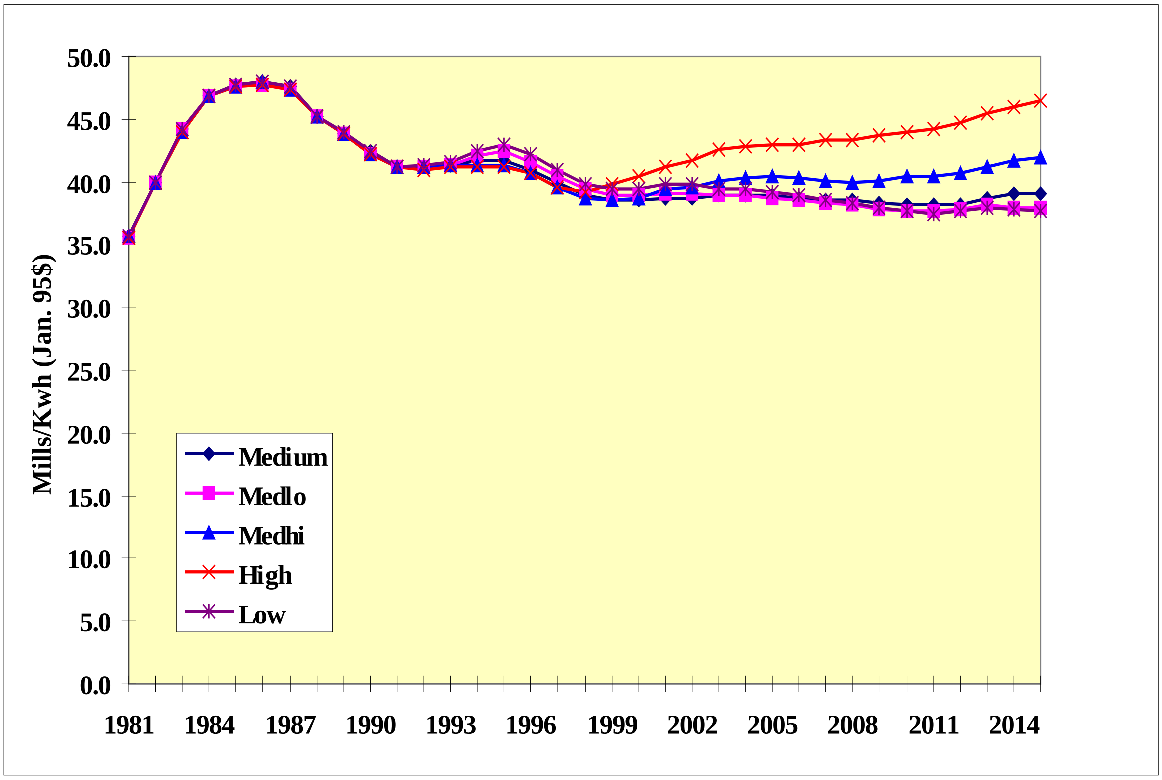
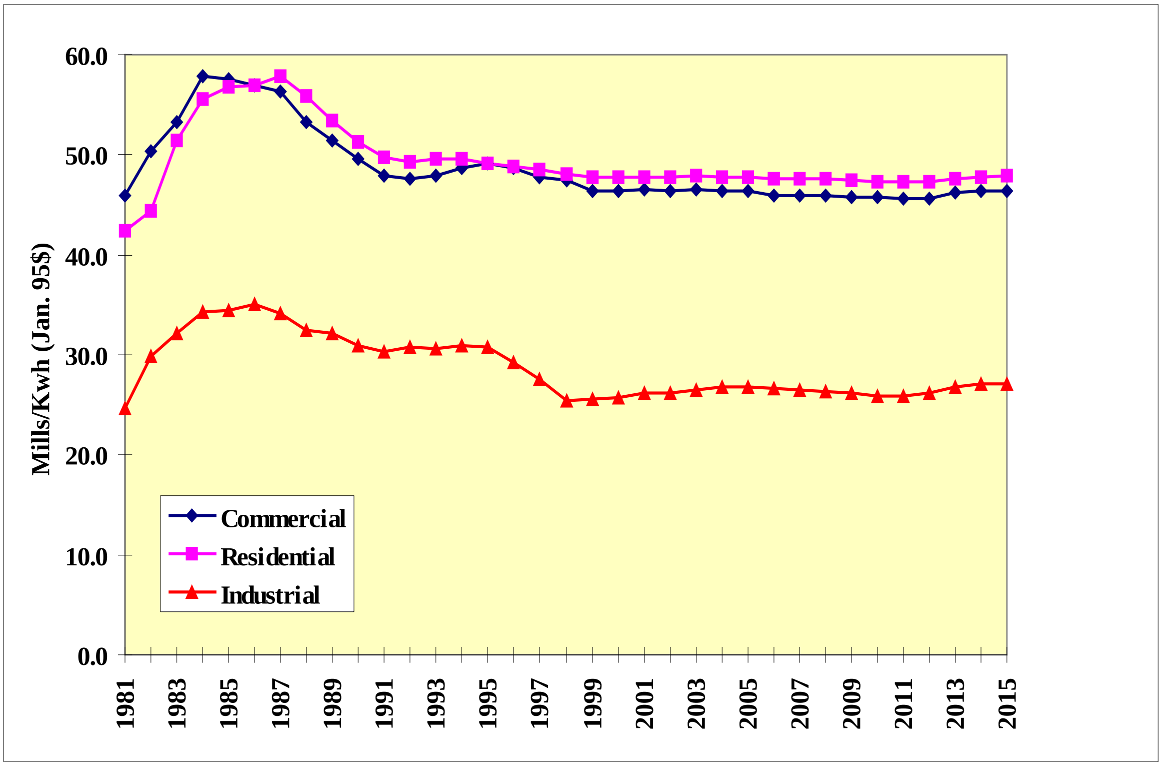


Figure D-22 shows electricity price forecasts for the medium case by consuming sector. The assumption that industrial customers will be able to improve their price relative to residential and commercial customers in the early years of competitive markets is reflected in this graph. Following this initial adjustment, the sectors all can expect stable real electricity prices over time if the forecast is correct.

It is quite possible that the opening up of competition in wholesale electricity will result in improvements in efficiency beyond those reflected in the modified price model. Progress in opening up retail markets to competition could result in even further efficiency improvements. The price forecasts here do not reflect any significant efficiency increases, nor is the basic pricing structure of electricity changed from the cost of service approach. As a result there is a chance that electricity price growth could turn out even lower than the forecasts in this draft plan. To some extent this would be self correcting in the forecast. Lower prices would stimulate more rapid demand growth, but there is still some growth penalty expected, and that would increase prices as the demand grows faster.

Figure D-22
Retail Price Forecasts by Sector, Medium Case



One-page summary tables for each forecast scenario and each forecast concept follow. There are five forecast scenarios from low to high and three forecast concepts; sales, frozen efficiency, and price effects. Thus, there are fifteen tables in total. Following the forecast summary tables are five tables for the detailed industrial sector forecasts. The industrial tables are price effects or frozen efficiency because there is no difference between these two cases in the industrial sector.

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