Fuel Price Forecasts

INTRODUCTION

Fuel prices affect electricity planning in two primary ways. They influence electricity demand because oil and natural gas are substitute sources of energy for space and water heating, and other end-uses as well. Fuel prices also influence electricity supply and price because oil, coal, and natural gas are potential fuels for electricity generation. Natural gas, in particular, has become a cost-effective generation fuel when used to fire efficient combined-cycle combustion turbines. This second effect is the primary use of the fuel price forecast for the Council's Fifth Power Plan.

Traditionally, the Council has developed very detailed forecasts of electricity demand using models that are driven by economic, fuel price, and technological assumptions. For a number of reasons, the Council has chosen to retain many elements of its long-term demand forecasts from the Fourth Power Plan, making modifications as needed to reflect significant changes that might affect the long-term trend of electricity use. Therefore, the fuel price assumptions did not directly drive the demand forecasts of this power plan.

The fuel price forecasts do affect the expected absolute and relative cost of alternative sources of electricity generation. Through their effects on generation costs, they also largely determine the future expected prices of electricity.

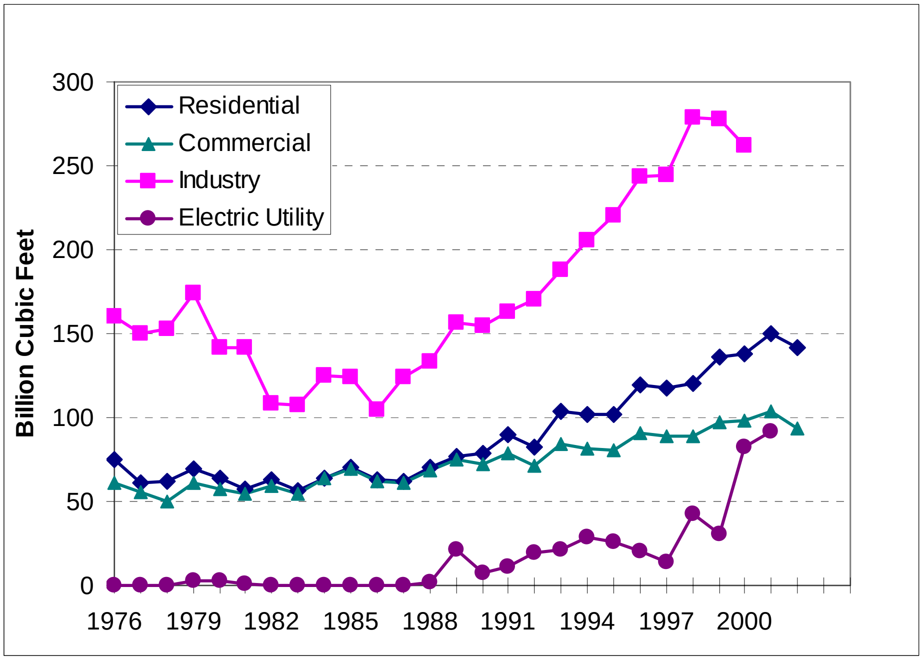
The forecast describes fuel price assumptions for three major sources of fossil fuels: natural gas, oil, and coal.

NATURAL GAS

Historical Consumption and Price

In 2000, the Pacific Northwest consumed 581 billion cubic feet (bcf) of natural gas. About 45 percent of this natural gas was used in the industrial sector, which included electricity generation by non-utility power plants. About a quarter of the natural gas use was in the residential sector and about 17 percent was in the commercial sector. In 2000, electric utilities consumed 83 bcf of natural gas, or about 14 percent of the regional total natural gas consumption. Utility natural gas consumption in 2000 was nearly three times the amount consumed in 1999, and it remained high in the early months of 2001. However, natural gas use for electricity generation was extraordinary in 2000 and early 2001 due to the electricity crisis in the West. Generating plants normally used only for extreme peak electricity needs were operated for much of the winter of 2000-2001. However, new gas-fired generation has been constructed and planned recently, which will increase normal levels of gas use for electricity generation.

The regional consumption of natural gas has grown rapidly over the last several years. Between 1986 and 2000 regional natural gas consumption grew 6.8 percent a year, more than doubling natural gas consumption over a 14-year period. Figure B-1 shows natural gas use by sector since 1976. After 1986, all sectors grew, but the industrial sector, which included independent electricity generation, accounted for nearly half of the increase in gas consumption and grew at a higher rate than residential and commercial use. Increasing electric utility use of natural gas is also apparent in Figure B-1.



Source: Energy Information Administration and NPCC calculations.

Figure B-1: Pacific Northwest Natural Gas Consumption

The rapid growth in natural gas use since 1986 coincided with a period of ample natural gas supplies and attractive prices, coupled with strong economic growth in the region. Figures 2a and 2b illustrate the Pacific Northwest natural gas prices and consumption since 1976 for the residential and industrial sectors. High natural gas prices and a severe economic downturn in the early to mid-1980s kept natural gas consumption low. However, following the deregulation of natural gas prices in the late 1980s, prices fell and demand began to grow rapidly. Natural gas displaced oil and other industrial fuels for economic and environmental reasons during this time. Higher electricity and oil prices for residential consumers combined with lower natural gas prices made natural gas a more attractive heating fuel for homes.

The most significant trend in natural gas markets has been the increasing use of natural gas for electricity generation. This is a relatively recent trend, but attracts a lot of attention because of expectations of rapid growth in the future. Figure B-1 shows some use of natural gas for electricity generation by electric utilities in the region since 1988. It increased recently, but is still a relatively small amount of the total natural gas used in the region. Non-utility electricity generators have used additional natural gas, but, until recently, the data did not allow it to be broken out from overall industrial sector natural gas use. Given the level of concern about natural gas supplies, and the potential for a greatly increased use for electricity generation, it is worth understanding the current and potential role of natural gas in electricity generation.

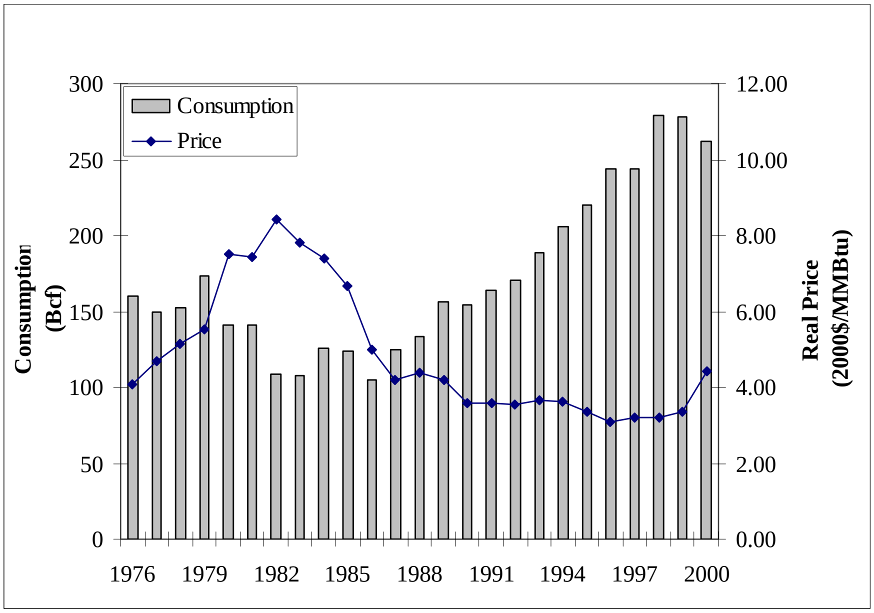


Figure B-2a: Pacific Northwest Industrial Natural Gas Consumption and Price

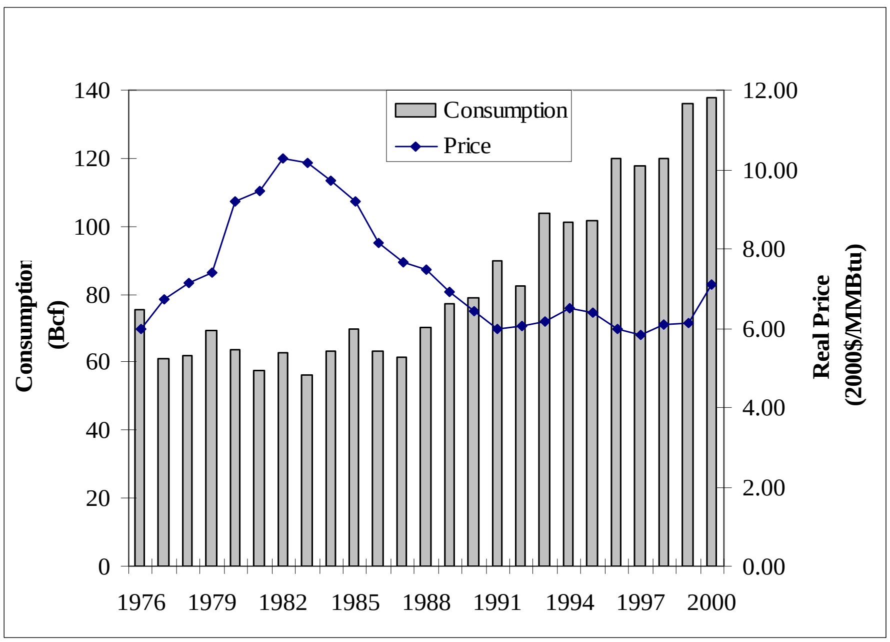


Figure B-2b: Pacific Northwest Residential Natural Gas Consumption and Price

Natural gas currently accounts for only 13 percent of the region's electricity generation capacity. In terms of average energy generated, the share is higher at 20 percent. That is because the hydroelectric capacity, which dominates the region's generating capacity, is limited in its annual production by the amount of water available so that its share of average generation is much lower than its capacity rating.

At the end of 1999 there were 38 plants that could generate electricity using natural gas with a combined generating capacity of 3,400 megawatts. Over half of this capacity (2,000 megawatts) had been built since 1990. Sixty percent of this capacity was owned by electric utilities and two-thirds of the capacity is located west of the Cascade Mountains. Many of these plants have the ability to burn other fuels such as wood waste, refinery gas, or oil.

If all of the plants using natural gas as their primary fuel were operating, they would be able to burn 668 million cubic feet of natural gas per day. Plants on the West side could burn as much as 476 million cubic feet per day. For perspective, this can be compared to the total capacity to deliver natural gas to the I-5 corridor on a peak day in 2004, which was estimated to be 3,760 million cubic feet per day.[1] If operated continuously for a year, the region's gas-fired generators in 1999 could burn 242 billion cubic feet of natural gas. This compares to an estimated 2001 total regional natural gas consumption of 670 billion cubic feet.

However, gas-fired generating plants in the region have not operated for a large part of the year, nor have they typically operated during peak natural gas demand events. This is partly due to the fact that in most years there is surplus hydroelectricity in the region. For example, utility-owned natural gas-fired generating plants in place at the end of 1999 had the capability to burn 141 billion cubic feet a year if operated at an 85 percent capacity factor on natural gas. However, as shown in Figure B-1, utilities only consumed 30 billion cubic feet of natural gas in 1999. In other words, utility-owned gas-fired generating facilities only consumed 20 percent of their capability in 1999. If the non-utility electricity generating capacity were assumed to operate at the same relative rate, they would have consumed only 14 billion cubic feet out of the 262 billion cubic feet of total industrial consumption in 1999.

In 2000, natural gas consumed for utility-owned electricity generation increased dramatically from 30 billion cubic feet in 1999 to 83 billion cubic feet. Non-utility generation from natural gas increased as well, but by a smaller percentage. This was not a result of additional gas-fired generation capacity being added in 2000. It was in response to the energy crisis of 2000 and the extremely high electricity prices that accompanied it. Existing gas-fired generation was operated far more intensively than normal because it was very profitable to do so.

Significant amounts of gas-fired generation have been added in the region since 2000. In 2001 an additional 1,176 megawatts of gas-fired generation capacity was put in service in the region, a 32 percent increase in gas-fired generation capacity. Another 1,330 megawatts was added in 2002, and an additional 1,560 megawatts in 2003. This new gas-fired generation will have a substantial impact on natural gas consumption in the region. According to the U.S. Energy Information Administration, the four Northwest states used 132 billion cubic feet of natural gas for electricity generation in 2003. This accounted for nearly a quarter of all natural gas consumption in the region.

In the past, most natural gas-fired electricity generation in the region has not operated on firm natural gas supplies and delivery. By buying interruptible service, the cost of natural gas could be reduced substantially. When interruptions came, during peak natural gas demand times, most of the plants, even if running, could switch to alternative fuels. Increasingly, new gas-fired generation plants are intended to operate at a high capacity factor and are more likely to use firm natural gas supplies and transportation.

The use of interruptible demand is a key feature in the ability of the natural gas industry to meet peak day demands for its product. Figure B-3 illustrates the role of interruptible consumers in meeting peak day natural gas demand.[2] The use of natural gas storage withdrawal and the injection

[1] 2004 Regional Resource Planning Study, Terasen Gas., July 2004.
[2] Based on Regional Resource Planning Study, BC Gas Utility Ltd., July 10, 2001.

of liquefied natural gas into pipelines are also used to meet peak requirements and help to increase the capacity utilization of natural gas pipelines.

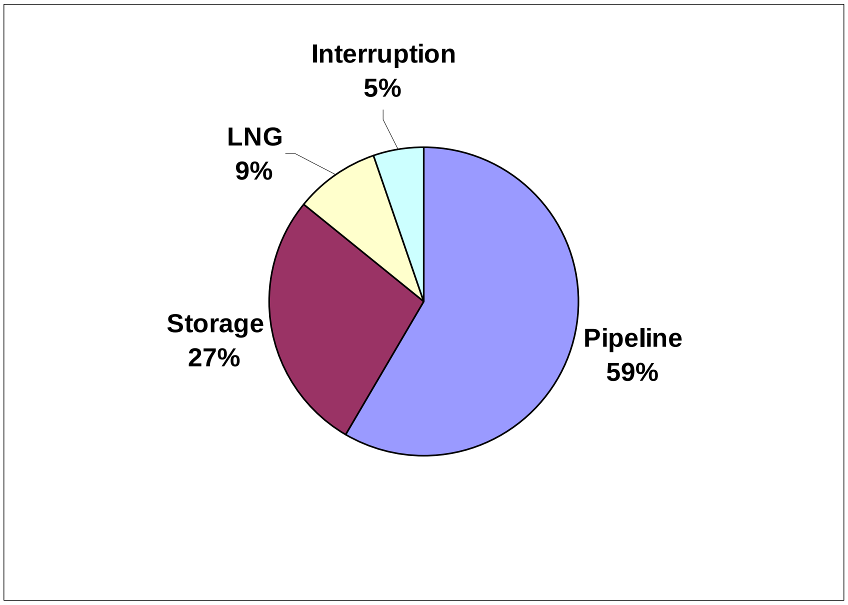


Figure B-3: Contributions to Peak Day Natural Gas Supplies

With a growing share of natural gas demand expected to be firm electricity generation, the share of interruptible demand may fall as a percent of total demand. This is likely to increase the value of other strategies for meeting peak gas demand such as storage and LNG injection. To the extent that increased gas-fired electricity generation turns out to add substantially to highly variable natural gas demand, the overall capacity factor of natural gas consumption would decrease. Lower capacity factors mean that, in general, the cost of natural gas on a per unit consumed basis could increase as fixed capacity costs are spread over a smaller amount of consumption per unit of capacity. This is not the only possibility, however. If many new gas-fired generating plants operate at a high capacity factor, or if they tend to operate more in the summer, they could have the opposite effect. They could partly offset the highly seasonal demand of the residential and commercial sectors, which peaks in the winter, and raise the overall capacity factor of the natural gas system.

In the summer of 2000, the use of natural gas-fired generation changed substantially on the West Coast. Poor hydroelectricity supplies and a growing electricity generating capacity shortage caused electricity prices to increase by a factor of 10 or more. The extremely high electricity prices made it attractive to burn gas for electricity generation; it was very profitable, and the electricity was badly needed to meet electricity demand. As a result, the use of natural gas on the West Coast for electricity generation increased dramatically. For example, it has been reported that California generators consumed 690 billion cubic feet of gas in 2000 compared to a normal consumption of 270 billion cubic feet.[3] Much of this increase in natural gas use began in the summer when natural gas use is typically lower and natural gas is injected into storage for use during the next winter heating season.

The problem created in natural gas markets may be some indication of the effects of the predicted growth of natural gas use for electricity generation in the future. In many regions, electricity use peaks in the summer. Growing use of natural gas for electricity generation has the potential to

[3] Natural Gas Week, Vol. 17, No. 18 (April 30,2001).

change the traditional seasonal patterns of natural gas storage and withdrawals. Less than expected storage injections in the summer and fall of 2000 led to concerns about natural gas shortages for the winter and pushed prices for natural gas to levels not seen since the early 1980s. This problem was especially severe in California, and combined with pipeline capacity strains, pushed prices in the West to several times historical levels.

However, the dramatic increase in the use of natural gas in existing generation plants in 2000 and early 2001 clearly had an exaggerated effect on natural gas markets and prices. Due to the sudden and severe shortage in electricity supplies and unprecedented electricity prices, the natural gas delivery system in the West was pushed far beyond normal operational patterns. Thus, the impacts on natural gas prices were more severe than should be expected from an orderly development of additional natural gas demands for electricity generation.

Although total natural gas consumption only recently returned to the levels of the early 1970s, substantial growth is now being projected due to growing plans for electricity generation. The U.S. Energy Information Administration is forecasting a growth in natural gas use of 1.4 percent per year for the next 20 years.[4] Residential and commercial natural gas use is projected to grow modestly at about 1 percent per year. Industrial sector use is projected to grow at 1.5 percent annually, but natural gas use for electricity generation is projected to grow by about 1.8 percent a year. The EIA forecasts would result in total U.S. natural gas consumption increasing from the current level of about 23 trillion cubic feet per year to 32 trillion cubic feet in 2025.

As an example of the possible effect of increased gas-fired electricity generation in the Pacific Northwest, complete reliance on natural gas-fired generation to meet a projected electricity demand growth of 1.0 percent a year for the next 20 years could add 217 billion cubic feet of natural gas consumption to the current 559 billion cubic feet per year. A modest 1.5 percent growth in other sectors' natural gas use could add another 147 billion cubic feet of new natural gas use in the region over the next 20 years. Meeting this demand would require continued expansion of natural gas supplies, pipeline capacity, and other elements of the natural gas delivery system, such as storage. Recent experience indicates that it will be increasingly difficult to expand North American natural gas production to meet increased demand. New sources of supply are likely to cost more and raise natural gas prices well above the levels enjoyed during the 1990s.

Natural Gas Resources

Natural gas is created by natural processes and is widespread. Most current recovery methods attempt to exploit natural geologic formations that are able to trap natural gas in concentrated pockets. However, natural gas occurs in more dispersed forms as well. Eventually, it is likely to become possible to recover natural gas from some of these formations. Coal bed methane is a good example. Substantial amounts of natural gas are often associated with coal deposits. In the last several years methods have developed, with some government incentives, to extract the natural gas from coal formations, and this coal bed methane has made substantial contributions to the natural gas supplies in the Rocky Mountain area. It now accounts for about 7.5 percent of U.S. natural gas production.[5] Expansion of natural gas supplies increasingly will have to move into these less conventional areas, increasing costs. The amount of increase depends a great deal on technological developments in the exploration and recovery field.

[4] U.S. Energy Information Administration, Annual Energy Outlook 2004.
[5] U.S. Geological Survey. "Coal-Bed Methane: Potential and Concerns." USGS Fact Sheet FS-123-00 (October 2000).

The availability of natural gas to meet growing demands is a key issue. Assessing natural gas resources is a confusing and difficult exercise. There is no absolute answer to the question of how much natural gas there is and how long it will last. Traditionally, the question has been approached on a North American basis, although Mexico has not traditionally played a large role. With the potential for increased use of liquefied natural gas (LNG) imports and exports, the market could become international, similar to current oil markets. Meanwhile, it may be instructive to look at North American natural gas resource estimates in a fairly traditional way.

There are two main categories of natural gas supplies. "Reserves" refers to natural gas that has been discovered and can be produced given the current technology and markets. Reserves are developed as needed by drilling wells in areas that are expected to hold natural gas producing potential. Reserves are often confused with the ultimate potential natural gas "resources," which is the second category of natural gas supplies. Natural gas "resources" are more speculative than reserves, and resource estimates are more uncertain. They are based on assessment of geologic structures, not direct drilling results. Resource estimates are speculative estimates of natural gas that could be developed with known technology and at feasible costs. Reserves are more like the amount of natural gas resource that has been developed and is available to be produced within a relatively short period. Reserves should be thought of as an inventory of natural gas to be produced and marketed within a few years.

Natural gas reserves have decreased relative to consumption levels since the deregulation of natural gas supplies and changes in Canadian export policies in the 1980s. Some have taken this decline as an indication that we are running out of natural gas. In reality, it is a result of reducing inventory holding costs as a response to increased competition. It is similar to the new approaches to other kinds of inventory in the modern economy where businesses hold down inventory storage time and costs. In Canada, it was also influenced by elimination of a rule that required Canada to have a 20-year reserve for Canada's internal natural gas demand before any natural gas could be exported. Canadian reserves are now closer to a 10-year supply.

So reserves are constantly being consumed and replaced. The relative rates of consumption and replacement vary with economic conditions and natural gas prices. During periods of low natural gas prices, consumption tends to increase and there is a reduced incentive to develop new reserves. Eventually, this leads to falling reserves and creates an upward pressure on prices such as the nation experienced recently. With the natural gas industry operating at narrower reserve margins, these cyclical patterns have become more severe and led to growing natural gas price volatility.

Another common error in assessing natural gas supplies is to assume that the estimates of ultimate natural gas resources are static. In reality, natural gas resource estimates have shown a tendency to increase over time as technology improves and new discoveries are made. To illustrate this point, note that in 1964 the Potential Gas Committee, which estimates natural gas resources, estimated potential natural gas resources to be 630 trillion cubic feet. By 1996, the nation had consumed more than 630 trillion cubic feet of natural gas. If the potential resource were a fixed limit, as many interpret it, we would have run out of natural gas by now. Instead the estimated potential remaining natural gas resource in 1996, at 1,038 trillion cubic feet excluding proved reserves, was actually higher than the estimate of what was remaining in 1964 in spite of over 30 years of continuing consumption. This does not mean that resource estimates will necessarily continue to increase in the future, but it illustrates the uncertain nature of natural gas resource estimates.

The Potential Gas Committee estimated that in 1996 the natural gas reserves and potential resources were 1,205 trillion cubic feet and noted that at then-current consumption rates, it would be a 63-year supply. A little different approach to estimating the years that the current estimated resource would last is to look at North American natural gas resource estimates and a predicted growing natural gas consumption to see how long those supplies would last. Table B-1 shows an estimate of remaining natural gas resources. Note that both of these calculations assume that potential natural gas resource estimates would not grow over time, as they have historically.

Table B-1: Remaining Natural Gas Resources in North America (Trillion Cubic Feet)

	Already Produced	Remaining Reserves	Remaining Resources
Lower 48 States	847	166	1,078-1,548
Alaska	0	0	237
Canada	103	51	559-630
Mexico	34	72	230-250
Total	984	289	2,104-2,665

Figure B-4 plots the growth in cumulative natural gas consumption into the future and identifies the years when the current resource estimate would be exhausted. The Mexican consumption of natural gas and its natural gas resources have been excluded from Figure B-4. U.S. and Canadian consumption is assumed to grow at 1.5 percent a year. Under these assumptions current estimated resources would last about 45 to 55 years. However, we should expect that the production of these resources will become increasingly difficult and expensive. If production rates cannot keep up with demand growth it will result in upward pressure on natural gas prices and increased volatility.

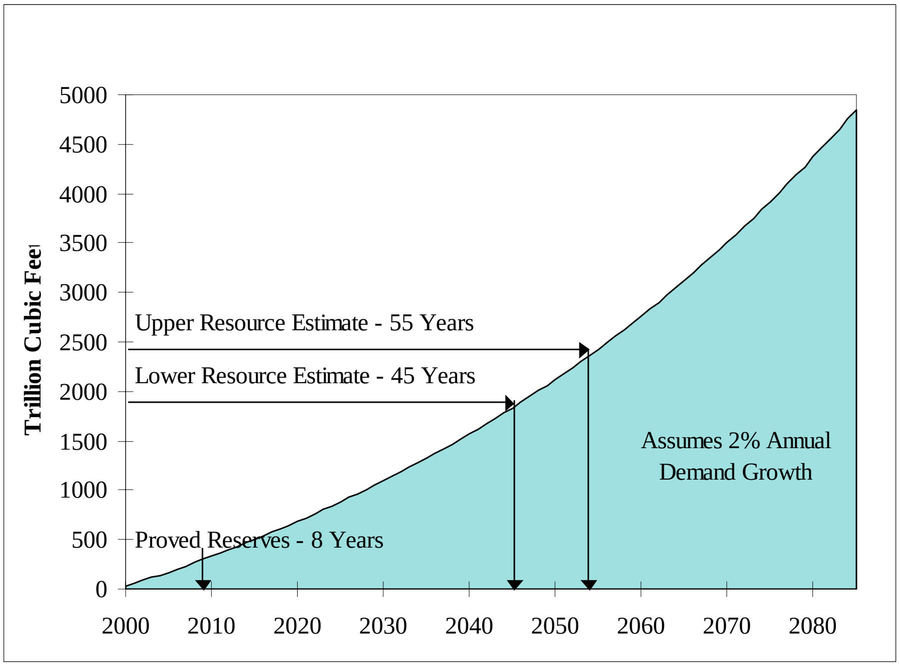


Figure B-4: Cumulative Natural Gas Production and Resources

However, based on past experience, the resource estimates are likely to increase over time in unpredictable ways. Some examples of potential changes will give some idea of what the future could hold in the longer term for natural gas resources. As in the case of oil, many natural gas resources lie outside of North America. Currently estimated conventional natural gas resources worldwide are 13,000 trillion cubic feet. As natural gas prices increase, the use of liquefied natural gas transportation will make these resources increasingly accessible to North America. In addition, natural gas occurs throughout nature in many forms. Besides coal bed methane, there are geopressurized brines and gas hydrates.[6] The ability to recover such sources is unknown at this point, but as new sources of gas are needed in the distant future, new technologies may facilitate some use of these resources. Gas hydrates, for example, are estimated to contain from 100,000 to 300,000,000 trillion cubic feet of natural gas resource.[7]

Natural Gas Delivery

Another important consideration in natural gas supply and cost is the capacity to transport the gas from the wells to the points of consumption. This involves gathering the gas from wells, processing the gas to remove liquids and impurities, moving the gas over long distances on interstate pipelines, and finally, distribution to individual consumers' homes and businesses.

Currently, U.S. natural gas supplies are largely domestic, supplemented by substantial imports from Canada. In 2001, the United States imported 3.75 trillion cubic feet of natural gas from Canada; and 1.1 trillion cubic feet of that were imported through Sumas and Kingsgate on the region's border with Canada, with a substantial amount of that gas destined for California markets.

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[6] U.S. Geological Survey. "Describing Petroleum Reservoirs of the Future." USGS Fact Sheet FS-020-97 (January 1997).

[7] U.S. Geological Survey. "Natural Gas Hydrates - Vast Resource, Uncertain Future." USGS Fact Sheet FS-021-01 (March 2001)

The sources of natural gas for the Pacific Northwest are the Western Canada Sedimentary Basin, in Alberta and Northeast British Columbia, and the U.S. Rocky Mountains. Two major interstate pipelines deliver natural gas into the Pacific Northwest region from Canada. Williams Northwest pipeline brings natural gas from British Columbia producing areas through Sumas, Washington where it receives gas from the Duke Westcoast pipeline in British Columbia. Williams Northwest pipeline also brings U.S. Rocky Mountain natural gas into the region from its other end. Thus, Williams Northwest is a bi-directional pipeline; it delivers gas from both ends toward the middle. The second interstate pipeline serving the region is the PG&E Gas Transmission Northwest (GTN) pipeline, which brings Alberta supplies through Kingsgate on the Idaho - British Columbia border. Much of the gas flowing on the GTN is destined for California. The GTN and Williams Northwest pipelines intersect near Stanfield, Oregon. The natural gas pipeline system serving the Pacific Northwest is illustrated in Figure B-5

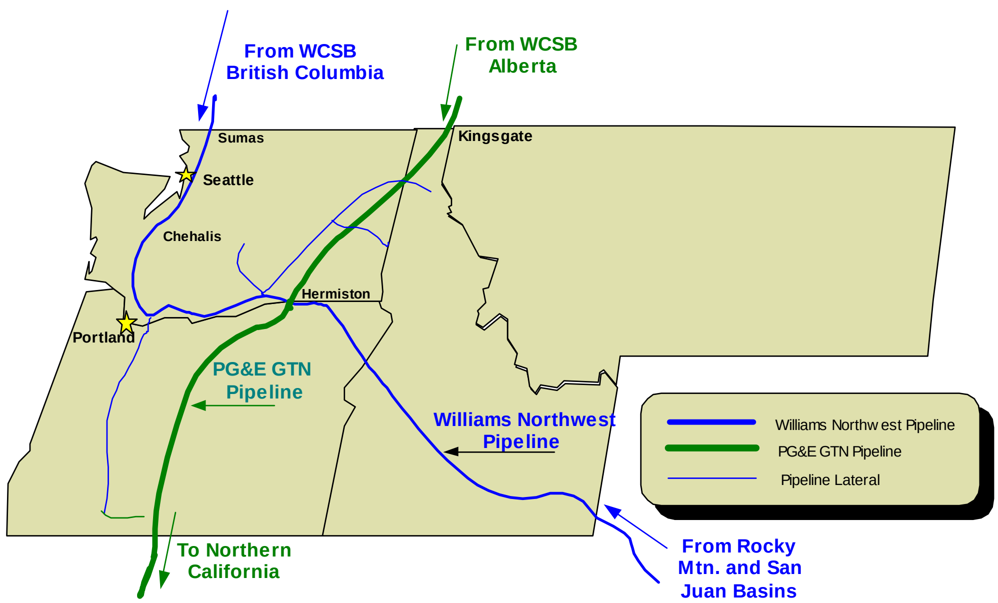


Figure B-5: Natural Gas Pipelines Serving the Pacific Northwest

The development of interstate pipeline capacity is based on the willingness of local distribution companies or other shippers of natural gas to subscribe to capacity additions. Historically, local gas distribution companies, the regulated utilities that serve core customers' natural gas demand, have owned much of the capacity on interstate pipelines. Because residential and commercial natural gas use varies seasonally and with temperatures, there is often pipeline capacity that is available for resale. Large industrial consumers and others who have some flexibility can acquire this capacity on a short term or capacity release basis. Interruptible consumers rely on this type of pipeline capacity, and it is typically available except on extremely cold winter days.

Growing natural gas demand results in pipeline capacity expansion as it is needed and as distributors or consumers are willing to pay for the capacity on an individual contractual basis. Interstate pipeline capacity is not expanded on a speculative basis based on someone's forecast of natural gas demand. Various expansions of pipeline capacity have been completed recently or are currently underway on both the Williams Northwest and the GTN systems, as well as on other pipelines throughout the West. Most of the entities committing to recent capacity expansions are electricity generators who are securing natural gas delivery capacity for proposed new electricity generating plants. Generating plant developers indicate that firm pipeline capacity is required in order to get financial backing for a new gas-fired combined cycle plant.

Over the long term, it should be expected that pipeline capacity will be expanded to deliver the necessary natural gas to regional consumers. In the short term, extremely unusual natural gas demands can place severe strain on pipeline delivery capacity, which can in turn cause serious natural gas price increases. This was the situation in the West in 2000-2001 when prices in California and the Northwest became disconnected from other U.S. prices.

Forecast Methods

Natural gas prices, as well as oil and coal prices, are forecast using an Excel spreadsheet model. The model does not address the basic supply and demand issues that underlie energy prices. Instead assumptions are made about the basic commodity price trends at a national or international level based on analysis of past price trends and market behavior, forecasts of other organizations that specialize in such analyses, and the advice of the Council's Natural Gas Advisory Committee. The model then converts the commodity price assumptions into wholesale prices in the Pacific Northwest and other pricing points in the West, and then adds transportation and distribution costs to derive estimates of retail prices to various end-use sectors.

Because natural gas is the primary end-use competitor for electricity, and because it is the electricity generation fuel of choice at this time, natural gas prices are forecast in more detail than oil and coal prices. Residential and commercial sector retail natural gas prices are based on historical retail prices compared to wellhead prices. For historical years the difference between wellhead prices and retail prices are calculated. For forecast years, the projected difference is added to the wellhead price forecast. The differences between retail and wellhead natural gas prices can be projected from historical trends, other forecasting models, or judgment.

Gas prices for small industrial gas users that rely on local gas distribution companies to supply their gas are forecast in the same manner as residential and commercial users. However, large firm or interruptible natural gas consumers, whether industrial or electric utility, must be handled with a different method. This is because there is no reliable historical price series for these gas users to base a simple mark-up on. For these customers, the difference between wellhead and end-user prices is built from a set of transportation cost components and regional gas price differentials appropriate to the specific type of gas use.

The components include pipeline capacity costs, pipeline commodity costs, pipeline fuel use, local distribution costs, and regional wellhead price differentials. The latter is necessary because the driving assumption is a national average wellhead gas price. Wellhead prices in British Columbia, Alberta, and the Rocky Mountains gas supply areas, the traditional sources of gas for the Pacific Northwest, have historically been lower than national averages. The fuel price model and assumptions are described in more detail in Appendix B1.

Forecasts

U.S. Wellhead Prices

There are a number of different indicators of U.S. natural gas commodity prices. The Council's analysis utilizes two of these measures. One is the U.S. wellhead price series published by the U.S. Energy Information Administration. The other is the Henry Hub cash market price. A link between U.S. wellhead prices and the Henry Hub cash price is estimated to relate the two series for the Council's analysis.

Figure B-6 shows the history of U.S. wellhead natural gas prices from 1970 to 2002. After the deregulation of wellhead natural gas prices around 1986, natural gas prices fell dramatically to the $2.00 per million Btu range in year 2000 dollars. Since then, until 2000, natural gas prices varied between $1.60 and $2.40 in year 2000 prices. In 2000, natural gas prices shot up, reaching a peak of over $9.00 by January 2001 as measured by spot prices at the Henry Hub in Louisiana. Although the 2000 price spike created expectations of significantly higher natural gas prices in the future, prices fell rapidly during 2001 and by September 2001 had returned to near their post-deregulation average of $2.15 in year 2000 prices. Many industry participants warned that the lower prices in the winter of 2001-02 were due to extremely warm temperatures, high natural gas storage inventories, and reduced demand as a result of higher prices and an economic slowdown and that there remained an underlying shortage of natural gas supplies.[8] Indeed, in the spring of 2002 prices firmed up to above $3.00 and prices in March 2003 averaged $8.00, with much higher excursions on a daily basis.

Wellhead natural gas prices averaged $4.81 in 2003 in year 2000 dollars. Prices have remained high in 2004 even with adequate storage levels and mild summer weather. Natural gas prices have been supported at a high level by high world oil prices. After 2005 prices are expected to begin moderating, but remain well above price levels of the 1990s. After 2005, prices decrease over several years as supply and demand adjust to the new conditions. By 2015 medium case prices remain $1.35 higher than the Fourth Plan forecast. The range of the forecast is wider in 2015 than in the Fourth Power Plan and it is significantly higher. The low is above the medium forecast of the Fourth Power Plan, and the high is $1.22 higher than the previous plan's high forecast.

Table B-2 shows actual U.S. wellhead prices for 1999 through 2003, annual forecasts for 2004 and 2005, and forecasts in five-year intervals after 2005. The last row of Table B-2 shows the average annual growth rate of real wellhead prices from 1999 to 2025. 1999 was chosen as the base year for growth rates because its price is close to the average price between 1986 and 1999. The projected growth in prices has already occurred, however, and from current prices the entire forecast range decreases. Figure B-7 shows the forecast range compared to historical prices.

[8] Natural Gas Advisory Committee, February 28, 2002

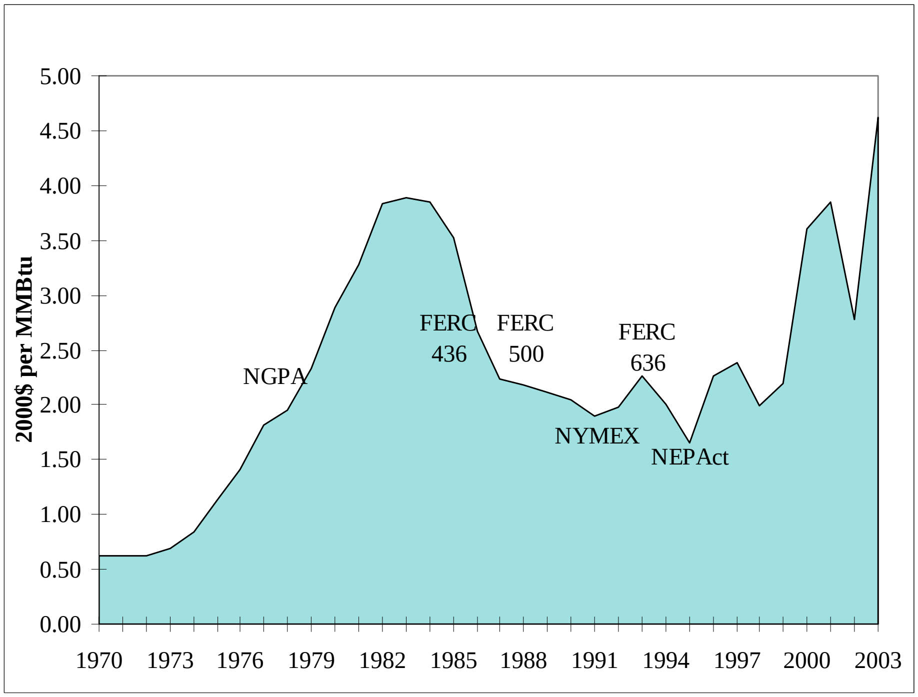


Figure B-6: History U.S. Wellhead Natural Gas Prices

Table B-2: U.S. Wellhead Natural Gas Prices (2000$ per million Btu)

Year	Low	Med-low	Medium	Med-high	High
1999			2.19		
2000			3.60		
2001			4.03		
2002			2.80		
2003			4.62		
2004	4.75	5.20	5.45	5.60	5.80
2005	4.50	4.90	5.30	6.00	6.35
2010	3.00	3.30	4.00	4.50	5.00
2015	2.75	3.40	3.80	4.30	4.90
2020	2.90	3.50	3.90	4.35	5.00
2025	3.00	3.50	4.00	4.50	5.10
1999-2025 Growth Rate	1.22	1.82	2.34	2.81	3.31

The reader should not be lured into complacency by the smooth appearance of these forecasted prices. Future natural gas prices are not expected to follow a smooth pattern as reflected in the forecasts; they will be cyclically volatile, but the forecasts only reflect expected averages. There is, in fact, reason to expect continued volatility in natural gas prices because competition has narrowed reserve margins in the industry, making prices more vulnerable to changes in demand due to weather or other influences.[9] The consequences of price volatility, and ways to mitigate its impact, will be addressed in the part of the power plan that addresses risk and uncertainty in regional resource planning.

The low case forecast reflects a situation where improved technology allows expanded natural gas supplies to occur with relatively moderate real price increases. Sources of natural gas would continue to be primarily from traditional natural gas sources and coal bed methane. Low oil prices provide strong competition in the industrial boiler fuel market to help keep natural gas prices low. Continuing declines in coal prices, coupled with improved environmental controls, may moderate the growth in natural gas reliance for electricity generation.

The high case reflects a scenario with less successful conventional natural gas supply expansion. In the high case, higher prices would mean a growing role for frontier supply areas and liquefied natural gas imports. High prices of oil and slower progress on environmental mitigation of the effects of burning coal leave natural gas in a state of higher demand growth.

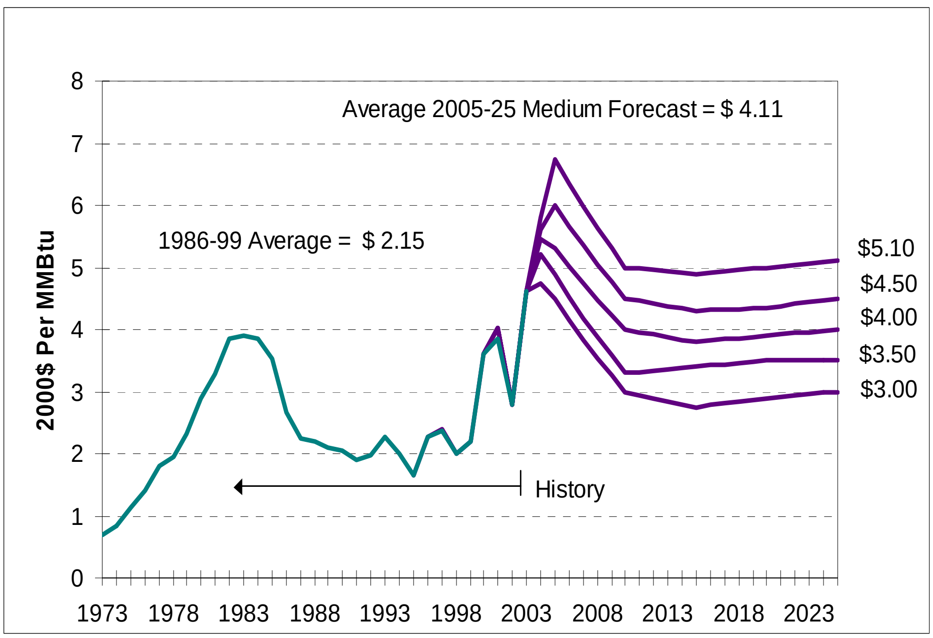
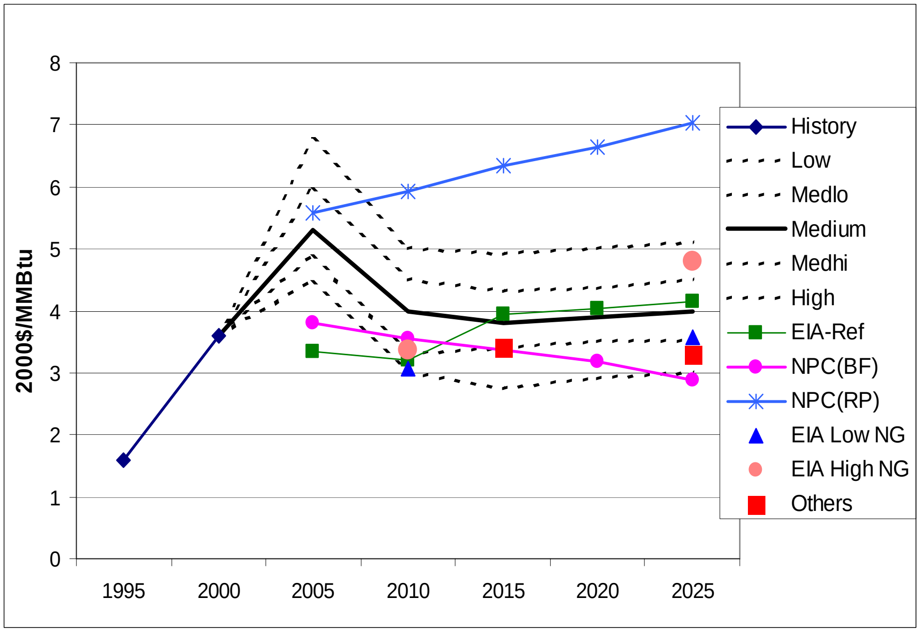


Figure B-7: U.S. Wellhead Prices: History and Forecast

Figure B-8 compares the Council's range of natural gas price forecasts to forecasts by some other organizations. A forecast in the U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2004 is similar to the Council's medium forecast. The main difference is that EIA's forecast is lower in 2005 and 2010. EIA also has a high and low natural gas price forecast based on alternative assumptions about technological advances in natural gas exploration and production. These cases differ little from the reference forecast in 2010, but in 2025 the EIA high case is between the Council's medium-high and high forecasts. EIA's low price case falls between the Council's low and medium-low forecasts. EIA reviewed several other forecasts that were available to them. The average of these other forecasts is shown as "others" in Figure B-8 and falls between the Council's medium-low and low forecasts. These forecasts were likely done in early to mid 2003

[9] Natural Gas Advisory Committee, February 29, 2002

and may have been revised upward since then. Another recent forecast was done by the National Petroleum Council (NPC), which completed a comprehensive analysis of natural gas supplies and markets. The NPC study shows two futures, one called the "reactive path" (RP), and the other called the "balanced future" (BF). The reactive path scenario illustrates the consequences of poor natural gas policies. It results in prices well above the Council's high case. The balanced future case results in natural gas prices that generally fall between the Council's medium-low and low cases.



Sources: U.S. Energy Information Administration, *Annual Energy Outlook 2004*; National Petroleum Council. *Balancing Natural Gas Policy - Fueling the Demand of a Growing Economy*. September 25, 2003.

Figure B-8: Comparison of Natural Gas Price Forecasts

Regional Natural Gas Price Differences

As noted above, for the AURORA® model analysis of electricity supplies and pricing, a forecast of Henry Hub cash market prices is used as the U.S. commodity price. Figure B-9 shows the difference between the Henry Hub price of natural gas and the U.S. wellhead price from 1989 through 2003. Excluding the most extreme values, the difference averaged $0.23 per million Btu in year 2000 dollars. To forecast Henry Hub prices, an equation was estimated from monthly inflation-adjusted historical prices that relates the Henry Hub price to the U.S. wellhead natural gas price.

AURORA® also requires information about future natural gas and other fuel prices for several pricing points throughout the Western United States. In the draft fuel price forecast in April 2003 the Council used fixed real dollar adjustments between Henry Hub and the other pricing points in the West. In the final power plan, these constant adjustments have been replaced with estimated equations similar to the one used to adjust wellhead prices to Henry Hub prices.[10]

Natural gas commodity prices in the Pacific Northwest have typically been lower than national prices. Between 1990 and 2003, Canadian natural gas prices delivered to the Washington border at Sumas averaged $.62 per million Btu less than the national market index at Henry Hub, Louisiana. Prices at the Canadian border at Kingsgate have averaged about $.08 lower than the Washington

[10] See Council staff paper on "Developing Basis Relationships Among Western Natural Gas Pricing Points".

border price at Sumas. As shown in Figure B-10, however, these regional price differences have been extremely volatile. Figure B-10 shows monthly regional price differences from Henry Hub to Sumas and Kingsgate from 1990 through 2003. Occasionally, regional natural gas prices have even been above Henry Hub prices. In December of 2000, they were dramatically so, reflecting regional pipeline constraints caused, in part, by the electricity crisis in the West and the sudden increase in the use of natural gas to generate electricity. The average differences exclude the extreme values in the winter of 1995-96 and 2000-01.

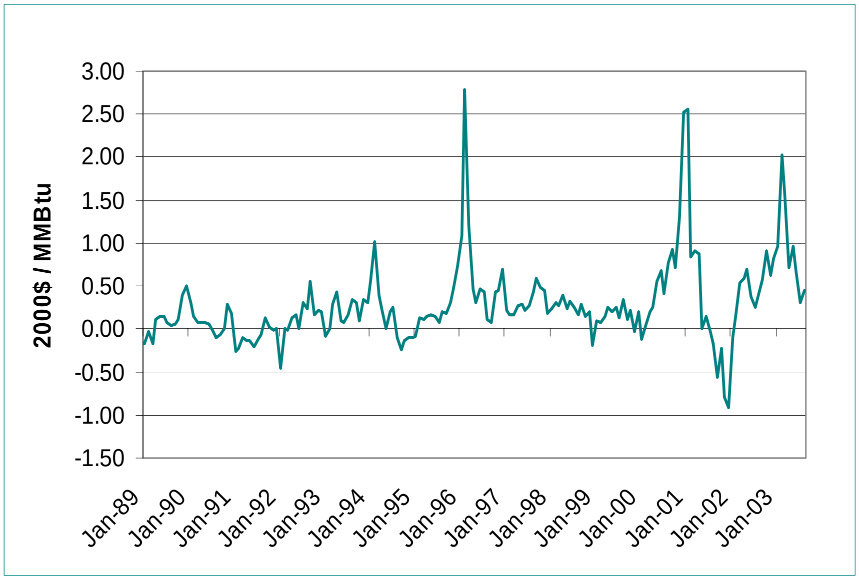


Figure B-9: Difference Between Henry Hub and U.S. Wellhead Natural Gas Prices

In addition to Canadian natural gas supplies through Sumas and Kingsgate, the Pacific Northwest receives natural gas supplies from the Rocky Mountain supply area on Williams Northwest Pipeline. Thus, Rocky Mountain natural gas supplies also play an important role in setting natural gas prices in the region. However, because of the direct competition among the various natural gas sources in the region, Rocky Mountain prices have generally tended to be similar to Canadian prices delivered into the region.

For purposes of forecasting regional natural gas prices in the eastern part of the region, a liquid pricing point in Alberta called the AECO-C hub is used as a focal point for regional natural gas prices. AECO-C prices have averaged $.81 per million Btu (2000$) less than Henry Hub prices since 1990. Prices in the western part of the region are estimated from Sumas prices at the Washington and British Columbia border. Sumas prices are estimated based on AECO and Rockies prices. The emerging natural gas pricing point in British Columbia is Station 2 in Northeastern British Columbia. However, there was insufficient historical data on Station 2 prices to estimate a relationship.

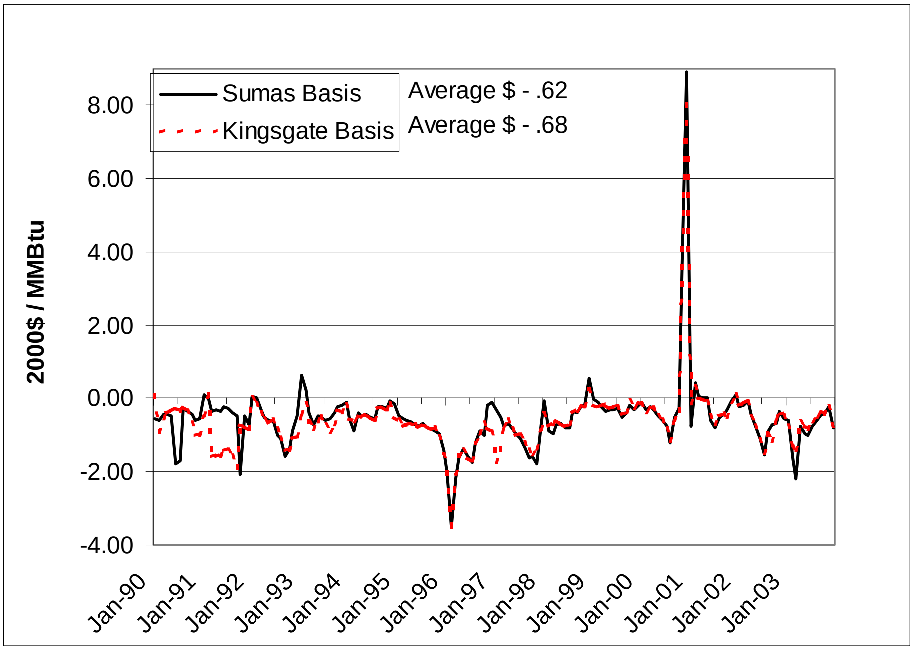


Figure B-10: Canadian Gas Price Differences from Henry Hub

Retail Prices

The forecast prices paid by regional consumers of natural gas are based on the U.S. and Canadian commodity prices described in the previous section. The exact method depends on the consuming sector being considered and will be explained below.

Figure B-11 shows the regional retail natural gas price forecasts for end-use sectors compared to the U.S. wellhead price forecast for the medium case. The residential and commercial forecasts are based on historical differences between regional retail price and U.S. wellhead prices. Industrial price forecasts are a weighted average of three different price estimates; direct-purchase firm gas, direct-purchase interruptible gas, and local distribution company-served industrial customers. Direct-puchase gas is gas supply that is purchased directly by industrial customers instead of from local gas distribution companies (LDCs). The ability of industrial users to purchase natural gas directly in the market began with natural gas deregulation in the mid-1980s. The effect on industrial prices is apparent in Figure B-11, where the average industrial price moves toward the utility and wellhead price and away from the utility-served residential and commercial prices during the 1980s. The differences between U.S. wellhead and regional retail prices are discussed further below.

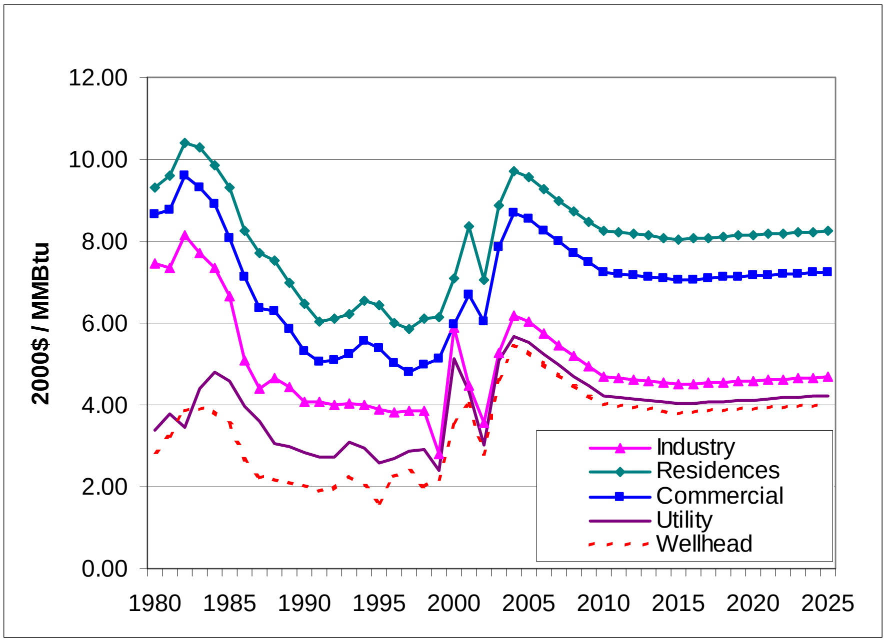


Figure B-11: Retail and Wellhead Prices History and Medium Forecast

Residential and commercial sector prices are based on observed differences from U.S. wellhead natural gas prices between 1989 and 2000. Figure B-12 shows that these differences declined during the 1980s. Since then, the differences have leveled off. The forecast assumes a $4.25 difference for residential and a $3.25 difference for commercial. These differences are held constant over the forecast period and across forecast cases.

As noted above, the industrial price shown in Figure B-11 is a blended price. The prices of the three components are derived in different ways. The LDC-provided prices are developed in the same way as residential and commercial prices. The forecast addition to U.S. wellhead prices to estimate LDC-provided retail prices starts at about $1.70, but unlike the residential and commercial adders, declines gradually over time. It does not, however, vary among forecast cases.

Directly purchased industrial natural gas prices are built from wellhead prices using estimates of the various components of gas supply and transportation costs. These components are described in detail in the Appendix B1, but Table B-3 shows, as an example, an estimate of regional industrial directly-purchased natural gas prices for 2010 in the medium case forecast. The example is a large, high-capacity-factor, industrial consumer. For electricity generators, natural gas and transportation costs are assumed to be different on the west and east side of the Cascade Mountains. There is no distinction applied to the industrial price forecasts; they are calculated using west side costs.

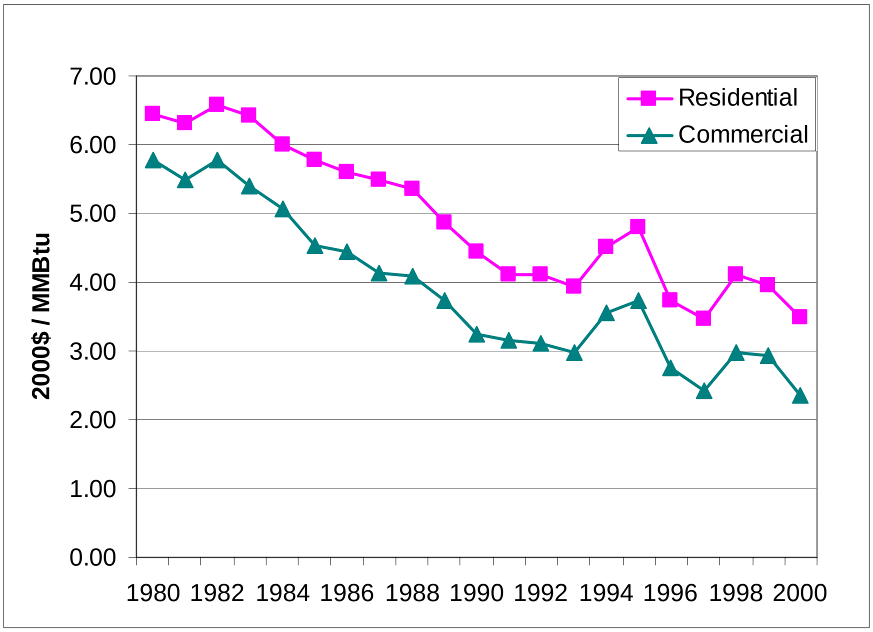


Figure B-12: Historical Difference Between Regional Residential and Commercial Retail Natural Gas Prices and U.S. Wellhead Prices

There is some disagreement whether a consumer who buys natural gas supplies on a firm basis would generally pay a premium for firm supplies. In this forecast, it is assumed that there is no premium. It is assumed that a large, high-capacity-factor industrial consumer would likely pay a negotiated rate for gas transportation by the local distribution utility and that there is no difference between firm or interruptible distribution service for such customers. This may only be the case for a customer with a potential to bypass the local distribution company, but the assumption about LDC transport cost only applies to industrial consumers and the forecast of industrial electricity demand in the Fifth Power Plan is not directly affected.

To combine the components into a blended price it is assumed that 30 percent of industrial natural gas consumption is purchased from the local distribution utility. The remaining 70 percent is purchased directly by industrial consumers. 90 percent of these direct purchases are assumed to be interruptible. It is assumed that a consumer that doesn't hold firm pipeline capacity will acquire released capacity or short-term firm capacity. In Figure B-11, the average difference between the U.S. wellhead price and the blended industrial users' price is small compared to the residential and commercial sectors. It is important to remember that the differences encompass a negative adjustment from Henry Hub commodity prices to AECO and Sumas, as described in the previous section.

Natural gas prices for electricity generators reflect the assumption that all electricity generators will buy their gas directly from suppliers rather than the local utility, and that generators will receive their gas supplies directly from interstate pipelines. Like industrial direct purchases, these purchases can be made on a firm or interruptible basis. In this forecast, it is assumed that all electric generator gas purchases are made on a firm transportation basis. Electric generator natural gas prices are calculated both in terms of average cost per million Btu, and in terms of fixed and variable natural gas costs. Again these assumptions are detailed in Appendix B1. Table B-4a shows an example of the calculation of natural gas costs for a new generating plant on the west side of the Cascade Mountains. Table B-4b shows the same derivation for a plant on the east side of the Cascade

Mountains. The examples are for the year 2010 in the medium forecast case. Appendix B3 shows annual natural gas price forecasts for the U.S. wellhead and retail prices for the residential, commercial, industrial and utility sectors for each forecast case. In addition, Appendix B2 shows similar information for electricity generators on the west and east side of the Cascade Mountains.

Table B-3: Estimation of 2010 Industrial Firm and Interruptible Direct-Purchase Natural Gas Cost (2000$/MMBtu)

Price Components	Price Adjustments	Firm	Interruptible
Henry Hub Price		$ 4.31	4.31
Sumas Price		3.77	3.77
In Kind Fuel Cost	+ 1.74%	3.84	3.84
Firm Pipeline Capacity (Rolled-in)	+ .28	4.12	
Interruptible Pipeline Capacity	+ .21		4.05
Pipeline Commodity Charge	$ + .04	4.16	4.09
Firm Supply Premium	$ + 0.0	4.16	
LDC Distribution Cost	+ .20	4.36	4.29

Table B-4a: Estimation of West Side Electric Generator Firm and Interruptible Natural Gas Cost (2000$/MMBtu)

Price Components	Price Adjustments	Firm	Interruptible
Henry-Hub Price		$ 4.31	$ 4.31
Sumas Price		3.77	3.77
In-Kind Fuel Charge	+ 1.74%	3.84	3.84
Firm Pipeline Capacity (Incremental)	$ + .56	4.40	
Interruptible Pipeline Capacity	$ + .21		4.05
Pipeline Commodity Charge	$ + .04	4.44	4.09
Firm Supply Premium	$ + .00	4.44	

Table B-4b: Estimation of East Side Electric Generator Firm and Interruptible Natural Gas Cost (2000$/MMBtu)

Price Components	Price Adjustments	Firm	Interruptible
Henry Hub Price		$ 4.31	$ 4.31
AECO Price		3.66	3.66
In-Kind Fuel Charge	+ 2.8%	3.76	3.76
Firm Pipeline Capacity (Incremental)	$ + .45	4.21	
Interruptible Pipeline Capacity	$ + .23		3.99
Pipeline Commodity Charge	$ + .01	4.22	4.00
Firm Supply Premium	$ + .00	4.22	

Inputs to the AURORA® model are configured differently, but they are based on the same underlying U.S. wellhead price forecast. Adjustment from U.S. wellhead prices to AURORA® market area prices are described in Appendix B1.

Treatment of Natural Gas Prices in the Portfolio Model

The discussion above described long-term trend forecasts for natural gas prices. These are important for the expected cost trends over the forecast horizon. However, the choice of generating and conservation resources also must consider volatility and risk inherent in natural gas prices. The Council's portfolio model assessed such price behavior and its affect on the cost and risk of alternative resource plans.

The portfolio model introduces additional kinds of variation into the analysis of natural gas prices to electricity generators in the region. Normal seasonal patterns are added to the annual trends, and random commodity price cycles are added with periods of extreme price variation. The result is an analysis of natural gas prices with much greater variation than the trend forecasts. Figure B-13 illustrates a sample of natural gas price futures evaluated in the portfolio model. The range of trend forecasts is shown as the shaded band. Clearly the portfolio analysis considers price excursions well outside the annual trend range, especially on the high price side.

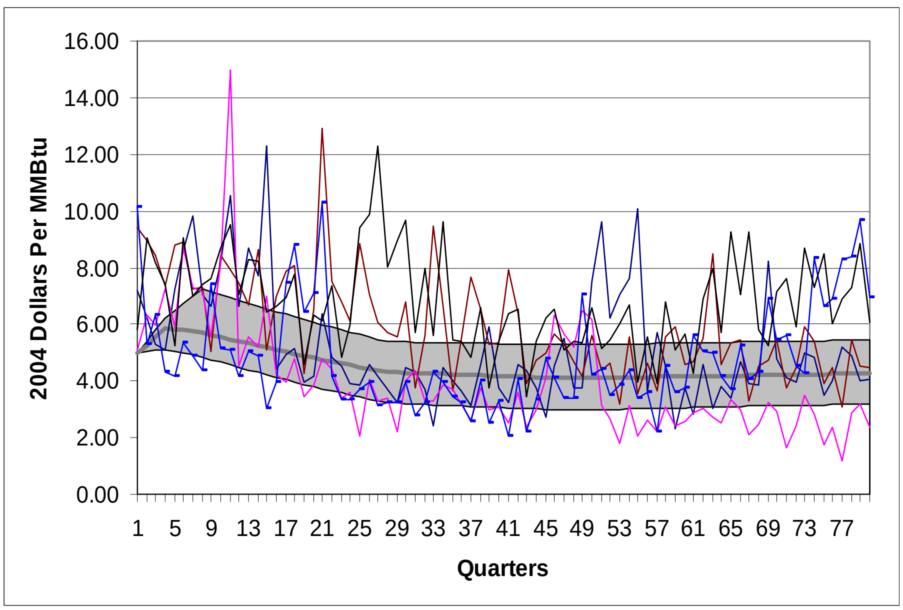


Figure B-13: Illustration of Natural Gas Price Futures in the Portfolio Model

OIL

Historical Consumption and Price

Oil products are playing a decreasing role in both electricity generation and in residential and commercial space heating in the Pacific Northwest. Figure B-14 shows that both distillate and residual oil consumption have generally been declining in all sectors since the mid-1970s.

To a large extent, declining oil consumption reflects growing natural gas use. Some increases in oil consumption are evident during the mid-1980s when natural gas prices were high. Substitution possibilities between natural gas and oil use in large industrial applications is a key feature of fuel markets. The substitution of oil for natural gas, for example, played an important role during 2001 in reducing high natural gas prices. In the Pacific Northwest, the displacement of industrial residual oil use is particularly dramatic as shown in Figure B-14.

In general, the price of oil products is determined by the world price of crude oil. Figure B-15 shows crude oil prices from 1978 to 2000 compared to refiner prices for residual oil and distillate oil. The differences are relatively stable with residual oil being priced lower than crude oil and distillate oil higher. On average, during this time period distillate oil was priced $1.00 per million Btu higher than crude oil. Residual oil was on average priced $.80 lower than crude oil. (Prices are in nominal dollars.) Retail prices of oil products follow very similar patterns, but at different levels.

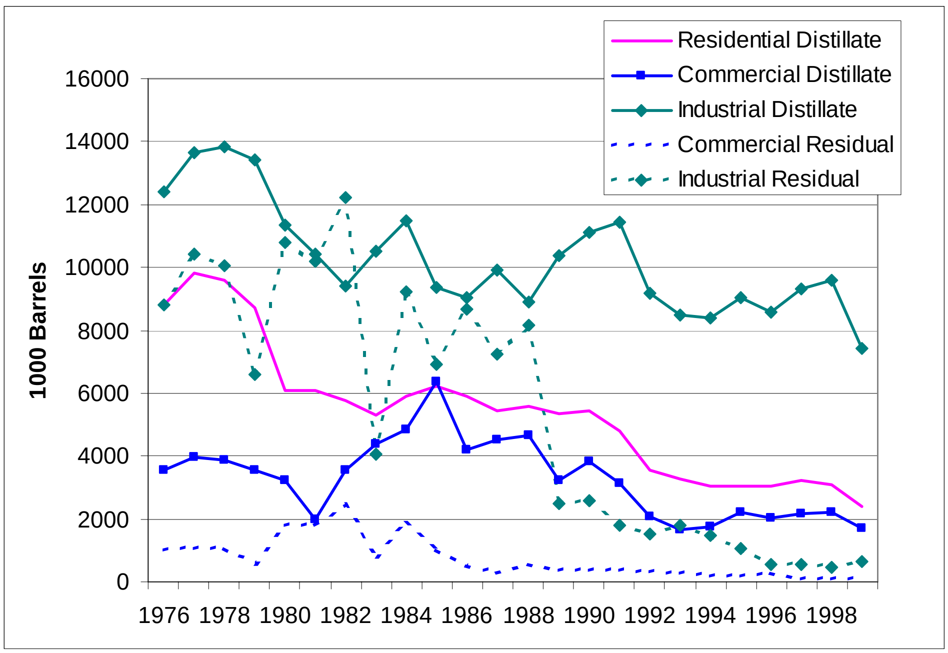


Figure B-14: Historical Oil Consumption in the Pacific Northwest

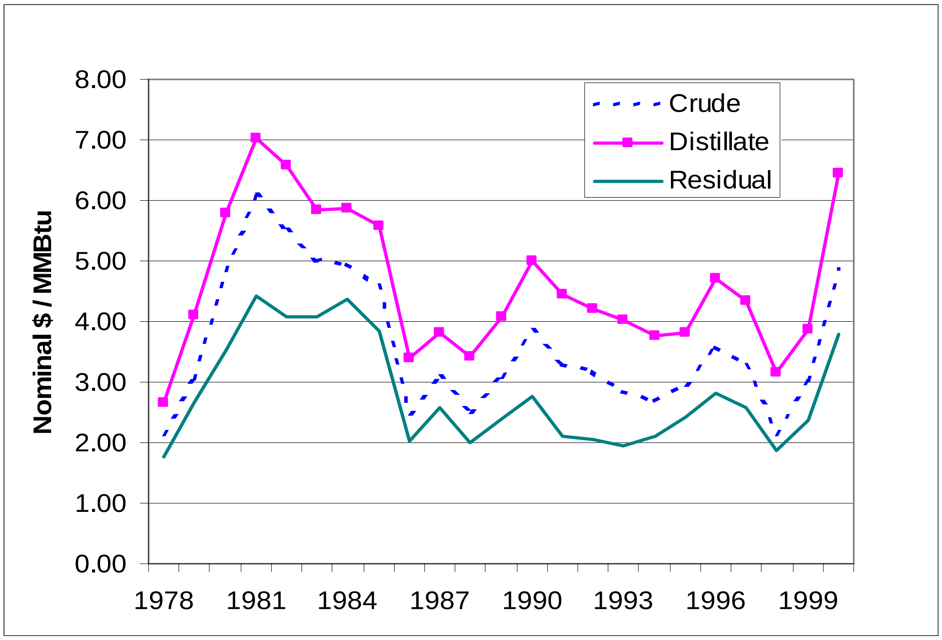


Figure B-15: Comparison of Crude Oil and Refiner Product Prices

Methods

The forecasts of oil prices are based on assumptions about the future world price of crude oil. Refiner prices of distillate and residual oil are derived from formulas relating product prices to crude oil prices and refining costs. The formulas are based on a conceptual model of refinery costs and assume profit-maximizing decisions by refiners regarding the mix of distillate and residual oil production. Appendix B1 describes this model in more detail.

Although the refinery model is very simple, and the refining cost estimates and energy penalties have not been changed since the early days of the Council's planning, the ability of the equations to simulate historical prices remains good. Figures 16a and 16b show a comparison of predicted residual oil and distillate oil prices, respectively, based on actual world crude oil prices, to actual prices from 1978 to 2000. The equations appear to be predicting well, especially after the mid-1980s.

Forecasts of retail oil prices to end-use sectors are based on historical differences between the refiner price estimates for residual and distillate oil and actual retail prices. These mark-ups are assumed constant over time and across alternative forecast cases.

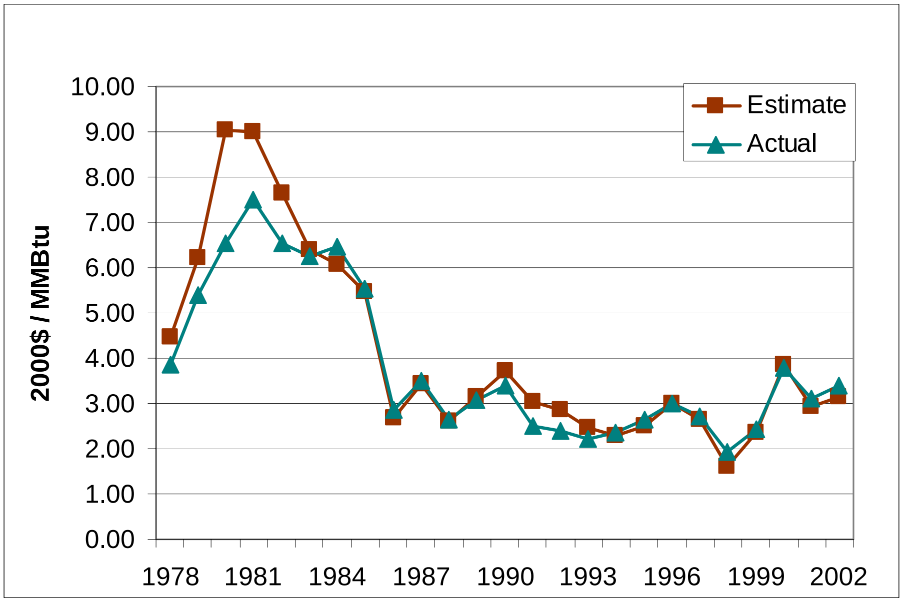


Figure B-16a: Comparison of Forecast and Actual Residual Oil Prices

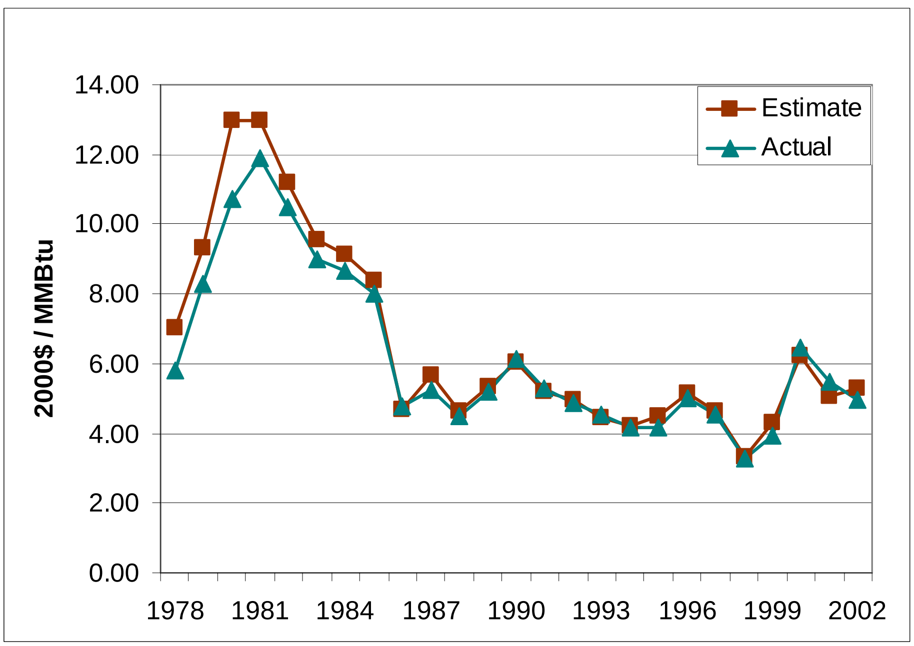


Figure B-16b: Comparison of Forecast and Actual Distillate Oil Prices

World Crude Oil Price Forecast

The situation in world oil markets is very different from natural gas markets. Oil has much more of a world market than natural gas because it is easier to transport. The world's proved reserves of oil are about 1,000 billion barrels. World consumption of oil in 2000 was 27 billion barrels (based on BP and USGS data). Oil reserves are dominated by the Middle East, which has 65 percent of the world's proven reserves. The Middle East's reserves can be produced at low cost, but the middle eastern countries and their partners in the Organization of Petroleum Exporting Countries (OPEC) attempt to limit production so that world oil prices remain in the range of $22 to $28 per barrel. Proven oil reserves in the Middle East are 80 times the actual production rate in 2000. As a result, world oil prices are likely to depend on OPEC actions for the duration of the forecast period.

Although fluctuating world oil demand, Middle East conflicts, lapses in OPEC production discipline, and other world events will result in volatile oil prices over time, we have assumed a range of stable average prices in the forecast. Figure B-17 shows historical world oil prices and the five forecast cases.

Since the mid-1980s, world oil prices have averaged $21 a barrel in year 2000 prices. However, they varied from a low of $12.49 per barrel in 1998 to $27.69 in 2000. During 2001 and 2002, prices averaged in the low $20 range. Table B-5 shows historical world oil prices and forecasts for individual years between 2000 and 2005 and in five-year increments thereafter. A number of factors have caused an increase in world oil prices in 2003 and 2004. These include the Iraq situation, strikes in Venezuela, and a lower value of the U.S. dollar. In 2003 world oil prices averaged $26.23 and they have moved substantially higher in 2004, at times nearing $50. The forecasts assume that oil prices this high are a temporary condition. After 2010 the medium-low to medium-high forecast range settles to the $23 to $29 dollar range.

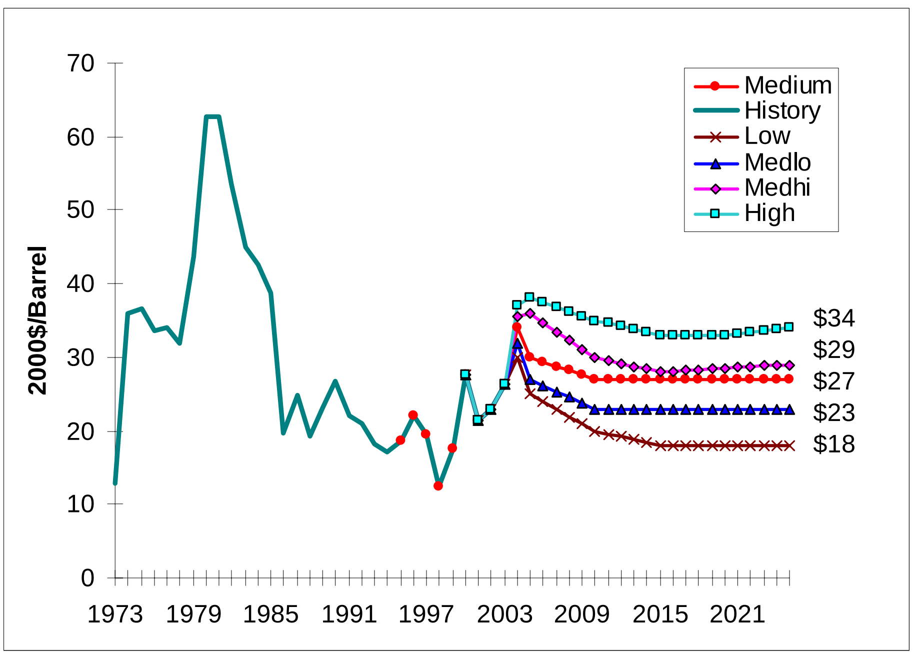


Figure B-17: World Oil Price: History and Forecasts

Table B-5: World Oil Price Forecasts (2000$ per MMBtu)

	Low	Medium-Low	Medium	Medium-High	High
2000			27.69		
2001			21.52		
2002			22.91		
2003			26.23		
2004	30.00	32.00	34.00	35.50	37.00
2005	25.00	27.00	30.00	36.00	38.00
2010	20.00	23.00	27.00	30.00	35.00
2015	18.00	23.00	27.00	28.00	33.00
2020	18.00	23.00	27.00	28.50	33.00
2025	18.00	23.00	27.00	29.00	34.00

The assumptions about future oil prices are based on observation and analysis of historical prices and on comparisons among forecasts made by other organizations that put substantial resources into the analysis of future oil price trends. Figure B-18 shows historical world oil prices for 1990, 1995 and 2000 compared to the forecast range and a range of other forecasts. The U.S. Energy Information Administration (EIA) is the source of the summary of other forecasts.[11] Figure B-18 shows EIA's forecast range and the average of 8 other forecasts that EIA compared to their own forecast. EIA's reference case forecast falls between our medium-low and medium cases after 2005. EIA's range is also consistent with our low to high range after 2005. The average of the 8 other forecasts falls between our low and medium-low forecasts. These other forecast did were done during 2003 and did not have the advantage of knowing about recent oil prices, so their 2005 forecasts are well below the Council's in the near term. Appendix B4 contains tables of annual forecasts for world oil prices and retail sector oil prices for each forecast case.

[11] U.S. Energy Information Administration, Annual Energy Outlook 2004.

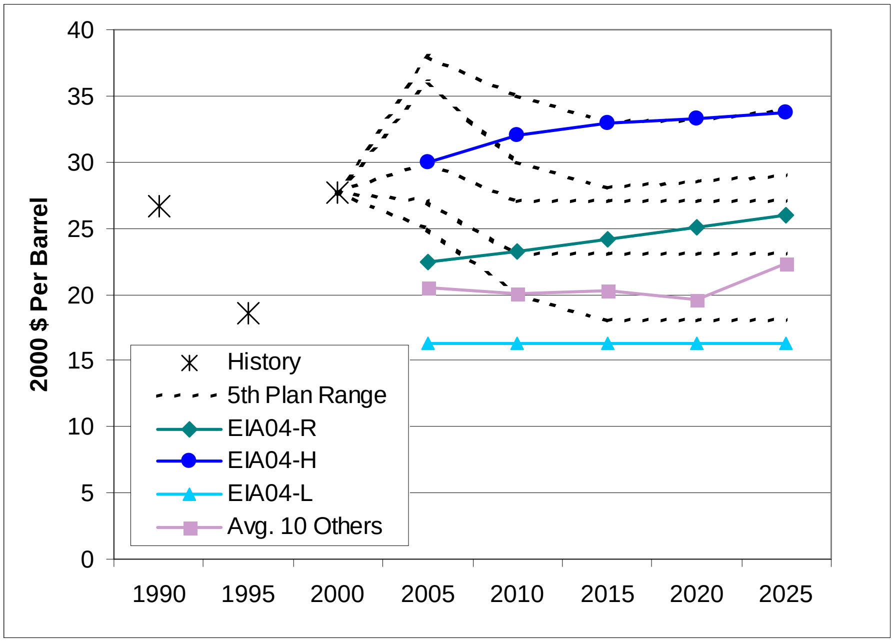


Figure B-18: Comparison to Other World Oil Price Forecasts

Consumer Prices

Using the methods described earlier, world oil price forecasts are converted to refiner prices of residual oil and distillate oil. Figure B-19 shows the forecast relationship among the prices of these refiner products for the medium case. A set of mark-ups is used to derive forecasts of retail prices for various products to end use sectors. These retail mark-ups, shown in Table B-6, are generally assumed constant over time and across forecast cases. The mark-ups are based on historical average price relationships during the 1980s and 1990s. Appendix B5 contains detailed tables for the oil price forecast.

Table B-6: Retail Mark-up Assumptions for Oil Products and Sectors

INDUSTRIAL SECTOR	
Residual Oil Over Refinery	$ .24
Distillate Oil Over Refinery	$ 1.00
UTILITY SECTOR	
Residual Oil Over Refinery	$ .24
Distillate Oil Over Refinery	$ .46
COMMERCIAL SECTOR	
Residual Oil Over Industrial	$ .05
Distillate Oil Over Industrial	$ -.42
RESIDENTIAL SECTOR	
Distillate Oil Over Industrial	$ 1.98

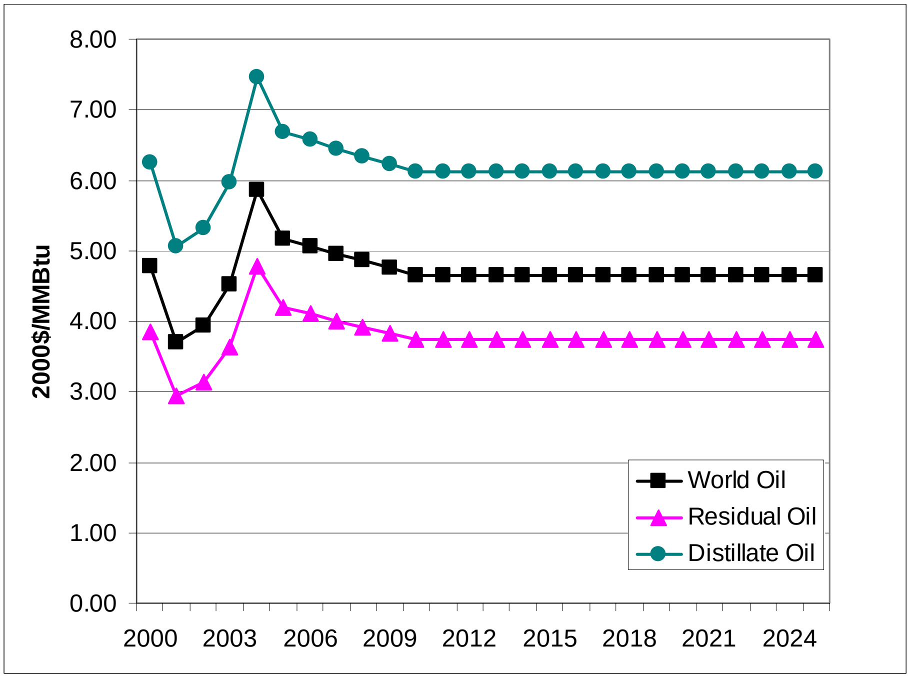


Figure B-19: Refiner Prices of Residual and Distillate Oil Compared to World Crude Oil Price (Medium Case)

COAL PRICE FORECASTS

Coal prices play little role in determining regional electricity demand. There are not many end uses where coal and electricity substitute for one another and coal consumption is relatively minor in the Pacific Northwest in any case. Coal as a percent of total industrial fuel purchases in the region in 1999 was 0.7 percent compared to 6.1 percent for the U.S. as a whole. Coal is also a relatively minor electricity generation fuel in the region compared to the U.S. In 1999, coal accounted for 14 percent of regional utility fuel purchases compared to 55 percent for the nation. Only Montana had a coal generation share similar to the US for electricity generation.

Nevertheless, coal may be an important alternative as an electricity generation fuel in the future. The trade-off is that while coal is a plentiful and relatively inexpensive domestic energy source, it also has substantial environmental impacts both during extraction and burning. Thus its future may depend on technological progress in emissions controls and policies with regard to air quality and global warming.

Coal resources, like natural gas, are measured in many different forms. The EIA reports several of these.[12] One measure is "demonstrated reserve base," which measures coal more likely to be mined based on seam thickness and depth. EIA estimates that the 1997 U.S. demonstrated reserve base of coal is 508 billion short tons. Only 275 billion short tons of these resources are considered "recoverable" due to inaccessibility or losses in the mining process. This is still a large supply of coal relative to the current production of about 1 billion short tons a year.

About half of the demonstrated reserve base of coal, 240 billion short tons, is located in the West. Western coal production has been growing due to several advantages it has over Appalachian and

[12] U.S. Energy Information Administration, U.S. Coal Reserves: 1997 Update, February 1999.

interior deposits. Western coal is cheaper to mine due to its relatively shallow depths and thick seams. More important, Western coal is lower in sulfur content. Use of low-sulfur coal supplies has been an attractive way to help utilities meet increased restrictions on SO_2 emissions under the 1990 Clean Air Act Amendments that took effect on January 1, 2000. The other characteristic that distinguishes most Western coal from Eastern and interior supplies is its Btu content. Western coal is predominately sub-bituminous coal with an average heat content of about 17 million Btu's per short ton. In contrast, Appalachian and interior coal tends to be predominately higher grade bituminous coal with heat rates averaging about 24 million Btu per short ton.

Western coal production in 2000 was 510.7 million short tons. Two-thirds of that production came from Wyoming, 338.9 million short tons. The second largest state producer was Montana at 38.4 million tons. Colorado, New Mexico, North Dakota and Utah produced between 26 and 31 million short tons each, and Arizona produced about 13 million short tons.

Productivity increases have been rapid, especially in Western coalmines. As a result, mine-mouth coal prices have decreased over time. In constant dollars, Western mine-mouth coal prices declined by nearly 6 percent per year between 1985 and 2000. Expiring higher priced long-term contracts have also contributed to declining coal prices.

The price of delivered coal is very dependent on transportation distances and costs. In addition, delivered costs may have very different time trends from mine-mouth costs due to long-term coal supply contracts. Figure B-20 shows Pacific Northwest delivered industrial and utility sector coal prices from 1976 to 1999.[13] Coal prices increased during the late 1970s with other energy prices, but since the early 1980s have declined steadily. On average, regional industrial coal prices decreased at an annual rate of 3.2 percent between 1980 and 1999. Regional utility coal prices have followed a similar pattern of decline, although utility prices were delayed a few years in following industrial prices downward. This may have been due to longer-term coal contracts for the coal-fired generation plants in the region.

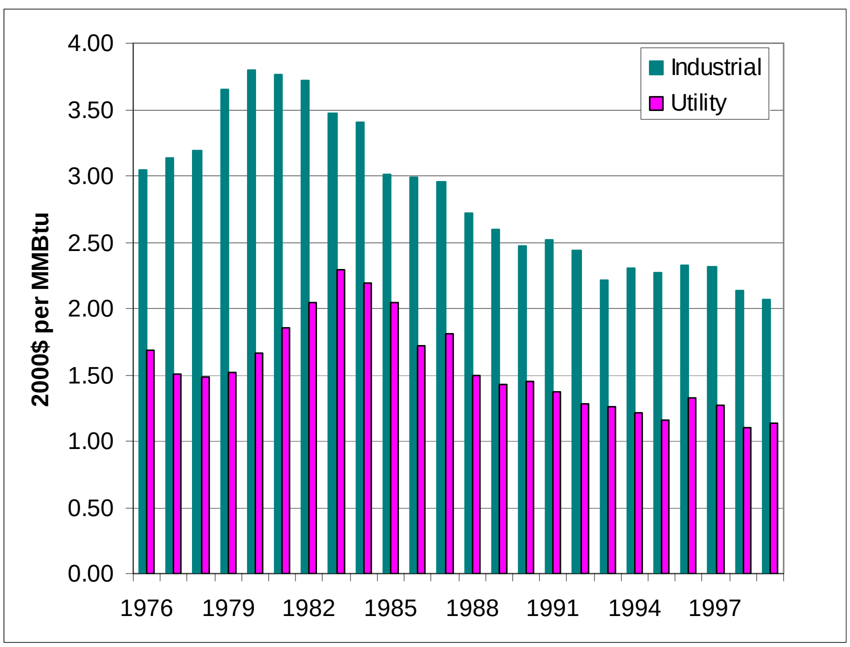


Figure B-20: Pacific Northwest Industrial and Utility Historical Coal Price Trends

[13] U.S. Energy Information Administration

Forecasts of coal prices rely on a very simple method. Different constant rates of price change for Western mine-mouth coal prices are assumed for the five forecast cases. The assumptions are shown in Table B-7. In all cases, the rapid declines in coal prices over the last 20 years are assumed to end. The medium case assumes stable prices. The lower cases assume slight decreases, and the higher cases slight increases. The EIA forecast of Western Coal prices grows at about the same rate as the Council's medium-high forecast.

Table B-7: Assumed Western Mine-mouth Coal Price Growth Rates

Forecast Case	Average Annual Rate of Growth
Low	- 0.8 %
Medium Low	- 0.5 %
Medium	0.0 %
Medium High	+ 0.5 %
High	+ 0.9 %

Delivered prices to Pacific Northwest industries and utilities are estimated by applying fixed mark-ups from Western mine-mouth prices to delivered prices. Because transportation costs are significant for coal, states that are farther away from the mines tend to have significantly higher delivered coal costs. Montana and Wyoming delivered costs, however, can be quite close to the mine-mouth price. Some coal-fired electricity generating plants are located at the mine and have little, if any, transportation cost. In more distant states, like Washington, the delivered cost can be more than 3 times the mine-mouth price. Table B-8 shows the additions to Western mine-mouth coal prices for the states in the West and the 2010 medium forecast of coal prices that result. Appendix B5 contains annual forecasts of coal prices for each of the forecast cases.

Table B-8: Derivation of State Electricity Generator Coal Prices, 2010 Medium Forecast (2000$ per Million Btu)

	Mark-up from Mine	Price Forecast
Western Mine-mouth		$ 0.51
Washington	$ + .99	1.50
Oregon	+ .53	1.05
Idaho	+ .45	.96
Montana	+ .01	.52
Utah	+ .62	1.13
Wyoming	+ .19	.70
Colorado	+ .47	.98
New Mexico	+ .86	1.37
Arizona	+ .82	1.33
Nevada	+.88	1.39

APPENDIX B1 - FUEL PRICE FORECASTING MODEL

Introduction

This Appendix describes the fuel price forecasting model that was used for the Council's Fifth Power Plan. The model consists of several worksheets linked together in an EXCEL "workbook."

The model includes forecasts of natural gas, oil and coal prices. Retail fuel prices for the various demand sectors are derived from the forecasts of basic energy commodity prices; that is, the world price of oil, the average wellhead price of natural gas, and Western mine-mouth coal prices. These energy prices are forecast by several organizations that specialize in energy market forecasting. Thus, basic energy price trends can be compared to a variety of forecasts which helps define a range of possible futures based on much more detailed modeling and analysis than the Council has the resources to accomplish alone. The prices of oil, natural gas, and coal, are not explicitly linked to one another. Rather, the relationships should be considered by the analyst in developing fuel price scenarios.

Retail prices are estimated by adding cost components to the basic energy commodity prices. Where possible these additional costs, or mark-ups, are based on historical relationships among energy costs to various sectors. Thus, the basic driving forces in the fuel price model are world oil price forecasts, wellhead natural gas price forecasts, coal price growth rates, and mark-ups to retail prices in various end-use sectors. In the case of natural gas, prices at various trading points in the West are estimated using equations describing the basis relationships among various locations.

The degree of detail devoted to each fuel depends on its relative importance to electricity planning. For example, natural gas is a very important determinant of both electricity demand and the cost of electricity generation from gas-fired plants. As a result, the natural gas forecasting approach is significantly more detailed than oil or coal. Oil plays a smaller role in competition with electricity use and in electricity generation and receives less attention. Coal plays little role in determining electricity demand and is treated very briefly in the model using assumed annual growth rates.

Model Components

Historical retail data for each fuel are kept on separate Excel files. These spreadsheets contain historical retail price data by state and consuming sector from the "State Energy Price and Expenditure Report" compiled by the U.S. Energy Information Administration (EIA). In addition, they contain consumption data from the "State Energy Data Report," also published by EIA. The spreadsheets convert the prices to real 2000 dollars and calculate consumption weighted average regional prices for each end-use sector. In addition, wholesale market price data is maintained in separate files.

Forecasts of world oil prices and natural gas wellhead prices are developed in the WOPFC and NGFC tabs, respectively, in the FUELMOD04 Excel Workbook. They take historical data, consistent with the historical fuel price worksheets described in the previous paragraph, and merge it with forecasts in five-year intervals. The worksheet interpolates between the five-year forecasts to get annual values. These tabs also contain previous Council forecasts and forecasts by other organizations for comparison purposes.

MAIN contains the forecasts of basic oil and gas commodity prices calculated in WOPFC and NGFC for a specific forecast case and any other scenario dependent assumptions and parameters. It also compares the model estimates of industrial residual oil prices, interruptible gas prices, and coal prices. Wellhead gas prices feed into the gas price model and world oil prices feed into the oil price model. MAIN contains the scenario controls and variables for the entire model. The varying scenario assumptions and their cell locations are as follows:

Scenario Name	B2
Wellhead Natural Gas Price	B30:B54
World Oil Price	C30:C54
Real Growth Rate of Incremental Pipeline Costs	D60
Coal Price Growth Rate	D61
Firm Natural Gas Supply Share	D62

The separate tabs in FUELMOD04 are described at the end of this appendix in a section entitled Model Components, which is a printout of the first tab ("DOC") in the model. The model structure is described in more detail below.

Natural Gas Model

The natural gas price-forecasting component is far more detailed than the oil or coal components. This is not only because natural gas is currently the strongest competitor to electricity, but also because of the lack of reliable historical price information for large industrial and electric utility gas purchases.

The natural gas price forecasts begin with a forecast of average U.S. wellhead prices. These are used to estimate prices at other trading points throughout the West in the tab called NG West. In addition, state utility natural gas prices are estimated in NG West. Where supported by historical data, regression equations were estimated that relate these various natural gas prices. For a description of the data and estimations see Council staff paper "Developing Basis Relationships Among Western Natural Gas Pricing Points".

There are three separate worksheets for Pacific Northwest natural gas price forecasts by sector: INDUST, which contains industrial sector forecasts; NWUTIL which contains electricity generator forecasts; RES_COM which contains residential and commercial forecasts. A separate worksheet, COMPONENTS, supports the industrial and electricity generator price forecasts by accounting for the various components of cost that are incurred between the wellhead and the end-user. The worksheet GASSUM is simply a report that summarizes the natural gas price forecasts. The tabs 00$NWUtil and AURORA report fixed and variable cost of natural gas for electricity generators.

Residential and commercial sector gas prices are based on historical regional retail prices compared to U.S. wellhead prices. For historical years, the difference between wellhead prices and retail prices are calculated. For forecast years, the projected difference is added to the wellhead price forecast. The differences, or mark-ups, can be projected from historical trends, other forecasting models, or judgment.

Gas prices for small industrial gas users that rely on local gas distribution companies to supply their gas are forecast in the same manner as residential and commercial users. However, large firm or interruptible customers, whether industrial or electricity generators, must be handled with a different method. This is because there is no reliable historical price series for these gas users to base a simple mark-up on. For these customers, the difference between wellhead and end user prices is built up from a set of transportation cost components appropriate to the specific type of gas use. These components are developed in the worksheet COMPONENTS.

The components include pipeline capacity costs, pipeline commodity costs, pipeline fuel use, local distribution costs, and firm gas supply premiums, if any. These adjustments are applied to AECO prices for the regional eastside prices, and to Sumas for the regional westside prices. Three types of pipeline capacity costs are used; incremental firm, rolled-in firm, and interruptible or capacity release. New electricity generation plants are assumed to require incremental firm pipeline capacity. The part of pipeline capacity costs that could not likely be recovered from the capacity release market becomes a part of fixed fuel costs.

Tables B1-1 and B1-2 show the various transportation components, their column location in the COMPONENTS worksheet, and the current value or range of values in the model. Table B1-1 applies to a large natural gas consumer on the west side of the Cascades and Table B1-2 applies to the same kind of consumer on the east side.

Table B1-1: West-Side Cost Components for Calculating Delivered Natural Gas Prices.

Cost Component	Components Column	Constant Costs (2000$/MMBtu)	Scenario Variant				
			L	ML	M	MH	H
U.S. Wellhead Price	B						
Henry Hub Price	C						
Sumas Price *	Q						
Pipeline Capacity Costs							
Firm Rolled-In	E	+ .28					
Firm Incremental	G	+.55 in 2006 + growth	-0.1	0.1	0.3	0.5	0.7
Released Capacity Cost *	I	+ .21					
Pipeline Commodity Cost	K	+ .04					
Pipeline In-Kind Fuel Cost *	E61	+ 1.74 %					
LDC Distribution Cost	M	+ .20					
Firm Supply Premium	N	+ 0.0					

* Summer and winter values are different from the averages show here

The resource planning models require utility gas prices in terms of their fixed and variable components. Variable costs include wellhead prices adjusted for regional differences, pipeline fuel costs, and pipeline commodity charges. These are costs that can be avoided if electricity is not generated. In addition, some portion of the pipeline capacity charge may be avoided through resale in the capacity release market. The share of firm pipeline capacity costs that can be recovered by resale in the capacity release market is a parameter in the model and is currently assumed to equal 10 percent. For example, if it were not possible to recover any pipeline capacity costs then they become fixed costs. The other potentially fixed cost is any premium that must be paid to secure firm gas supply, but this is currently assumed to be zero. Fixed costs are expressed in dollars per kilowatt per year, instead of dollars per million Btu.

Table B1-2: East-Side Cost Components for Calculating Delivered Natural Gas Prices.

Cost Component	Components Column	Constant Costs (2000$/MMBtu)	Scenario Variant				
			L	ML	M	MH	H
U.S. Wellhead Price	B						
Henry Hub Price	C						
AECO Price	P						
Pipeline Capacity Cost							
Firm Rolled-In	F	+ .29					
Firm Incremental	H	+.45 in 2007 + growth	-0.1	0.1	0.3	0.5	0.7
Released Capacity Cost *	J	+ .23					
Pipeline Commodity Cost	L	+ .01					
Pipeline In-Kind Fuel Cost *	F62	+ 2.80 %					
LDC Distribution Cost	M	+ .20					
Firm Supply Premium	N	+ 0.0					

* Summer and winter values are different from the averages show here

Oil Model

The oil price forecasting model first estimates the refiner price of distillate and residual oil based on the assumed world price for crude oil. This is done using a very simple model of refinery economics.[14] Retail prices of oil products for the industrial, residential, and commercial sectors are then calculated by adding mark-ups based on the historical difference between calculated refiner wholesale prices and actual retail prices.

The simple model of refiner economics considers the cost of crude oil, the cost of refining crude oil into heavy and light oil products, and the value of those products in the market. It assumes that refiners will decide on their production mix so that their profits will be maximized. That is, the difference between the revenue received from the sale of products and the costs of crude oil and refining it into products will be maximized.

The underlying assumptions are as follows:

Refining costs:

Simple refining
- $2.15 per barrel in 2000$.
- Saudi light yields 47 percent heavy oil.
- 3 percent energy penalty.

Complex refining
- $5.38 per barrel in 2000$.
- yield 100 percent light oil.
- 12 percent energy penalty, about 6-8 percent above simple refining.

Desulpherization
- $3.91 per barrel in 2000$.
- 4 to - 8 percent energy penalty.
- Assumed not to be necessary in NW.

Profit Equations:

<u>Simple refinery</u>

Revenue = .47H + .53L
Cost = C + .03C + 2.15
Profit = (.47H + .53L) - (C + .03C + 2.15)

Where:
.47 is residual oil output share.
.53 is distillate oil output share.
H is residual oil wholesale price.
L is distillate oil wholesale price.
C is cost of crude oil
.03 is the energy penalty for simple refining.

[14]This refinery model evolved from the old Council fuel price forecasting method developed by Energy Analysis and Planning, Inc. That company has evolved into Economic Insight Inc.

2.15 is the refining cost per barrel.

Complex refinery

Revenue $= L$
Cost $= C + .12C + 5.38$
Profit $= L - (C + .12C + 5.38)$

Equilibrium Condition: Profit from heavy products equals profit from light products at the margin.

$$.47H + .53L - C - .03C - 2.15 = L - C - .12C - 5.38$$

Solve for product prices:

$$.47H + .53L - L = .03C - .12C - 5.38 + 2.15$$

$$.47(H - L) = -.09C - 3.23$$

$$(H - L) = -.1915C - 6.8723$$

Using $L = C + .12C + 5.38$ gives

$$H = -.1915C - 6.8723 + C + .12C + 5.38$$

$$H = .9285C - 1.5133$$ (Equation for residual oil price as a function of crude oil price.)

The simple refinery model thus gives the estimates of residual oil (heavy) and distillate oil (light) prices based on the assumed crude oil prices. Distillate wholesale prices equals 112 percent of the crude oil price plus $5.38 (2000$) per barrel. Residual oil wholesales price equals 93 percent of the crude oil price less $1.51

Historically based mark-ups are added to get retail prices for residual and distillate oil for the commercial, industrial and utility sectors. The two oil products prices are then consumption weighted to get an average oil price for the sector. The residential sector does not use residual oil so only a distillate retail price is calculated.

Coal Model

The coal model is a very simple approach. Average Western mine-mouth coal prices are forecast by applying assumed, scenario-specific, growth rates to a base year level. Regional utility and industry prices, and state-specific utility prices are forecast based on time- invariant differentials from western the mine-mouth prices.

Model Components (Tabs in the Excel Workbook)

DOC	-- Describes files in the forecast model
NGFC	-- Contains historical prices and the forecast range of wellhead gas prices. Scenarios are to be copied into MAIN for each case. Contains GDP deflators for converting historical to study year dollars.
WOPFC	-- Contains historical prices and the forecast range of world oil prices. Scenarios are to be copied into MAIN for each case.
MAIN	-- Contains drivers for forecast model and includes scenario varient values. (Avg. wellhead, world oil, GNP deflators etc. Displays boiler fuel relative gas, oil, coal prices
Basis	-- Contains regional basis differential assumptions for each scenario To be copied into MAIN for each scenario.
NG West	-- Develops forecasts of natural gas prices at major Western pricing points
Components	-- Combines the various components of pipeline and distribution cost, regional wellhead price difference, and other add-ons to the wellhead gas price. These adders are used in the INDUST and NWUTIL sheets.
RES_COM	-- Residential & Commercial gas price model, linked to MAIN wellhead prices by retail price differences.
INDUST	-- Industrial gas price model, linked to MAIN wellhead Large interruptible, Avg. transport, through LDC & Mixed
NWUTIL	-- PNW Utility gas price model, linked to MAIN wellhead Interruptible and Firm burner-tip
00$ NWUtil	-- Shows derivation of West-side and East-side Firm utility gas prices
AURORA	-- Develops fixed and variable natural gas prices for AURORA™ Model pricing points in the WECC
GASSUM	-- Summary table for gas price forecasts, linked to the individual sector worksheets.
OILMOD	-- Estimates retail oil prices for all sectors, linked to MAIN

world oil price forecasts.

OilSum -- Summary of retail oil price forecasts for residual and distillate in both midyear 2000 dollars and Jan 2000 dollars.

COALMOD -- Forecasts industrial coal prices based on exogenous growth rate read from MAIN.

Tables -- Develops tables to be included in forecast documents

FUELS -- Puts the fuel price forecasts in the format needed for input to demand forecasting models, converts to 1980 dollars

Export -- File to be exported for demand model inputs.

APPENDIX B2 - FORECAST TABLES FOR U.S. WELLHEAD AND REGIONAL MARKET PRICES

Table B2-1 - Medium
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

Medium Case					
Year	U.S. Wellhead Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	5.98	6.58	3.77
2001	4.03	4.14	3.59	4.15	4.59
2002	2.80	2.57	2.65	3.18	2.97
2003	4.62	4.94	4.32	4.88	5.41
2004	5.45	5.12	5.21	5.85	5.66
2005	5.30	4.97	5.06	5.69	5.50
2006	5.01	4.68	4.78	5.45	5.22
2007	4.74	4.40	4.50	5.17	4.99
2008	4.48	4.14	4.24	4.91	4.72
2009	4.23	3.89	4.00	4.67	4.47
2010	4.00	3.66	3.77	4.43	4.23
2011	3.96	3.62	3.73	4.39	4.19
2012	3.92	3.58	3.69	4.35	4.15
2013	3.88	3.54	3.65	4.32	4.11
2014	3.84	3.50	3.61	4.28	4.07
2015	3.80	3.46	3.57	4.24	4.03
2016	3.82	3.48	3.59	4.26	4.05
2017	3.84	3.50	3.61	4.28	4.07
2018	3.86	3.52	3.63	4.30	4.10
2019	3.88	3.54	3.65	4.33	4.12
2020	3.90	3.56	3.67	4.35	4.14
2021	3.92	3.58	3.69	4.37	4.16
2022	3.94	3.60	3.71	4.39	4.18
2023	3.96	3.62	3.73	4.41	4.21
2024	3.98	3.64	3.75	4.44	4.23
2025	4.00	3.66	3.77	4.46	4.25

Table B2-2 - Low
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

Low Case					
Year	U.S. Wellhead Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	5.98	6.58	3.77
2001	4.03	4.14	3.59	4.15	4.59
2002	2.80	2.57	2.65	3.18	2.97
2003	4.62	4.94	4.32	4.88	5.41
2004	4.75	4.41	4.52	5.14	4.93
2005	4.50	4.16	4.27	4.88	4.67
2006	4.15	3.81	3.92	4.58	4.33
2007	3.83	3.49	3.60	4.25	4.05
2008	3.53	3.19	3.30	3.95	3.74
2009	3.25	2.91	3.03	3.67	3.45
2010	3.00	2.65	2.77	3.41	3.19
2011	2.95	2.60	2.72	3.36	3.13
2012	2.90	2.55	2.67	3.31	3.08
2013	2.85	2.50	2.62	3.25	3.03
2014	2.80	2.45	2.57	3.20	2.98
2015	2.75	2.40	2.53	3.15	2.93
2016	2.78	2.43	2.55	3.18	2.96
2017	2.81	2.46	2.58	3.21	2.99
2018	2.84	2.49	2.61	3.24	3.02
2019	2.87	2.52	2.64	3.27	3.05
2020	2.90	2.55	2.67	3.30	3.08
2021	2.92	2.57	2.69	3.32	3.10
2022	2.94	2.59	2.71	3.34	3.12
2023	2.96	2.61	2.73	3.36	3.14
2024	2.98	2.63	2.75	3.38	3.16
2025	3.00	2.65	2.77	3.40	3.18

Table B2-3 - Medium-Low
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

Medium Low Case					
Year	U.S. Wellhead Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	5.98	6.58	3.77
2001	4.03	4.14	3.59	4.15	4.59
2002	2.80	2.57	2.65	3.18	2.97
2003	4.62	4.94	4.32	4.88	5.41
2004	5.20	4.87	4.96	5.59	5.40
2005	4.90	4.57	4.67	5.29	5.09
2006	4.53	4.19	4.30	4.96	4.72
2007	4.18	3.84	3.95	4.61	4.42
2008	3.87	3.52	3.64	4.29	4.09
2009	3.57	3.23	3.34	3.99	3.78
2010	3.30	2.96	3.07	3.72	3.50
2011	3.32	2.98	3.09	3.74	3.52
2012	3.34	3.00	3.11	3.76	3.54
2013	3.36	3.02	3.13	3.78	3.57
2014	3.38	3.04	3.15	3.80	3.59
2015	3.40	3.06	3.17	3.82	3.61
2016	3.42	3.08	3.19	3.84	3.63
2017	3.44	3.10	3.21	3.86	3.65
2018	3.46	3.12	3.23	3.89	3.67
2019	3.48	3.14	3.25	3.91	3.69
2020	3.50	3.16	3.27	3.93	3.71
2021	3.50	3.16	3.27	3.93	3.71
2022	3.50	3.16	3.27	3.93	3.71
2023	3.50	3.16	3.27	3.93	3.72
2024	3.50	3.16	3.27	3.93	3.72
2025	3.50	3.16	3.27	3.93	3.72

Table B2-4 - Medium-High
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

Medium High Case					
Year	U.S. Wellhead Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	5.98	6.58	3.77
2001	4.03	4.14	3.59	4.15	4.59
2002	2.80	2.57	2.65	3.18	2.97
2003	4.62	4.94	4.32	4.88	5.41
2004	5.60	5.27	5.36	6.00	5.81
2005	6.00	5.67	5.76	6.40	6.23
2006	5.66	5.34	5.43	6.11	5.90
2007	5.35	5.02	5.11	5.80	5.62
2008	5.05	4.72	4.81	5.49	5.31
2009	4.77	4.43	4.53	5.21	5.02
2010	4.50	4.16	4.27	4.94	4.75
2011	4.46	4.12	4.23	4.91	4.71
2012	4.42	4.08	4.19	4.87	4.67
2013	4.38	4.04	4.15	4.83	4.63
2014	4.34	4.00	4.11	4.79	4.59
2015	4.30	3.96	4.07	4.76	4.55
2016	4.31	3.97	4.08	4.77	4.57
2017	4.32	3.98	4.09	4.78	4.58
2018	4.33	3.99	4.10	4.79	4.59
2019	4.34	4.00	4.11	4.81	4.61
2020	4.35	4.01	4.12	4.82	4.62
2021	4.38	4.04	4.15	4.85	4.65
2022	4.41	4.07	4.18	4.89	4.68
2023	4.44	4.10	4.21	4.92	4.72
2024	4.47	4.13	4.24	4.95	4.75
2025	4.50	4.16	4.27	4.99	4.79

Table B2-5 - High
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

High Case					
Year	U.S. Wellhead Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	5.98	6.58	3.77
2001	4.03	4.14	3.59	4.15	4.59
2002	2.80	2.57	2.65	3.18	2.97
2003	4.62	4.94	4.32	4.88	5.41
2004	5.80	5.47	5.56	6.20	6.02
2005	6.75	6.43	6.51	7.16	7.00
2006	6.36	6.03	6.12	6.81	6.62
2007	5.99	5.66	5.75	6.44	6.28
2008	5.64	5.31	5.40	6.09	5.92
2009	5.31	4.98	5.07	5.77	5.59
2010	5.00	4.67	4.77	5.46	5.27
2011	4.98	4.65	4.75	5.44	5.25
2012	4.96	4.63	4.73	5.42	5.24
2013	4.94	4.61	4.71	5.41	5.22
2014	4.92	4.59	4.69	5.39	5.20
2015	4.90	4.57	4.67	5.37	5.18
2016	4.92	4.59	4.69	5.40	5.21
2017	4.94	4.61	4.71	5.42	5.23
2018	4.96	4.63	4.73	5.45	5.26
2019	4.98	4.65	4.75	5.47	5.28
2020	5.00	4.67	4.77	5.50	5.30
2021	5.02	4.69	4.79	5.52	5.33
2022	5.04	4.71	4.81	5.55	5.35
2023	5.06	4.73	4.83	5.57	5.38
2024	5.08	4.75	4.85	5.59	5.40
2025	5.10	4.77	4.87	5.62	5.42

APPENDIX B3 - FORECAST TABLES FOR U.S. WELLHEAD AND REGIONAL RETAIL NATURAL GAS PRICES

Table B3-1 - Medium
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

Medium Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	5.91	5.13
2001	4.03	8.38	6.68	4.49	4.32
2002	2.80	7.05	6.05	3.55	3.03
2003	4.62	8.87	7.87	5.29	5.10
2004	5.45	9.70	8.70	6.18	5.67
2005	5.30	9.55	8.55	6.02	5.52
2006	5.01	9.26	8.26	5.73	5.24
2007	4.74	8.99	7.99	5.45	4.97
2008	4.48	8.73	7.73	5.19	4.71
2009	4.23	8.48	7.48	4.94	4.46
2010	4.00	8.25	7.25	4.70	4.22
2011	3.96	8.21	7.21	4.66	4.18
2012	3.92	8.17	7.17	4.62	4.14
2013	3.88	8.13	7.13	4.58	4.10
2014	3.84	8.09	7.09	4.54	4.06
2015	3.80	8.05	7.05	4.50	4.02
2016	3.82	8.07	7.07	4.51	4.04
2017	3.84	8.09	7.09	4.53	4.06
2018	3.86	8.11	7.11	4.55	4.08
2019	3.88	8.13	7.13	4.57	4.10
2020	3.90	8.15	7.15	4.59	4.13
2021	3.92	8.17	7.17	4.61	4.15
2022	3.94	8.19	7.19	4.63	4.17
2023	3.96	8.21	7.21	4.65	4.19
2024	3.98	8.23	7.23	4.67	4.21
2025	4.00	8.25	7.25	4.68	4.23

Table B3-2 - Low
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

Low Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	5.91	5.13
2001	4.03	8.38	6.68	4.49	4.32
2002	2.80	7.05	6.05	3.55	3.03
2003	4.62	8.87	7.87	5.29	5.10
2004	4.75	9.00	8.00	5.47	4.96
2005	4.50	8.75	7.75	5.22	4.70
2006	4.15	8.40	7.40	4.86	4.36
2007	3.83	8.08	7.08	4.53	4.04
2008	3.53	7.78	6.78	4.23	3.73
2009	3.25	7.50	6.50	3.95	3.45
2010	3.00	7.25	6.25	3.69	3.19
2011	2.95	7.20	6.20	3.64	3.14
2012	2.90	7.15	6.15	3.59	3.09
2013	2.85	7.10	6.10	3.54	3.04
2014	2.80	7.05	6.05	3.49	2.99
2015	2.75	7.00	6.00	3.44	2.94
2016	2.78	7.03	6.03	3.46	2.97
2017	2.81	7.06	6.06	3.49	3.00
2018	2.84	7.09	6.09	3.52	3.03
2019	2.87	7.12	6.12	3.55	3.06
2020	2.90	7.15	6.15	3.58	3.09
2021	2.92	7.17	6.17	3.60	3.11
2022	2.94	7.19	6.19	3.62	3.13
2023	2.96	7.21	6.21	3.64	3.15
2024	2.98	7.23	6.23	3.66	3.17
2025	3.00	7.25	6.25	3.68	3.19

Table B3-3 - Medium-Low
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

Medium Low Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	5.91	5.13
2001	4.03	8.38	6.68	4.49	4.32
2002	2.80	7.05	6.05	3.55	3.03
2003	4.62	8.87	7.87	5.29	5.10
2004	5.20	9.45	8.45	5.92	5.42
2005	4.90	9.15	8.15	5.62	5.11
2006	4.53	8.78	7.78	5.24	4.75
2007	4.18	8.43	7.43	4.89	4.41
2008	3.87	8.12	7.12	4.57	4.08
2009	3.57	7.82	6.82	4.27	3.78
2010	3.30	7.55	6.55	4.00	3.50
2011	3.32	7.57	6.57	4.02	3.52
2012	3.34	7.59	6.59	4.03	3.54
2013	3.36	7.61	6.61	4.05	3.56
2014	3.38	7.63	6.63	4.07	3.58
2015	3.40	7.65	6.65	4.09	3.61
2016	3.42	7.67	6.67	4.11	3.63
2017	3.44	7.69	6.69	4.13	3.65
2018	3.46	7.71	6.71	4.15	3.67
2019	3.48	7.73	6.73	4.17	3.69
2020	3.50	7.75	6.75	4.19	3.71
2021	3.50	7.75	6.75	4.19	3.71
2022	3.50	7.75	6.75	4.18	3.71
2023	3.50	7.75	6.75	4.18	3.71
2024	3.50	7.75	6.75	4.18	3.71
2025	3.50	7.75	6.75	4.18	3.71

Table B3-4 - Medium-High
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

Medium High Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	5.91	5.13
2001	4.03	8.38	6.68	4.49	4.32
2002	2.80	7.05	6.05	3.55	3.03
2003	4.62	8.87	7.87	5.29	5.10
2004	5.60	9.85	8.85	6.33	5.83
2005	6.00	10.25	9.25	6.73	6.24
2006	5.66	9.91	8.91	6.39	5.91
2007	5.35	9.60	8.60	6.07	5.60
2008	5.05	9.30	8.30	5.77	5.29
2009	4.77	9.02	8.02	5.48	5.01
2010	4.50	8.75	7.75	5.21	4.73
2011	4.46	8.71	7.71	5.17	4.69
2012	4.42	8.67	7.67	5.12	4.65
2013	4.38	8.63	7.63	5.08	4.61
2014	4.34	8.59	7.59	5.04	4.58
2015	4.30	8.55	7.55	5.00	4.54
2016	4.31	8.56	7.56	5.01	4.55
2017	4.32	8.57	7.57	5.02	4.56
2018	4.33	8.58	7.58	5.03	4.57
2019	4.34	8.59	7.59	5.04	4.58
2020	4.35	8.60	7.60	5.04	4.59
2021	4.38	8.63	7.63	5.07	4.63
2022	4.41	8.66	7.66	5.10	4.66
2023	4.44	8.69	7.69	5.13	4.69
2024	4.47	8.72	7.72	5.16	4.72
2025	4.50	8.75	7.75	5.19	4.75

Table B3-5 - High
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

High Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	5.91	5.13
2001	4.03	8.38	6.68	4.49	4.32
2002	2.80	7.05	6.05	3.55	3.03
2003	4.62	8.87	7.87	5.29	5.10
2004	5.80	10.05	9.05	6.53	6.03
2005	6.75	11.00	10.00	7.49	7.01
2006	6.36	10.61	9.61	7.09	6.62
2007	5.99	10.24	9.24	6.71	6.25
2008	5.64	9.89	8.89	6.36	5.90
2009	5.31	9.56	8.56	6.03	5.56
2010	5.00	9.25	8.25	5.71	5.25
2011	4.98	9.23	8.23	5.69	5.23
2012	4.96	9.21	8.21	5.67	5.21
2013	4.94	9.19	8.19	5.65	5.19
2014	4.92	9.17	8.17	5.63	5.17
2015	4.90	9.15	8.15	5.61	5.16
2016	4.92	9.17	8.17	5.62	5.18
2017	4.94	9.19	8.19	5.64	5.20
2018	4.96	9.21	8.21	5.66	5.22
2019	4.98	9.23	8.23	5.68	5.24
2020	5.00	9.25	8.25	5.70	5.27
2021	5.02	9.27	8.27	5.72	5.29
2022	5.04	9.29	8.29	5.74	5.31
2023	5.06	9.31	8.31	5.76	5.33
2024	5.08	9.33	8.33	5.78	5.36
2025	5.10	9.35	8.35	5.80	5.38

APPENDIX B4 - FORECAST TABLES FOR WORLD OIL AND REGIONAL RETAIL OIL PRICES

Table B4-1 - Medium
Retail Oil Price Forecast

Medium Case		Industrial	Industrial	Average	Commercial	Commercial	Average	Average	Utility	Utility
Year	World Oil Price (00$/Bbl.)	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Industrial Oil Price	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Commercial Oil Price	Residential Oil Price (00$/MMBtu)	Residual Oil Price (00$/MMBtu)	Distillate Oil Price
2000	27.70	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	21.49	3.17	6.06	5.89	3.22	5.64	5.52	8.04	3.17	5.52
2002	22.81	3.37	6.31	6.14	3.42	5.89	5.77	8.29	3.37	5.77
2003	26.23	3.87	6.97	6.78	3.92	6.55	6.42	8.95	3.87	6.43
2004	34.00	5.02	8.46	8.26	5.07	8.04	7.90	10.44	5.02	7.92
2005	30.00	4.43	7.69	7.50	4.48	7.27	7.14	9.67	4.43	7.15
2006	29.37	4.34	7.57	7.38	4.39	7.15	7.02	9.55	4.34	7.03
2007	28.76	4.25	7.45	7.27	4.30	7.03	6.90	9.43	4.25	6.91
2008	28.16	4.16	7.34	7.15	4.21	6.92	6.79	9.32	4.16	6.80
2009	27.57	4.07	7.23	7.04	4.12	6.81	6.68	9.21	4.07	6.69
2010	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2011	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2012	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2013	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2014	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2015	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2016	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2017	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2018	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2019	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2020	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2021	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2022	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2023	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2024	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2025	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58

Table B4-2 - Low
Retail Oil Price Forecast

Low Case		Industrial	Industrial	Average	Commercial	Commercial	Average	Average	Utility	Utility
Year	World Oil Price (00$/Bbl.)	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Industrial Oil Price	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Commercial Oil Price	Residential Oil Price (00$/MMBtu)	Residual Oil Price (00$/MMBtu)	Distillate Oil Price
2000	27.70	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	21.49	3.17	6.06	5.89	3.22	5.64	5.52	8.04	3.17	5.52
2002	22.81	3.37	6.31	6.14	3.42	5.89	5.77	8.29	3.37	5.77
2003	26.23	3.87	6.97	6.78	3.92	6.55	6.42	8.95	3.87	6.43
2004	30.00	4.43	7.69	7.50	4.48	7.27	7.14	9.67	4.43	7.15
2005	25.00	3.69	6.73	6.55	3.74	6.31	6.19	8.71	3.69	6.19
2006	23.91	3.53	6.52	6.34	3.58	6.10	5.98	8.50	3.53	5.98
2007	22.87	3.38	6.32	6.15	3.43	5.90	5.78	8.30	3.38	5.78
2008	21.87	3.23	6.13	5.96	3.28	5.71	5.59	8.11	3.23	5.59
2009	20.91	3.09	5.94	5.78	3.14	5.52	5.41	7.92	3.09	5.40
2010	20.00	2.95	5.77	5.60	3.00	5.35	5.24	7.75	2.95	5.23
2011	19.58	2.89	5.69	5.52	2.94	5.27	5.16	7.67	2.89	5.15
2012	19.17	2.83	5.61	5.45	2.88	5.19	5.08	7.59	2.83	5.07
2013	18.77	2.77	5.53	5.37	2.82	5.11	5.00	7.51	2.77	4.99
2014	18.38	2.71	5.46	5.30	2.76	5.04	4.93	7.44	2.71	4.92
2015	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2016	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2017	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2018	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2019	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2020	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2021	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2022	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2023	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2024	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2025	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84

Table B4-3 - Medium-Low
Retail Oil Price Forecast

Medium Low Case		Industrial	Industrial	Average	Commercial	Commercial	Average	Average	Utility	Utility
Year	World Oil Price (00$/Bbl.)	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Industrial Oil Price	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Commercial Oil Price	Residential Oil Price (00$/MMBtu)	Residual Oil Price (00$/MMBtu)	Distillate Oil Price
2000	27.70	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	21.49	3.17	6.06	5.89	3.22	5.64	5.52	8.04	3.17	5.52
2002	22.81	3.37	6.31	6.14	3.42	5.89	5.77	8.29	3.37	5.77
2003	26.23	3.87	6.97	6.78	3.92	6.55	6.42	8.95	3.87	6.43
2004	32.00	4.73	8.08	7.88	4.78	7.66	7.52	10.06	4.73	7.54
2005	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2006	26.15	3.86	6.95	6.77	3.91	6.53	6.41	8.93	3.86	6.41
2007	25.32	3.74	6.79	6.61	3.79	6.37	6.25	8.77	3.74	6.25
2008	24.52	3.62	6.64	6.46	3.67	6.22	6.10	8.62	3.62	6.10
2009	23.75	3.51	6.49	6.31	3.56	6.07	5.95	8.47	3.51	5.95
2010	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2011	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2012	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2013	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2014	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2015	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2016	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2017	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2018	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2019	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2020	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2021	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2022	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2023	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2024	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2025	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81

Table B4-4 - Medium-High
Retail Oil Price Forecast

Medium High Case		Industrial	Industrial	Average	Commercial	Commercial	Average	Average	Utility	Utility
Year	World Oil Price (00$/Bbl.)	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Industrial Oil Price	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Commercial Oil Price	Residential Oil Price (00$/MMBtu)	Residual Oil Price (00$/MMBtu)	Distillate Oil Price
2000	27.70	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	21.49	3.17	6.06	5.89	3.22	5.64	5.52	8.04	3.17	5.52
2002	22.81	3.37	6.31	6.14	3.42	5.89	5.77	8.29	3.37	5.77
2003	26.23	3.87	6.97	6.78	3.92	6.55	6.42	8.95	3.87	6.43
2004	35.50	5.24	8.75	8.54	5.29	8.33	8.18	10.73	5.24	8.21
2005	36.00	5.32	8.85	8.64	5.37	8.43	8.28	10.83	5.32	8.31
2006	34.71	5.13	8.60	8.39	5.18	8.18	8.03	10.58	5.13	8.06
2007	33.47	4.94	8.36	8.16	4.99	7.94	7.80	10.34	4.94	7.82
2008	32.27	4.77	8.13	7.93	4.82	7.71	7.57	10.11	4.77	7.59
2009	31.11	4.59	7.91	7.71	4.64	7.49	7.35	9.89	4.59	7.37
2010	30.00	4.43	7.69	7.50	4.48	7.27	7.14	9.67	4.43	7.15
2011	29.59	4.37	7.61	7.42	4.42	7.19	7.06	9.59	4.37	7.07
2012	29.18	4.31	7.53	7.35	4.36	7.11	6.98	9.51	4.31	6.99
2013	28.78	4.25	7.46	7.27	4.30	7.04	6.91	9.44	4.25	6.92
2014	28.39	4.19	7.38	7.19	4.24	6.96	6.83	9.36	4.19	6.84
2015	28.00	4.13	7.31	7.12	4.18	6.89	6.76	9.29	4.13	6.77
2016	28.10	4.15	7.33	7.14	4.20	6.91	6.78	9.31	4.15	6.79
2017	28.20	4.16	7.35	7.16	4.21	6.93	6.80	9.33	4.16	6.81
2018	28.30	4.18	7.36	7.18	4.23	6.94	6.81	9.34	4.18	6.82
2019	28.40	4.19	7.38	7.20	4.24	6.96	6.83	9.36	4.19	6.84
2020	28.50	4.21	7.40	7.22	4.26	6.98	6.85	9.38	4.21	6.86
2021	28.60	4.22	7.42	7.23	4.27	7.00	6.87	9.40	4.22	6.88
2022	28.70	4.24	7.44	7.25	4.29	7.02	6.89	9.42	4.24	6.90
2023	28.80	4.25	7.46	7.27	4.30	7.04	6.91	9.44	4.25	6.92
2024	28.90	4.27	7.48	7.29	4.32	7.06	6.93	9.46	4.27	6.94
2025	29.00	4.28	7.50	7.31	4.33	7.08	6.95	9.48	4.28	6.96

Table B4-5 - High
Retail Oil Price Forecast

High Case		Industrial	Industrial	Average	Commercial	Commercial	Average	Average	Utility	Utility
Year	World Oil Price (00$/Bbl.)	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Industrial Oil Price	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Commercial Oil Price	Residential Oil Price (00$/MMBtu)	Residual Oil Price (00$/MMBtu)	Distillate Oil Price
2000	27.70	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	21.49	3.17	6.06	5.89	3.22	5.64	5.52	8.04	3.17	5.52
2002	22.81	3.37	6.31	6.14	3.42	5.89	5.77	8.29	3.37	5.77
2003	26.23	3.87	6.97	6.78	3.92	6.55	6.42	8.95	3.87	6.43
2004	37.00	5.46	9.04	8.83	5.51	8.62	8.47	11.02	5.46	8.50
2005	38.00	5.61	9.23	9.02	5.66	8.81	8.66	11.21	5.61	8.69
2006	37.38	5.52	9.11	8.90	5.57	8.69	8.54	11.09	5.52	8.57
2007	36.77	5.43	8.99	8.78	5.48	8.57	8.43	10.97	5.43	8.45
2008	36.17	5.34	8.88	8.67	5.39	8.46	8.31	10.86	5.34	8.34
2009	35.58	5.25	8.76	8.56	5.30	8.34	8.20	10.74	5.25	8.22
2010	35.00	5.17	8.65	8.45	5.22	8.23	8.09	10.63	5.17	8.11
2011	34.59	5.11	8.57	8.37	5.16	8.15	8.01	10.55	5.11	8.03
2012	34.19	5.05	8.50	8.29	5.10	8.08	7.93	10.48	5.05	7.96
2013	33.79	4.99	8.42	8.22	5.04	8.00	7.86	10.40	4.99	7.88
2014	33.39	4.93	8.34	8.14	4.98	7.92	7.78	10.32	4.93	7.80
2015	33.00	4.87	8.27	8.07	4.92	7.85	7.71	10.25	4.87	7.73
2016	33.00	4.87	8.27	8.07	4.92	7.85	7.71	10.25	4.87	7.73
2017	33.00	4.87	8.27	8.07	4.92	7.85	7.71	10.25	4.87	7.73
2018	33.00	4.87	8.27	8.07	4.92	7.85	7.71	10.25	4.87	7.73
2019	33.00	4.87	8.27	8.07	4.92	7.85	7.71	10.25	4.87	7.73
2020	33.00	4.87	8.27	8.07	4.92	7.85	7.71	10.25	4.87	7.73
2021	33.20	4.90	8.31	8.11	4.95	7.89	7.75	10.29	4.90	7.77
2022	33.40	4.93	8.34	8.14	4.98	7.92	7.78	10.32	4.93	7.80
2023	33.60	4.96	8.38	8.18	5.01	7.96	7.82	10.36	4.96	7.84
2024	33.80	4.99	8.42	8.22	5.04	8.00	7.86	10.40	4.99	7.88
2025	34.00	5.02	8.46	8.26	5.07	8.04	7.90	10.44	5.02	7.92

APPENDIX B5 - FORECAST TABLES FOR WESTERN MINE-MOUTH AND REGIONAL DELIVERED COAL PRICES

Table B5-1 - Medium
Coal Price Forecasts
(2000$ Per MMBtu)

Medium Case			Selected State Electricity Generation Coal Prices					
Year	Western Minemouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.65	1.09	0.71	0.00	1.39	0.81
2001	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2002	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2003	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2004	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2005	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2006	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2007	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2008	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2009	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2010	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2011	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2012	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2013	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2014	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2015	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2016	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2017	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2018	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2019	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2020	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2021	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2022	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2023	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2024	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2025	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70

Table B5-2 - Low
Coal Price Forecasts
(2000$ Per MMBtu)

Low Case			Selected State Electricity Generation Coal Prices					
Year	Western Minemouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.65	1.09	0.71	0.00	1.39	0.81
2001	0.51	2.11	1.50	1.04	0.52	0.96	1.13	0.70
2002	0.51	2.11	1.50	1.04	0.52	0.96	1.13	0.70
2003	0.50	2.10	1.49	1.03	0.51	0.95	1.12	0.69
2004	0.50	2.10	1.49	1.03	0.51	0.95	1.12	0.69
2005	0.49	2.09	1.48	1.03	0.50	0.94	1.11	0.68
2006	0.49	2.09	1.48	1.02	0.50	0.94	1.11	0.68
2007	0.49	2.09	1.48	1.02	0.50	0.94	1.11	0.68
2008	0.48	2.08	1.47	1.01	0.49	0.93	1.10	0.67
2009	0.48	2.08	1.47	1.01	0.49	0.93	1.10	0.67
2010	0.47	2.07	1.46	1.01	0.48	0.92	1.09	0.66
2011	0.47	2.07	1.46	1.00	0.48	0.92	1.09	0.66
2012	0.47	2.07	1.46	1.00	0.48	0.92	1.09	0.66
2013	0.46	2.06	1.45	1.00	0.47	0.91	1.08	0.65
2014	0.46	2.06	1.45	0.99	0.47	0.91	1.08	0.65
2015	0.46	2.06	1.45	0.99	0.47	0.91	1.08	0.65
2016	0.45	2.05	1.44	0.98	0.46	0.90	1.07	0.64
2017	0.45	2.05	1.44	0.98	0.46	0.90	1.07	0.64
2018	0.44	2.04	1.43	0.98	0.45	0.89	1.06	0.63
2019	0.44	2.04	1.43	0.97	0.45	0.89	1.06	0.63
2020	0.44	2.04	1.43	0.97	0.45	0.89	1.06	0.63
2021	0.43	2.03	1.42	0.97	0.44	0.88	1.05	0.62
2022	0.43	2.03	1.42	0.96	0.44	0.88	1.05	0.62
2023	0.43	2.03	1.42	0.96	0.44	0.88	1.05	0.62
2024	0.42	2.02	1.41	0.96	0.43	0.87	1.04	0.61
2025	0.42	2.02	1.41	0.95	0.43	0.87	1.04	0.61

Table B5-3 - Medium-Low
Coal Price Forecasts
(2000$ Per MMBtu)

Medium Low Case			Selected State Electricity Generation Coal Prices					
Year	Western Minemouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.65	1.09	0.71	0.00	1.39	0.81
2001	0.51	2.11	1.50	1.04	0.52	0.96	1.13	0.70
2002	0.51	2.11	1.50	1.04	0.52	0.96	1.13	0.70
2003	0.51	2.11	1.50	1.04	0.52	0.96	1.13	0.70
2004	0.50	2.10	1.49	1.04	0.51	0.95	1.12	0.69
2005	0.50	2.10	1.49	1.03	0.51	0.95	1.12	0.69
2006	0.50	2.10	1.49	1.03	0.51	0.95	1.12	0.69
2007	0.50	2.10	1.49	1.03	0.51	0.95	1.12	0.69
2008	0.49	2.09	1.48	1.03	0.50	0.94	1.11	0.68
2009	0.49	2.09	1.48	1.02	0.50	0.94	1.11	0.68
2010	0.49	2.09	1.48	1.02	0.50	0.94	1.11	0.68
2011	0.49	2.09	1.48	1.02	0.50	0.94	1.11	0.68
2012	0.48	2.08	1.47	1.02	0.49	0.93	1.10	0.67
2013	0.48	2.08	1.47	1.01	0.49	0.93	1.10	0.67
2014	0.48	2.08	1.47	1.01	0.49	0.93	1.10	0.67
2015	0.48	2.08	1.47	1.01	0.49	0.93	1.10	0.67
2016	0.47	2.07	1.46	1.01	0.48	0.92	1.09	0.66
2017	0.47	2.07	1.46	1.00	0.48	0.92	1.09	0.66
2018	0.47	2.07	1.46	1.00	0.48	0.92	1.09	0.66
2019	0.47	2.07	1.46	1.00	0.48	0.92	1.09	0.66
2020	0.46	2.06	1.45	1.00	0.47	0.91	1.08	0.65
2021	0.46	2.06	1.45	0.99	0.47	0.91	1.08	0.65
2022	0.46	2.06	1.45	0.99	0.47	0.91	1.08	0.65
2023	0.46	2.06	1.45	0.99	0.47	0.91	1.08	0.65
2024	0.46	2.06	1.45	0.99	0.47	0.91	1.08	0.65
2025	0.45	2.05	1.44	0.99	0.46	0.90	1.07	0.64

Table B5-4 - Medium-High
Coal Price Forecasts
(2000$ Per MMBtu)

Medium High Case			Selected State Electricity Generation Coal Prices					
Year	Western Minemouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.65	1.09	0.71	0.00	1.39	0.81
2001	0.52	2.12	1.51	1.05	0.53	0.97	1.14	0.71
2002	0.52	2.12	1.51	1.05	0.53	0.97	1.14	0.71
2003	0.52	2.12	1.51	1.05	0.53	0.97	1.14	0.71
2004	0.52	2.12	1.51	1.06	0.53	0.97	1.14	0.71
2005	0.53	2.13	1.52	1.06	0.54	0.98	1.15	0.72
2006	0.53	2.13	1.52	1.06	0.54	0.98	1.15	0.72
2007	0.53	2.13	1.52	1.06	0.54	0.98	1.15	0.72
2008	0.53	2.13	1.52	1.07	0.54	0.98	1.15	0.72
2009	0.54	2.14	1.53	1.07	0.55	0.99	1.16	0.73
2010	0.54	2.14	1.53	1.07	0.55	0.99	1.16	0.73
2011	0.54	2.14	1.53	1.08	0.55	0.99	1.16	0.73
2012	0.55	2.15	1.54	1.08	0.56	1.00	1.17	0.74
2013	0.55	2.15	1.54	1.08	0.56	1.00	1.17	0.74
2014	0.55	2.15	1.54	1.08	0.56	1.00	1.17	0.74
2015	0.55	2.15	1.54	1.09	0.56	1.00	1.17	0.74
2016	0.56	2.16	1.55	1.09	0.57	1.01	1.18	0.75
2017	0.56	2.16	1.55	1.09	0.57	1.01	1.18	0.75
2018	0.56	2.16	1.55	1.09	0.57	1.01	1.18	0.75
2019	0.56	2.16	1.55	1.10	0.57	1.01	1.18	0.75
2020	0.57	2.17	1.56	1.10	0.58	1.02	1.19	0.76
2021	0.57	2.17	1.56	1.10	0.58	1.02	1.19	0.76
2022	0.57	2.17	1.56	1.11	0.58	1.02	1.19	0.76
2023	0.58	2.18	1.57	1.11	0.59	1.03	1.20	0.77
2024	0.58	2.18	1.57	1.11	0.59	1.03	1.20	0.77
2025	0.58	2.18	1.57	1.11	0.59	1.03	1.20	0.77

Table B5-5 - High
Coal Price Forecasts
(2000$ Per MMBtu)

High Case			Selected State Electricity Generation Coal Prices					
Year	Western Minemouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.65	1.09	0.71	0.00	1.39	0.81
2001	0.52	2.12	1.51	1.05	0.53	0.97	1.14	0.71
2002	0.52	2.12	1.51	1.06	0.53	0.97	1.14	0.71
2003	0.53	2.13	1.52	1.06	0.54	0.98	1.15	0.72
2004	0.53	2.13	1.52	1.07	0.54	0.98	1.15	0.72
2005	0.54	2.14	1.53	1.07	0.55	0.99	1.16	0.73
2006	0.54	2.14	1.53	1.07	0.55	0.99	1.16	0.73
2007	0.55	2.15	1.54	1.08	0.56	1.00	1.17	0.74
2008	0.55	2.15	1.54	1.08	0.56	1.00	1.17	0.74
2009	0.56	2.16	1.55	1.09	0.57	1.01	1.18	0.75
2010	0.56	2.16	1.55	1.09	0.57	1.01	1.18	0.75
2011	0.57	2.17	1.56	1.10	0.58	1.02	1.19	0.76
2012	0.57	2.17	1.56	1.10	0.58	1.02	1.19	0.76
2013	0.58	2.18	1.57	1.11	0.59	1.03	1.20	0.77
2014	0.58	2.18	1.57	1.11	0.59	1.03	1.20	0.77
2015	0.59	2.19	1.58	1.12	0.60	1.04	1.21	0.78
2016	0.59	2.19	1.58	1.13	0.60	1.04	1.21	0.78
2017	0.60	2.20	1.59	1.13	0.61	1.05	1.22	0.79
2018	0.60	2.20	1.59	1.14	0.61	1.05	1.22	0.79
2019	0.61	2.21	1.60	1.14	0.62	1.06	1.23	0.80
2020	0.61	2.21	1.60	1.15	0.62	1.06	1.23	0.80
2021	0.62	2.22	1.61	1.15	0.63	1.07	1.24	0.81
2022	0.63	2.23	1.62	1.16	0.64	1.08	1.25	0.82
2023	0.63	2.23	1.62	1.16	0.64	1.08	1.25	0.82
2024	0.64	2.24	1.63	1.17	0.65	1.09	1.26	0.83
2025	0.64	2.24	1.63	1.18	0.65	1.09	1.26	0.83

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