Technical Appendix E: Thermal Fuels Forecast

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Thermal Fuels in the Northwest Power System

The Northwest electric power system runs on a mix of generating technologies. While hydroelectric generation is the largest contributor to the mix, thermal generation plays an important role both for annual generation and during extreme weather events. Table E - 1 shows how much electricity was generated in the Northwest by different resource types in 2024 on an annual basis. Thermal resources are highlighted in light red. The table shows total in-region generation and excludes imports and exports, although the region has been a net exporter on an annual basis in recent years. During high demand events the proportion of energy coming from thermal resources often increases compared to annual energy.[1]

Table E - 1: Annual Energy Generation in the Northwest, 2024[2]

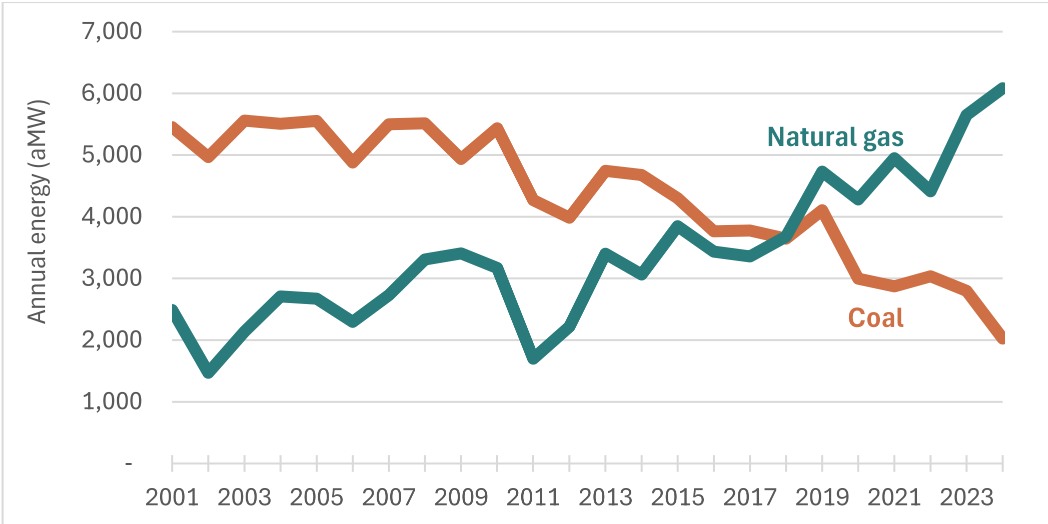
Fuel type	Annual energy (aMW)	Percent
Hydro	12,110	48%
Natural gas	6,080	24%
Wind	3,110	12%
Coal	2,030	8%
Nuclear	1,140	4%
Other	480	2%
Solar	440	2%
Fuel oil	10	0.04%

Natural Gas in the Northwest Power System

Natural gas is the main thermal fuel used to generate electricity in the Northwest power system today. Its role has grown in the past few decades as illustrated in Figure E - 1, with annual energy from gas generation surpassing coal generation in 2018. Part of this growth is due to an increase in total natural gas generating capacity, with the Northwest adding thousands of megawatts of new nameplate capacity in the 2000s. Part of this growth, especially in recent years, is due to increased utilization of the existing system: from 2016 to 2023 no new natural gas power plants came online, yet annual generation grew. In 2024, Northwest natural gas capacity increased via the new Yellowstone reciprocating engine facility in Montana, and the Jim Bridger coal to gas conversion in Wyoming.[3] Please see Technical Appendix B – Existing System and Polices for more discussion on the existing natural gas power plant fleet.

[1] For an example of this please see the Council discussion on the January 2024 high stress event: https://www.nwcouncil.org/fs/18649/2024_03_5.pdf.
[2] EIA data. Includes total electric power industry generation in the states of ID, MT, OR, WA, 100% output from Jim Bridger (located in WY) and 50% of North Valmy (located in NV). The data are for year 2024 which was a below average hydro generation year, which often leads to higher levels of thermal generation.
[3] Although Wyoming is geographically not in the Northwest footprint as defined by the Power Act, Jim Bridger is a resource that serves Northwest load.

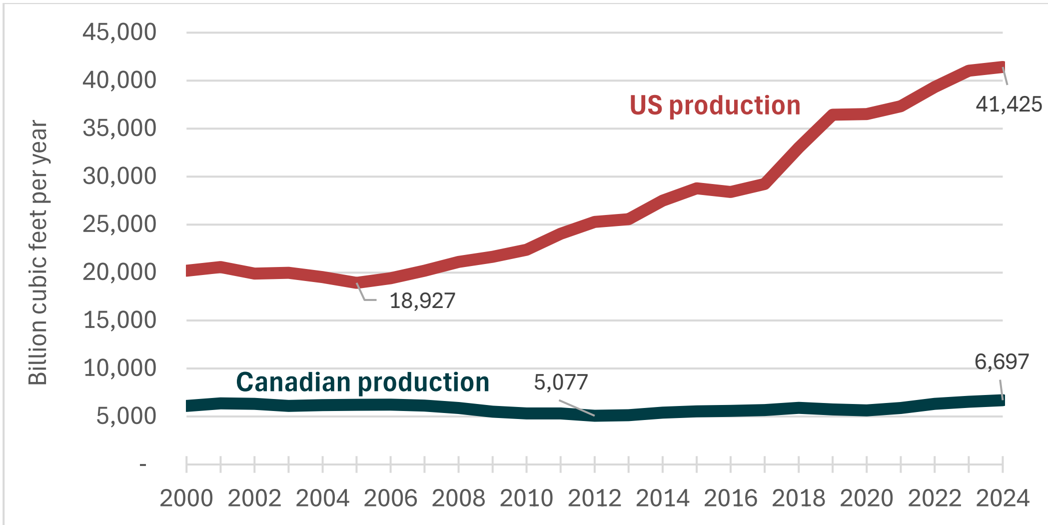
Figure E - 1: Natural gas and coal generation in the Northwest, 2001-2024



The Northwest imports natural gas from Canada and the greater US, with most of the imports coming from Canada.[4] Both the US and Canada have seen increases in natural gas production in the last decade. Much of the growth in production is due to increased use of horizontal drilling and hydraulic fracturing. Today, the majority of US gas is produced using this method.[5] Figure E - 2 below shows total Canadian and US marketable gas production from 2000 through 2024, with the production lows and highs in that time frame labeled. Today, the US is the top natural gas producer in the world, with Canada ranked number five.[6]

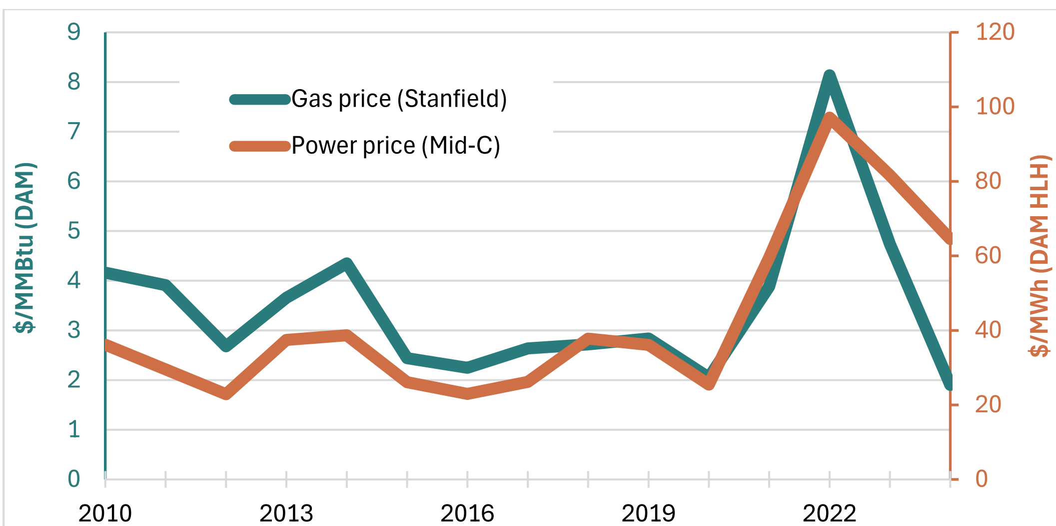
[4] Northwest Gas Association 2024 Outlook: https://d588fb10-0cdf-4398-b6a6-77beee46f98e.filesusr.com/ugd/054dfe_da78848821a448c1b897a5a32d94cbd8.pdf.
[5] US EIA: https://www.eia.gov/tools/faqs/faq.php?id=907.
[6]US EIA: https://www.eia.gov/international/rankings/country/USA?pid=4413&aid=1&f=A&y=01%2F01%2F2023&u=0&v=none&pa=287.

Figure E - 2: US and Canadian annual marketed natural gas production[7]



Natural gas is often the fuel on the margin for the power market. As a result, power prices, which are typically associated with the marginal resource cost, are highly influenced by the price of natural gas. This relationship is shown in the figure below which compares the annual average price of natural gas at Stanfield, a Northwest hub, and power at Mid-Columbia, a common Northwest trading point. Going forward, as more variable energy and storage resources are expected to arrive in the Western power system, this relationship may weaken if gas is on the margin for fewer hours.

Figure E - 3: Average annual gas and power price relationship in the Northwest



[7] US data from the US EIA: https://www.eia.gov/dnav/ng/hist/n9050us2a.htm Canadian data from Canada Energy Regulator: https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/natural-gas/statistics/marketable-natural-gas-production-in-canada.html.

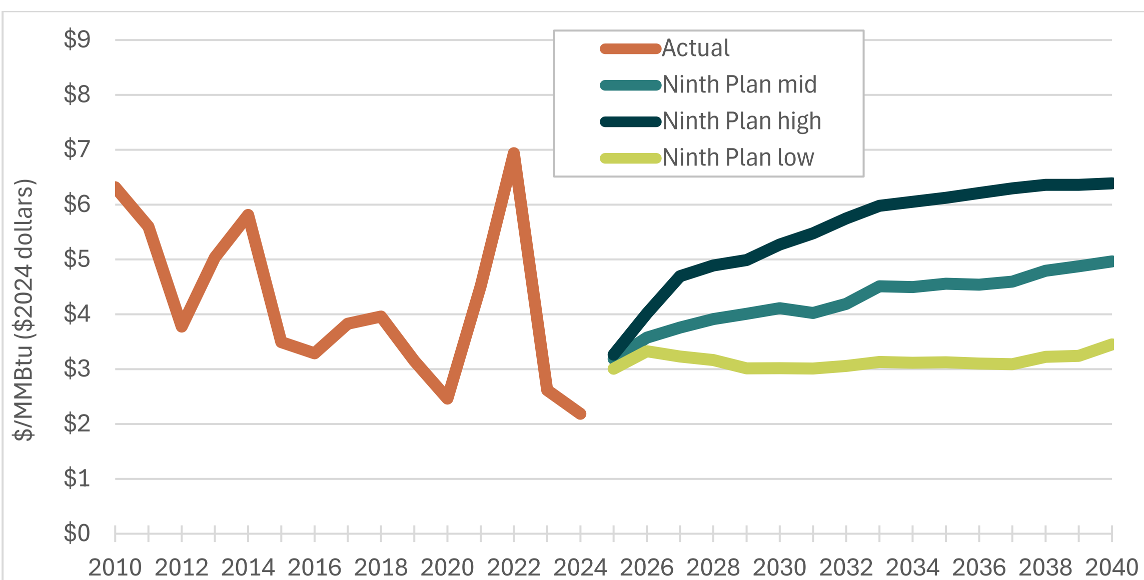
Natural Gas Price Forecast

The Council has an established methodology for forecasting natural gas prices. It is outlined in the steps below. Compared to past Council gas price forecasts, step 6 is implemented slightly differently in the Ninth Plan.

1. Surveys are sent to the members of the Fuel Advisory Committee asking for annual natural gas price forecasts at Henry Hub at a low, medium, and high levels; publicly available forecasts from the US EIA and the California Energy Commission are collected as well
2. The price forecasts are aggregated, and the median (50^{th} percentile) forecast for each year is selected as the starting price for the Council forecast
3. The first few years of the price forecast is blended with a futures strip (CME Group)
4. The Henry Hub forecast is translated to western hub forecasts using historical price deltas
5. Input from the Committee is solicitated – for the Ninth Plan one key input was to increase prices at select hubs in years 2027 through 2029 due to liquified natural gas (LNG) developments in the West
6. Monthly shaping and volatility are added to each hub based on the past 10 years of historical data (this step is different than the monthly shaping and volatility step in the 2021 Power Plan)
7. The forecast with volatility is shared with the Committee for feedback
8. The forecast is shared with Council members for finalization

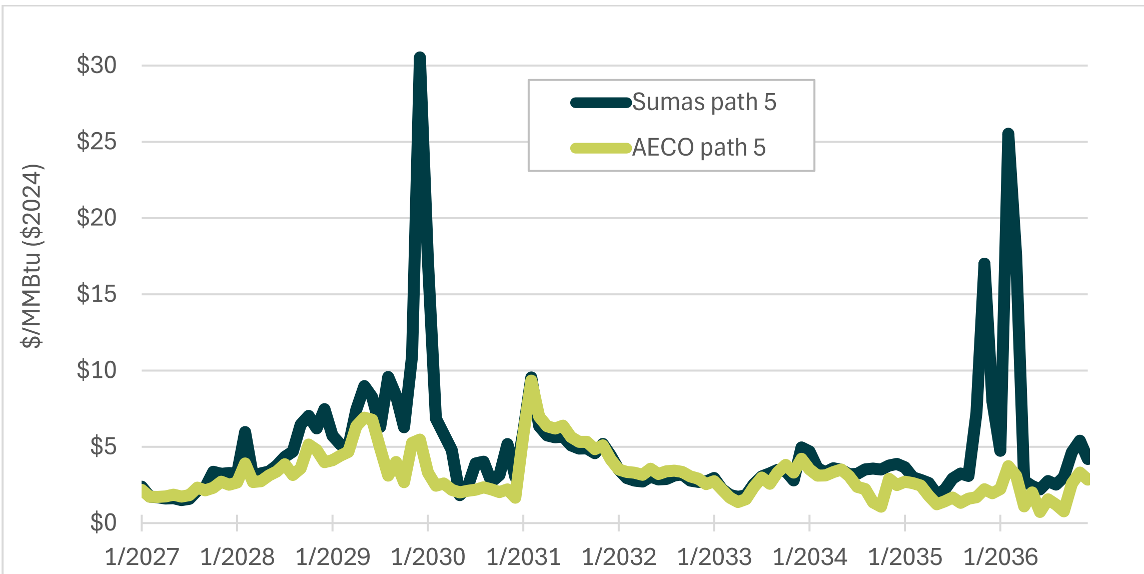
The final annual low, mid, and high Henry Hub forecasts are shown below in real 2024 dollars. For comparison, historical prices at Henry Hub are included.

Figure E - 4: Low, Mid, and High Natural Gas Price Forecasts (Henry Hub)



For modeling, there are ten different volatility pathways available (the pattern shifts one-year in each pathway) for the low, medium, and high forecasts. This results in 30 different forecasts in total. Due to the volatility patterns, the median (50th percentile) forecast ends up being lower than the mean (average) forecast. Figure E - 5 below shows one monthly hub level forecast pathway (path five) from the Sumas and AECO hubs. As seen in the figure, in recent years, Sumas gas has traded at a premium to AECO and has had greater volatility.

Figure E - 5: Volatility in Gas Price Forecasts Example



Going forward, the Fuels Advisory Committee is more concerned with pipeline capacity and congestion leading to high prices rather than total gas supply (this sentiment is not necessarily universally shared among Committee members). In the figure above, the gas price excursions are tied to historical events. While the Council does not expect these same events to occur again, they are used as proxies for potential future events.

Regarding future price events, the Fuels Committee expressed concerns that LNG export facility development in the West could put upward price pressure on Western hubs. To date, most North American LNG export facilities have been located on the Gulf of Mexico or the US East Coast.[8] The Committee discussed three Western facing LNG export facilities, and their potential to impact Northwest prices, in lead up to the Ninth Power Plan. The LNG developments that the Committee focused on are below. For scale, the Northwest used around 360 BCF of gas for power generation in 2024:

a) Woodfibre LNG, located roughly 40 miles north of Vancouver, British Columbia (approximate export capacity of 675 BCF/year). At the time of forecast publication, the project was expected online around 2027. It will source gas from near the Sumas hub. Committee

[8] US EIA: https://www.eia.gov/todayinenergy/detail.php?id=66384.

members expressed concerns that this will cause pipeline constraints and competition for gas at the Sumas hub. As a result, a price adder was put into the forecast from 2027 through 2029, at which point a pipeline expansion is expected to relieve congestion.

b) LNG Canada, located in Kitimat, British Columbia (approximate export capacity of 100 BCF/year). At the time of forecast publication this project was nearly done with construction and entering start up and testing. It will source its natural gas from the 416-mile-long Costal GasLink pipeline that runs from the facility to near Dawson Creek, close to the British Columbia and Alberta border. Although the project is much larger than the Woodfibre LNG project, a price adder was not included in the forecast for it. This is due to the additional pipeline capacity that accompanies the project, and the expectation that Alberta and British Columbia will be able to increase gas production to support the project.

c) Costa Azul, located near Ensenada, Baja California (approximate export capacity of 150 BCF/year). At the time of forecast publication this project was expected online in 2025 (this timeline has moved to 2026). Although not physically close to the Northwest, there are concerns that this facility could increase pipeline congestion into the California market, which would in turn increase California's demand on natural gas from the Northwest, impacting regional prices.

Natural Gas Transportation Cost

Natural gas is transported from hubs to generators via pipelines. At times, multiple pipeline segments are used to move the commodity. There is a cost associated with using pipelines to transport gas. This cost is considered in the Council’s power planning models. For simplicity, the Ninth Plan assumes that it costs $0.40/MMBtu to move gas from a hub to a generator.

The $0.40/MMBtu transportation cost assumption is an oversimplification: actual costs will vary depending on the generator location and the hub the gas is purchased from. Council staff considered exploring a more sophisticated gas transportation cost allocation in the Ninth Plan, but decided against it due to time constraints and challenges with gathering the data. The $0.40/MMBtu value was discussed with the Fuels Committee who agreed it worked as a rough general proxy. Actual transportation costs for any given generator will vary.

Beyond the transportation cost an additional 1.25% price adder is included. The adder represents gas used for compression which is needed to move gas along the pipeline. Like the $0.40/MMBtu transportation cost, this is a general approximation.

Detailed Gas Prices for the Ninth Plan

A workbook with more details and values for the gas price forecast is available on the Ninth Power Plan webpage.[9]

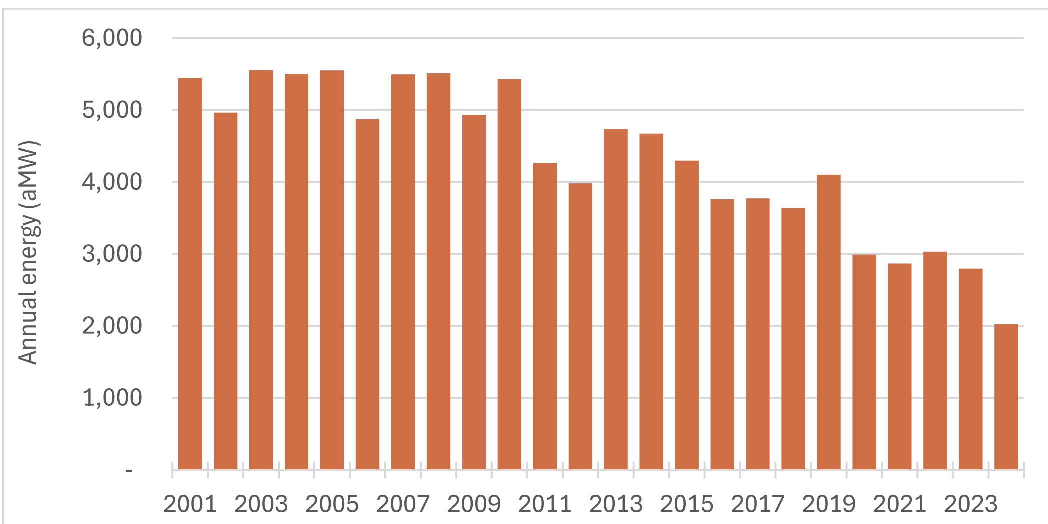
Renewable Natural Gas

Council staff did not create a renewable natural gas forecast for the Ninth Power Plan. This is due to the assumption that renewable natural gas is more highly valued by local distribution companies for decarbonization as compared to the electric power industry. This assumption is based on similar assumptions found in the integrated resource plans of dual-fuel utilities in the Northwest.[10]

Coal in the Northwest Power System

The role of coal generation in the Northwest power system has declined over the past two decades and is expected to further decline going forward. The figure below shows the decreasing use of coal in the Northwest power system on an annual average energy basis.

Figure E - 6: Coal Generation in the Northwest, 2001-2024



The reduction in coal generation is due to multiple factors, with coal retirements playing a role. The Northwest has seen four large coal unit retirements in recent years: Boardman, Centralia Unit 1, and Colstrip Units 1 and 2 (there have been smaller unit retirements as well). In recent years, other coal units have converted to gas or made plans to convert to gas. These conversions are two units at Jim

[9] For the detailed analysis of gas prices, see: https://www.nwcouncil.org/energy/ninthpowerplan/technical-elements.
[10] Please see page E.14 in the appendix of Puget Sound Energy's 2023 Gas Utility Integrated Resource Plan and page 6-20 of Avista's 2023 Electric IRP

Bridger (already done), a planned conversion at Centralia Unit 2, and planned conversions at North Valmy units 1 and 2.[11] Please see Technical Appendix B – Existing System and Polices for more discussion on coal retirements and conversions.

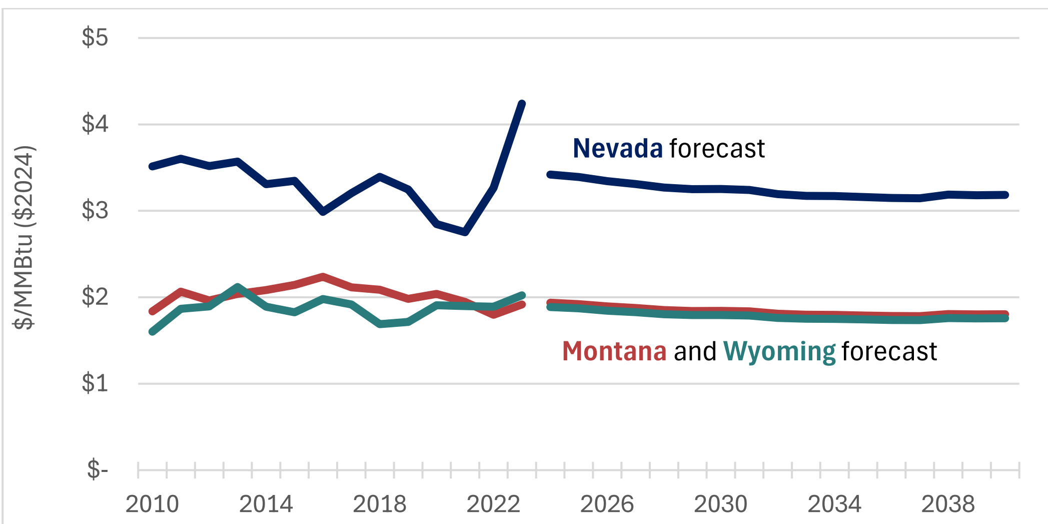
Coal Price Forecast

The Council's coal price forecast is based on EIA forecasts and data. The forecast steps are below:

1. The national EIA Annual Energy Outlook coal forecast sets the general forecast trend (the 2023 forecast was used since the EIA did not publish a 2024 Annual Energy Outlook)
2. The EIA forecast is scaled to state level forecasts using three-year average historical commodity prices for electric power sector delivered coal
3. The forecast is brought to the Fuel Advisory Committee for review
4. The forecast is brought to the Council Members for review

The final forecast for coal price in the Ninth Power Plan is shown in Figure E - 7below. Prices are relatively stable to slightly declining in real dollar terms over the forecast period. This is due to the underlying EIA forecast that exhibits the same behavior.

Figure E - 7: Ninth Plan Coal Price Forecast



[11] https://www.idahopower.com/energy-environment/energy/energy-sources/our-path-away-from-coal.

Detailed Coal Prices for the Ninth Plan

A workbook with more details and values for the coal price forecast is available online on the Ninth Power Plan webpage.[12]

Fuel Oil in the Northwest Power System and Price Forecast

Fuel oil is rarely used in the Northwest, comprising under 0.1% of 2024 annual energy generated in the region. The forecast for the Ninth Power Plan is based on EIA forecasts and data. The forecast steps are below:

1. Historical distillate fuel oil prices at the state level are collected, the state prices are averaged into one Northwest price
2. The EIA 2023 Annuel Energy Outlook forecast is used to inform the general price trend of future prices
3. The EIA forecast is relatively flat, for simplicity the Ninth Plan forecast is pegged at the 2025 forecast value (this value is closest to the midpoint of the EIA forecast range from the 2023 AEO)
4. Discuss final forecast with Fuels Advisory Committee
5. Discuss forecast with the Council for review

The fuel oil price forecast for the Ninth Plan is $20.88/MMBtu. Biofuels, which appear late in the plan (starting in 2045), are assumed to have the same price based on current price trends (in 2025 biofuels, like bio or renewable diesel, are similarly priced to distillate fuel oil).[13, 14]

Nuclear Power in the Northwest Power System & Fuel Forecast

The Northwest has one nuclear reactor, the Columbia Generating Station (CGS). It generates around 1,100 aMW of energy per year, slightly less during refueling years (which occur on odd-numbered years). For the Ninth Power Plan, the Council did not create a standalone nuclear fuel price forecast.

[12] For details on the coal price forecast, see: https://www.nwcouncil.org/energy/ninthpowerplan/technical-elements.
[13] Average renewable diesel and diesel prices in California: https://afdc.energy.gov/data/10969.
[14] More information can be found in the final two slides of this presentation: https://nwcouncil.app.box.com/s/ctds6n6jmvfq7ybckmzzy8mwuubh8jp9.

Rather, the cost of fueling CGS is imbedded into the resource operating costs. The embedded costs are the same as were used in the 2021 Power Plan.

Fuel Related Emissions

Existing System Emissions

Please see the Technical Appendix B – Existing System and Polices, for discussion on emissions from generation.

Upstream Methane Emissions

The 2021 Power Plan included estimates for upstream emissions associated with natural gas and coal. In the 2021 Plan, this increased CO_2e emissions from the combustion of a MMBtu of gas from 118 lbs. to 136 lbs., and for coal from 216 lbs. to 219 lbs.[15]

While upstream emissions related to natural gas and coal still exist, for the Ninth Power Plan, upstream emissions are not included. This is due to three reasons:

- Symmetry issues: many resources that could be picked in the Ninth Plan arguably have upstream emissions and/or other environmental externalities.
- Residual emissions issues: Rules in the US (via the EPA), BC (via the BCER), and Alberta (via the Alberta Energy Regulator) are addressing upstream methane emissions going forward (US rule estimated to reduce upstream emissions ~80% compared to BAU).[16] Once regulated, the Council typically views the cost of regulatory compliance as imbedded and any additional emissions as residual.[17] Please see Technical Appendix C - Environmental Methodology for more discussion on residual emissions.
- Treatment of existing vs. new resource: the Council's environmental methodology is focused on new resources, but this value has a large impact on existing resources.

[15] Details on these values are available here: https://www.nwcouncil.org/2021powerplan_upstream-methane-emissions.
[16] https://www.epa.gov/newsreleases/biden-harris-administration-finalizes-standards-slash-methane-pollution-combat-climate#:~:text=EPA's%20final%20rule%20leverages%20the,the%20impacts%20of%20this%20rulemaking.