APPENDIX B: WHOLESALE AND RETAIL PRICE FORECAST

Contents

List of Figures and Tables

INTRODUCTION

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 (Mid C) trading hub. The 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. The RPM creates excursions below and above the price forecast to reflect the volatility and uncertainty in future wholesale electricity prices.

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:

1. Electricity load
2. Fuel price delivered to generation
3. Existing and new generation capabilities and costs
4. Renewable Portfolio Standards which drive new resource builds
5. Greenhouse gas emission policies

KEY FINDINGS

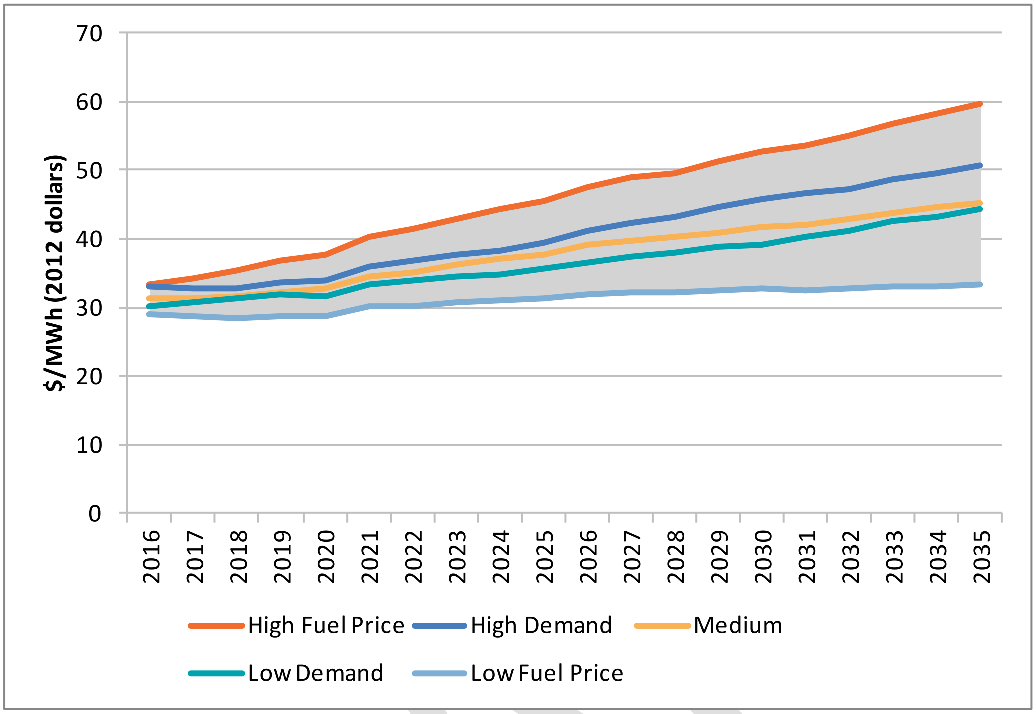
Prices for wholesale electricity at the Mid-Columbia trading hub remain relatively low, reflecting the abundance of low-variable cost generation from hydropower and wind, as well as continued low natural gas fuel prices. The average wholesale electricity price in 2014 was $32.50/MWh. By 2035 prices are forecast to range from $33 to $60 per MWh in 2012 dollars. 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 upper and lower bounds for the forecast wholesale electricity price were set by the associated high and low natural gas price forecast. It's important to note that the region depends on externally sourced gas supplies from Western Canada and the U.S. Rockies.

Five primary forecast cases were developed for this forecast cycle.

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

Figure B - 1 displays the wholesale electricity price results for the five cases on an average annual basis. Note that the high fuel and low fuel cases provide the boundaries for the range of expected prices.

Figure B - 1: Annual Wholesale Electricity Price Forecast at Mid C



In summary, the key findings from the forecast are as follows:

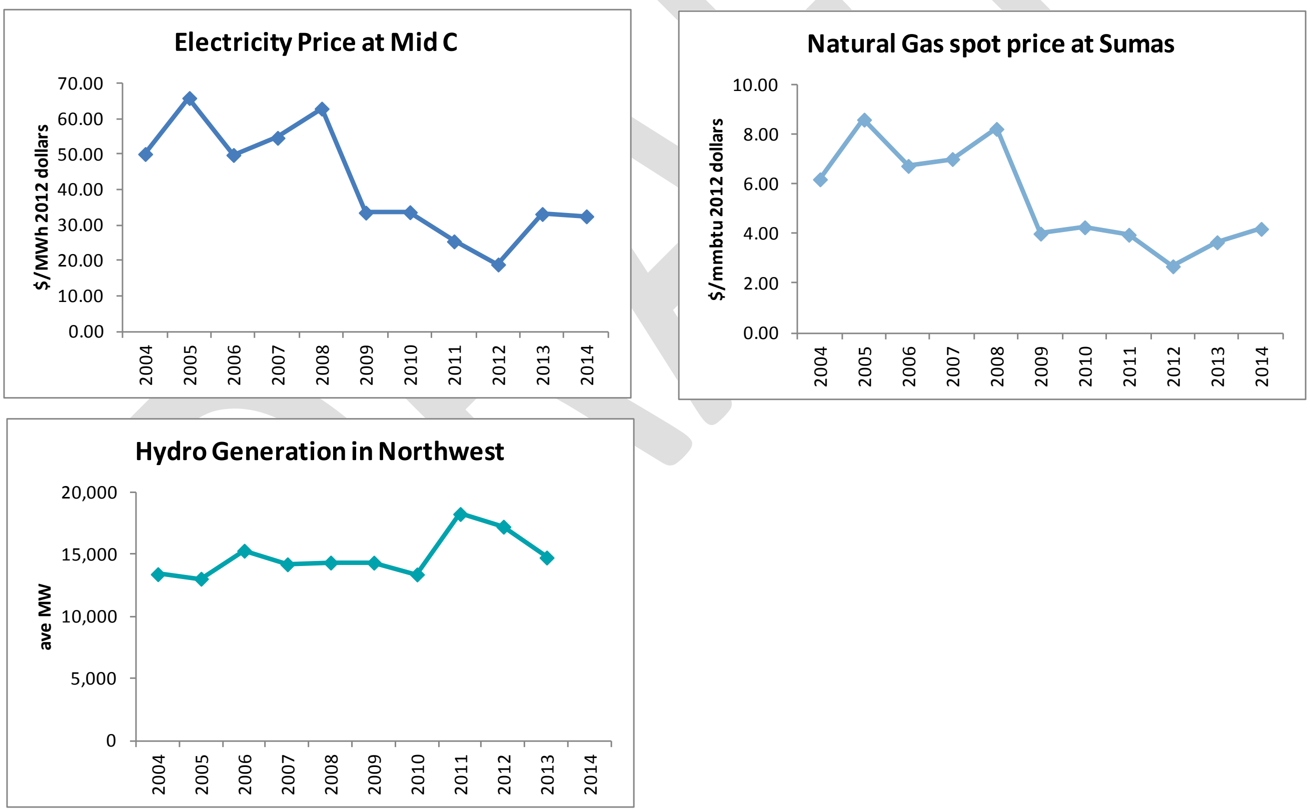
1. The primary factors acting to keep wholesale electricity prices low are
   a. Low natural gas prices due to robust supplies in North America
   b. Existing hydro power in the region supplies around 60 % of the generation at low-variable cost
   c. Regional load growth remains slow
   d. Renewable Portfolio Standards are driving new resource development such as wind power, which have low-variable costs due to the lack of dependence on fuel
2. Natural gas prices can act as a general indicator of where wholesale electricity prices are headed in the region
3. Planned Coal plant retirements in the region will
   a. Result in lower regional CO_2 emissions over time as lower emitting natural gas-fired generation and renewable power supplant the power supplied by coal
   b. Further enhance the influence of natural gas prices on electricity prices and a as gas plants become the primary marginal resource

BACKGROUND

The Mid C hub, one of 8 electricity trading hubs in the Western United States, represents an aggregation of the electricity market for the Northwest. Many factors can impact prices from year to year, such as the level of demand for electricity (weather and economy driven), fuel prices used for generation, and regional hydro power conditions. For example, with strong hydro conditions, more hydro power generation may occur, reducing the need for other more expensive power sources, such as coal and natural gas. In years of high demand for natural gas demand, fuel prices may rise and bring electricity prices up with them.

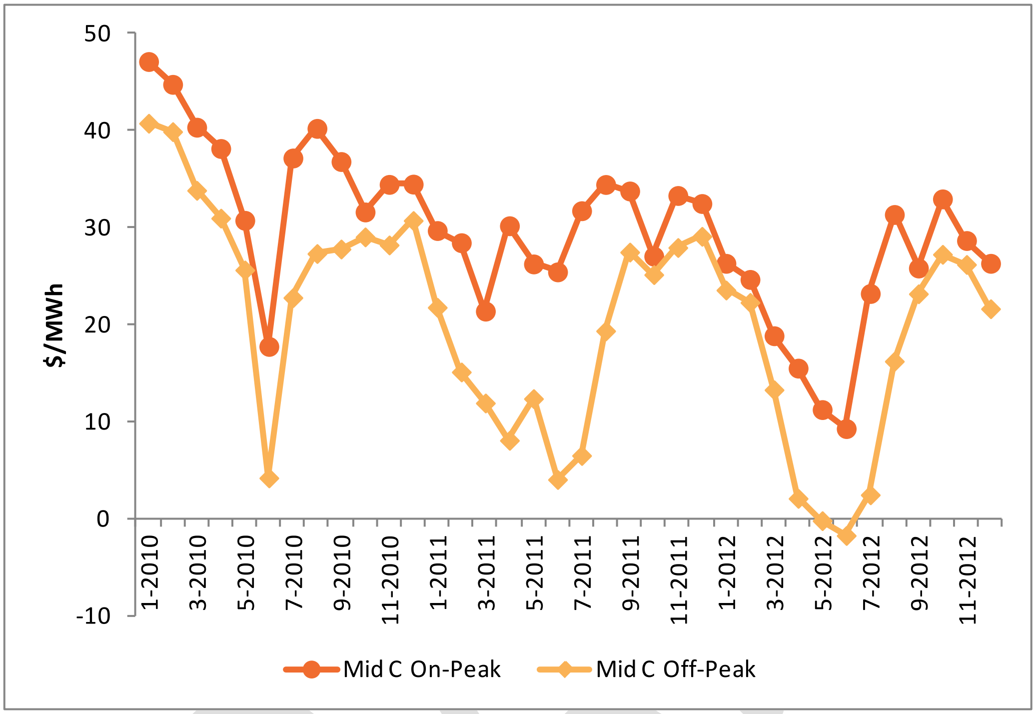
Figure B - 2 highlights wholesale electricity prices, natural gas prices, and regional hydro power output over the past 11 years. Over this time frame, on an annual basis, electricity prices hit a low in the year 2012. This same year also experienced the lowest natural gas prices along with strong hydro power generation. Electricity prices hit a high in 2005, while gas prices were also at a high point and hydro power generation was at a low point.

Figure B - 2: Electricity Prices, Natural Gas Prices and Hydro Power Output



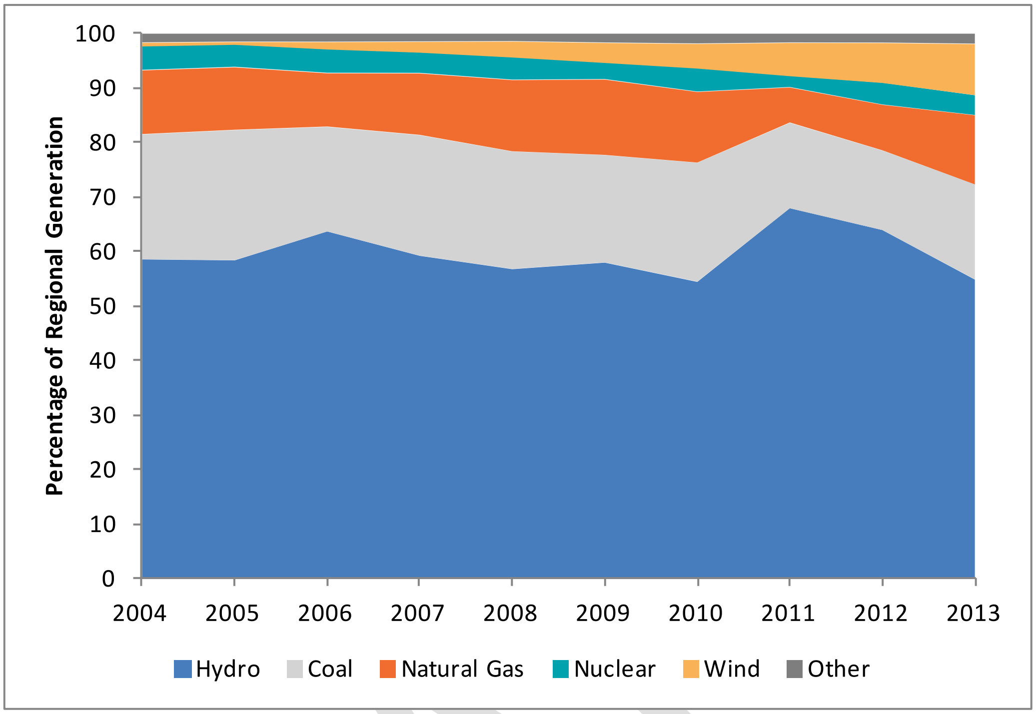
Electricity prices in the Northwest often exhibit a seasonal pattern. Typically, lower prices occur in the spring and early summer when hydro run-off and wind generation are peaking, and prices run higher in the winter with cold weather and higher gas prices. Figure B - 3 shows the average monthly electricity prices at the Mid C for the years 2010 through 2012 where the effect of excess supply is reflected in very low prices in the months of May and June. On-peak hours are defined as the morning through evening hours when demand is highest, while off-peak hours include the later night time and early morning hours.

Figure B - 3: Historic Average Monthly Electricity Prices 2010-2012



In addition to hydropower, there are four other primary sources of power in the Northwest: coal, natural gas, nuclear, and wind. For the years 2004 through 2013, on average, hydropower supplied 60 percent of the region's generation. However, hydropower's contribution to the region can vary from year to year depending on the water conditions. Coal and natural gas fired generation in region comprised, on average, 31 percent of the region's generation over the same time period, while winds' share has been steadily increasing. Figure B - 4 displays the percentage of overall regional generation by resource type.

Figure B - 4: Historic Regional Generation



Hydropower and wind power sources have low-variable costs which can act to keep electricity prices low. For natural gas generation, the price of fuel is a key determinant of the plant's variable cost, and since gas plants are often the marginal generating units which set electricity prices, the price paid for natural gas fuel can directly influence wholesale electricity prices.

METHODOLOGY

One of the key tools the Council uses to produce the forecast is the AURORAxmp Electricity Market Model provided by EPIS. This is an economic dispatch model which means that electricity prices are based on the variable cost of the most expensive generating plant (marginal plant) or increment of load curtailment required for meeting load for each hour of the forecast period. Plant dispatch is simulated for 16 load-resource areas or zones which comprise the Western Electricity Coordinating Council (WECC). Each of the 16 zones are modeled to reflect their unique characteristics in terms of transmission constraints, load forecasts, existing generating units, scheduled project additions and retirements, fuel price forecasts, and new resource options. The dispatch model may add discretionary new resources within zones on an economic basis to maintain capacity reserve requirements or to provide energy. The demand within a zone may be served by native generation, curtailment or by imports from other zones based on economic decisions if the transmission capability exists. Transmission interconnections are characterized by transfer capacity, losses and wheeling costs. In addition to meeting demand, planning reserve margin targets are included in the model. These targets are based on the single highest hour of demand during the year.

The modeling process involves two main steps. First, a congruent set of assumptions and inputs (load, fuel prices, resource availability and costs, etc.) is established and a long-term resource optimization run is performed. This run will set any economically driven capacity additions or retirements over the planning horizon. Then an hourly dispatch run is completed to determine electricity prices for each zone. In addition to electricity prices, the model can also be used to evaluate generation mix, fuel consumption, and CO_2 emission levels.

Sixteen zones or load-resource areas were used to model the WECC electric reliability area. Table B – 1 provides a summary. In this forecast, the region referenced as Northwest is composed of the zones Pacific Northwest Eastside (PNWE), Pacific Northwest Westside (PNWW), and Idaho South (ID S). The reference 4-State Region has the Northwest region plus Montana East. The forecast prices in the PNW East zone are used to represent the Mid C wholesale electricity pricing hub.

Table B - 1: Load Resource Areas

Zone Name	Geographic Area
PNW East	Eastern Oregon, Eastern Washington, Avista Idaho, Northern Idaho, Western Montana
PNW West	Western Oregon, Western Washington, PacifiCorp CA area
S Idaho	Southern Idaho including Idaho Power and PacifiCorp Idaho areas
E Montana	Montana east of the Continental Divide
California North	California north of Path 15
California South	California south of Path 15
Wyoming	Wyoming
Colorado	Colorado
New Mexico	New Mexico
Arizona	Arizona
Utah	Utah
Nevada North	Sierra Pacific area
Nevada South	Nevada Power area
British Columbia	British Columbia Canada
Alberta	Alberta Canada
Baja	WECC interconnected grid in Baja CA

Inputs and Assumptions

Load

The load values input into the dispatch model are net of conservation. The energy and peak load forecasts for the 4-State Northwest zones were based on the Council's 2014 Demand Forecast. For the remaining zones, results from the Western Electricity Coordinating Council Transmission Expansion Planning Policy Committee were used. High and low forecasts were built around the medium forecast. On an average annual load basis, the high forecast case was seven percent higher than the medium forecast, and the low forecast case was nine percent lower than the medium case.

Fuel Prices

The fuel price inputs for each zone were based on updated natural gas and coal forecasts from the Council's fuel model. This is a fundamentals gas model which estimates prices at western gas hubs. High and low fuel price forecasts were also developed around the medium forecast. The high price case was 31 percent higher than the medium case on an average annual basis, while the low price case was 26 percent lower than the medium case. The high and low bands around the gas price assume there is more room for prices to run higher; it's generally accepted that there is a floor to prices at which there would be a cut back on drilling rigs, resulting in a more firm lower price band.

Resources

A comprehensive update of the resource base for the dispatch model was completed. The data sources included the 2012 EIA-860 Annual Electric Generation Data Report, the Council's Northwest Generating Resource database, and the Council's resource tracking worksheets. As in previous Council forecasts, projects under construction and resources in advanced development are considered to be committed and completed as scheduled.

Announced retirements are assumed to occur when scheduled. Several coal plants, including Boardman, Centralia and North Valmy in the Northwest are assumed to close by 2026. Table B - 2 contains a list of a few key coal unit retirements with dates and capacity.

Table B - 2: Retiring Coal Units

Unit	Zone	Fuel	Retirement Year	Installed Capacity MW
Corette 1	MT E	Coal	2015	154
Boardman 1	PNW E	Coal	2020	585
Centralia 1	PNW W	Coal	2020	670
Centralia 2	PNW W	Coal	2025	670
North Valmy	Nevada N	Coal	2025	522

Pacific Northwest Hydro Modeling

To simulate Pacific Northwest hydroelectric generation in AURORAxmp, annual average capacity factors and monthly shape factors were calculated for the three load-resource areas: PNW West, PNW East, and S Idaho based on historic data. The data set was comprised of 80 years of stream flow data from the years of 1929 through 2008.

Renewable Portfolio Standards

Washington, Oregon, and Montana have all passed renewable portfolio standards (RPS) in which a certain percentage of qualifying utilities' electricity sales are required to be produced from renewable resources. While each state has a unique standard with varying factors (e.g. eligible resources, technology minimums, banking provisions), they all have the same overall objective to encourage the development and procurement of renewable resources in the Pacific Northwest over the next decade or so.

Table B - 3: RPS in the Northwest

	Montana	Oregon	Washington
Standard	10% in 2010 15% in 2015*	5% in 2011 15% in 2015 20% in 2020 25% in 2025*	3% in 2012 9% in 2016 15% in 2020*

* and each year thereafter

So far, the region has been on track, and ahead, in meeting most of the interim targets set by the renewable portfolio standards. The significant development of wind power in the late 2000's and early 2010's set the region as a whole up to be in good shape until around 2020, when further renewable resource acquisition will be needed to meet the final goals.

CO_2 Regulatory Policy

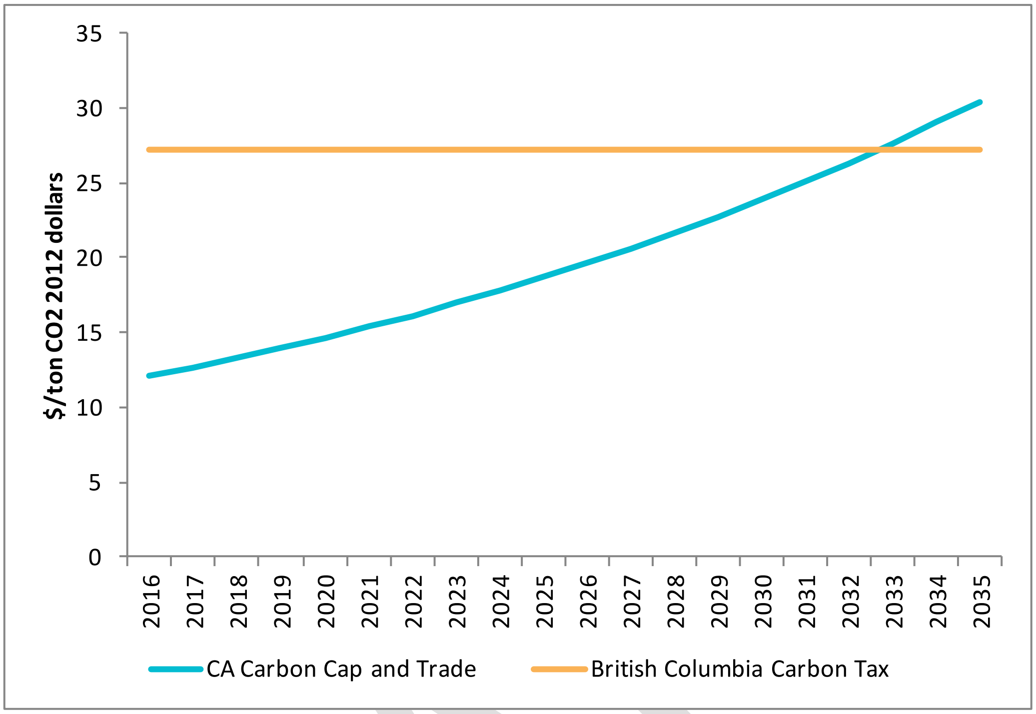
CO_2 emission pricing policies can impact electricity prices by attaching an emission cost to fossil fuel generation, and by influencing decisions to incorporate more non-emitting resources into the generation mix. In the Western US, California implemented a Cap and Trade program for carbon in 2013 and the British Columbia Parliament begin imposing a carbon tax in 2008.

A CO_2 price curve for the California Cap and Trade program was implemented in the model as a cost in terms of \$/ton of CO_2 emitted for generation residing in the two California zones. In addition, a hurdle rate expressed in \$/MWh was applied to energy that was imported to California based on emitting intensity. The initial cost point for the CO_2 cost curve was based on the CO_2 allowance price from the California Air Resources Board Quarterly Auction, and was increased each year at an annual rate of 5 percent as suggested by the Resources Board.

British Columbia instituted a carbon tax in July of 2008 at \$10/metric ton CO_2, and increased the tax five dollars per year until reaching \$30/metric ton in 2012. For this forecasting cycle, it is expected that the tax would remain at the \$30 level for the forecast horizon. This price for carbon was attached to CO_2 emitting resources that reside within British Columbia.

The CO_2 price curves which were used in the model are shown in Figure B-5.

Figure B - 5: CO_2 Emission Prices as Modeled



RESULTS

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

1. Medium
2. High Demand
3. Low Demand
4. High Fuel
5. Low Fuel

For each of the cases, the same RPS and Greenhouse Gas policies were assumed, as well as average hydro conditions. The *Medium* case used the medium forecasts for electricity load and natural gas, and coal fuel prices. For the *High Demand* case, load was adjusted up by approximately seven percent while keeping the medium fuel price forecast. In the *Low Demand* case, load was adjusted down by approximately nine percent from the medium case. In the *High Fuel* case, the medium demand forecast was used, but fuel prices were increased by roughly 31 percent. In the *Low Fuel* case, the fuel price forecast was dropped by approximately 26 percent as seen in Figure B - 1, the *High Fuel* and *Low Fuel* cases provided the upper and lower bounds for the wholesale electricity price forecast range.

In addition to electricity prices, other outputs from the forecast model include generation output by type, CO_2 emission levels, and fuel consumption.

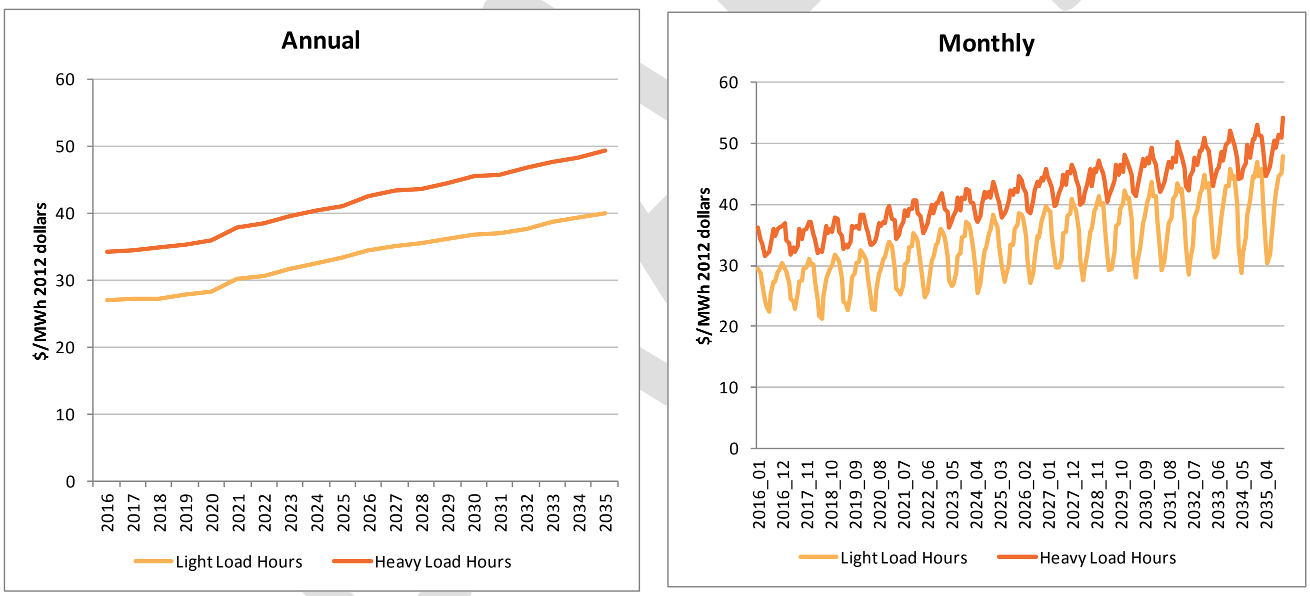
Medium Case

Under medium forecast conditions (load, fuel, hydro) and current greenhouse gas emission policies, the price for electricity at the Mid C in real 2012 dollars is expected to increase from year to year at an average rate of 2 percent. Prices generally follow annual increases in fuel price. The largest annual jumps in electricity price occur in the years 2021 and 2026, following expected closures of regional coal plants (Boardman and Centralia 1 in 2020, Centralia 2 in 2025). However these price increases remain modest (see Figure B-6).

Annual and Monthly Prices

Figure B - 6 displays the wholesale electricity price forecast broken out into high and low load hours on an annual and monthly basis. Heavy load hours are defined as the morning through evening hours when demand is highest, while the light load hours include the later night time and early morning hours. The seasonal effect of hydro and wind can be seen in the monthly prices. Typically prices are lowest in May and June with modest demand and strong hydro power generation, and highest in December and January when demand is highest under cold weather.

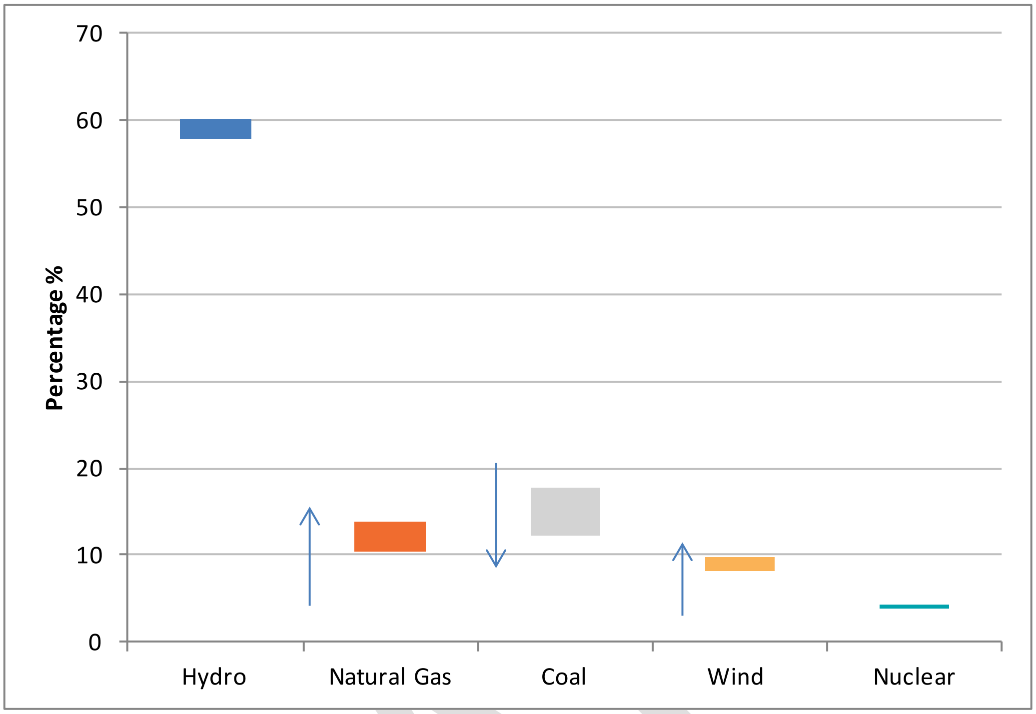
Figure B - 6: Wholesale Electricity Price Forecast at Mid C



Generation Mix

Figure B - 7 shows the range of percentages that each resource type produces in the forecast model. Because average hydro conditions are assumed for each year, the range of generation from hydro power does not vary much from year to year in the forecast and is consistent with historic results. The percentage of generation from coal is seen to decline over time as coal plant retirements occur, while natural gas and wind generation increases.

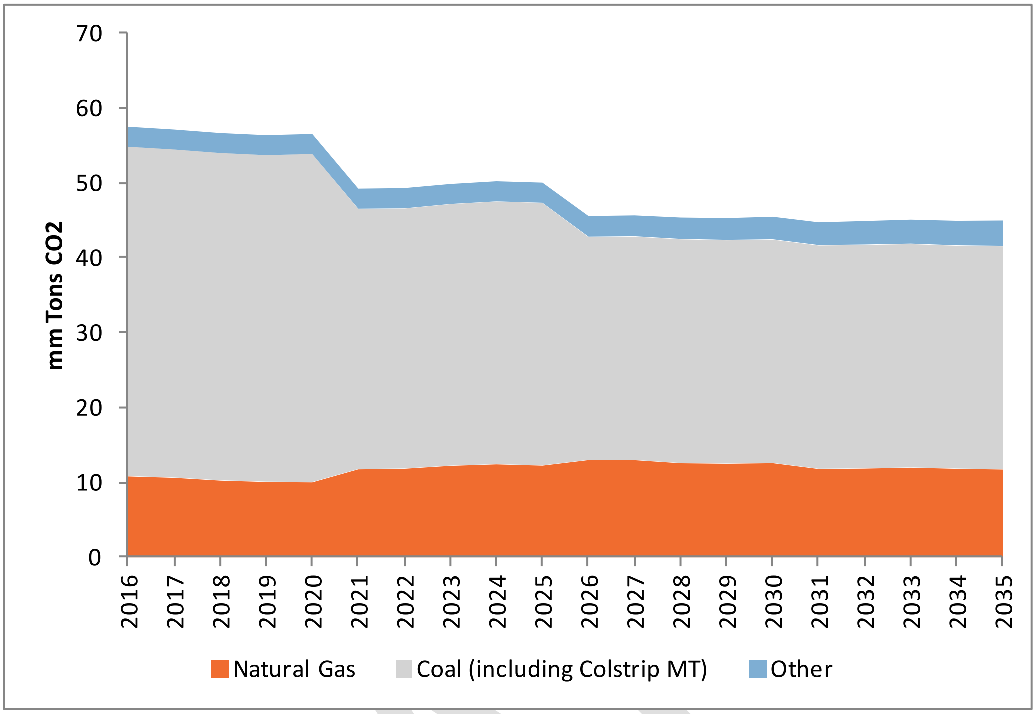
Figure B - 7: Forecast Regional Generation



CO2 Emissions

In the Medium Forecast case, CO_2 emissions from regional power generation decline over time as the coal units in Boardman and Centralia are retired. On an intensity basis of pounds CO_2 per MWh of electricity produced, the forecast shows the region declining from 0.51 pounds per MWh in 2016 to 0.41 pounds per MWh by 2031. This includes all generating resources. On an intensity basis, the Northwest emits at a low rate relative to other regions due to the dominance of non-emitting hydro and wind power. Figure B - 8 displays CO_2 power generation emissions from the region on an annual basis. The effect of the coal unit retirements in 2020 and 2025 can clearly be seen in the chart.

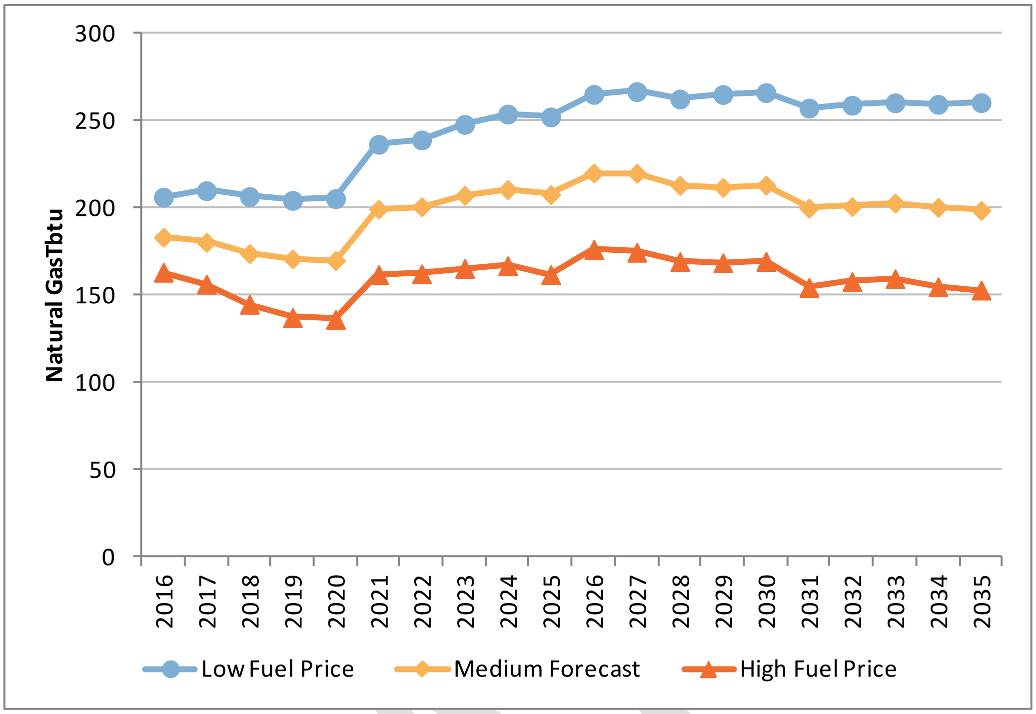
Figure B - 8: Forecast Regional CO_2 Emission from Power Generation



Fuel Consumption

Consumption of natural gas jumps considerably with coal unit retirement in the forecast cases. Figure B - 9 displays natural gas fuel consumption for electricity generation in the region by year for the Medium, *High Fuel Price* and *Low Fuel Price* forecasts. In the *Medium* case, gas consumption jumps by 17 percent between 2020 and 2021, indicating that gas may initially fill in for the loss of coal fired generation. This could have implications for the regional natural gas infrastructure since some parts of the region could brush up against pipeline constraints. As expected, the price for natural gas figures in heavily on the amount purchased and consumed for power generation.

Figure B - 9: Regional Natural Gas Fuel Consumption Forecast

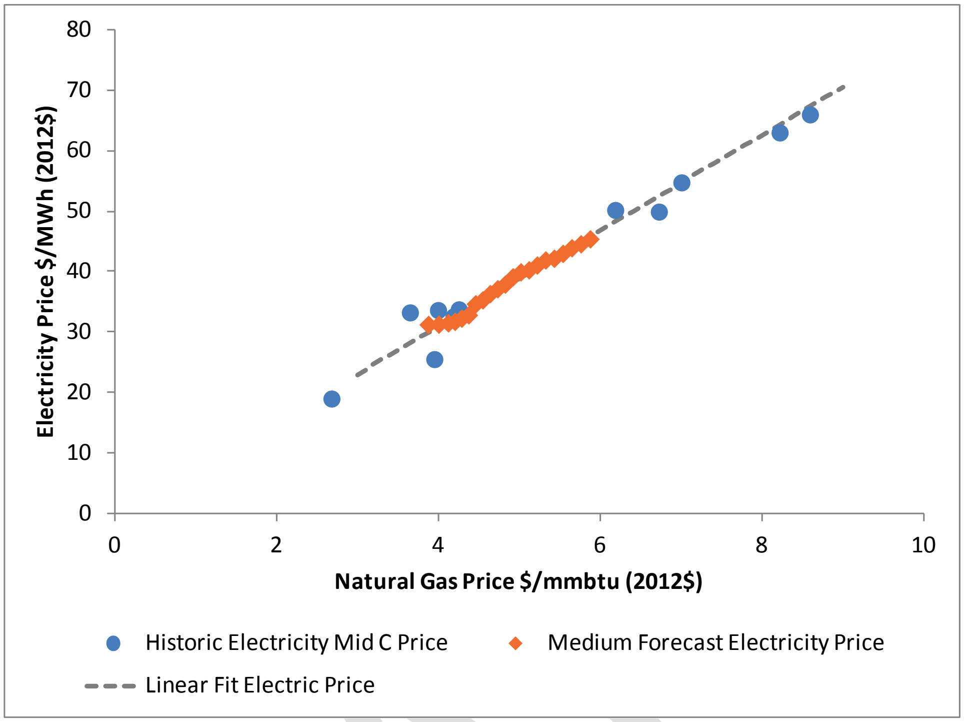


Natural Gas Price and Electricity Price

As mentioned earlier, the price of natural gas used as fuel for generating electricity has a strong influence on wholesale electricity price, and this relationship is expected to continue in the future. Existing hydro and wind power provide low-variable cost (no on-going fuel related expenses) power to the region. Coal and especially natural gas fired plants (more easily dispatched) have larger variable costs and are therefore often the marginal generating unit which set wholesale electricity prices. A major variable cost component for gas plants is fuel consumption; therefore the price for the fuel that is consumed becomes highly influential. Moving forward, as the regional coal units retire through time, the Northwest may be even more influenced by the price of natural gas.

Figure B - 10 displays the relationship between the wholesale electricity price and natural gas price. Annual natural gas prices are shown on the x-axis, and corresponding annual electricity prices on the y-axis. The graph shows both historic and forecast data points from the Mid C and the Sumas gas pricing hub. The result is a linear relationship between gas and electricity, which suggests that it would be wise to spend time examining expectations around future natural gas prices in order to see where electricity prices may be headed.

Figure B - 10: Relationship of Electricity Price to Natural Gas Price



FORECAST OF RETAIL ELECTRICITY PRICES

Introduction

This section presents the methodology used to estimate the average revenue requirement per megawatt-hour and average residential bills for the least risk resource plan under various scenarios. Revenue requirements are the amount of revenue a utility needs to collect to pay for all generation, transmission, distribution, conservation program and non-program costs, and for investor-owned utilities, the allowed return on capital investments. The average revenue requirement per megawatt-hour is calculated by dividing the total revenue requirement by the megawatt hours of sales to customers. Average residential bills are calculated by dividing the residential sector's share of total revenue requirement by number of residential customers. The scenarios are described in Chapter 3 ("Resource Strategy"). These average revenue requirements and bills reflect the impact of conservation investment, CO_2 tax revenues and the cost of other resources developed in the least cost resource strategy for each scenario.

It should be emphasized that these average revenue requirements per megawatt-hour are not intended to represent the Council's estimates of retail electricity rates. The methodology used to derive average revenue requirements per megawatt-hour is a gross simplification of the detailed calculations and regulatory approval process that is used to establish utility retail rates. Actual rate setting procedures and calculations will vary across utilities, class of customers and regulatory jurisdictions. The average revenue requirements per megawatt-hour calculations presented here are averaged across all customer classes, so relative changes among classes are not reflected. The results should, however, be valid for comparison across scenarios.

Methodology for Estimating Average Revenue Requirements

To estimate the average revenue requirement per megawatt-hour, the total regional revenue requirement in dollars is divided by the total regional retail sales of electricity. To calculate the total regional revenue requirement, the fixed cost of the existing power system that must be paid for was added to the average development and operational cost of the future power system across all 800 futures estimated by the RPM for each scenario. The fixed cost of the existing power system is assumed to remain unchanged at 2015 levels in real terms over the 20 year period covered by the Seventh Plan. This implicitly assumes that the capital additions to necessary to maintain the existing power system are exactly equal to the depreciation of the cost of the existing power system. The future system costs consist of the capital cost of the new resources and the non-capital cost of the existing and future power system. The future system cost is the cost calculated in the Regional Portfolio Model (RPM). The consumer's contribution to conservation measures is netted from the total system cost calculated in the RPM. The average revenue requirements per megawatt-hour and average residential monthly electric bills are an average of the revenue requirements and bills across all 800 possible futures.

Estimating Existing Power System Cost:

The total regional revenue from electricity sales for the Northwest power system in 2013, as reported by EIA-Form 861, was $12.8 billion. The Council estimates that about 85 percent of that requirement, about $10.8 billion per year, is the fixed costs of the existing system.

Estimating Future Power System Cost:

The cost of the future power system calculated in the Regional Portfolio Model (RPM) consists of levelized costs of conservation resources and capital and non-capital costs of other new resources as well as the variable cost of existing system. However, general practice among utilities for at least the last decade has been to "expense" their conservation expenditures, that is, to recover them in rates immediately rather than capitalize the expenditures and recover them (and accumulated interest) over the life of the conservation measures. To reflect this practice in the Council's estimates of average revenue requirement per megawatt-hour, estimated conservation costs "as incurred" were substituted for the levelized conservation costs[1] used in the RPM. Based on recent history, $420 million per year of conservation expenses were assumed to be included in the 2015 revenue requirement; so that conservation development expenses in the future would only increase revenue requirements to the extent they are higher than $420 million per year.

To estimate these "as incurred" costs, Council staff converted the levelized costs of the conservation developed by the RPM into a single payment to be made at the time of the conservation measures' installation. This payment covers the full installation cost of the measures, and their administration cost over their lifetime, expressed as 2012 dollars per average megawatt of yearly savings. This approach assures the calculation method is consistent with the method used to develop the conservation supply curve costs used by the RPM. The average *total* cost per average megawatt of all conservation developed by the RPM over the 20 years covered by the Seventh Plan was estimated at $6.25 million in 2012 dollars.

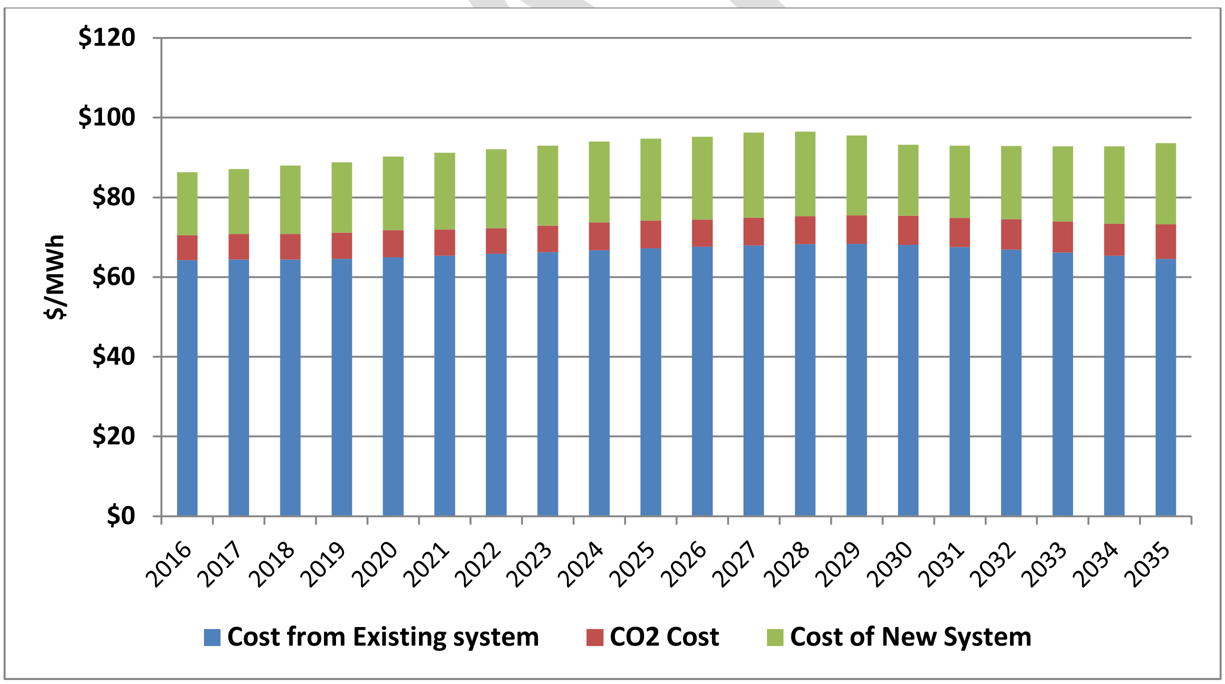
Since consumers traditionally share in the cost of conservation, not all of the $6.25 per average megawatt cost must be recovered in utility revenue requirements. Based on historical experience in the region, the Council assumed that approximately 65 percent of the cost of conservation is paid by the utility system and, therefore, must be recovered in revenue requirements. Two further adjustments were made to reflect the fact that conservation savings defer investments in distribution and transmission and compensate for the 10 percent Regional Power Act Conservation Credit which was included in the original $6.25 million per average megawatt costs. The result of these adjustments results in an average utility cost of $3.01 million per average megawatt of conservation savings.

[1] The conservation premium used to select the level of conservation acquisition does not change the cost of conservation resources and the levelized cost of conservation and the cash-flow of expensed conservation do not differ greatly if conservation acquisition levels are increasing smoothly and do not have significant jumps from one year to next.

Cost of CO_2 Tax Revenues

The default accounting in the RPM includes cost of CO_2 tax revenues, when they are assumed, as though a tax were paid on every ton of CO_2 emitted. However, given uncertainty regarding the impact of CO_2 costs on power system revenue requirements, the impacts on revenue requirements are calculated with and without CO_2 tax revenues. To the extent that CO_2 tax revenues are included in the power system revenue requirement, they are recovered from the consumers served by the generators emitting the CO_2, regardless of whether the generators are physically in the region or not. That is, CO_2 emissions from power exported from the region are subtracted from CO_2 emissions due to regional load and CO_2 emissions from power imported to meet regional load are added to CO_2 emissions due to regional load. The addition of CO_2 tax revenues as though they are paid on every ton of emissions raises average revenue requirements by amounts that vary between $6 and $8 per megawatt-hour over most of the 2016-2035 period. Figure B-11 shows the relative magnitude of the cost of the existing and new power system as well as CO2 tax revenues for the Social Cost of Cabon – Mid-Range scenario. Tables B-4 and B-5 show the average revenue requirement for nine scenarios with and without carbon tax revenues..

Figure B - 11: Average Revenue Requirement ($/MWh) Disaggregated by Component
Social Cost of Carbon – Mid-Range Scenario



Calculated Average Revenue Requirements

The methodology described above results in the annual and levelized revenue requirements per megawatt-hour for the period 2016 through 2035. The results in Tables B-4 and B-5 illustrate nine of the scenarios described in Chapter 3. As an illustrative example, under the **Carbon Cost Risk** scenario the average revenue requirement increases from $82 per megawatt-hour in 2016 to $83 per megawatt-hour by 2035 if CO2 taxes are not borne by consumers and nearly $89 per megawatt-hour in 2035 if they are.

Table B - 4: Annual Average Revenue Requirement per mega-watt hours in $2012/MWh - Excluding CO2 Tax Revenues

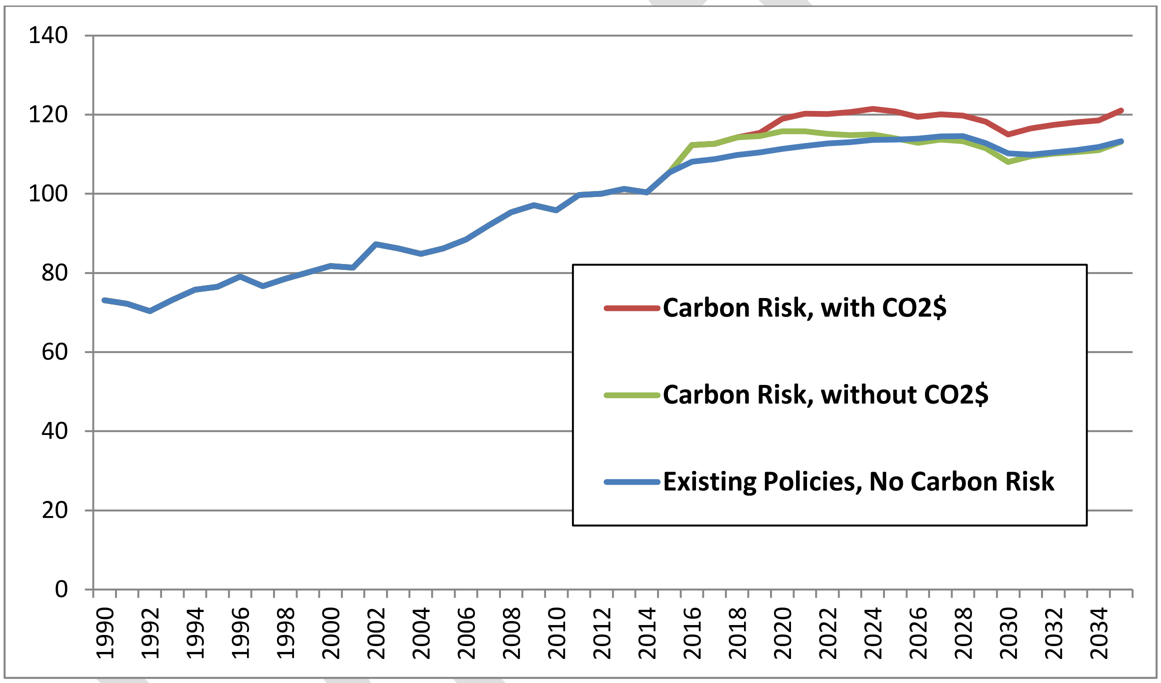
	Existing Policy	Social Cost of Carbon – Mid-Range	Carbon Cost Risk	Maximum Carbon Reduction - Existing Technology	Unplanned Loss of Major Non GHG Emitting Resources	Planned Loss of Major Non-GHG Emitting Resources	Increased Market Reliance	RPS @ 35%	Lower Conservation
2016	79.12	80.03	82.24	79.45	80.04	80.00	78.84	78.95	78.06
2017	79.65	80.70	82.58	80.14	80.69	80.72	79.19	79.45	78.25
2018	80.33	81.54	83.78	80.97	81.57	81.61	79.79	80.21	78.73
2019	80.97	82.14	84.18	81.73	82.16	82.23	80.35	80.90	79.00
2020	82.01	83.42	85.53	82.94	83.47	83.42	81.30	82.56	79.33
2021	83.02	84.57	86.11	84.06	84.76	84.67	82.20	86.72	79.77
2022	84.03	85.67	86.20	85.16	85.82	85.81	83.13	89.36	80.18
2023	84.79	86.34	86.60	87.22	86.50	86.47	83.84	91.53	80.87
2024	85.67	87.08	87.29	88.51	87.31	87.29	84.60	93.76	81.28
2025	86.24	87.70	87.10	89.20	87.91	87.84	85.05	96.74	81.56
2026	86.93	88.37	86.77	90.50	88.63	88.50	85.66	98.06	82.20
2027	87.73	89.33	87.82	93.26	89.80	89.63	86.38	98.47	83.21
2028	88.06	89.55	87.85	94.01	90.13	89.93	86.58	98.70	83.26
2029	86.83	88.41	86.63	93.64	89.07	88.80	85.29	97.22	83.91
2030	84.42	85.89	83.59	91.42	86.44	86.07	82.79	94.46	82.38
2031	83.55	85.69	84.11	90.72	86.58	86.08	81.90	93.50	82.17
2032	83.11	85.22	83.79	90.77	86.19	85.76	81.47	92.50	82.08
2033	82.57	84.99	83.11	90.18	85.82	85.47	80.90	91.73	82.38
2034	82.13	84.79	82.50	89.79	85.66	85.13	80.52	90.82	82.69
2035	82.24	84.94	83.05	90.19	85.91	85.38	80.74	90.22	83.61
Levelized	$90.97	$92.67	$92.76	$94.68	$93.03	$92.87	$89.83	$97.31	$88.22
Annual Rate of growth	0.2%	0.3%	0.1%	0.7%	0.4%	0.3%	0.1%	0.7%	0.4%

Table B - 5: Annual Average Revenue Requirement per mega-watt hours in $2012/MWh - Including CO2 Cost

	Existing Policy	Social Cost of Carbon – Mid-Range	Carbon Cost Risk	Maximum Carbon Reduction - Existing Technology	Unplanned Loss of Major Non GHG Emitting Resources	Planned Loss of Major Non-GHG Emitting Resources	Increased Market Reliance	RPS @ 35%	Lower Conservation
2016	79.12	86.29	82.24	79.45	86.31	86.32	78.84	78.95	78.06
2017	79.65	87.12	82.58	80.14	87.14	87.30	79.19	79.45	78.25
2018	80.33	87.98	83.78	80.97	88.11	88.21	79.79	80.21	78.73
2019	80.97	88.76	84.77	81.73	88.94	89.07	80.35	80.90	79.00
2020	82.01	90.25	87.86	82.94	90.50	90.59	81.30	82.56	79.33
2021	83.02	91.18	89.40	84.06	91.57	91.52	82.20	86.72	79.77
2022	84.03	92.13	89.95	85.16	92.50	92.67	83.13	89.36	80.18
2023	84.79	93.00	90.98	87.22	93.44	93.57	83.84	91.53	80.87
2024	85.67	94.04	92.20	88.51	94.59	94.71	84.60	93.76	81.28
2025	86.24	94.71	92.30	89.20	95.28	95.36	85.05	96.74	81.56
2026	86.93	95.22	91.82	90.50	95.84	95.97	85.66	98.06	82.20
2027	87.73	96.26	92.80	93.26	97.15	97.11	86.38	98.47	83.21
2028	88.06	96.53	92.91	94.01	97.60	97.56	86.58	98.70	83.26
2029	86.83	95.56	91.90	93.64	96.70	96.60	85.29	97.22	83.91
2030	84.42	93.22	88.96	91.42	94.48	94.10	82.79	94.46	82.38
2031	83.55	92.96	89.51	90.72	94.45	93.96	81.90	93.50	82.17
2032	83.11	92.86	89.28	90.77	94.57	94.17	81.47	92.50	82.08
2033	82.57	92.83	88.81	90.18	94.40	93.99	80.90	91.73	82.38
2034	82.13	92.81	88.09	89.79	94.54	93.90	80.52	90.82	82.69
2035	82.24	93.61	88.86	90.19	95.52	94.87	80.74	90.22	83.61
Levelized	$90.97	$100.22	$96.56	$94.68	$100.97	$100.91	$89.83	$97.31	$88.22
Annual Rate of growth	0.2%	0.4%	0.4%	0.7%	0.5%	0.5%	0.1%	0.7%	0.4%

Comparison of annual electric revenues collected in the region, for the past 24 years, with the forecasted future revenue requirement is presented in the Figure B-12. To make the comparison across time appropriate all costs were first converted to 2012 dollars and then indexed so that 2012 has an index value of 100. Between 1990 and 2012, Northwest power systems revenue requirement increased by approximately 27 index points. In the future period, the revenue requirement is expected to increase from an index of 100 points to 110 to 120 points, depending on how CO_2 tax revenues are incorporated into the revenue requirement. The future increase in average revenue requirement per megawatt-hour is anticipated to be less than historic experience under the Carbon Cost Risk scenario with or without consideration of CO2 tax revenues.

Figure B - 12: Comparison of Historic Revenue Collected and Future Revenue Requirement Indexed to 2012



Calculated Monthly Bills

Representative residential average monthly bills were estimated using the total revenue requirements calculated earlier. The residential sector's share of those annual revenue requirements was estimated at 47 percent based on the most recent data. To compute average monthly residential bills 47 percent of future revenue requirements were divided by the projected number of households in future years and then again by 12 to arrive at monthly bills per household. The results of those calculations are shown in Tables B-6 and B-7.

Table B - 6: Average Residential Bills for Least Cost Resource Strategy by Scenario – CO2 Tax Revenues Excluded

(Bills are expressed in 2012$/month/household)

	Existing Policy	Social Cost of Carbon – Mid-Range	Carbon Cost Risk	Maximum Carbon Reduction - Existing Technology	Unplanned Loss of Major Non GHG Emitting Resources	Planned Loss of Major Non-GHG Emitting Resources	Increased Market Reliance	RPS @ 35%	Lower Conservation
2016	$87	$ 88	$ 91	$ 88	$ 88	$ 88	$ 87	$ 87	$ 86
2017	$88	$ 89	$ 91	$ 89	$ 89	$ 89	$ 88	$ 88	$ 87
2018	$89	$ 91	$ 93	$ 90	$ 91	$ 91	$ 89	$ 89	$ 88
2019	$90	$ 91	$ 94	$ 91	$ 91	$ 91	$ 90	$ 90	$ 89
2020	$91	$ 92	$ 95	$ 92	$ 92	$ 92	$ 91	$ 92	$ 90
2021	$92	$ 93	$ 95	$ 93	$ 94	$ 94	$ 91	$ 97	$ 90
2022	$93	$ 94	$ 95	$ 94	$ 94	$ 95	$ 92	$ 99	$ 91
2023	$94	$ 95	$ 95	$ 96	$ 95	$ 95	$ 93	$ 101	$ 92
2024	$94	$ 95	$ 96	$ 97	$ 95	$ 95	$ 93	$ 104	$ 93
2025	$95	$ 95	$ 95	$ 97	$ 96	$ 96	$ 94	$ 107	$ 94
2026	$95	$ 96	$ 94	$ 98	$ 96	$ 96	$ 94	$ 108	$ 95
2027	$96	$ 97	$ 95	$ 101	$ 97	$ 97	$ 95	$ 109	$ 96
2028	$96	$ 97	$ 95	$ 102	$ 97	$ 97	$ 95	$ 109	$ 97
2029	$95	$ 96	$ 94	$ 102	$ 96	$ 96	$ 94	$ 108	$ 98
2030	$93	$ 94	$ 91	$ 100	$ 94	$ 94	$ 92	$ 105	$ 97
2031	$93	$ 94	$ 93	$ 100	$ 95	$ 95	$ 92	$ 106	$ 98
2032	$94	$ 95	$ 94	$ 102	$ 96	$ 96	$ 93	$ 106	$ 99
2033	$95	$ 96	$ 94	$ 103	$ 97	$ 97	$ 94	$ 107	$ 100
2034	$96	$ 97	$ 95	$ 104	$ 98	$ 98	$ 95	$ 107	$ 102
2035	$97	$ 99	$ 97	$ 106	$ 100	$ 100	$ 96	$ 108	$ 105
Levelized	$101	$ 102	$ 103	$ 105	$ 103	$ 103	$ 100	$ 109	$ 102
Annual Rate of growth	0.6%	0.6%	0.4%	1.0%	0.7%	0.6%	0.5%	1.1%	1.0%

Table B - 7: Average Residential Bills for Least Cost Resource Strategy by Scenario – Including CO2 Tax Revenues

(Bills are expressed in 2012$/month/household)

	Existing Policy	Social Cost of Carbon – Mid-Range	Carbon Cost Risk	Maximum Carbon Reduction - Existing Technology	Unplanned Loss of Major Non GHG Emitting Resources	Planned Loss of Major Non-GHG Emitting Resources	Increased Market Reliance	RPS @ 35%	Lower Conservation
2016	$ 87	$ 95	$ 91	$ 88	$ 95	$ 95	$ 87	$ 87	$ 86
2017	$ 88	$ 96	$ 91	$ 89	$ 96	$ 97	$ 88	$ 88	$ 87
2018	$ 89	$ 98	$ 93	$ 90	$ 98	$ 98	$ 89	$ 89	$ 88
2019	$ 90	$ 99	$ 94	$ 91	$ 99	$ 99	$ 90	$ 90	$ 89
2020	$ 91	$ 100	$ 97	$ 92	$ 100	$ 100	$ 91	$ 92	$ 90
2021	$ 92	$ 101	$ 99	$ 93	$ 101	$ 101	$ 91	$ 97	$ 90
2022	$ 93	$ 101	$ 99	$ 94	$ 102	$ 102	$ 92	$ 99	$ 91
2023	$ 94	$ 102	$ 100	$ 96	$ 102	$ 103	$ 93	$ 101	$ 92
2024	$ 94	$ 103	$ 101	$ 97	$ 103	$ 104	$ 93	$ 104	$ 93
2025	$ 95	$ 103	$ 101	$ 97	$ 104	$ 104	$ 94	$ 107	$ 94
2026	$ 95	$ 103	$ 100	$ 98	$ 104	$ 104	$ 94	$ 108	$ 95
2027	$ 96	$ 104	$ 101	$ 101	$ 105	$ 105	$ 95	$ 109	$ 96
2028	$ 96	$ 104	$ 101	$ 102	$ 105	$ 106	$ 95	$ 109	$ 97
2029	$ 95	$ 103	$ 100	$ 102	$ 105	$ 105	$ 94	$ 108	$ 98
2030	$ 93	$ 102	$ 97	$ 100	$ 103	$ 103	$ 92	$ 105	$ 97
2031	$ 93	$ 102	$ 99	$ 100	$ 104	$ 104	$ 92	$ 106	$ 98
2032	$ 94	$ 104	$ 100	$ 102	$ 105	$ 105	$ 93	$ 106	$ 99
2033	$ 95	$ 105	$ 101	$ 103	$ 107	$ 107	$ 94	$ 107	$ 100
2034	$ 96	$ 107	$ 102	$ 104	$ 109	$ 108	$ 95	$ 107	$ 102
2035	$ 97	$ 109	$ 104	$ 106	$ 111	$ 111	$ 96	$ 108	$ 105
Levelized	$ 101	$ 111	$ 107	$ 105	$ 111	$ 111	$ 100	$ 109	$ 102
Annual Rate of growth	0.6%	0.7%	0.7%	1.0%	0.8%	0.8%	0.5%	1.1%	1.0%