APPENDIX C:
FUEL PRICE FORECAST

Contents

List of Figures and Tables

Throughout this write-up fuel forecast is presented in form of a low and high range. This is done to reinforce the fact that future is uncertain. Council's planning process does not use a single deterministic future to drive the analysis. The stochastic variation introduced in the Regional Portfolio Model tests a wide range of future uncertainties in load, fuel prices etc.

Please note that a companion workbook will be available with additional detail on forecasted prices on the Council's website at http://www.nwcouncil.org/energy/powerplan/7/technical

INTRODUCTION

This appendix summarizes fuel price forecasts for natural gas, oil and coal. Since the millennium, the trend for fuel prices has been one of uncertainty and volatility. The price of crude oil was $25 per barrel in January of 2000. In July 2008 it averaged $127/barrel, even approaching $150/barrel some days, today it is less than $45/barrel. Natural gas prices at the wellhead averaged $2.37 per million Btu in January 2000. In June 2008, the average wellhead price of natural gas averaged $12.60/mmBtu, as of April 13, 2015 Henry Hub price was $2.60/mmBtu. The reduction in oil and natural gas prices were the result of large supply availability and low demand. Demand was low due to slow global recovery and supply was high due to greater use of hydraulic fracturing of source rock.

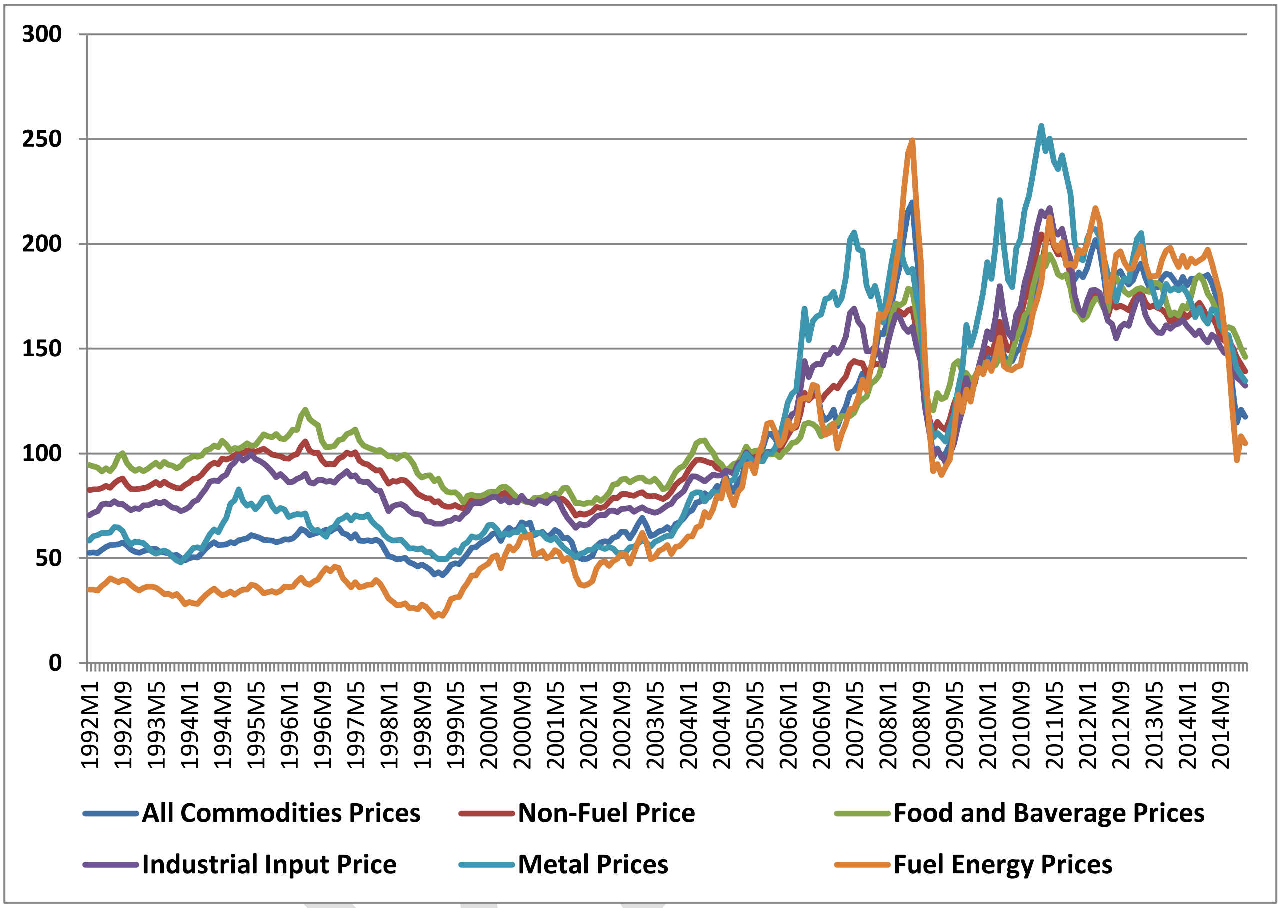
The Seventh Power Plan natural gas price forecast is significantly lower than the Sixth Power Plan's forecast. However, price uncertainty remains, not only with fuels, but also with other commodities such as metals, concrete, plastics, and other construction materials have all experienced fluctuation in prices. Various factors have contributed to higher or lower commodity prices in general, and to fuel prices in particular, including: fluctuations in world economic growth, fluctuating value of the dollar, response of conventional energy supplies to higher prices, continuing conflicts in the Middle East and Eastern Europe, uncertainty about the direction of climate change policy, and changing commodity market dynamics.

The relative contribution of these factors to fluctuation in prices is uncertain, as is the direction of change for many of them. Conventional sources of oil and natural gas in North America are expected to be difficult to expand significantly. Growth in supplies, therefore, will increasingly depend on the development of unconventional sources and liquefied natural gas (LNG) exports. With the recent fluctuations in natural gas prices and technological improvements in drilling, nonconventional supplies of natural gas have expanded rapidly. United States is going from being an importer of LNG to a significant exporter of LNG.

High prices can bring about changes on the demand side of the market. High prices encourage curtailing energy use and also create incentives to invest in energy-efficient technologies. Such responses to high prices set in motion the forces to reduce prices. Over time, these cycles are likely to reach higher high points and higher low points, forming a series of upward-stepping cycles. Investments in new supplies and energy efficiency also tend to follow these cycles. Expectations that prices will fall from high points in the cycle make consistent investments in supply and energy efficiency less robust.

Accurately forecasting future fuel prices is an impossible task. Even long-term forecasts tend to assume that current conditions will, to a large extent, continue. During periods of high fuel prices, forecasts tend to increase, and during periods of low prices, they tend to decrease. The Council's practice has been to recognize the inherent uncertainty and build power plants that minimize the risk from price forecasts that turn out to be wrong. Figure C - 1 shows the monthly fluctuations in commodity prices, according to International Monetary Fund. Planning deterministically under the range of fluctuations will lead to errors.

Figure C - 1: Fluctuations in commodity prices Indexed to 2005



DEALING WITH UNCERTAINTY AND VOLATILITY

In spite of their uncertainty, fuel prices are an important consideration for electricity planning. Fuel prices affect both the demand for, and the cost of electricity. As an important determinant of electricity cost, fuel prices also affect the cost-effective amount of conservation through the avoided cost of alternative generation resources. The uncertainty and volatility of fuel prices create risks for the Northwest power system. These risks and others are addressed in the Council's electricity planning process in the Regional Portfolio Model.

The range of trend forecasts discussed in this section represents only one aspect of fuel price uncertainty addressed in the Council's power plan. The low to high trend forecasts of fuel prices are meant to reflect current analysis and views on the likely range of future prices, but the plan's analysis also considers variations expected to occur around those trends. In the Power Plan this additional volatility was applied to natural gas prices. This was because oil prices are insignificant as either a demand alternative to electricity or a generation fuel. Coal prices are a significant determinant of electricity costs because of existing coal-fired generation, and coal is also a potential future source of energy. However, coal prices had not experienced the same level of uncertainty and volatility as oil and natural gas prices, and were therefore not considered to be a major source of risk and uncertainty.

The plan reflects three distinct types of uncertainty in natural gas prices: (1) uncertainty about long-term trends, (2) price excursions due to disequilibrium of supply and demand that may occur over a number of years, and (3) short-term and seasonal volatility due to factors such as temperatures, storms, or natural gas storage levels. The fuel price forecasts include only the first uncertainty. Shorter-term variations are addressed in the Council's Regional Portfolio Model analysis.

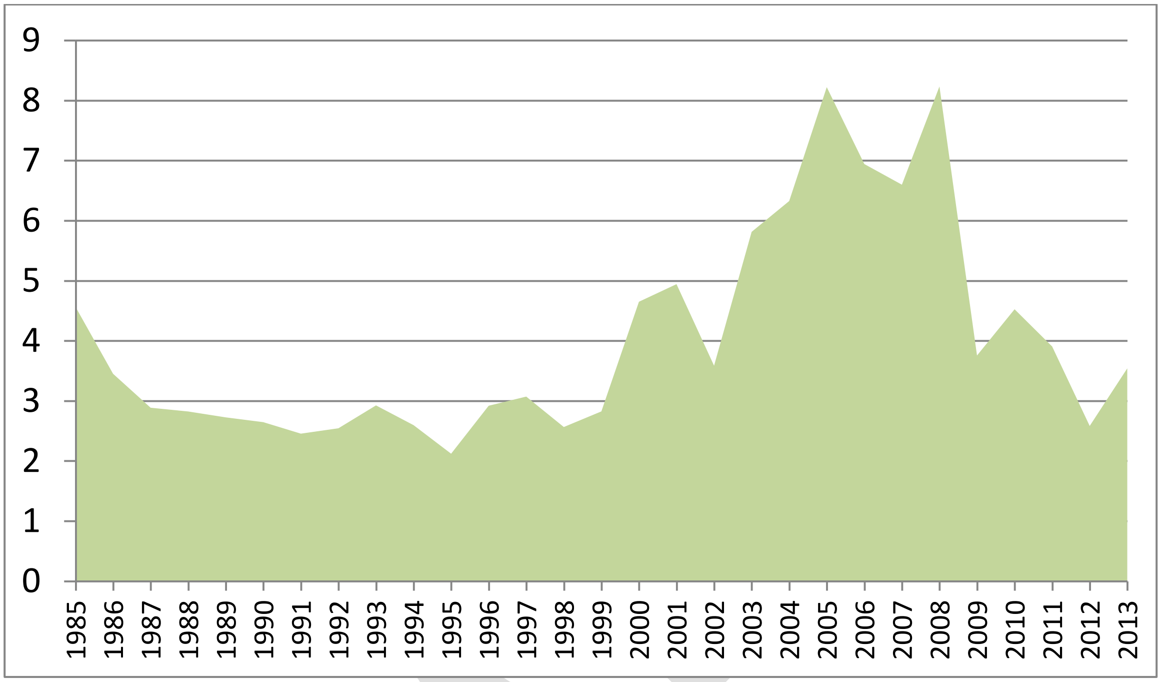
There are additional uncertainties to the cost of fuel from the effects of climate policies, such as CO2 costs from taxes or a cap and trade structure. These additional costs are explicitly treated in the Council's portfolio model and affect the cost of using various fuels, but are not a part of the commodity prices discussed in this appendix.

NATURAL GAS

Background

The Council's forecast of natural gas prices starts with a national level commodity price, the average natural gas wellhead price in the lower-48 states. The past behavior of these prices gives perspective for the forecasts. Figure C - 2 shows wellhead natural gas prices (in constant 2012 dollars per million Btu) from 1980 through 2014. Following deregulation of natural gas markets in the late 1980s, prices fell to nearly $2.30/mmBtu and remained near that level for all of the 1990s. After 2000, prices began to increase rapidly and became highly volatile. By 2008 the wellhead price of natural gas averaged $8/mmBtu, nearly four times the levels of the 1990s. In some months since 2000, prices have reached over $10/mmBtu as they responded to the effects of hurricanes, storage levels, oil prices, and other market effects. With this historical context, it is difficult to predict future natural gas prices with any certainty. Post 2008 we see a period of declining base prices. By 2013 and 2014 natural gas prices have been in the $3.50 to $2.50/mmBtu.

Figure C - 2: Historical Wellhead Natural Gas Price ($2012/mmBtu)



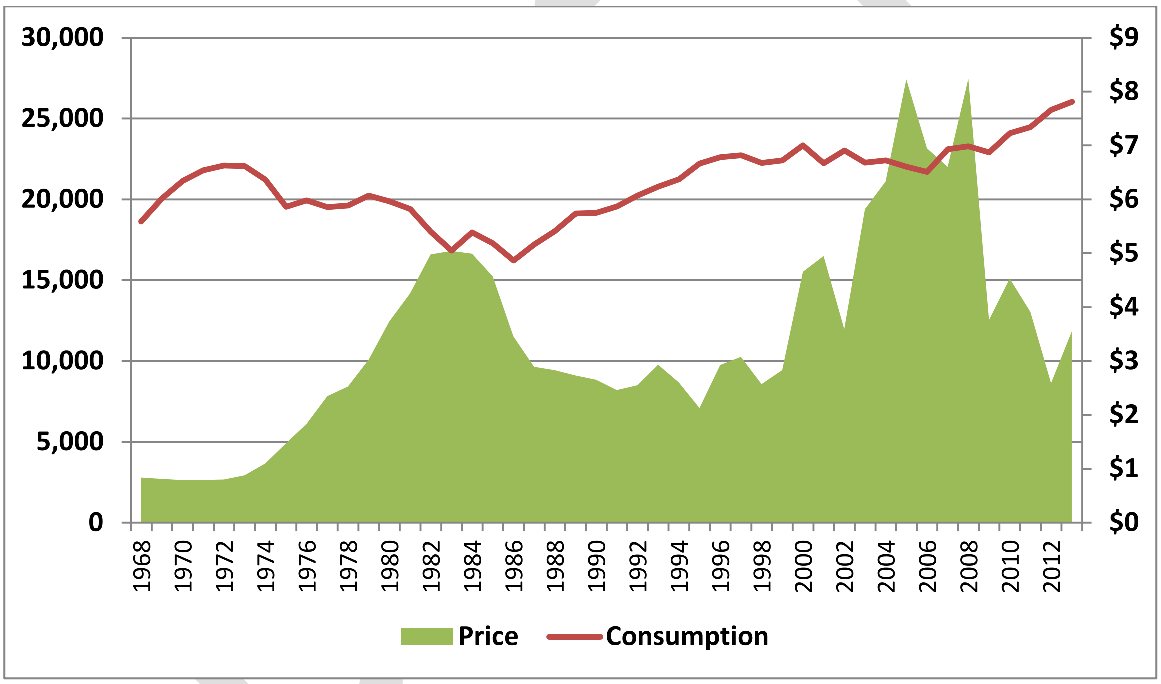
The Council's forecast of natural gas prices is informed by national level forecasts of prices from other organizations that specialize in analysis of fuel commodity markets. Such forecasts rely on estimates of the fundamentals of supply, demand, and the transportation capacity to move natural gas from supply sources to demand locations. Nevertheless, these forecasts are far from stable over time since they tend to respond to the most recent conditions, which can change drastically. The variation of forecasts from various organizations helps scale the uncertainty between the high and low forecasts. However, the range is also informed by analysis of long term trends in prices and analysis of how prices respond to changing conditions over long periods of time.

Forecasting future fuel prices is particularly difficult following large changes in markets, which is the case with the natural gas market since 2000. It requires sorting out temporary influences from longer-term factors that are expected to persist into the future. For example, regulation of natural gas supplies dampened the supply response to the growing demand for natural gas in the early 1980s, leading to rapid price escalation. Regulatory incentives to find new natural gas supplies, but not increase production from existing supplies, resulted in a slow supply response, but also created large new supplies in the longer term. When natural gas was deregulated in the late 1980s, prices collapsed due to the so-called "gas bubble" and remained low throughout the 1990s. During this time, low prices were expected to continue for many years and estimates of the cost of finding new natural gas were low.

By the end of the 1990s, the more permanent effects of deregulated natural gas supplies were becoming clear. Companies no longer held large inventories of proven reserves and as excess reserves declined, prices became more volatile. This volatility was exacerbated by the development of spot and futures trading markets. Without significant changes to natural gas market regulation, this volatility is expected to be a long-term feature of these markets. As noted earlier, that volatility is reflected in the Council's Power Plan, but this forecast addresses only a range of long-term price trends around which such volatility will occur. For example, the portfolio model includes short periods of time where prices can substantially exceed the high trend price forecast.

It is important to understand that the collapse of prices in the late 1980s was not all due to a supply bubble; there was also a significant reduction in natural gas use. During the two decades prior to 1970, natural gas use had grown rapidly as supplies expanded and natural gas pipeline expansion made the supplies available to users. However, as natural gas prices escalated during the 1970s (more than quadrupling), demand for natural gas dropped precipitously. Similarly, as prices dropped following deregulation and remained low during the 1990s, demand grew, but failed to return to its previous 1973 high level until 1995. Figure C - 3 shows these patterns. Also evident in Figure C - 3 is the moderating effect of recent natural gas price increases on natural gas use since 2000. Since 2008 natural gas prices declined sharply as natural gas supplies became more abundant and as the US and global recession continued Concurrent with the price decline we see increase in consumption of natural gas.

Figure C - 3: Historical Natural Gas Prices 2012$/mmBtu and Consumption (Trillion Cubic Ft)



Price Forecasts

U.S. Natural Gas Commodity Prices

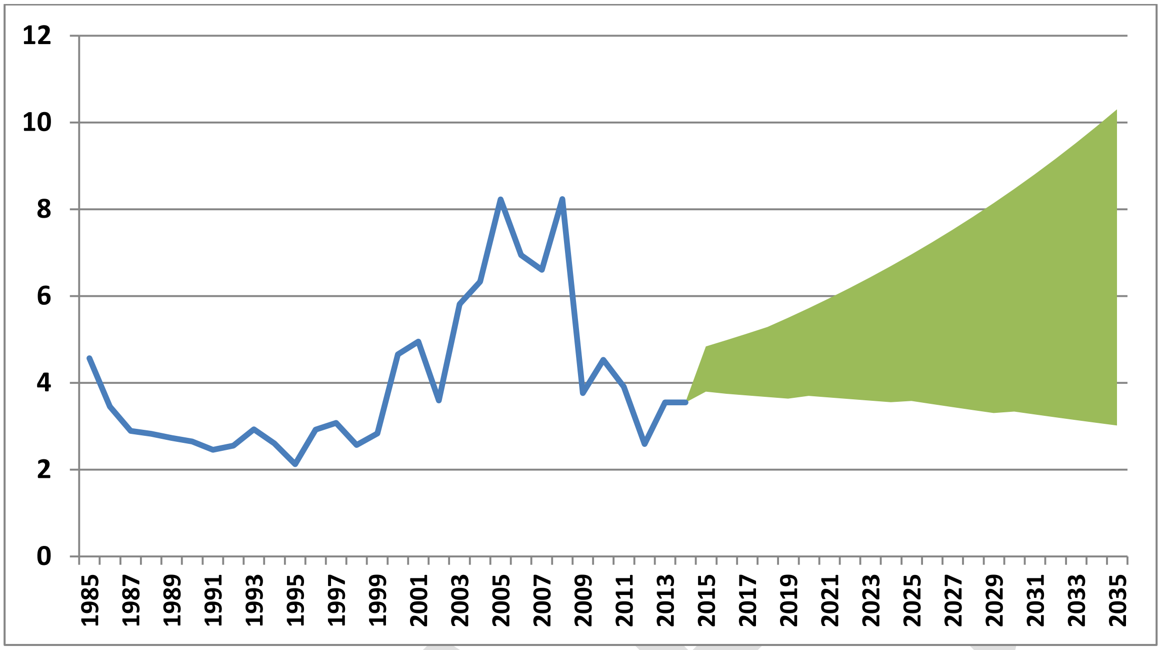
There are several characteristics of the recent price fluctuations that have implications for the future long-term trends in natural gas price. On the supply side, it has become clear that conventional natural gas supplies are increasingly difficult to expand. This does not mean that supply will not be able to expand. Recently, there have been significant increases in nonconventional supplies of natural gas, such as coal-bed methane and shale deposits like the Barnett Shale in North Texas, Haynesville in East Texas, Fayetteville in Arkansas, and Montney and Horn River in British Columbia. It is estimated that such nonconventional supplies of natural gas now account for more than half of U.S. natural gas production. The Potential Gas Committee April 2015 report shows a potential recoverable potential of 2,515 trillion cubic feet (Tcf). Production from nonconventional sources has been made feasible by improved drilling and production technologies, but these are also more expensive. For example, development of new shale natural gas supplies is estimated to cost between $4 and $5/mmBtu.

Another factor with implications for the long-term trend of natural gas prices is on the demand side of the equation. The significant reduction in demand during the 1970s was partly due to the ability to switch industrial uses of natural gas to alternative fuels. With today's climate concerns, the use of oil and coal are becoming constrained and limit the ability of industries (including power generation) to reduce natural gas use as prices increase. Further, the response to climate concerns and regulations is expected to increase the demand for natural gas. Examples include electric vehicles, where the electricity generation is likely to require increased amounts of natural gas, and biofuels, where natural gas is required to produce ammonia fertilizer to grow biofuel crops and provide process heat to refine the biofuels.

Cycles will continue in the future as markets develop and respond to changing supply and demand conditions. The large drop in natural gas prices in 2009 is a good example. However, the view expressed in the central part of the Council's natural gas price forecast range is that the trend through these future cycles will be upward. Given that the market appears to be starting from a low point in a commodity cycle, most of the forecast range includes increases from recent levels. Trend prices do not fall back to the $2.30/mmBtu natural gas prices of the 1990s, even in the lowest price forecast.

Figure C - 4 shows the range of U.S. wellhead price forecasts proposed for the Seventh Power Plan. As shown in the graph, natural gas prices nearly doubled between 2000 and 2008. Past the high prices in 2008, we see continued decline in prices. Not shown, is the doubling of prices in 2000 from the previous few years. Thus, 2008 prices were nearly four times their levels from 10 years ago.

Figure C - 4: U.S. Wellhead Natural Gas Price Forecast Range 2012 $/mmBTU



The forecast shows prices in the range of $3.50-$3.0/mmBtu between 2015 and 2035, under ample supplies and slow demand recovery to high of $3.50-$10/mmBtu (in constant $2012). These prices represent the current expectations of many experts in the fuel markets, including many of the members of the Council's Natural Gas Advisory Committee.

The high and low forecasts are intended to be extreme views of possible future prices from today's context. The high case prices increase to $10/mmBtu by 2030. The Council's forecasts assume that more rapid world economic growth will lead to higher energy prices, even though the short-term effects of a rapid price increase can adversely impact the economy. For long-term trend analysis, the stress on prices from increased need to expand energy supplies is considered the dominant relationship. The high natural gas scenario assumes rapid world economic growth. This scenario might be consistent with very high oil prices, high environmental concerns that limit use of coal, limited development of world LNG capacity, and slower improvements in drilling and exploration technology, combined with the high cost of other commodities and labor necessary for natural gas development. It is a world where both alternative sources of energy and opportunities for demand reductions are very limited.

The low case assumes slow world economic growth which reduces the pressure on energy supplies. It is a future where world supplies of natural gas are made available through aggressive development of LNG capacity, favorable nonconventional supplies and the technologies to develop them, and low world oil prices providing an alternative to natural gas use. The low case would also be consistent with a scenario of more rapid progress in renewable electric generating technologies, thus reducing the demand for natural gas. In this case, the normal increases in natural gas use in response to lower prices would be limited by aggressive carbon-control policies. It is a world with substantial progress in efficiency and renewable technologies, combined with more stable conditions in the Middle East and other oil and natural gas producing areas.

The intermediate cases are variations on the medium case that are considered reasonably likely to occur. The medium-high case would contain elements of the high scenario, however not to the same degree. Similarly, the medium-low case would contain some of the more optimistic factors described for the low case.

In reality, prices may at various times in the future resemble any of the forecast range. Such cycles in natural gas prices, as well as shorter-term volatility, are captured in the Council's Regional Portfolio Model. Table C - 1 shows the range of natural gas price trend forecasts for selected years. In the Council's portfolio analysis, however, prices at any given time may fall anywhere within, or even outside, the range in figure C - 4.

For a more detailed year-by-year forecast of prices, please see the companion workbook from the Council website.

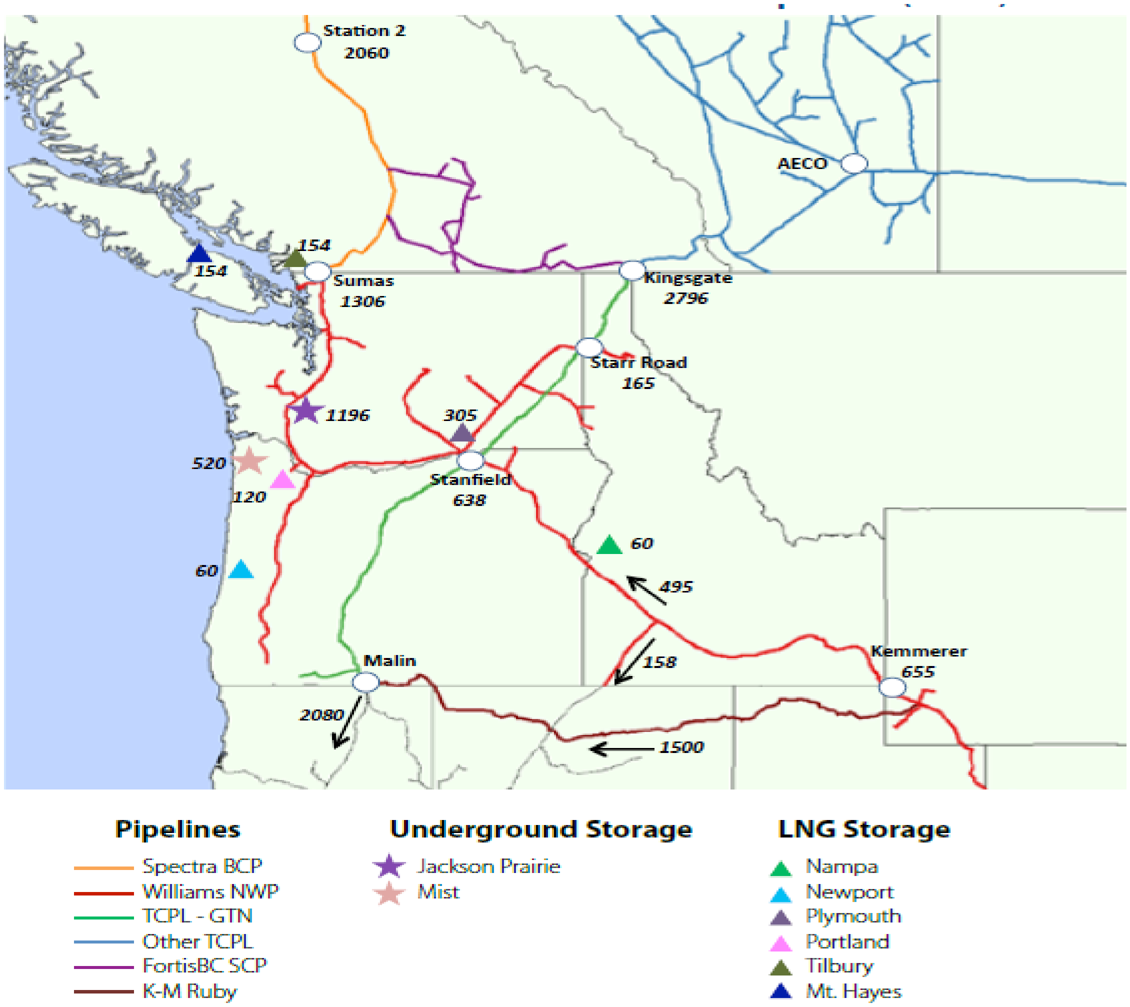
For a comparison of the Sixth and Seventh Power Plan forecasts please see the Fuel Price Forecast, July 2014, available for Council website. http://www.nwcouncil.org/energy/forecast/

Northwest Natural Gas Supplies and Price

Given a forecast of U.S. level commodity prices, the next step is to estimate the cost of natural gas within the Pacific Northwest region and the rest of the Western United States. This is necessary because there is significant regional variation in natural gas prices.

Natural gas supplies for the Pacific Northwest come from two sources: the Western Canada Sedimentary Basin (WCSB) in Alberta and Northeastern British Columbia, and the U. S. Rocky Mountains. Natural gas from these areas is delivered into the region by two pipelines. The Williams Northwest Pipeline delivers supplies from the U.S. Rocky Mountains as well as down from Sumas at the B.C. border. The other pipeline is TransCanada Gas Transmission Northwest, which brings supplies from Alberta, through the Northwest and on down to the California border. Figure C - 5 illustrates the Northwest's natural gas delivery system (figure adopted from 2014 Natural Gas Outlook).

Figure C - 5: Pacific Northwest Natural Gas Infrastructure and Capacities (Millions of Dekatherms)



In the past, the Northwest has been fortunate to be linked to expanding natural gas supply areas that had limited transmission to other areas. This resulted in natural gas prices in the region that are lower than most other areas of the country. In recent years, the ability of WCSB to expand production has decreased and it is projected that imports from that area to the U.S. are unlikely to be able to meet growing natural gas demand in the future. A more optimistic view of the ability of Western Canada to continue providing natural gas to the region would recognize that there is substantial coal bed and shale gas potential in the WSCB that could be developed. Further the internal demand for natural gas for oil sands development could be substantially replaced by liquefaction of petroleum coke (a byproduct of oil sands refining), development of nuclear technologies to provide electricity and steam for oil sands production and processing, or cogeneration of electricity from natural gas use.

The Rocky Mountain supply area is still a growing production area. Pipelines from the Rockies to the east are likely to reduce the price advantage of Rockies natural gas unless supplies expand even faster than pipeline capacity. The pipeline capacity to bring Rockies gas to the Northwest is constrained and will need to be expanded for the Northwest to be able to access growing Rockies supplies.

There is general agreement that natural gas will have to play an important role in electricity supplies for the Council's planning horizon. The cost of that natural gas will depend on the demand for natural gas and the supply and deliverability to the region. The deliverability of natural gas depends not only on access to supplies and pipeline capacity, but also on storage capability and other natural gas peaking resources like line pack, LNG storage, and interruptible demand.

The growing use of natural gas for electricity generation will require increased coordination between the electricity and natural gas industries. This is particularly true for natural gas used for peaking generation or ancillary services. Natural gas is currently scheduled on a daily basis, but electricity is scheduled on an hourly basis with constant adjustment to actual demands through load following and regulation services. Increasing amounts, and perhaps different forms, of natural gas flexibility within the day may be required as the use of natural gas increases for providing flexibility and ancillary services for the electricity sector. There has been significant coordination of efforts between the Natural Gas Association members and electric utility representative organizations in the past few years, in large part due to coordination and communication requirements ordered by FERC. The Northwest Mutual Assistance Agreement helps coordinate regional response during gas emergencies. FERC is attentive to the growing gas and electric overlap and is considering synchronizing the gas and electric scheduling day.

In order to plan for the region's electricity needs, the Council must forecast natural gas prices, not only in the Northwest, but also in other areas of the West. To do this, the Council has developed relationships among the various natural gas pricing hubs in the West. Most relevant to the Northwest are prices at the AECO-NIT pricing hub in Alberta, the Sumas hub on the Washington-B.C. border, and the Rocky Mountain hub.

Forecasts of natural gas delivered to specific parts of the Pacific Northwest are based on the forecasts of hub prices at Sumas, AECO, and the Rockies plus estimated costs of transporting the fuel via regional pipelines. Pipeline costs include three general types of cost: capacity charges, commodity charges, and in-kind fuel costs. Capacity costs are by far the largest component of the transportation cost, and they are considered to be fixed costs. Existing users of natural gas are assumed to pay rolled-in pipeline capacity costs, but future power plants are assumed to pay incremental capacity costs, which reflect new pipeline capacity costs that escalate in real terms over time. The rate of escalation varies with the forecast case. Pipeline commodity and in-kind fuel charges are small and are a variable cost of natural gas, along with the cost of the gas itself.

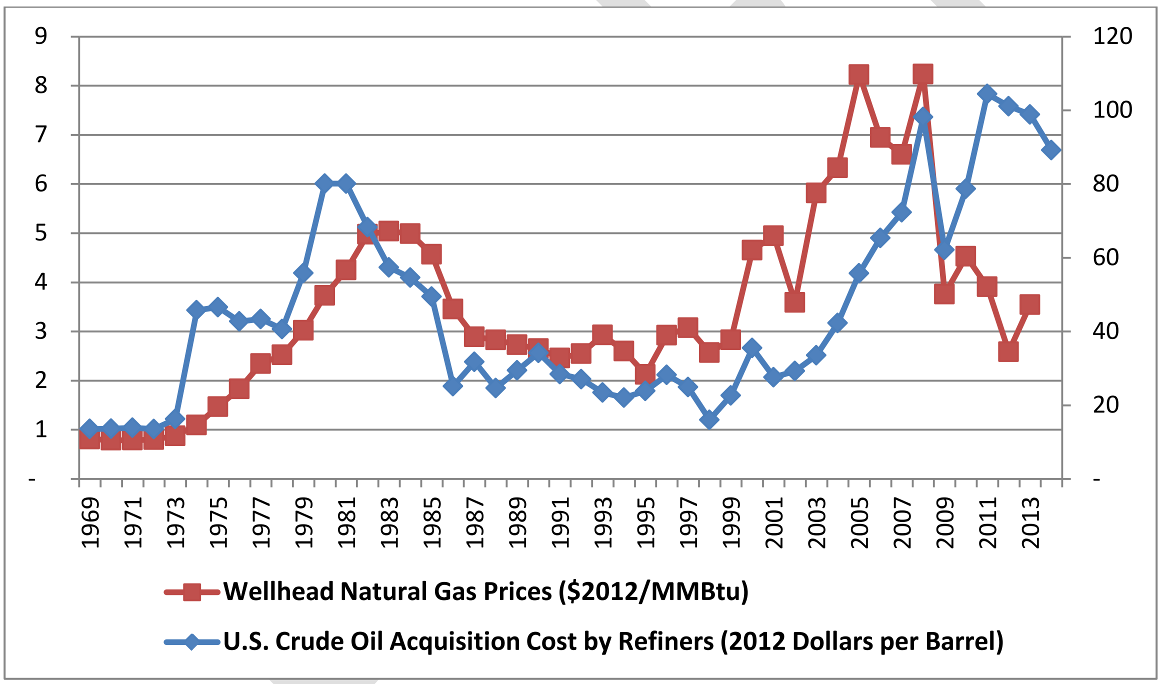
For the full range of forecast prices for national and regional hubs, please see the companion spreadsheet provided as part of the Seventh Power Plan from Council's website at: http://www.nwcouncil.org/energy/powerplan/7/technical

OIL

Background

Forecasts of oil prices play a less direct role in the Council's Power Plan than natural gas prices. Oil is not a significant fuel for electricity generation, nor is it an important competitor with electricity in end-use applications. However, oil prices do have an influence on natural gas prices and other energy sources. The relationship is not exact, but as shown in Figure C - 6, crude oil and natural gas commodity prices do tend to move together in the long-term. Oil is most significant as a transportation fuel. In that role, oil prices enter into determining delivered coal prices at various points in the West. This is due to the reliance on diesel fuel to run the trains that deliver coal from supply areas in Wyoming and Montana. In the 2011 world oil prices reached the highest level ever recorded. The price of $104 per barrel of oil (2012$) was six and half times the average price for a year in 1998. Then world oil price crashed in late 2014 and by first quarter of 2015 world oil prices have been hovering in the low $50-$60/barrel range.

Figure C - 6: Historical Comparison of Crude Oil and Wellhead Natural Gas Prices



Oil Price Forecast Range

The oil price forecast proposed here is somewhat different from the forecast included in the Council's Six Power Plan. The medium forecast of world oil prices, defined as refiners' acquisition cost of imported oil, varies between $89 and $102/barrel (2012$), slightly lower than prices at the end of 2008, which were partially influenced by the global financial crisis and recession. Prices generally fall following a period of extremely high prices as new sources of supply, substitution of other energy sources, and reduced demand bring markets into balance. However, as oil production increases, more expensive sources of oil are required so that over time, prices ratchet upward. With the shale oil revolution large volume of supplies has become available. However, delivery infrastructure and retooling of the domestic refiners have hampered decrease in oil prices reaching customers. The effects of new technologies on supplies and uses, climate policies, and political factors in oil producing countries create large uncertainties about future oil prices, and therefore, a large range of price forecasts. Figure C - 7 shows the historical world oil prices and the range of future oil prices assumed in the Seventh Power Plan.

Neither the high price nor the low price cases are unlikely in the long term because of the alternative supplies and reductions in use that are likely to occur at such prices. There are still ample supplies of conventional and unconventional oil in the world. On the demand side, very high oil prices will stimulate improved efficiency and possibly reduced economic growth. In the years following the high oil prices of the 1970s and early 1980s, the petroleum intensity of the U.S. economy decreased by 7 barrels per million dollars of Gross Domestic Product (2005$) in 1970, to 2.3 in 2012 (see Figure C - 8). As the world continues to tackle the climate change issue, improved efficiency and expanded use of renewable energy sources will grow and further reduce the demand for oil in the long run. Uncertainty about the amount of supply and demand adjustments and their costs contribute to the wide range of possible future oil prices.

Figure C - 7: World Oil Prices: History and Forecast (2012$/Barrel)

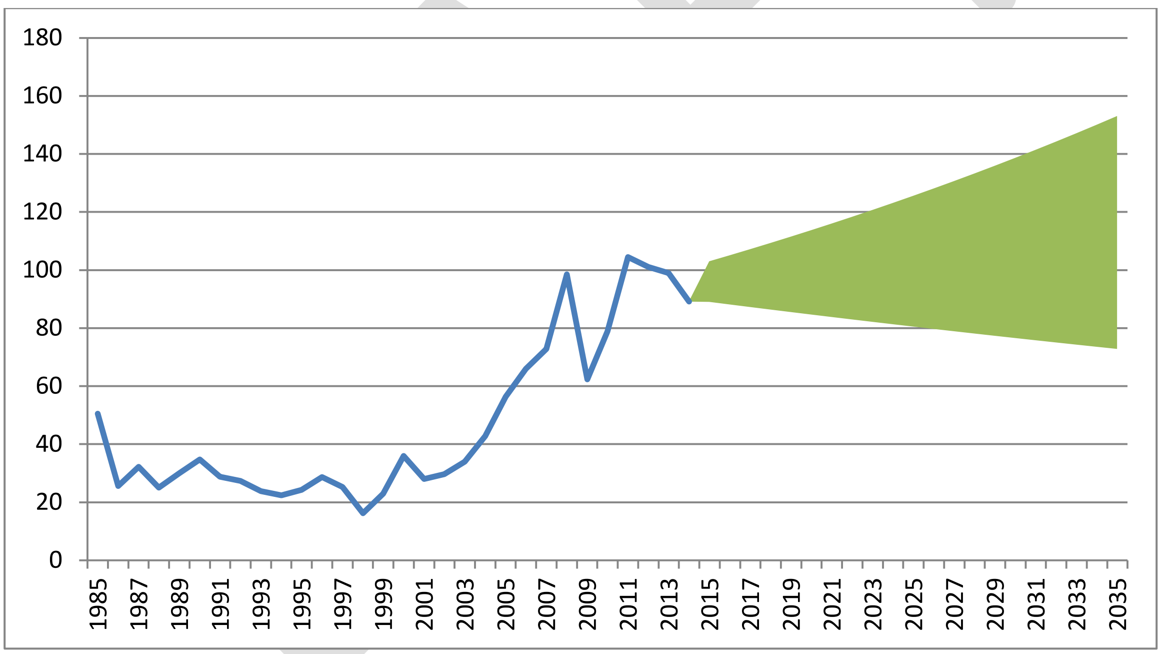
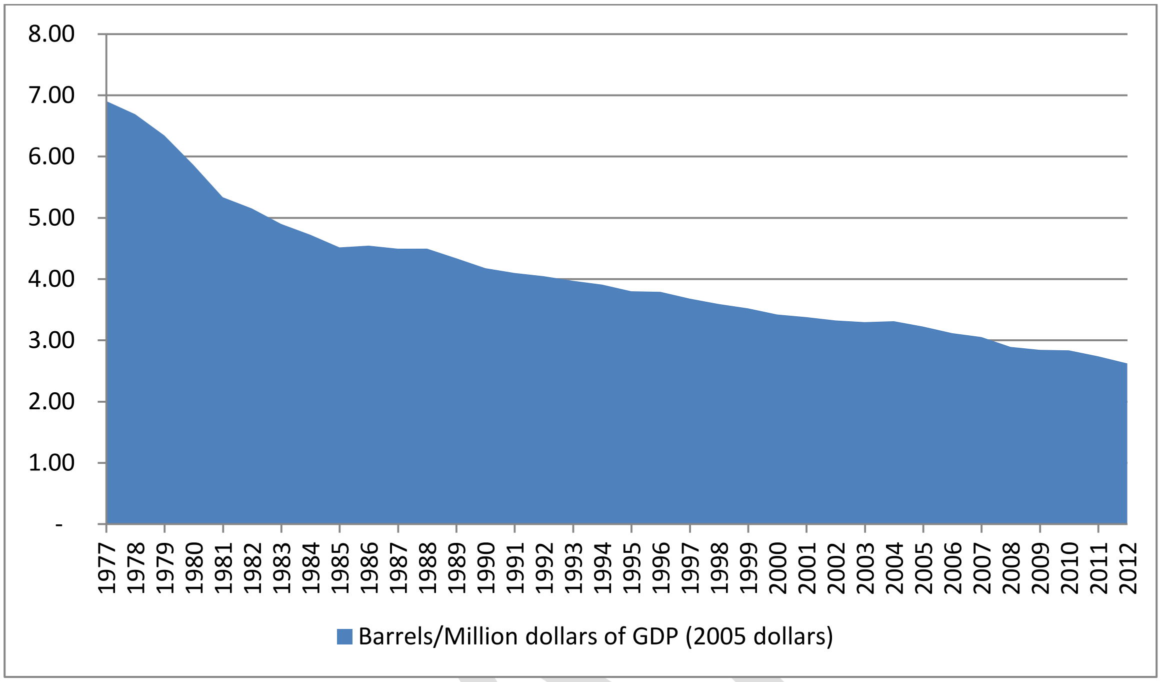


Figure C - 8: Total U.S. Petroleum Use per Millions of 2005 Dollar of Gross Domestic Product



As in the case of natural gas, oil commodity prices are used to estimate future oil product prices at the wholesale and retail level. The refiner wholesale prices of heavy and light oil products are based on refinery costs and a simple profit maximization calculation. Retail price forecasts are based on simple historical relationships between wholesale oil product prices.

More detail on retail and wholesale oil prices is provided in the companion workbook, available from Council website.

COAL

Coal Commodity Prices

Coal is a plentiful energy source in the United States. Coal resources, like natural gas, are measured in many different forms. The EIA reports several of these.[1] One measure is "demonstrated reserve base," which measures coal more likely to be mined based on seam thickness and depth. EIA estimate as of January 2014**,** the demonstrated reserve base (DRB) was estimated to contain 480 billion short tons. In the United States, coal resources are larger than remaining natural gas and oil resources, based on total British thermal units (Btus). Annually, EIA reports remaining tons of coal in the DRB, which is comprised of coal resources that have been identified to specified levels of accuracy. EIA annually estimates recoverable coal reserves by adjusting the DRB to reflect accessibility and recovery rates in mining. As of January 1, 2014, EIA estimated that the remaining U.S. recoverable coal reserves totaled over 256 billion short tons, from a DRB of 480 billion short tons.

About half of the demonstrated reserve base of coal, 480 billion short tons, and 160 billion short-tons of recoverable reserves out of 256 billion short-tons nationally is located in the West. Western coal production has been growing due to several advantages it has over Appalachian and interior deposits. Western coal, especially Powder River Basin 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 sulfur dioxide 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. Another drawback of some Western coal is a relatively high arsenic content, which will require more expensive treatment for removal under stricter environmental rules.

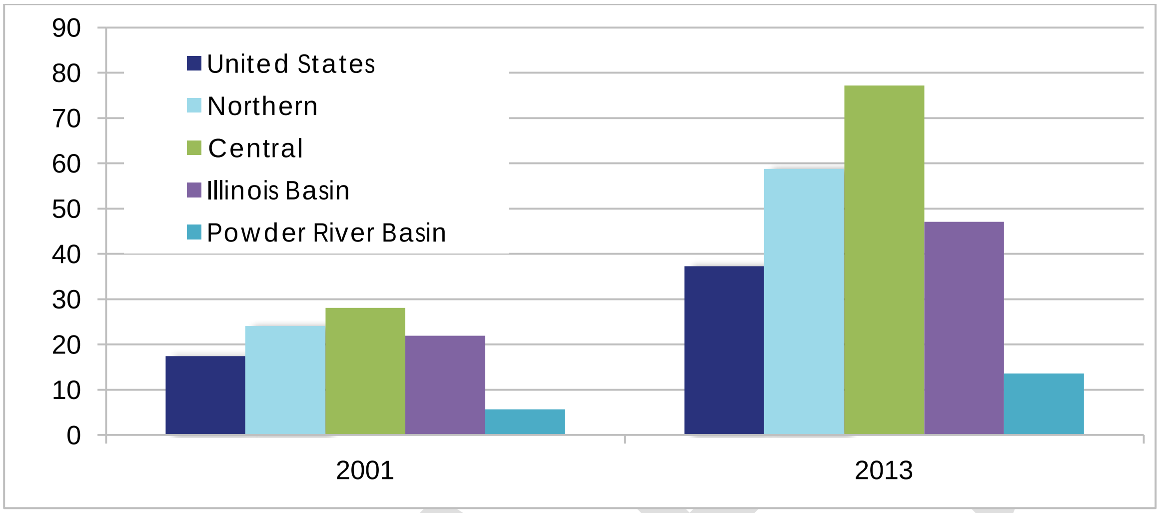
Western coal production in 2013 was 528 million short tons, with 74 percent of that production coming from Wyoming (388 million short tons). The second largest state producer was Montana at 42 million tons. Colorado, New Mexico, North Dakota and Utah produced between 22 and 28 million short tons each, and Arizona produced about 8 million short tons.[2]

Historical productivity increases have been rapid, especially in Western coal mines. As a result, mine-mouth coal prices have decreased over time. In constant dollars, Western mine-mouth coal prices declined by an average of 1.6 percent per year between 1985 and 2005. Expiring higher-priced long-term contracts have also contributed to declining coal prices.

[1] U.S. Energy Information Administration, U.S. Coal Reserves: Update, January 2014.
[2] U.S. Energy Information Administration, EIA Interactive Coal Report, April 2015.

Most of the coal used in the Pacific Northwest comes from the Power River Basin in Wyoming and Montana. As noted above, the cost of Power River Basin coal is very low relative to other coal. Figure C - 9 shows historical coal cost from various basins and for the United States in aggregate.

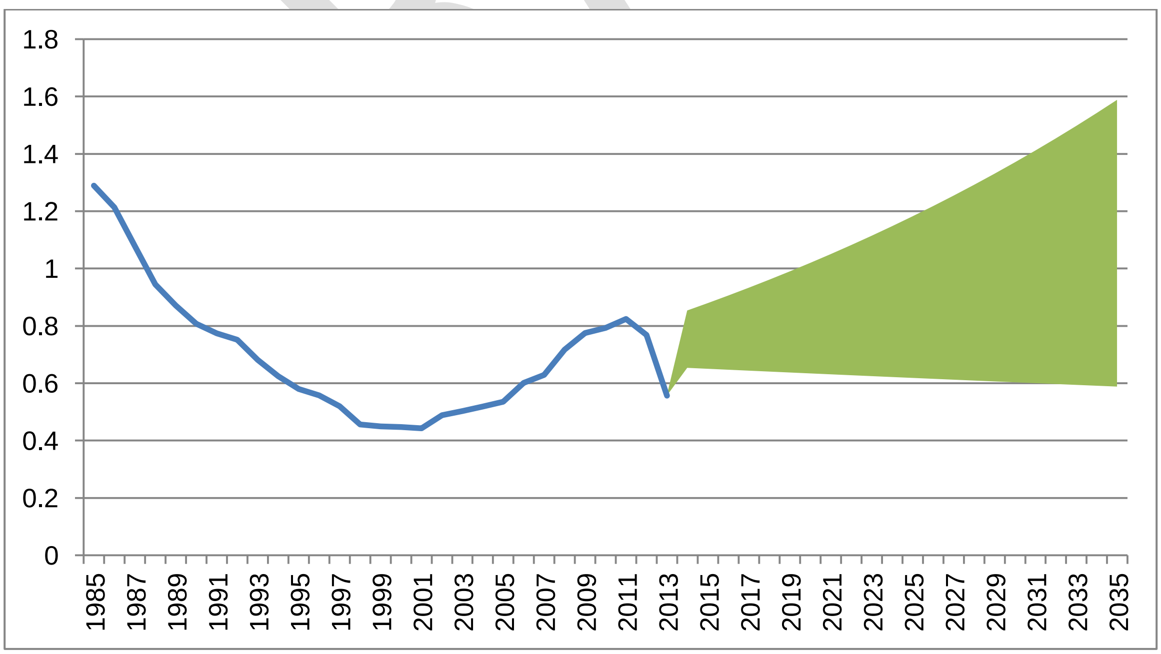
Figure C - 9: Coal Price Trends from Major Supply Areas ($/Short tons)



Coal Price Forecast

The forecast cost of coal to the Pacific Northwest is based on projected Powder River Basin coal prices. These forecasts are simple price growth rate assumptions from 2015 to 2035. Figure C - 10 shows the resulting forecast range.

Figure C - 10: Range of Powder River Basin Coal Price Forecasts (2012$/mmBtu)



More detail on retail and wholesale oil prices is provided in the companion workbook, available on the Council's website.

METHODOLOGY

From Source to Burnertip

Methodology for taking the source/hub prices and estimating burner-tip prices for coal and oil did not change for the Seventh Power Plan. For a detail look at the methodology for estimating the burner-tip fuel prices please see Appendix A-6 of the Sixth Power Plan. The methodology for estimating burner-tip natural gas prices was enhanced in the Seventh Power Plan. The relationship between burner-tip prices and hub prices were developed using EIA data (utility purchased price of gas at state level or at plant level). A summary of these relationships are shown in Table C - 1. Starting with the forecast of wellhead prices, described earlier in this appendix, the Council calculated the forecast of prices at Henry hub. Then, using relationship between various hubs and Henry Hub, the Council estimated prices for other hubs. In the third stage, the Council estimated burner-tip prices at target locations (based on Aurora wholesale market price model's topology). Then, this price forecast was further enhanced by developing monthly price shapes using historic monthly price data from 2000-2012 (see Table C - 2). The monthly shapes show ratio of a monthly price to annual price.

Table C - 1: Relationship between Wellhead, Henry Hub and Burner-tip prices

	HENRY
Source Hub	Wellhead
Coeff. For Hub	1.04
Constant	-

AECO	ROCKIES	SUMAS	SAN_JUAN	PERMIAN
Henry	Henry	Henry	Henry	Henry
1.02	0.83	0.90	0.87	0.92
(0.94)	-	-	-	-

Burner-tip Located at	PNW_EAST	MTE	CA_N	NV_N	AB	UT	WY
Source Hub	AECO	Rockies	AECO	AECO	AECO	Rockies	Rockies
Coeff. For Hub	1.03	**0.87**	0.53	1.13	1.00	0.74	1.00
Constant	-	**2.19**	2.76	1.05	(0.24)	1.67	0.47

Burner-tip Located at	PNW_WEST	ID_S	BC	CO	CA_S	AZ	NM	NV_S
Source Hub	AECO	Rockies	AECO	Rockies	San Juan	San Juan	Permian	Permian
Coeff. For Hub	1.03	**0.55**	1.00	0.74	1.05	0.96	0.90	1.02
Constant	(0.05)	**4.67**	0.24	1.74	1.01	1.01	1.12	-

Additional information can be located in the supporting file located at:
http://www.nwcouncil.org/energy/powerplan/7/technical

Table C - 2: Monthly Shape of Prices

Monthly Shapes	AZ	CA	CO	NM	NV	OR
January	1.03	1.04	1.05	1.05	1.13	1.10
February	1.03	1.01	1.09	1.01	1.05	1.01
March	0.96	1.01	1.07	0.98	1.08	1.00
April	0.98	0.97	1.01	0.96	0.97	1.00
May	0.99	0.98	0.92	0.97	0.97	1.10
June	1.00	1.00	1.00	1.01	0.96	0.98
July	1.01	0.99	0.99	1.03	0.95	0.94
August	0.96	0.96	0.97	0.95	0.96	0.90
September	0.92	0.93	0.83	0.92	0.97	0.86
October	0.97	0.99	0.95	0.97	0.96	0.92
November	1.02	1.00	1.00	1.06	0.95	1.05
December	1.14	1.09	1.11	1.07	1.05	1.15

Monthly Shapes	UT	WA	WY	ID	MT
January	1.09	1.16	1.13	1.17	1.12
February	1.13	0.98	1.14	1.14	1.07
March	1.14	0.97	0.99	1.32	1.02
April	0.98	1.24	0.88	0.91	0.91
May	0.95	1.10	1.10	1.06	0.92
June	0.97	1.08	0.91	1.09	1.02
July	1.03	0.90	1.05	0.96	1.12
August	0.96	0.89	0.90	0.90	1.01
September	0.87	0.88	0.88	0.76	0.86
October	1.00	0.90	0.81	0.78	0.80
November	1.00	0.99	1.16	0.92	1.09
December	0.87	0.97	1.03	1.00	1.05

Monthly Shapes	NV_N	NV_S	CA-S	CA-N	PNW-E	PNW-W	ID-S
January	1.13	1.03	1.00	1.05	1.06	1.15	1.09
February	1.06	1.04	0.99	1.02	1.01	1.02	1.06
March	1.05	1.11	0.99	1.01	0.99	0.92	1.10
April	0.97	0.91	0.97	0.96	0.99	1.06	0.96
May	0.99	0.93	1.00	0.97	1.18	0.99	1.00
June	0.96	0.95	1.00	0.97	0.92	1.06	1.03
July	0.94	1.07	1.01	0.99	0.98	0.96	0.96
August	0.98	0.95	0.98	0.95	0.93	0.92	0.97
September	0.98	0.84	0.93	0.95	0.92	0.86	0.90
October	0.95	0.92	0.95	0.98	0.93	0.88	0.91
November	0.99	0.96	1.06	1.05	1.03	1.00	0.97
December	1.00	1.26	1.13	1.10	1.07	1.19	1.04