CHAPTER 8: ELECTRICITY AND FUEL PRICE FORECASTS

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KEY FINDINGS

Prices for wholesale electricity at the Mid-Columbia trading hub remain relatively low, reflecting the abundance of low-variable cost generation from hydropower and wind, as well as continued low natural gas fuel prices. The average wholesale electricity price in 2014 was around $30 per megawatt-hour, and in 2015 had dipped to around $23 per megawatt-hour. By 2035, prices are forecast to range from $25 to $67 per megawatt-hour in 2012 dollars. The upper and lower bounds for the forecast wholesale electricity price were set by the associated high and low natural gas price forecast. Although the dominant generating resource in the region is hydropower, natural gas fired plants are often the marginal generating unit for any given hour. Therefore, natural gas prices exert a strong influence on the wholesale electricity price, making the natural gas price forecast a key input. The region depends on externally-sourced gas supplies from Western Canada and the U.S. Rocky Mountain region.

Prices for natural gas have dropped significantly since reaching a high in 2008, and are expected to remain relatively low moving forward. Historically, natural gas prices have been volatile and so a range of forecasts was developed to capture most potential futures. The low range for prices starts at $2.64 per million British Thermal Units (mmBtu) at Henry Hub in 2015, and increases in real dollar terms to $3.60 per mmBtu by 2035. This low range case represents a future with slow economic growth, low gas demand, and robust supplies. The high range of the forecast climbs to $10 per mmBtu by 2035, which represents a future with high economic growth, high demand for natural gas, and a limited gas supply. It should be noted that the higher price range for natural gas implicitly incorporates potential regulatory compliance costs for reducing methane emissions.

The Regional Portfolio Model (RPM) uses both natural gas and wholesale electricity prices as the basis for creating 800 futures. Each future has a unique series of natural gas and electricity prices through the 20-year planning period. These price series include excursions below and above the price ranges shown here for both electricity and natural gas to reflect the volatility and uncertainty in future commodity prices. See Chapter 15 and Appendix L for discussions of how these natural gas and wholesale electricity price forecasts are translated into the 800 futures used in the RPM.

WHOLESALE ELECTRICITY PRICES

The Council periodically updates a 20-year forecast of electric power prices, representing the future price of electricity traded on the wholesale spot market at the Mid-Columbia trading hub. The current forecast is an input to the Regional Portfolio Model (RPM). It provides the benchmark quarterly power price under average fuel price, hydropower generation, and demand conditions. A more complete description of the development of the electricity price forecast and results is provided in Appendix B.

The forecast used for the Seventh Power Plan is an update to the Council's 2013 forecast.[1] There was little change in prices from the previous forecast cycle. A few key findings from the current forecast cycle include:

- Wholesale electricity prices at the Mid-Columbia trading hub remain relatively low, reflecting low-variable cost of ample hydropower and wind generation in the region, continued low price of natural gas, and slow demand growth.
- Natural gas prices exert a strong influence on electricity prices, both in the forecast and historically. As a result, the forecast span of electricity prices was based on high and low gas price forecasts.

The Council uses the AURORAxmp Electricity Market Model, as provided by EPIS Inc. to develop the wholesale electricity price forecast. This is an hourly dispatch model which calculates an electricity price based on the variable cost of the marginal generating unit. The key price drivers include:

- Load at generation – electricity demand net of energy efficiency and inclusive of line loss[2]
- Fuel prices delivered to generation
- Existing and new generation capabilities and costs
- Renewable Portfolio Standards driving resource builds
- Greenhouse gas emission policies

There are two steps in the modeling process that produces the forecast. First, a congruent set of assumptions and inputs are established and a long-term resource optimization model run is performed. This run determines the mix of generation resources that are available over the planning horizon, and may include new resource builds for capacity and energy, as well as retirements. A second run is then performed to determine the hourly dispatch using those resources, producing an hourly price for each pricing zone. Low-variable cost resources such as hydropower and wind are dispatched first, followed by efficient or otherwise low-cost thermal resources such as gas or coal. As load increases, less efficient and/or more expensive resources are dispatched.

In the Council's configuration of the model, electricity prices are calculated for 16 zones which comprise the entire Western Electricity Coordinating Council (WECC) area. The Northwest region is broken into three zones:

1. PNWW – Western Oregon and Washington
2. PNWE – Eastern Oregon and Washington, along with Northern Idaho and Western Montana
3. Southern Idaho

The PNWE zone serves as a proxy for the Mid-Columbia trading hub.

[1] http://www.nwcouncil.org/media/6829307/wholesaleelectricity.pdf
[2] The Council adjusts retail sales (and energy savings) to load at the generator by adjusting for transmission and distribution system losses. For the Seventh Power Plan, transmission system losses were assumed to be 2.3 percent and distribution system losses were assumed to be 4.7 percent.

Generating plants that physically sit outside the Northwest but serve load within the region are counted as in-region resources. Average hydropower and wind generating conditions are used for each year of the 20 year planning horizon. Forecasts for load, fuel prices, and Renewable Portfolio Standards (RPS) are input to the model. Renewable resource development associated with RPS requirements tends to dampen wholesale electricity prices because their low operating costs are not dependent on fuel purchases.

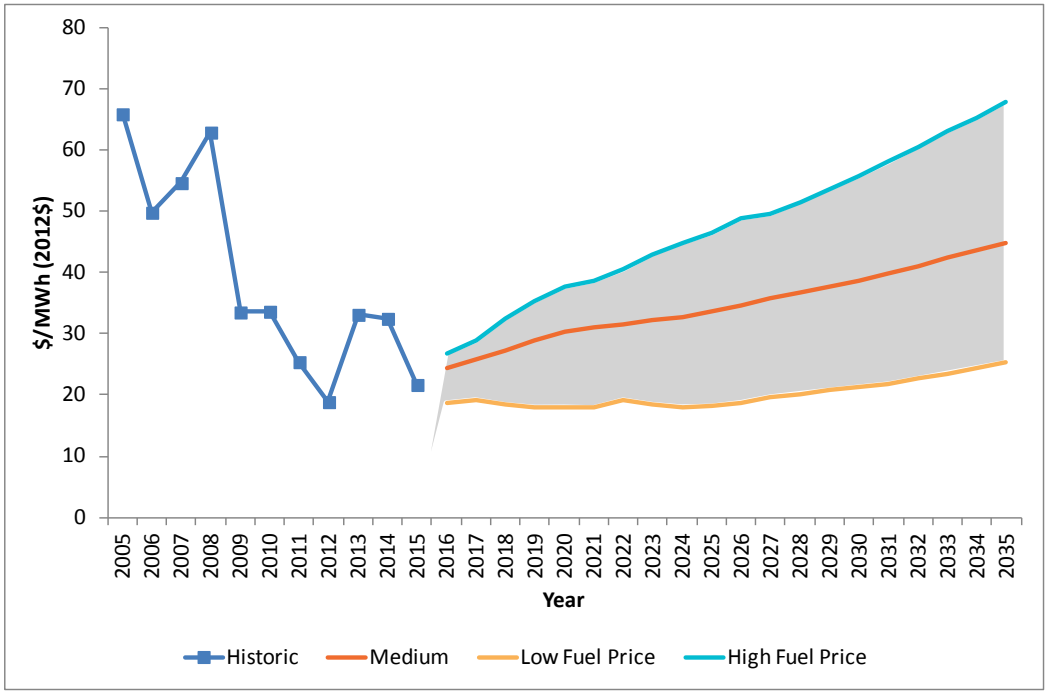
Pricing policies associated with carbon dioxide (CO_2) emissions can influence wholesale electricity prices. In this forecast cycle, the British Columbia carbon tax, initiated in 2008, was included, as was an estimate of the CO_2 prices ($ per ton CO_2) associated with California's Cap and Trade program. These policies have the effect of increasing the dispatch cost for CO_2-emitting resources within British Columbia and California and for electricity imported to those regions.

Five primary forecast cases were defined for this forecast cycle and run through the AURORAxmp pricing model:

1. Medium - medium forecasts for electricity demand and fuel price
2. High Demand - high electricity demand forecast
3. Low Demand - low electricity demand forecast
4. High Fuel - high fuel-price forecast (primarily natural gas)
5. Low Fuel - low fuel-price forecast (primarily natural gas)

The forecast results are summarized in Figure 8 - 1, along with recent historic pricing at the Mid-Columbia hub. The upper and lower bounds which define the range of electricity prices over the planning horizon are set by the high and low fuel-price forecast cases.

Figure 8 - 1: Historic and Forecast Annual Wholesale Electricity Price at Mid-C



The input assumptions for demand growth and fuel price, along with electric price results are summarized in Table 8 - 1.

Table 8 - 1: Electricity Price Forecast Assumptions and Results[1]

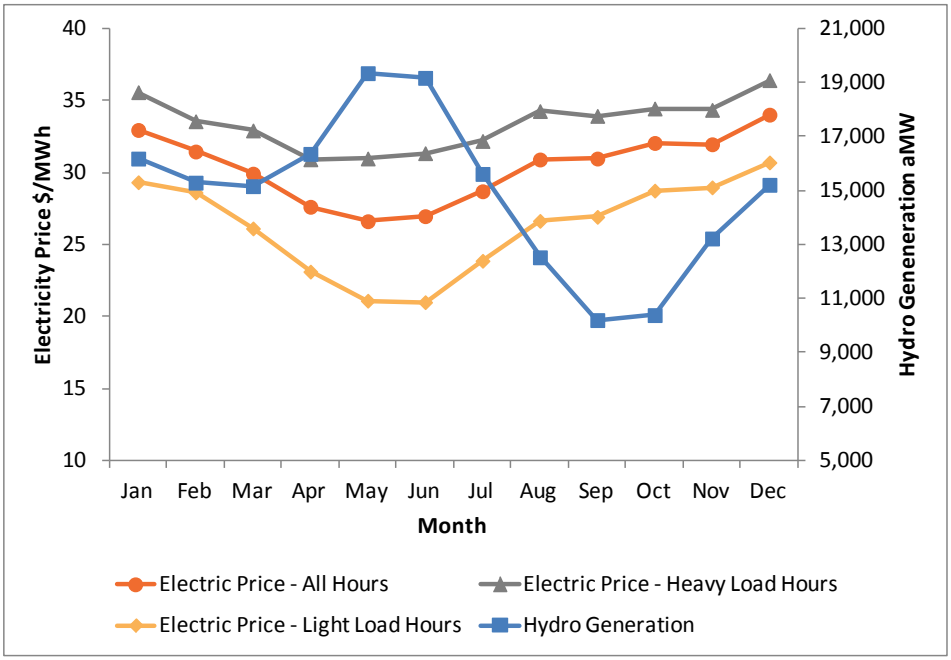
Forecast Case	Average Annual Demand Growth %	Levelized Natural Gas Price ($/mmBtu)	Levelized Electricity Price at Mid C ($/MWh)
Medium	0.38	3.87	33.34
High Demand	1.05	3.87	34.18
Low Demand	0.23	3.87	31.73
High Fuel	0.38	5.80	44.77
Low Fuel	0.38	2.21	19.65

[1]Note

- Time horizon 2016 – 2035
- Demand compiled from 3-zone region that comprises the Northwest and is net of conservation (Sixth Plan level)
- All costs in 2012 dollars
- 4 percent discount rate applied to levelized costs

Electricity prices exhibit a seasonal pattern, reflecting the Northwest's unique demand and generation characteristics. Figure 8 - 2 shows monthly price results for the medium forecast case for a single year (2020), along with the monthly hydropower generation in the region. The chart illustrates the typical seasonal price pattern at the Mid-Columbia trading hub: high prices in the winter when demand for heating is high, and low prices in the late spring/early summer due to low demand, abundant hydro run-off, and strong wind generation. Load can be divided into two time periods. Heavy load hours are defined as the morning through evening hours when demand is highest, while light load hours include the later night time and early morning hours.

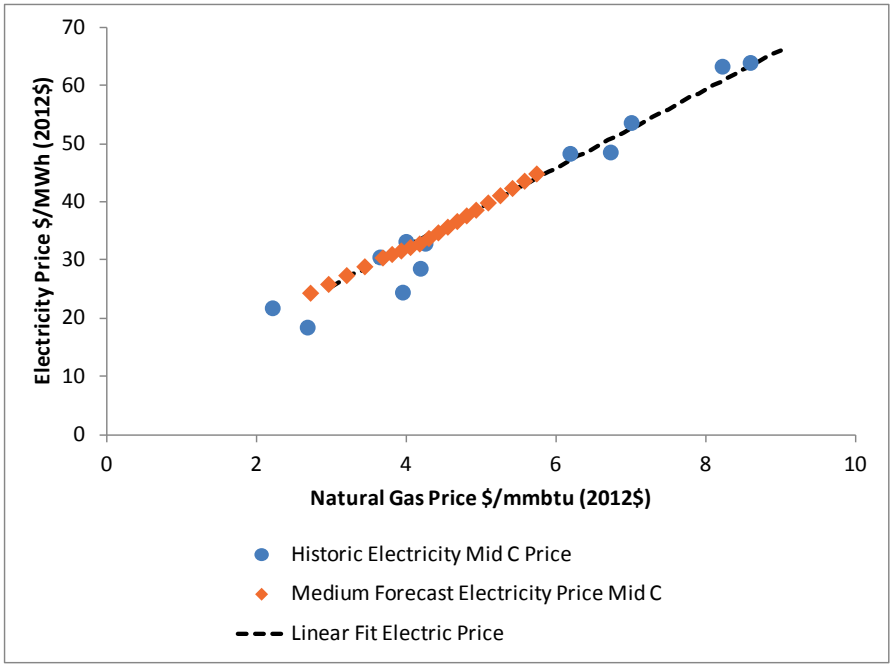
Figure 8 - 2: Monthly Electricity Prices and Hydro Generation in year 2020



In addition to hydropower, there are four other primary sources of power in the Northwest: coal, natural gas, nuclear, and wind. For a typical year, hydropower generation supplies around 60 percent of the region's overall generation. This low-variable cost source of power, along with wind generation and energy efficiency has kept wholesale electricity prices low. Though hydropower is the dominant source of generation in the region, the price of natural gas strongly influences the electricity price. This is because natural-gas fired power plants are often the marginal generating unit which set prices, so the variable cost of fuel for these power plants influences the electricity price. The region depends on external sources for natural gas, with approximately 75 percent coming from the Western Canadian Sedimentary Basin and the rest from the U.S. Rocky Mountain region.

Figure 8 - 3 shows the relationship between the wholesale electricity price and the natural gas price. The annual natural gas price is shown on the x-axis, and the related annual electricity price is on the y-axis. The relationship holds in historic conditions as well as forecast conditions.

Figure 8 - 3: Relationship of Electricity Price to Natural Gas Price

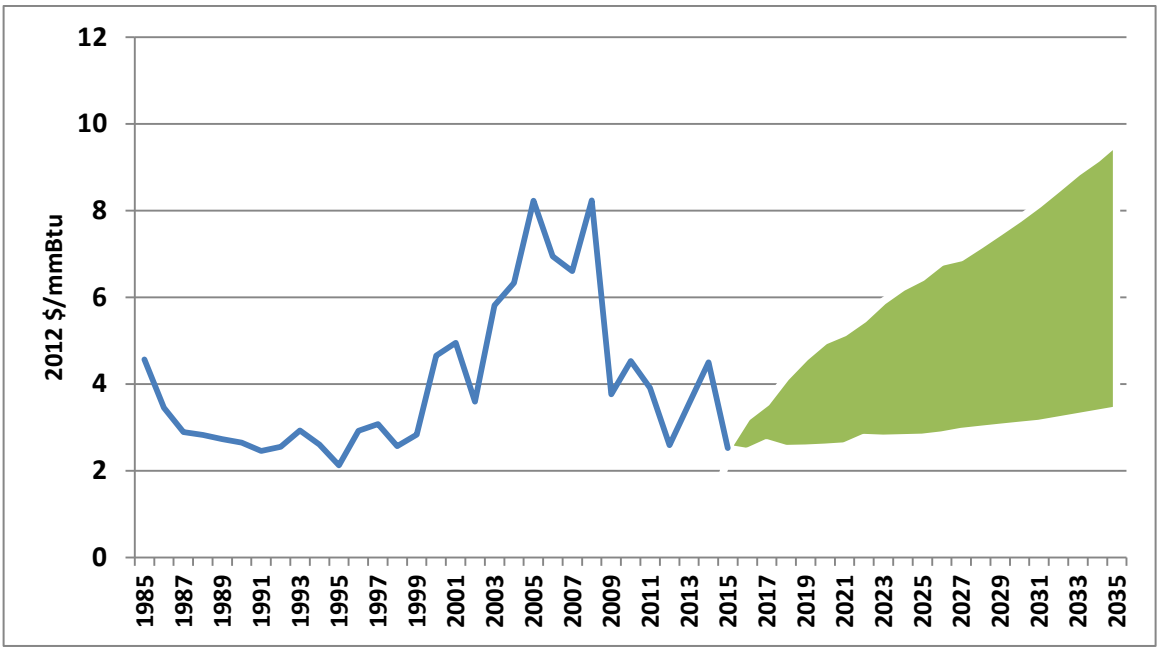


As a result of this linear relationship, the bound for the wholesale electricity price forecast was defined by the high and low fuel-price forecasts. Future bounds with new gas prices could be defined by the linear fit relating electricity price to natural gas price.

Other Fuel Price Forecasts - U.S. Natural Gas Commodity Prices

Natural gas prices are a key fuel price input in determining future electricity prices. Factors determining the future price of natural gas are supply and demand for natural gas. The regional price for natural gas is influenced by the national markets in the United States and Canada. The history of natural gas prices reflects changing supply and demand conditions. Figure 8 - 4 shows the range of U.S. wellhead natural gas price forecasts proposed for the Seventh Power Plan. As shown in the graph, natural gas prices nearly doubled between 2000 and 2008. Since the high in 2008, prices have continued to decline.

Figure 8 - 4: U.S. Wellhead Natural Gas Price Forecast Range 2012$/mmBtu



The low forecast shows prices that range from $ 2.45 per mmBtu in 2016 to $3.40 per mmBtu by 2035 under ample supplies and slow recovery in demand. The high forecast shows prices that range from $3.23 per mmBtu in 2016 to $9.58 per mmBtu in 2035 (in constant 2012$). These prices represent the range of current expectations as expressed by the Council's Natural Gas Advisory Committee. Please note that during the resource planning analysis, the RPM model includes short-term excursions below and above the price range shown here.

The high and low forecasts are intended to be extreme future price variations from today's relatively consistent market. The high case prices increase to nearly $10 per mmBtu by 2035. The Council's forecasts assume that more rapid world economic growth will lead to higher energy prices, even though short-term effects of a rapid price increase can adversely influence the economy. For long-term trend analysis, the stress on prices from an increased need to expand energy supplies is considered the dominant relationship. The high natural gas price 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 liquefied natural gas (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 in which there are limited alternative sources of energy and opportunities for demand reductions.

The low case assumes slow world economic growth which reduces the pressure on energy supplies. It is a future in which world supplies of natural gas are made available through aggressive development of LNG capacity, favorable nonconventional supplies (an example of non-conventional natural gas source would be natural gas produced through fracking of source rock) 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 development of renewable

electric generating technologies, thus reducing 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.

In reality, prices may at various times in the future resemble any in the forecast range. Such cycles in natural gas prices, as well as shorter-term volatility, are captured in the Council's Regional Portfolio Model. For a more detailed year-by-year forecast of natural gas, oil, and coal prices, please see Appendix C and the companion workbook from the Council's website.

In December 2015, the Council updated its July 2014 forecast of natural gas prices. For updated values please see the 7th plan technical workbook:

Companion Spreadsheet for 7th Plan with Demand Forecast Data including - Regional and state level details on economic drivers, fuel prices, demand and load forecast - available from following link: http://www.nwcouncil.org/energy/powerplan/7/technical