Review of Northwest Natural Gas 2022 Integrated Resource Plan—Final Report

Assessing Compliance with the Oregon IRP Guidelines and the Greenhouse Gas Reduction Requirements from the Climate Protection Program

Prepared for Staff of Oregon Public Utilities Commission

March 20, 2023

AUTHORS

Ellen Carlson
Philip Eash-Gates, P.E.
Bob Fagan
Asa Hopkins, PhD

Synapse
Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

EXECUTIVE SUMMARY

In this report we examine Northwest Natural Gas's (NWN) 2022 Integrated Resource Plan (IRP). We focus on NWN's application of Oregon IRP Guideline 1(c), which identifies the primary cost metric to consider when determining a least-cost gas resource plan. The introduction of the Climate Protection Program in Oregon directly disrupts historical approaches to gas IRP because it dramatically limits emissions that are a direct by-product of consuming conventional natural gas. Because of this disruption, NWN should revert to fundamentals analysis of revenue requirements components—particularly the projected distribution system costs whose drivers have historically not varied much as new gas customer load continued. Going forward, both the numbers of new customers and average use per customer are subject to potentially steep declines and ahistorical trends.

We consider how NWN analyzes requirements to meet both physical gas needs (annual energy and peak day demands) and compliance with the Climate Protection Program. The Climate Protection Program introduces direct greenhouse gas emission reduction requirements on the combustion of natural gas for both NWN's retail customers and NWN's delivery responsibilities for gas purchased by others (NWN's transport customers).

NWN's analytical framework for gas IRP includes scenarios with lower annual gas load and lower peak day demands, but the resource solution framework does not directly include demand-side alternatives—such as the effect of electrification in lowering gas load—that compete with supply-side options for either physical needs or Climate Protection Program compliance in the optimization step. NWN does not estimate the cost associated with electrification in its scenarios that include electrified load (the effect of fuel-switching from gas) and does not compare the NPVRR across scenarios. NWN does not include computed revenue requirements streams or NPVRR values in its IRP; in Reply Comments in February 2023, NWN did provide a table of NPVRR values across scenarios but did not provide underlying transparency on how it computed those amounts, what they mean in comparison to one another, or how they guide selection of least-cost planning solutions.

NWN's framework excludes electrification as a costed resource offering, even though it is the most important planning alternative to renewable natural gas solutions to achieve decarbonization. A planning framework that is required to focus on overall least-cost (PVRR) solutions options must explicitly address the tradeoffs among at least all prominent, viable, and potentially economic options. In this instance, that must include electrification. Electrification of end-use load is the direct competitor to use of RNG for meeting Climate Protection Program requirements, but NWN's IRP does not attempt to directly ascertain which of these two competing decarbonization pathways is likely more economic. This oversight is problematic given recent building and industrial sector policies and market trends—nationally and especially in Oregon—that point toward an increasing rate of fuel-switching from natural gas appliances and equipment to electric alternatives.

While the analysis to consider this fundamental question is not easily structured or executed, as it is fraught with uncertainty of input assumptions and performance values for both forms of decarbonizing resource, it needs to be part of NWN's approach to gas resource planning going forward in order to meet the direct intentions of the Oregon IRP Guidelines. While the analysis required to do this also implicates cross-fuel planning, regulatory and accounting considerations, those elements do not need resolution in order to examine—within the bounds of the IRP Guidelines—the resource planning issues in both a qualitative and quantitative manner.

In NWN's optimization approach, there is no explicit inclusion of distribution system capital additions that would vary under different load scenarios, or inclusion of distribution operations and maintenance costs that would vary with load. There is also no explicit inclusion of existing supply-side resources that may not be needed in future scenarios (i.e., there is no analytical allowance for "exogenous retirement" of storage or firm pipeline contracts, as an economically derived constraint forming a part of an optimization). These omissions impact any PVRR computation and could affect the optimization results from NWN's PLEXOS modeling.

Critically, how the PLEXOS model configuration allows for competition between the lowest-cost compliance resource (community climate investment, or CCI, credits)[1] and RNG directly impacts the validity of a "least cost" solution to meet the CPP. The way in which the model structure allows for competition between these CCI credits or RNG, *and* load-lowering resource effects (from energy efficiency or electrification) also impacts the validity of any claimed least-cost solution for meeting CPP requirements. NWN's IRP treats the RNG voluntary target percentages described in Senate Bill 98 (SB 98) (RNG as a percentage of gas sales) as a constraint in its PLEXOS modeling, as if it were a mandatory renewable portfolio standard (RPS) for gas, which it is not.[2] This has the direct effect of reducing the volume of less expensive CCI credits for use in the earlier years of the planning horizon (through 2036), when RNG is more expensive than CCI credits.

Absent a clear analysis of the cost of electrification and its impact on the cost of a decarbonization pathway with lower demand (such as seen in Scenarios 3, 4, 5, or 6), and considering NWN's constraints in the model targeting SB 98 gas procurement (even though it is more expensive than CCI credits throughout the first half of the planning horizon), it is difficult to determine the quantitative extent to which RNG (biofuel), hydrogen, or synthetic methane supply is part of a least-cost solution for compliance with the CPP. The economically optimal mix of RNG, CCI credits, and load reduction through electrification is not assessed under NWN's construct.

[1] See, for example, NWN IRP Figure 1.10 "Emissions Compliance Option Cost Trajectories", page 24.

[2] IRP, page 181: "The policy that has had the largest impact to date on NWN's procurement of RNG is Oregon Senate Bill 98, which established volumetric targets for RNG that the Company internalized as its own RNG targets after the law passed". IRP, page 26: "The majority of scenarios and simulation draws show that in the OR-CPP's first compliance period biofuel RNG to meet SB 98 targets make up the majority of the needed compliance action."

NWN's Monte Carlo analysis determines a preferred portfolio that draws from a universe of gas load trajectory possibilities that are biased towards greater gas consumption. This sampling bias reduces the credibility of the resulting resource outcomes. NWN's Monte Carlo simulation approach did not explicitly consider the actions of utility customers, each of whom makes a fuel choice when replacing equipment (most notably space and water heating equipment) when considering the likelihood of different load trajectories.

NWN calculates that gas rates would double or more from today's rates, in real terms, by 2050, in all scenarios. Meanwhile, Oregon's relatively low electric rates have meant that Oregon has a greater penetration of electric heat than is typical for its climate zone (when viewed across the country), and this competition would only tilt further in electricity's favor if gas rates rise steadily and substantially (and as the cost and performance of electric equipment improves with time). By not considering the agency of its customers to choose a lower-cost fuel in a scenario-consistent way within each scenario, NWN risks being surprised by a reduction in sales or customers that deviates from its planned path.

In this report we estimate electrification costs to roughly gauge the costs to consumers who electrify to meet, at least in part, space and water heating needs and potentially industrial process thermal end uses. This analytical step allows for an apples-to-apples comparison across resource solution options meeting a set level of thermal end-use needs that include supply- and demand-side resources.

We provide estimates of the revenue requirements and NPV of those requirements assuming electrification costs as a proxy for the cost to consumers of fuel-switching from gas to electricity. The result of our analysis demonstrates primarily that making comparisons across scenarios with different levels of gas load is possible when using an estimate of the costs of the electrification (or, increased energy efficiency) required to reduce the gas loading. It also begins to illustrate the importance of sensitivity testing of scenarios to help understand the relative economic impact of a planning path that potentially relies on RNG. While the exercise is not meant to definitively determine which resource path is least-cost, it does illustrate, roughly, that under scenarios of higher RNG costs, even the most aggressive of the electrification scenarios posed by NWN (Scenario 6) costs less over the planning horizon than Scenario 1, under the assumptions we make for the cost of electrification.

Our analysis leads to a series of conclusions and recommendations. The highlights of those findings is as follows:

- NWN's analysis fails to provide a robust economic comparison across resource solution alternatives that meet the Climate Protection Program requirements. NWN does not provide a sufficient evaluation at this time of the costs of a resource solution consisting of greater levels of electrified end uses and lower levels of gas load, versus a resource solution that achieves decarbonization through the use of RNG (biofuel), hydrogen, and synthetic methane. Therefore, we do not recommend acknowledgment of the longer-term resource paths arising out of NWN's preferred portfolio, which consists of a mix of biofuel RNG, hydrogen, and synthetic methane.
- The analysis performed by NWN is incomplete. It does not appropriately trade off across the costs of RNG, the lower costs of CCI credits, and the costs of electrification as a

means of lowering gas demand. The combination of prioritizing RNG (per SB 98 targets) and reducing use of CCI credits, and not including an estimate of electrification cost in the model to allow for scenario comparison is a key shortcoming. This is particularly impactful in the early years of the planning horizon when CCI credits are underutilized.

- While the overall effect of demand response alternatives (and incremental energy efficiency) beyond that contained in the various scenarios may be uncertain, the resource solution options must at least include demand response options as a means of reducing future peak day needs. This enables the model to better assess tradeoffs between demand-side and supply side firm capacity alternatives.
- NWN's partial revenue requirements construct could constitute a valid analytical approach, as some costs are likely to remain fixed over time; but NWN does not include those revenue requirement components (that vary with load) necessary for a true optimization across all Climate Protection Program compliance options. Distribution capital investments and their associated costs are critical components of a trajectory of future revenue requirements. These costs are excluded from NWN's analysis, as are the potential cost savings arising under lower peak day loading scenarios if upstream pipeline or other firm capacity resources were allowed to economically "retire" as part of the modeling.
- The Monte Carlo simulation is based on a sampling approach across the 500 draws that is biased towards high load outcomes. This is an underlying weakness of the Monte Carlo exercise; when coupled with the exclusion of modeled costs that may vary with load (i.e., distribution system expansion), the exclusion of electrification options as a means towards meeting Climate Protection Program requirements, and the treatment of RNG vs. CCI credit solutions, we find that the simulation does not sufficiently evaluate the risks of moving ahead with resource solutions that plan for a dependence on RNG supply sources.
- We recommend an Action Plan that includes maximum use of less-expensive CCI credits for the first few Climate Protection Program compliance periods; and fully excludes planned procurement of incremental RNG resources until a more rigorous economic assessment is performed.
- As long as future IRP exercises clearly include the ability for the model to "retire" unneeded firm delivery capacity from contracted upstream pipelines importing to NWN's territory, we recommend considering acknowledgement of the retention of the Portland Cold Box peak shaving capacity. It is a relatively inexpensive peak day capacity resource available to support needs across the entire system[3] and is not dependent on RNG solution pathways.
- We also recommend expedited scoping of a demand response program and deployment (if needed) to help meet peak day demands. The inclusion of a fairly stringent peak day planning standard logically implies a need to include in the optimization modeling for capacity needs all resources that can contribute towards meeting (or reducing or avoiding) the peak day load.

[3] See, for example, NWN IRP Table 6.14 "Capacity Resource Cost and Deliverability", page 243.

1. INTRODUCTION AND BACKGROUND

Purpose of Report

Synapse Energy Economics prepared this report on behalf of the staff of the Oregon PUC. Its purpose is to present our findings from a review of Northwest Natural Gas's (NWN) Integrated Resource Plan (IRP) for 2022. We analyze NWN's approach, input assumptions, methodology, and results. We directly consider the effect of Oregon's Climate Protection Program (CPP) on NWN's IRP.

While our review considered the entirety of the IRP, our focus in this report is on four interrelated areas: NWN's scenario analysis and Monte Carlo simulation framework; CPP compliance resource tradeoffs between community climate investment (CCI) credits and renewable natural gas (RNG) under different gas load scenarios; the way in which electrification as a CPP compliance pathway is considered by NWN (and our estimation of electrification costs); and the use of the present value of revenue requirements (PVRR) comparisons across scenarios to guide selection of least-cost planning solutions.

Initial Expert Report Summary

In November of 2022 Synapse developed an initial report outlining key areas of substance to consider when analyzing NWN's IRP. In that report we identified technical areas of concern that we address in this report, including: (i) the importance of comparing the costs of electrification to that of RNG and CCI solutions for CPP compliance, (ii) the overall use of the PVRR construct to gauge relative value of alternative decarbonization solutions, (iii) the comprehensiveness of resource solutions "offered" to the planning model, and (iv) the importance of including in the analysis future cost streams that may vary with load.

The focus of that original assessment included NWN's approach to determining the least-cost resource plan, how it utilized its PLEXOS modeling platform, the nature of its input assumptions, how it factored in the introduction of the constraints of the CPP, and the extent to which its approach followed Oregon's IRP guidelines.

Gas IRP Planning under Climate Protection Program

Optimal Solutions for Energy, Capacity, and CPP Compliance

Gas IRP planning historically utilized recent customer and consumption trends, in part, to determine least-cost planning solutions. Oregon's introduction of a greenhouse gas emission reduction requirement for natural gas utilities upends historical approaches to gas IRP. The prospect of dramatic changes in the pace of fuel-switching to electricity for certain end uses and sectors, and/or supply-side transformation to RNG sources will restructure gas planning.

Regulatory and Legislative Factors

The IRP modeling and outcomes are heavily influenced by relatively recent regulatory and legislative developments, in addition to the use of a new peak day planning standard.

Climate Protection Program

The Oregon Department of Environmental Quality (OR DEQ) CPP consists in part of a binding carbon dioxide emission constraint and an associated compliance obligation for natural gas utilities. The CPP is a critical, specific constraint that directly impacts the resource choices arising from NWN's optimization approach to developing a preferred resource portfolio. Under NWN's most aggressive scenarios for gas demand reduction, CPP compliance could generally be met with relatively low reliance on RNG and use of CCI credits.

Community Climate Investments

CCI credits are a compliance mechanism allowing NWN to fund external actions that contribute to meeting the greenhouse gas reduction requirement. CCI credits are limited to a share of the overall required compliance obligation. For the 2022–2024 planning period, the share limit is 10 percent. It rises to 15 percent for the second compliance period (2025–2027), and 20 percent thereafter. Notably, NWN uses less than the maximum amount allowed for CCI credits in the beginning of the planning horizon (through 2030) across most scenarios, as RNG contracted quantities comprise a large share of compliance needs.

Senate Bill 98 and RNG Procurement Rules

The 2019 Oregon Senate Bill 98 (SB 98) states that RNG can be used to reduce emissions from the direct use of natural gas, and that RNG can be included in the set of resources used to help reduce greenhouse gas emissions.[4] The law allows NWN to recover costs for the purchase of RNG, through rules to be (and that were) subsequently established by the Oregon PUC. The law allows NWN to voluntarily procure RNG as a percentage of overall gas sales, with volumes capped at targeted amounts (5–30 percent, in 5 percent increments each five years) out to 2050. While SB 98 preceded the establishment date of the CPP, RNG can be used to meet a portion of the overall CPP compliance obligation.

The Oregon PUC adopted new rules on July 16, 2020 in Order No. 20-227 (Docket No. AR 632, Renewable Natural Gas Program SB 98) detailing the process for NWN to purchase RNG, invest in new RNG infrastructure, and recover prudently incurred costs associated with the purchase of RNG.

Peak Day Planning Standard

NWN introduced the use of a new peak day capacity planning standard during the 2018 IRP, for implementation in the 2018 IRP and subsequent IRPs. The new standard created by NWN requires

[4] Oregon Senate Bill 98, text at https://olis.oregonlegislature.gov/liz/2019R1/Downloads/MeasureDocument/SB98/Enrolled.

supply capacity resources to meet the highest firm sales demand in a given year with 99 percent certainty.[5] The OR PUC Order acknowledging the 2018 IRP included OR PUC Staff Recommendation 5, requiring NWN to address its method of implementing the probabilistic methodology for the capacity planning standard and peak-hour standard for distribution system planning.[6] The peak day planning standard introduces a significantly higher peak day resource requirement relative to recent historical (actual) peak day gas deliveries.[7]

Rate Case Order (October 2022) – Line Extension Allowance Effect

The rate case Order in October 2022 set out a structure to reconsider the way in which line extension allowances are utilized within the NWN regulatory environment.[8] The effect of reconsidering line extension allowances policy will have an impact on the revenue requirements of NWN going forward, as NWN distribution system plant investment levels will be affected.

Structure and Content of this Report

This report first examines multiple issues areas from the IRP. It presents conclusions and recommendations from our analysis. It includes three appendices, in particular Appendix C, which contains an estimate of the costs of electrification across NWN's major sectors and the major end uses for gas consumption in those sectors.

2. Issue Areas

2.1. Overview

Integrated resource planning intentionally addresses interrelated issues in an analytical context. In this IRP, NWN produces a gas load forecast, examines the cost of RNG solutions (for CPP compliance) based on third-party reporting, incorporates the availability of CCI credits into its gas planning solution, produces a plan for meeting annual energy and peak day needs, and strives to determine a near-term

[5] NWN, 2018 IRP, Chapter 3, "Load Forecast," Section 7.2 "Capacity Planning Standard," page 3.41.

[6] OR PUC Order 19-073, Staff Recommendation #5. "Prior to the 2020 IRP, Staff recommends NWN coordinate a TWG focused on the Company's method of implementing probabilistic methodology for the capacity planning standard and peak hour standard for distribution system planning. NWN should share the relevant modeling inputs, outputs, and workpapers with stakeholders at least one week in advance of the TWG." NWN held a TWG session on June 3, 2021 on the standard.

[7] See, e.g., TWG #2 Presentation, "Load Forecast for the 2022 IRP Technical Working Group," Peak Day Firm Sales Forecast, slide 46. February 11, 2022. Slide 46 indicates a peak day design forecast of roughly 1 million Dekatherms/day, whereas recent historical actual sales are roughly *half* that amount.

[8] Oregon PUC, Order Number 22-388. October 24, 2023.

Action Plan and a future long-term portfolio that reflect its current understanding of the landscape for natural gas resource supply and consumption.

NWN uses a PLEXOS modeling framework to address the technical and economic issues that underlie the tenets of gas resource planning. NWN constructs a scenario framework, considers a number of different load forecasts, and seeks to optimize (to attain at least cost) a gas planning solution that includes RNG, CCI credits, energy efficiency impacts, and potentially some electrified load. It does so by considering a handful of specific resource solutions in its modeling exercise and configuring the PLEXOS model to address physical and CPP compliance constraints. It optimizes its solution by solving for an objective function that seeks to minimize the present value of a subset of NWN's total revenue requirements.

In this section we review some of the critical issue areas of NWN's modeling structure, input assumptions, and application of the Oregon IRP guidelines for integrated resource planning.

2.2. Scenario Analysis Framework and Resource Options Available as Planning Solutions

Scenario Analysis and Monte Carlo Simulation Framework

NWN's PLEXOS modeling framework,[9] used to determine resource planning solutions, consists of both deterministic scenario analysis and a stochastic approach whereby use of Monte Carlo simulation allows for inputs to be structured as distributions of key variables. NWN's Table 7.3, reproduced below as Figure 1, describes its 10 scenarios – a "reference" scenario (trend continuation case) and nine working scenarios.

[9] NWN describes its PLEXOS modeling environment in Section 7 and Appendix F of the IRP.

Figure 1. NWN's scenario descriptions

<table>
<tr><th colspan="2" rowspan="2">2022 IRP Scenarios- Summary Version</th><th rowspan="2">Reference (Trend Continuation) Case</th><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th><th>7</th><th>8</th><th>9</th></tr>
<tr><th>Balanced Approach</th><th>Carbon Neutral by 2050</th><th>Dual-Fuel Heating Systems</th><th>New Direct Use Gas Customer Moratorium in 2025</th><th>Aggressive Building Electrification</th><th>Full Building Electrification</th><th>RNG and H2 Production Tax Credit</th><th>Limited RNG Availability</th><th>Supply-Focused Decarbonization</th></tr>
<tr><td rowspan="5">Demand-Side</td><td>Weather</td><td colspan="10">Climate change adjusted expected ("normal") weather in each year</td></tr>
<tr><td>Customer Growth</td><td colspan="4">Current expectations</td><td colspan="3">No New Customers After 2025</td><td colspan="3">Current expectations</td></tr>
<tr><td>Space and Water Heating Equipment</td><td rowspan="3">Current EE expectations</td><td colspan="2">Moderate gas powered heat pump and hybrid heating adoption</td><td>All residential and commercial space heating becomes hybrid heating by 2050</td><td>Moderate gas heat pump and hybrid adoption for existing customers</td><td>High electrification of existing residential and commercial load by 2050</td><td>Full electrification of existing residential and commercial load by 2050</td><td colspan="2">Moderate gas heat pump and hybrid heating adoption</td><td>No gas powered heat pumps and low levels of hybrid heating</td></tr>
<tr><td>Industrial Use Efficiency</td><td>Consultant projection</td><td>High sensitivity</td><td colspan="2">Consultant projection</td><td>60% Electrified by 2050</td><td>90% Electrified by 2050</td><td colspan="3">Consultant projection</td></tr>
<tr><td>Building Shell Improvement</td><td>Energy Trust projection</td><td>Energy Trust high sensitivity projection</td><td colspan="4">Ajusted Energy Trust projection</td><td colspan="3">Energy Trust projection</td></tr>
<tr><td rowspan="5">Supply-Side Assumptions</td><td>Conventional Gas</td><td colspan="10">Expected pricing in each month</td></tr>
<tr><td>Capacity Resources</td><td colspan="10">All capacity resources available at expected cost</td></tr>
<tr><td>Renewable Natural Gas</td><td colspan="2">Expected availability and cost</td><td>Higher availability and expected cost</td><td colspan="4">Expected availability and cost</td><td>High avail and low cost to customers</td><td>Low availability and high cost</td><td>Expected availability and cost</td></tr>
<tr><td>Hydrogen</td><td colspan="2">20% Energy maximum (blended and dedicated) and expected cost</td><td>40% Energy maximum and expected cost</td><td colspan="4">20% Energy maximum and expected cost</td><td>30% energy max and low cost to customers</td><td>12% energy max and high cost</td><td>35% max and expected cost</td></tr>
<tr><td>Synthetic Methane</td><td colspan="7">No energy max and expected cost</td><td>No energy max and low cost to customers</td><td>No energy max and high cost</td><td>No energy max and expected cost</td></tr>
<tr><td colspan="2">OR- CCIs</td><td colspan="10">Costs and limits defined in CPP rule</td></tr>
<tr><td colspan="2">WA- Allowances & Offsets</td><td colspan="10">Higher of social cost of carbon or California allowance projection in each year</td></tr>
</table>

Source: NWN, Table 7.3 "2022 IRP Scenarios," page 255.

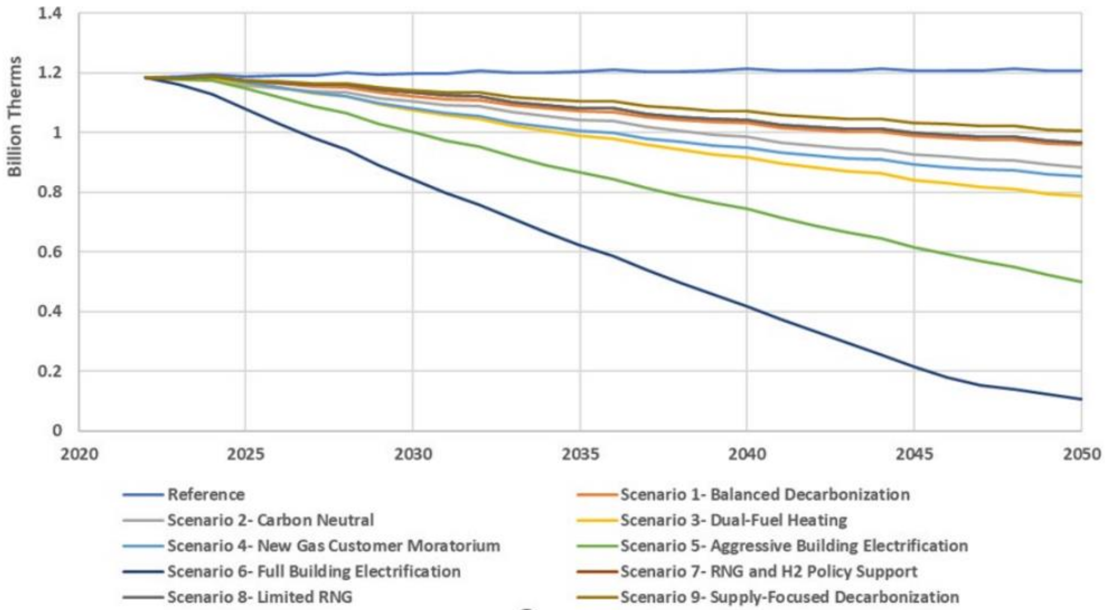
The scenarios allow for a range of input assumption variations, but they do not represent all possible permutations. We note the following:

- Capacity resource alternatives are the same across all scenarios; they exclude demand-side peak day load reduction alternatives such as demand response, or load reduction through electrification.
- One high-cost and one low-cost RNG scenario are included. Eight of nine scenarios use either expected or low-cost RNG.
- Seven of ten scenarios use "current expectations" for customer growth.
- Hydrogen is assumed available at 20 percent or higher percent blending in all but one scenario.

Load Forecasts by Scenarios

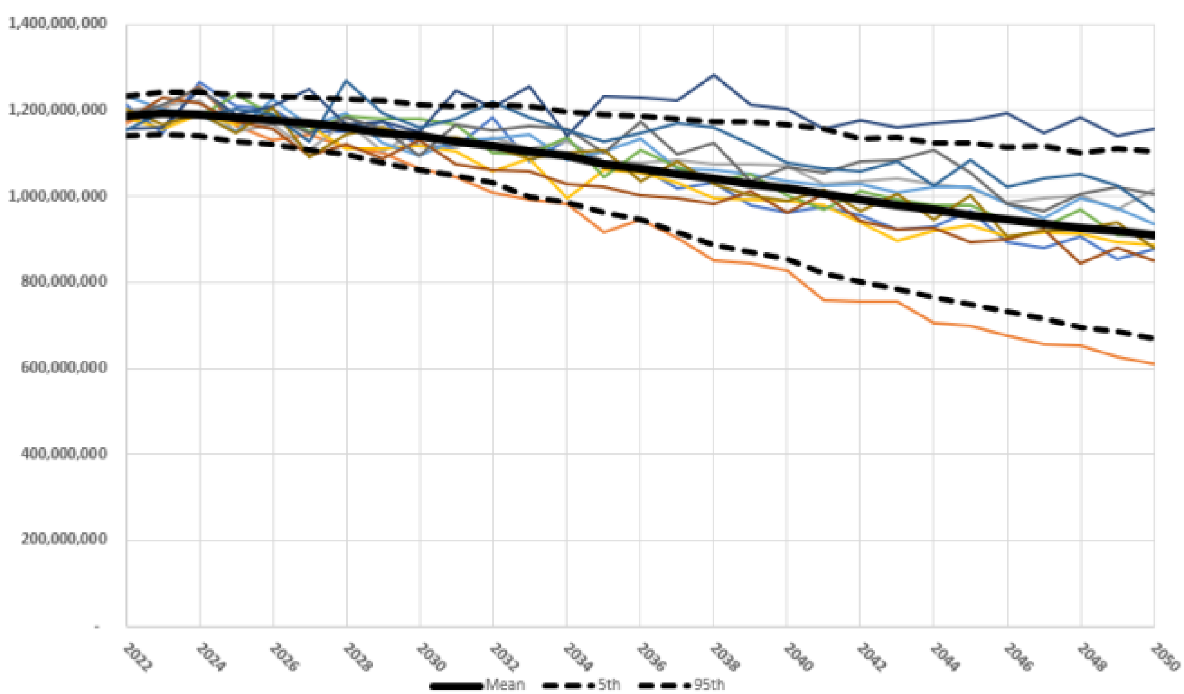
The following four figures (Figure 2 through Figure 5) from NWN's IRP show the variation in annual gas load (deliveries) and peak demand (peak day demand) for the deterministic scenarios and Monte Carlo draws.

Figure 2. Total system annual load (deliveries) by scenario (NWN Figure 3.38)



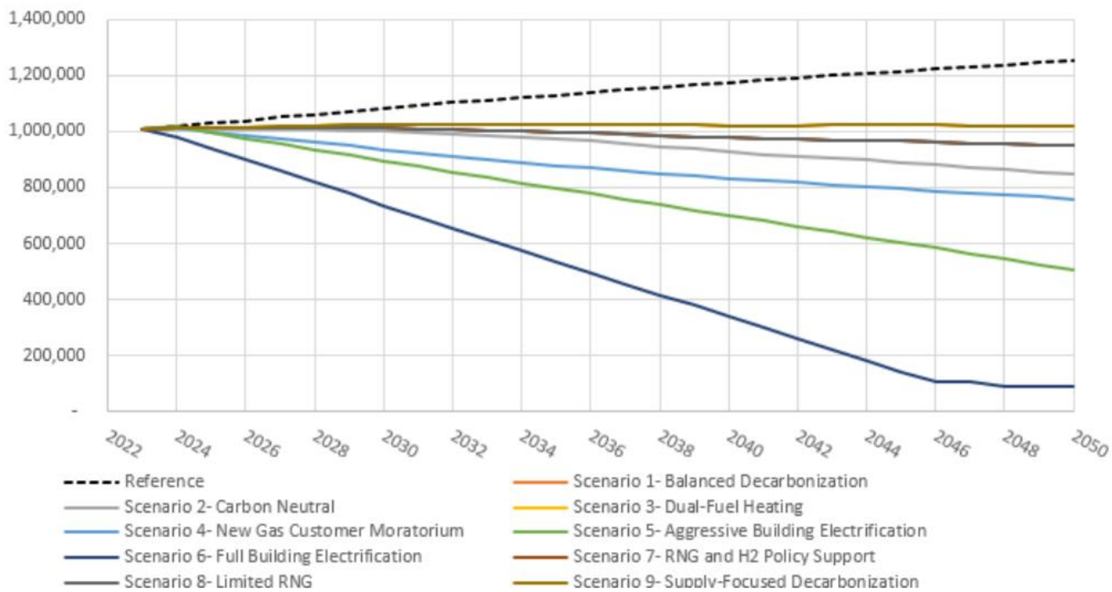
Source: NWN Figure 3.38, page 105.

Figure 3. Total system load energy delivery forecast for Monte Carlo simulation (NWN Figure 3.40)



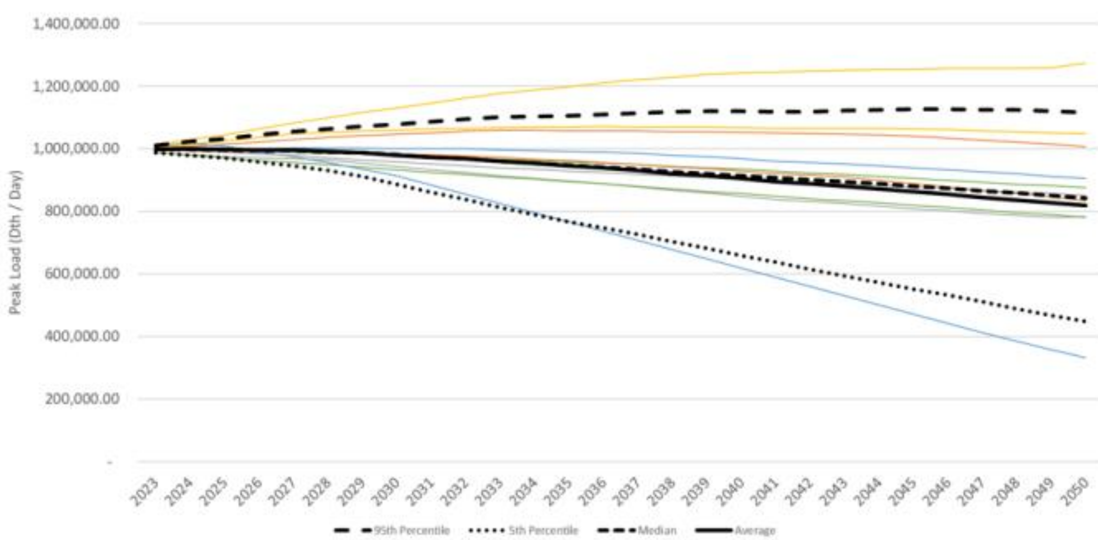
Source: NWN Figure 3.40, page 107.

Figure 4. Firm sales peak day load by scenario (NWN Figure 3.41)



Source: NWN, Figure 3.41, page 108.

Figure 5. Firm sales peak day load for Monte Carlo simulation (NWN Figure 3.42)



Source: NWN, Figure 3.42, page 109.

Figure 2 through Figure 5 show the range of load used in the Monte Carlo simulation analysis.

The annual energy deliveries forecasts (Figure 2 and Figure 3 above, corresponding to NWN Figures 3.38 and 3.40) illustrate that the preferred portfolio, which is the "average" line seen in the stochastic simulation (Figure 2, or NWN's Figure 3.40), roughly aligns with the load trajectory seen in Scenario 1.

For the peak day forecast load, the preferred portfolio levels (Figure 5, or NWN's Figure 3.42) are lower than the peak day load seen in Scenario 1 in Figure 4 (NWN's Figure 3.41) and align roughly with Scenario 2.

Resource Options

A central analytical element of NWN's IRP process[10] is its use of the PLEXOS model to evaluate gas system planning alternatives. The PLEXOS analytical approach and its outcome are intended to produce a gas system resource solution that meets energy and capacity needs, and CPP compliance requirements, at least cost—given the parameters of the modeling. NWN's use of PLEXOS replaces its prior reliance on the SENDOUT gas model software for resource planning.[11] NWN's IRP contains considerable information on the input assumptions used, the methodology employed, and the resulting outcomes from the use of the PLEXOS model. Critically, the resulting PLEXOS solution depends on the comprehensiveness of the set of resource options available to the model to solve the system planning problem, in addition to the constraints imposed on the model's objective function, and any related model configuration effects.

Resources Available for PLEXOS Solution

Table 1 below lists NWN's resource and CPP compliance options available to the PLEXOS model.

Table 1. PLEXOS inputs comprising solution options for capacity, energy, and CPP compliance

Capacity Resource	Energy resources	OR Compliance Alternative
Existing storage and pipeline capacity	Conventional gas imports	CCI credits
Mist recall	On-system RNG	New or existing RNG
Newport takeaway 1, 2 and 3	Mist production	New hydrogen
Mist expansion	Energy from storage	New synthetic methane
Upstream pipeline expansion	Recall energy	
Portland LNG cold box		
Interstate pipeline looping plus mist recall		
Mid corridor NWN system plus mist recall		

Source: NWN IRP, Table 1.2 and Table 1.3.

[10] IRP, page 11. NWN notes "three broad steps" in the IRP: (i) forecasting energy, capacity, and compliance needs; (ii) determining the options available to meet those needs; and (iii) identifying a resource portfolio to best meet the needs.

[11] IRP, page 248.

NWN structures demand-side options using a scenario analysis approach, where a different level of annual load and peak day demand is represented.

PLEXOS Configuration Excludes Electrification and Other Demand Reduction Solution Options

NWN offers a limited set of resource options to the PLEXOS model to be available as part of a capacity and energy resource and CPP compliance solution. The options (in Table 1 above) are limited on the supply side to a set of capacity resource expansions (focused on storage solutions and potential increases in pipeline capacity expansion), conventional gas, storage solutions, and RNG (including biofuel, hydrogen and synthetic methane). Compliance resources exclude demand-side load reductions as a means to reduce the need for supply-side or CCI credit solutions.

No incremental demand response options are directly included as possible solutions to help meet peak day demands, although NWN does include 24,000 Dth/day of existing demand response in its capacity data balancing.[12] The modeling structure excludes any incremental energy efficiency alternatives not already included as reductions to gas demand as part of each scenario's forecast load. While scenario analysis can be sufficient to capture the effects of varying levels of energy efficiency, NWN does not clearly address the difference between electrification and incremental energy efficiency effects in its load forecasts used with Scenarios 3, 4, 5, and 6.[13]

Demand- and supply-side options are not "integrated" in the modeling approach. The process relies upon scenario analysis to differentiate load-based drivers of solutions.

Notably, the PLEXOS model also does not have an electrification resource option available to lower peak and/or annual gas load demands for any given scenario. Instead, NWN has used different levels of presumed electrification to reduce both annual load and peak day demand, reflected in the gas load forecasts seen in the four figures above.

There are no incremental demand-side alternatives beyond what is hard-coded in as gas demand for any given scenario, and there is no explicit inclusion of existing supply-side resources that may not be needed in future scenarios. (That is, there is no "exogenous retirement" of plant assets or firm contracts as an economically derived result forming a part of an optimization). There is also no explicit inclusion of distribution system capital additions that would vary under different load scenarios. There are no explicit demand response, targeted demand response or energy efficiency, or targeted or general

---

[12] 2022 IRP Scenario Results Workpaper "capacity data" tab.

[13] NWN response to discovery on energy efficiency components in forecast – DR 78. "NW Natural has yet to breakdown the load reduction from each of the components analyzed in the IRP (traditional [energy efficiency] programs, natural gas heat pumps for space heating, hybrid heating systems, and natural gas heat pumps for water heating) or assumed to happened externally and impact load (i.e. fuel-switching not associated with hybrid/dual-fuel heating systems) as this was not possible to complete before filing the 2022 IRP. The calculations in the "Load Reduction Final" tab are not final and should not be used. With that, they are in units of 10,000 therms to align with the PLEXOS model and were meant to represent the share of load reduction from a reduction in energy services provide relative to the reference case (presumed to be fuel-switching via electrification) that is not from the dual-fuel hybrid reduction in energy services modeled directly in the IRP."

electrification-as-DSM (demand-side management) options. The modeling structure does not test the ability of any demand-side solution to be part of an optimal solution, beyond energy efficiency's inclusion as part of the load forecast for any given scenario.

The framework excludes electrification as a costed resource offering, even though it is the most important planning alternative to RNG solutions for meeting CPP requirements. A planning framework that is required to focus on overall least-cost (PVRR) solutions options must explicitly address the tradeoffs among at least all prominent, viable, and potentially economic options, which in this instance must include electrification.

The annual costs—revenue requirements—associated with new distribution system capital investment and also with carrying costs for existing firm supply resources (that may not be needed throughout the planning horizon) are not represented in the PLEXOS model. Either or both of these cost streams may vary in the future, depending on the scenario. Thus, NWN is applying the objective function of minimizing revenue requirements over the planning horizon to a subset of costs, not to the total costs it should consider. NWN should use PLEXOS to consider these other cost streams because they will vary with scenario load and would impact any comparison of NPVRR across scenarios.

Resource options need to directly include capital addition requirements that vary by scenario, especially distribution system costs associated with new load and distribution system costs beyond new load connections associated with any given load scenario. NWN does not include such costs in its construct.

Risk Analysis and Sensitivity Testing

NWN's overall approach to risk analysis is to use its Monte Carlo simulation, with a single set of 500 draws whose average value comprises its preferred portfolio. NWN did not test a different pattern of sampling from the input variables, such as a focus on the results if mostly lower load trajectories were sampled, or with different combinations of RNG pricing and lower load.

NWN's risk analysis consists of sampling from its envelope of 500 draws. The results from this method reflect (1) the limitations from resource options offered as inputs, and (2) the sampling method from the distribution of input parameters used to develop the 500 draws.[14] NWN notes considerable uncertainty in underlying driving parameters (e.g., load, gas price) but it does not clearly map how its approach truly addresses this uncertainty. NWN does not directly address how it determined the distribution of load reflected in its 500 draws, other than to essentially reinforce its statement in its TWG-2 presentation that "all scenarios [are] equally likely."[15] In response to discovery, NWN states "the distributions for the uncertain variables that feed into the final load forecast were defined based upon the dispersion found in the load forecasts across the scenarios."[16] This implies that the Monte Carlo draw approach reflects

[14] NWN responses to OPUC DRs 88 and 102 describes the process NWN used to sample input variables for the 500 draws.

[15] OPUC DR 102 question referencing NWN's TWG-2 presentation, at slide 122.

[16] Response to OPUC DR 102 c).

the load across the set of scenarios, in an equal-weight fashion. But it does not explain why an equal weight is appropriate, given that NWN did not provide or discuss ”likelihood of occurrence” for any given scenario. As seen in the clustering of load trajectory values in the figures above, there are only a few scenarios with considerably lower load, compared to many more scenarios with higher load trajectories. To use an ”equal weighting” approach for load trajectories for the Monte Carlo sampling without explaining why—especially given the market and behavioral forces at play in Oregon at this time—is to basically assume a loading outcome for the preferred portfolio without any evidentiary support.

For example, NWN’s Monte Carlo simulation did not explicitly consider the actions of utility customers, each of whom makes a fuel choice when replacing equipment (most notably space and water heating equipment). NWN calculates that gas rates would double or more from today’s rates, in real terms, by 2050 in all scenarios.[17] Meanwhile, Oregon’s relatively low electric rates have meant that Oregon has a greater penetration of electric heat than is typical for its climate zone (when viewed across the country), and this competition would only tilt further in electricity’s favor if gas rates rise steadily and substantially. By not considering the agency of its customers to choose a lower-cost fuel in a scenario-consistent way within each scenario, NWN risks being surprised by a reduction in sales or customers that deviates from its planned path. This is not accounted for in the logic behind choosing an “equal weighting” approach for the load trajectory for the scenarios considered.

Severity of Bad Outcomes

The IRP guidelines include a requirement to consider the “severity of bad outcomes.” Under its preferred portfolio, NWN presumes a reliance on RNG and a reliance on a certain load trajectory. To some extent, Scenario 8 is a test of a “bad outcome” in that high-cost RNG results in a higher PVRR across the planning horizon. And, testing a low load under Scenario 6 or 5 tests the effect under a gas load that deviates significantly from NWN’s preferred portfolio, or Scenario 1. However, NWN does not describe how its key Action Plan items, or even the longer-term implication of its preferred portfolio, would be affected by such bad outcomes. Further, NWN does not test important combinations such as lower load and higher RNG prices to determine how robust its preferred portfolio may be.

2.3. Electrification as Resource Option for CPP Compliance

Overview of Electrification’s Importance in the IRP Analytical Structure Under the CPP

Electrification of end-use load is the direct competitor to use of RNG for meeting CPP requirements. NWN’s IRP does not attempt to ascertain which of these two competing decarbonization pathways is likely more economic. The analysis to consider this fundamental question is not easily structured or executed, as it is fraught with uncertainty of input assumptions and performance values for both forms

[17] Based on the Oregon total bills and use per customer data in the “Oregon Bill Impacts” tab of the Scenario Results workpaper.

of decarbonizing resource. Nevertheless, it must be part of NWN's approach to gas resource planning going forward.

The creation of scenarios with lower gas load due in part to electrification for inclusion in NWN's IRP is not sufficient, on its own, to address the underlying resource economics question. However, this scenario analysis structure does lend itself to seeing how these resource alternatives can work together, to some extent, to achieve decarbonization aims. A key missing piece of NWN's analysis is an estimate for the cost of decarbonization from electrified end uses. NWN does estimate RNG costs, based on external studies, and it directly uses those costs in its modeling of resource solutions, however uncertain those cost trajectories must be. To not similarly estimate the cost of the competing resource pathway undermines the intent behind the IRP guidelines, which is to compare alternative resource costs.

The only electrification resources the IRP considers are the effects seen on gas demand in scenarios with greater levels of electrification, and the way in which gas demand is affected when dual-fuel or hybrid heat pump options are considered. There are no specific demand-side electrification options offered as part of any resource solution, including any incremental effect on gas system demand that could result from moratoriums on gas system expansion.

NWN defines four scenarios (6, 5, 4, and 3) with greater levels of electrified load displacing gas load than seen in the Reference and other scenarios. However, NWN does not explicitly consider electrification or gas moratoriums as a specific resource alternative the model can use to meet incremental capacity or energy needs; nor does NWN compare the NPV of revenue requirements (over the planning horizon) across scenarios with different levels of gas load due to electrification. The transformative policies underway in Oregon indicate that such analysis is likely to be required in future to carefully gauge the effect on ratepayers—electric and gas combined—of using RNG or electricity directly to achieve the decarbonization mandated by the CPP. This analysis is necessary to fully understand the ratepayer costs associated with such policies and to gauge the least-cost or lowest-risk resource solution option for energy end uses currently served by natural gas.

Cost and Quantity of Electrification

In this report we include an estimate of the cost impact of the electrified end uses to allow for a consistent comparison of NPVRR across scenarios with different levels of gas load. These proxy costs for electrified load enable a more direct comparison of NPVRR between scenarios with greater and lesser levels of electrified load. This comparison sheds light on the issue of RNG vs. electrification pathways to meet CPP greenhouse gas reduction targets—more so than NWN's scenario or Monte Carlo simulation analysis because the proxy cost approach allows for a "level playing field" comparison of the costs of the alternative pathways. While much more extensive analysis is required to firm up estimates of cost and performance of both electrification and RNG as a core resource for decarbonization, the starting point must directly address the overall resource cost question in the form of NPV of revenue requirements across the planning horizon.

The electrification cost estimate includes rough estimates of the incremental capacity costs and operating costs. Separately, we illustrate the effect of accounting for reduction in revenue requirements due to reduced distribution system capital investment and operating expense required by NWN.

We also assume marginal increases in Oregon electric load will be met with new and existing renewable resources in or imported into the Pacific Northwest, in alignment with the most recent Portland General Electric (PGE) planning paths and the forecast of new resources throughout the Pacific Northwest region.

Appendix C of this report contains an extensive analytical exercise estimating the cost of electrification options across the four sectors represented in NWN's modeling: residential, commercial, industrial, and transport gas volumes. The costs represent the incremental costs to install electrical equipment to serve end-use loads, and the cost to operate that equipment.

Scenario 1 serves as a NWN's rough approximation of its planned approach[18] to meeting CPP requirements and serving gas load in its territory. As seen in the Appendix, we examine the following elements to generate a proxy electrification cost that can be added to scenarios with lower load than Scenario 1 and allow comparison of NPVRR across scenarios:

- Incremental costs for equipment installed at end-of-life to meet thermal needs (heating, hot water, and process needs) across the residential, commercial, and industrial sectors. Since transport customer load makes up part of the CPP requirements, we include industrial electrification assumptions to meet a portion of such load.
- MWh quantities required per billion BTU reduction in gas load, based on comparison across NWN's annual load estimates by scenario, and considering the relative efficiency of serving thermal load with gas combustion, vs. serving that load with electricity.
- Operational costs of electrified load, using $/MWh average retail costs across the three major sectors. We use current electric rates in the Pacific Northwest (PGE as a proxy) and we assume constant real costs in electricity rates for electrified load.
- Performance of electrification equipment, which effectively is estimating the coefficient of performance factor (COP) for heat pumps delivering thermal requirements across the sectors.
- Proxy total costs—equal to the sum of incremental equipment costs and electric operating costs. Developing these costs allows for a comparison of electrified load scenarios to scenarios with less electrified and more gas load.

---

[18] NWN response to DR 69. "We do not believe it makes sense to choose a Scenario to base the Action Plan upon, but if forced to choose one of the Scenarios analyzed, we believe Scenario 1 is the most appropriate Scenario to understand NWN's regulatory compliance obligations and path for regulatory compliance."

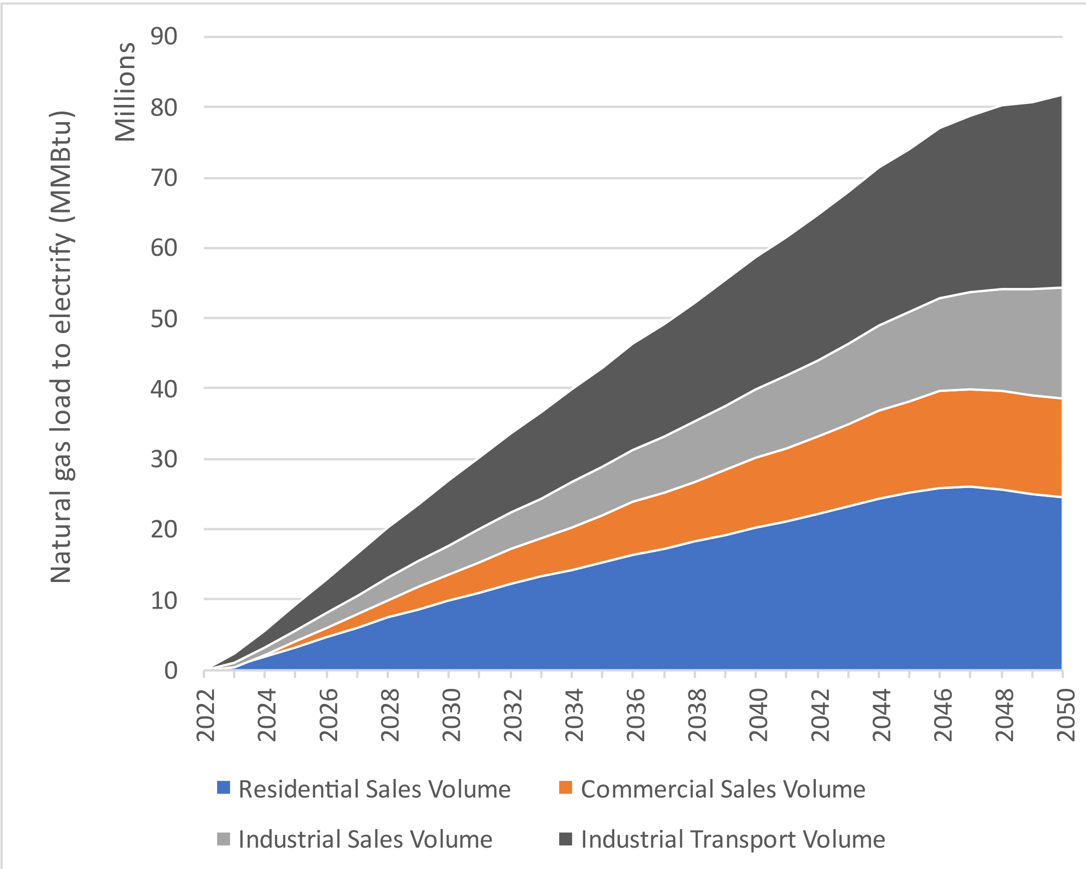
The following five graphs, Figure 6 through Figure 10, reproduced from the analysis contained in full in Appendix C, show the following:

1. The level of natural gas load whose electrification cost is estimated (millions of dekatherms/year, by sector);
2. The amount of electricity required to meet that electrification need (GWh/year);
3. The cost of electrification on a $ per mmBTU basis, consisting of incremental cost, plus operating cost components;
4. The summary costs for electrification across each of the scenarios, reflecting the difference in total natural gas load and modeled electrified load. Scenarios with load greater than Scenario 1 are shown as “negative” electrification costs, as a means to normalize the load and allow for PVRR comparisons across all scenarios; and
5. The NPV of the electrification costs, for each scenario.

Section 2.5 of this report uses the NPVRR values for the electrification cost estimate to illustrate the use of a proxy cost for electrified load as an additional revenue requirement component. This allows for an NPVRR comparison between scenarios with different levels of gas load as a resource solution comparison and a means to understand the magnitude and differences of PVRR component costs over time and between scenarios.

Natural gas load for electrification

Figure 6. Natural gas load to electrify, Scenario 6 relative to Scenario 1



For some scenarios and in some years, natural gas load is less than in Scenario 1, resulting in a "negative load to electrify." This results in a cost savings in Synapse's analysis, for those scenarios, representing "electrification not done," for example.

End-use electrified load and Estimated Per Unit Costs to Electrify

Figure 7. End-use electrified load, Scenario 6 relative to Scenario 1

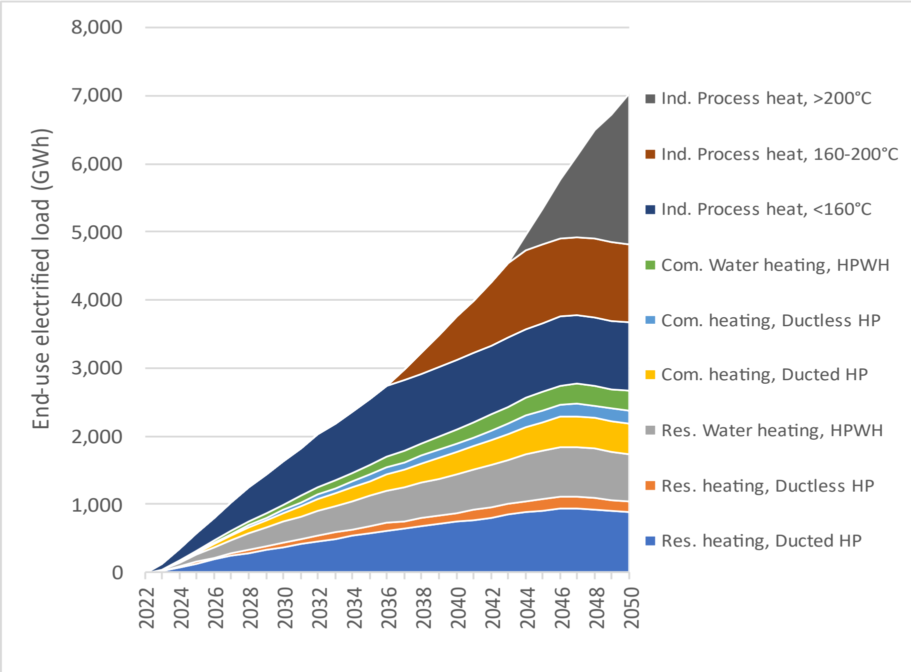
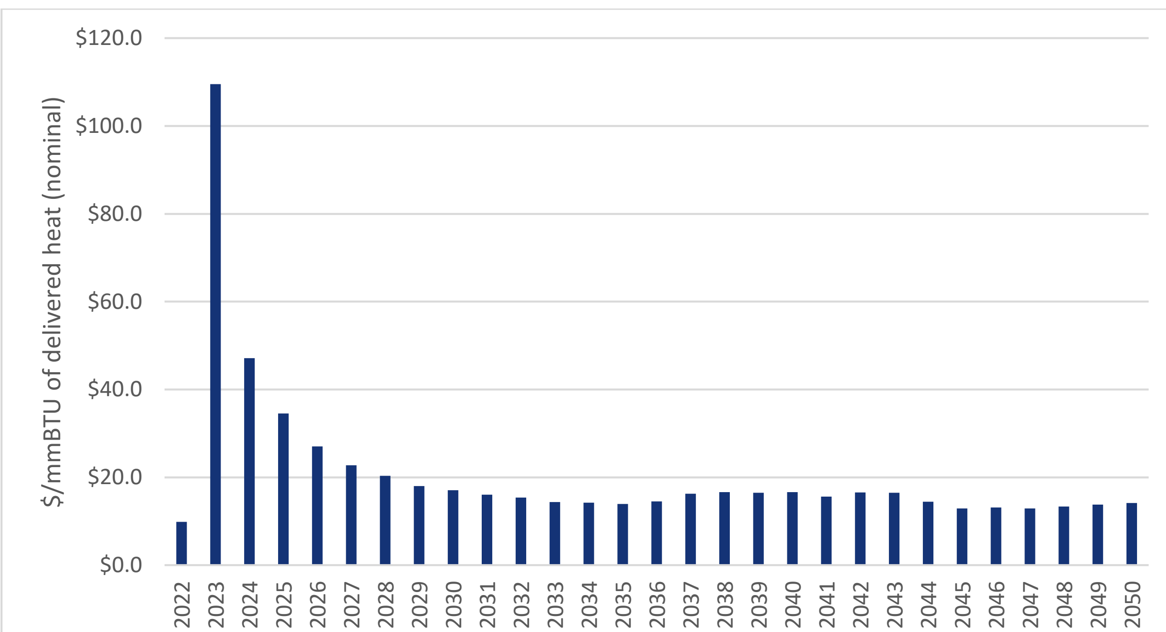


Figure 8. Estimated/proxy per unit costs of electrification, Scenario 6



Total Costs of Electrification

Figure 9. Annual system and customer electrification costs, all scenarios relative to Scenario 1

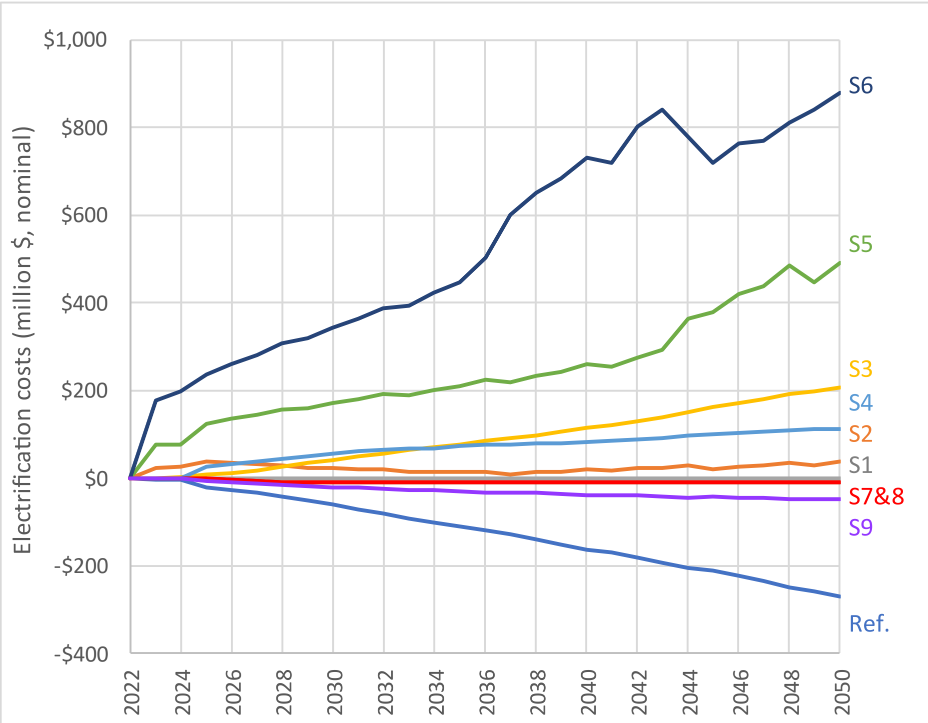
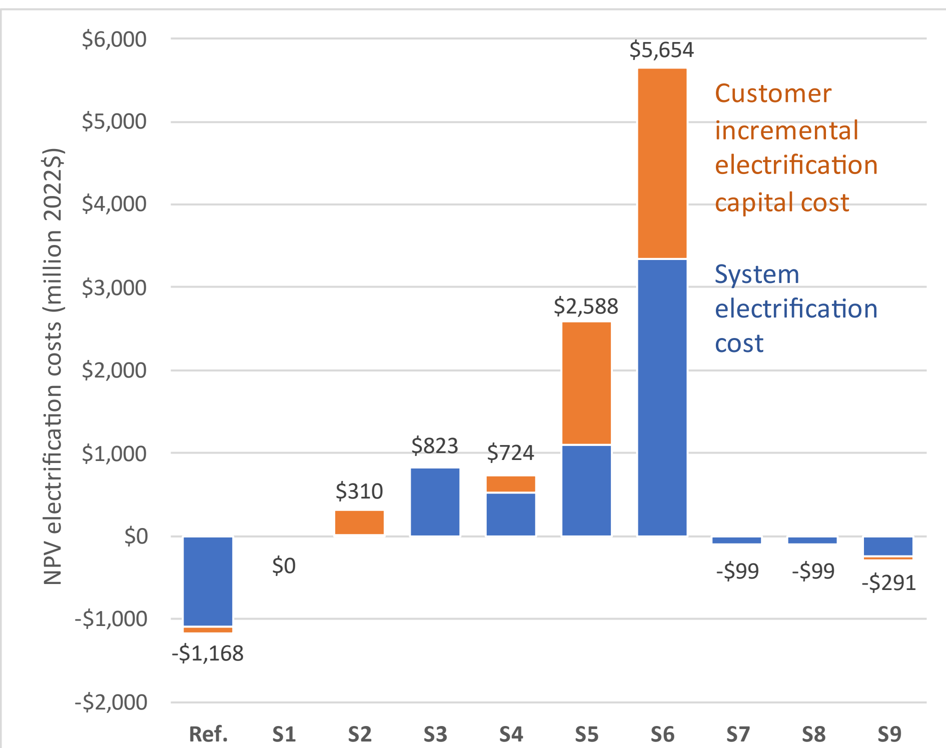


Figure 10. Net present value system and customer electrification costs, all scenarios relative to Scenario 1



Marginal System Emissions, Pacific Northwest Electric System

Increases in load due to electrification will be served by a mix of existing resource output and marginal resource development. Based on the current regional resource forecast from PNUCC (Pacific Northwest Utilities Conference Committee), the Northwest Regional Forecast of Power Loads and Resources, 2022–2032 (April 2022), going forward new resources in the Pacific Northwest are almost solely renewable or battery resources. The overall share of carbon-free resources in the Northwest grew from 76 percent in 2018 to 79 percent in 2022 and is expected to be at or above 83 percent by 2026.[19]

For the purposes of this proxy analysis, we assumed newly electrifying heating and hot water load to be zero carbon emissions. We note that RNG resources as used in the IRP context are also considered to be zero-carbon resources. While both these assumptions are likely inaccurate—RNG will have carbon emissions, and electricity will still carry an emission component in the early period of the transformation of the Pacific Northwest system to fully decarbonized sources—for the purpose of this report it is a reasonable assumption to make.

Appendix D contains additional summary information on the trajectory of renewable resource and energy storage additions for the Pacific Northwest electric system.

2.4. Cost and Availability of CCI credits, Renewable Natural Gas, Hydrogen, and Synthetic Methane for CPP Compliance

This section addresses the prices, cost, and NWN's use of RNG, hydrogen, synthetic methane, and CCI credits as CPP compliance resources within the IRP construct.

The Oregon Department of Environmental Quality (DEQ) CPP sets a binding greenhouse gas emission constraint and an associated compliance obligation for fuel suppliers including natural gas utilities. The emissions cap declines over time, reaching a 90 percent reduction in emissions by 2050.[20,21]

The CPP establishes three-year compliance periods starting in 2022. A covered fuel supplier's compliance obligation is equal to that fuel supplier's total quantity of covered emissions, rounded to the nearest metric ton of CO2e (carbon dioxide equivalent).[22] "Covered" emissions under the CPP include greenhouse gas emissions from fossil fuels such as diesel, gasoline, natural gas, and propane. Covered emissions do not include emissions that are from the combustion of biomass-derived fuels. Each year, DEQ will allocate compliance instruments to each covered fuel supplier equivalent to the fuel supplier's

---

[19] PNUCC 2022-2032 forecast.

[20] In comparison to the baseline, which is established as the average greenhouse gas emissions from covered entities from 2017 to 2019.

[21] Oregon Department of Environmental Quality. OAR 340-271-0020. "Oregon Climate Protection Program." Available at: https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=6597.

[22] Or. Admin. R. 340-271-0020.

share of that year's emissions cap. These compliance instruments allow a fuel supplier to emit one ton of greenhouse gases. At the end of each three-year period, covered fuel suppliers must submit a compliance instrument or CCI credit for every metric ton of their compliance obligation.

Overall, NWN has three main tools to comply with the CPP (beyond annual allotted compliance instruments): reducing demand (and thus emissions) through efficiency measures (or, potentially and eventually, through support for electrification), utilizing renewable and low carbon alternative fuels, and purchasing CCI credits up to the maximum level allowed under the CPP regulation.[23]

RNG and CCI Credit Solutions for CCP Compliance

The overall economics of the resources available to NWN to meet CPP compliance requirements depends on the pricing, availability, and regulatory limitations for deploying those resources. In the IRP, the modeling outcomes also depend on the way in which NWN configures the inputs to the model and constrains the operation of the model.

Critically, how the model configuration allows for competition between the lowest-cost compliance resource (CCI credits) and RNG directly impacts the validity of a "least cost" solution to meet the CPP. How, and if, the model structure allows for competition between CCI credits, RNG, and load-lowering resource effects (from energy efficiency or electrification) also impacts the validity of any claimed least-cost solution for meeting CPP requirements.

The Oregon PUC notes the following in its recent rate order:[24]

> SB 98 is a legislatively approved but voluntary RNG procurement target, while the CPP is a comprehensive, mandatory greenhouse gas emissions cap and reduction regime adopted by administrative rule.[279] Under the requirements of the CPP, any emissions reduction measure the utility takes, which may include RNG procurement, will necessarily be in service of CPP requirements. At the same time, the magnitude of the CPP's emissions reduction requirements and potential customer rate impacts require us to apply a high level of scrutiny to whether the utility is pursuing the least cost, least risk portfolio of emission reduction measures. **It is possible that a prudent strategy may include RNG, but this will depend on the costs and risks relative to alternatives**. We are concerned about the potential incentive created by the availability of an AAC to skew the company's analysis of costs and risks of alternative CPP compliance measures towards RNG projects. **Specifically, we are concerned about the potential for RNG to be automatically eligible for more favorable cost recovery up to the SB 98 spending**

[23] IRP page 53, and Synapse.

[24] Order 22-388, page 81.

limits without a demonstration that RNG at that level is least cost, least risk relative to other CPP compliance portfolio configurations. [**emphasis** added]

NWN's IRP treats RNG SB 98 voluntary target percentages (RNG as a percentage of gas sales) as a constraint in its PLEXOS modeling.[25] This has the direct effect of reducing the volume of less expensive CCI credits used in the earlier years of the planning horizon (through 2036), when RNG is more expensive than CCI credits.

Community Climate Investments

Fuel suppliers earn CCI credits by contributing funds to DEQ-approved CCI entities. The funds are invested in community projects that reduce greenhouse gas emissions.[26] The DEQ plans to make CCI credits available to covered fuel suppliers by the first demonstration of compliance. The CPP sets the price of CCI credits, starting at $71 per ton of CO2e (equivalent to $5.78 per MMBtu) for the first compliance period and rising slightly over time (to $7.22 per MMBtu by 2050). This price is considerably lower than RNG (of any form) through the first half of the 29-year planning period.

The CPP limits the share of CCI credits that can be used to comply in each compliance period to a share of the overall required compliance obligation. For the first compliance period (2022 to 2024) only 10 percent of a fuel supplier's compliance obligation can be met using CCI credits, rising to 15 percent during the second compliance period, and 20 percent for all subsequent compliance periods.[27] In a single year of a compliance period, the amount of CCI credits used can be greater than the percent limit, as long as the total CCI credits used for the three years of that compliance period are not above the established percent share limit of the compliance obligation.

Notably, CCI credits can be used to meet a majority or even all of the compliance requirements (after allowed emissions) during the first decade of the planning horizon, for some scenarios. From 2031 onward though, the ability to use CCI credits declines as their annual availability for compliance shrinks. The largest opportunity for lowering the cost of compliance (relative to NWN Scenario 1, for example) by using more CCI credits comes during the first decade of compliance.

The cost of CPP compliance and CPP compliance component makeup are included in NWN's workpapers for each year and each scenario.[28] In the PLEXOS model, NWN sets the cap on CCI credits as the

---

[25] IRP, page 181: "The policy that has had the largest impact to date on NWN's procurement of RNG is Oregon Senate Bill 98, which established volumetric targets for RNG that the Company internalized as its own RNG targets after the law passed." IRP, page 26: "The majority of scenarios and simulation draws show that in the OR-CPP's first compliance period biofuel RNG to meet SB 98 targets make up the majority of the needed compliance action."

[26] Oregon Department of Environmental Quality. Community Climate Investments. 2022. Available at: https://www.oregon.gov/deq/ghgp/cpp/Pages/Community-Climate-Investments.aspx.

[27] Oregon Department of Environmental Quality. Climate Protection Program Brief. 2021. Available at: https://www.oregon.gov/deq/ghgp/Documents/CPP-Overview.pdf.

[28] NWN Workpaper "2022 IRP Scenario Results", "Compliance Data" tab, for scenarios.

associated percent of the CPP emissions cap for each compliance period.[29] Table 2 below lists the percent limit, price, and maximum amount of CCI credits available to NWN for each compliance period.

Table 2. CCI credit maximum volumes (billion Btu/year) for CPP compliance

Compliance period	CCI limit	Maximum CCI credits (Bbtu)	CCI credit price ($/MMbtu)
2022-2024	10%	32,248	5.79
2025-2027	15%	42,567	5.95
2028-2030	20%	49,016	6.10
2031-2033	20%	41,277	6.26
2034-2036	20%	33,801	6.42
2037-2039	20%	28,171	6.58
2040-2042	20%	22,805	6.74
2043-2045	20%	17,439	6.90
2046-2048	20%	12,073	7.06
2049-2051	20%	7,304	7.20

Source: NWN 2022 IRP Scenario Results workpaper.

Renewable Natural Gas

The SB 98 states that RNG can be used by natural gas utilities to reduce emissions from the direct use of natural gas and can be included in the set of resources used to help reduce greenhouse gas emissions.[30] As defined in SB 98, RNG can refer to biogas; hydrogen derived from renewable energy sources; or synthetic methane derived from biogas, renewable hydrogen, or waste carbon dioxide. The legislation allows NWN to *voluntarily* procure RNG as a percentage of overall natural gas sales, with volumes capped at targeted amounts starting at 5 percent and increasing to 30 percent by 2050.[31] NWN uses this target in its PLEXOS modeling to ramp up the use of RNG.

The Oregon Public Utility Commission adopted rules for the program in 2020 regarding the process for NWN to purchase RNG, invest in new RNG infrastructure, and recover prudently incurred costs.[32] RNG procured under SB 98 may be acquired from local suppliers or from sources outside the Pacific Northwest.[33]

---

[29] NWN 2022 IRP PLEXOS Input Data Files: "Constraint_CCI Compliance Period Limit" and "Constraint_Emissions Allowances."

[30] SB 98. Available at: https://olis.oregonlegislature.gov/liz/2019R1/Downloads/MeasureDocument/SB98/Enrolled.

[31] NWN IRP page 54. Note that NWN clearly states that SB 98 sets "voluntary targets."

[32] Order No. 20-227. Rulemaking Regarding the 2019 Senate Bill 98 Renewable Natural Gas Programs. Docket AR 632. Available at: https://apps.puc.state.or.us/orders/2020ords/20-227.pdf.

[33] NWN IRP page 54.

On page 251 of the IRP, NWN states that user-defined constraints are included in the PLEXOS model to ensure that "least cost qualifying resources are acquired to meet SB 98 targets."[34,35] The PLEXOS input file "Supply Must Take Daily Supplies" also contains annual volumes of RNG from the five existing RNG sources NWN currently procures from: Element Markets NYC, Archaea Offtake Portfolio, Tyson – Lexington, Tyson – Dakota City, and Wasatch Resource Recovery.[36]

In the IRP, RNG resources are grouped into four categories: biofuel RNG divided into two supply tranches, synthetic methane, and hydrogen. NWN developed the supply tranches for RNG based on ICF's AGF 2019 RNG Supply[37] report and NWN's RFP process. Each tranche represents a portfolio-level set of RNG projects with associated average price and quantities. Tranche 1 RNG represents an approximate 13 million MMBtus of total annual production, with bundled portfolio costs of $14/MMBtu.[38] Tranche 2 RNG represents longer term and higher cost projects, approximately 27 million MMBtu annually, at a bundled cost of $19/MMBtu. NWN's summary Workpaper on Scenario Results includes the cost of RNG as an unbundled compliance resource, based on its incremental cost above the value of "brown gas."

RNG, Hydrogen, Synthetic Methane, and CCI Credit Price Comparison

NWN's IRP and summary workpaper contains the pricing for supply-side compliance resources and CCI credits. Figure 11 below illustrates the pattern of pricing used in all scenarios except Scenario 7 (which reflects lower-priced RNG, hydrogen, and synthetic methane) and Scenario 8 (which reflects higher-priced RNG, hydrogen, and synthetic methane). The subsequent Figure 12 contains the pricing pattern for Scenario 7 and Scenario 8.

For all scenarios, the trajectory of CCI credit prices remains the same across all scenarios, increasing slightly over time. For most scenarios, NWN's trajectory of pricing for RNG Tranche 1 compliance resources rises slightly from now to the 2030–2035 period, then declines slowly over the rest of the planning horizon. The trajectory of pricing for other supply-side compliance resources (hydrogen and synthetic methane) declines over the planning horizon.

The prices for RNG (either tranche 1 or 2, or hydrogen or synthetic methane) are higher than CCI credit prices until 2037 in most scenarios. In 2038, NWN projects hydrogen pricing to dip below CCI credit prices and remain below those prices for the rest of the planning horizon. NWN also projects synthetic

[34] NWN IRP page 251.

[35] NWN 2022 IRP PLEXOS Input Data Files: "Constraint_OR Senate Bill 98 RNG Targets."

[36] NWN response to OPUC DR 104.

[37] Renewable Source of Natural Gas: Supply and Emissions Reduction Assessment. American Gas Foundation Study Prepared by ICF, 2019.

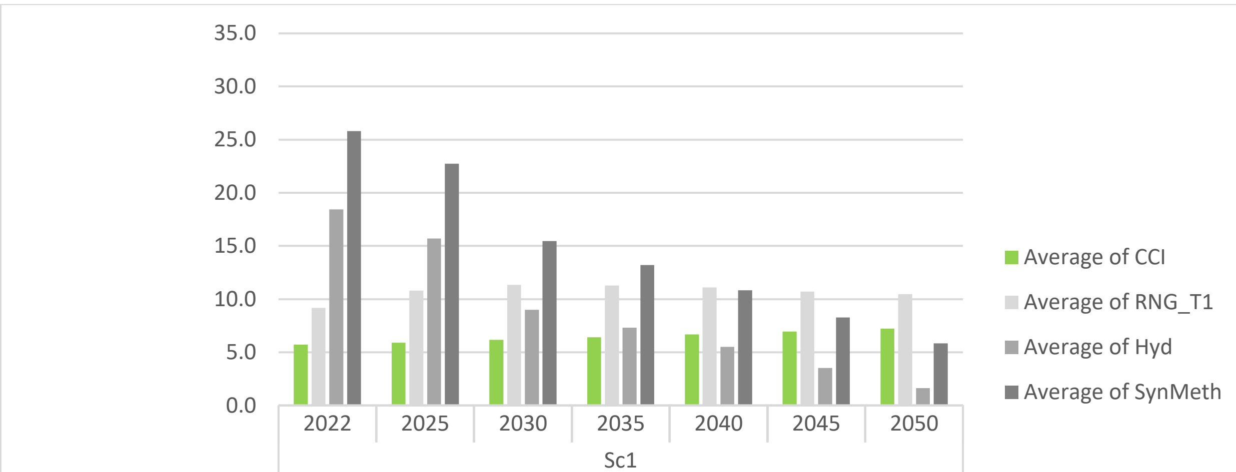
[38] NWN IRP page 212. Portfolio costs are also in Table 6.6 (page 217) and represent the bundled price of RNG including its renewable thermal certificate (RTC). Costs for compliance purposes (unbundled costs of the RTC) are in the "Compliance Data" tab of the summary results workpaper.

methane prices to dip below CCI credit prices in 2048, and to remain there for the last few years of the horizon.

Scenarios 7 and 8 reflect lower and higher (respectively) price trajectories for the supply-side compliance resources, relative to the rest of the scenarios.

The pricing for CCI credits was developed as part of the CPP, after passage of SB 98. Notably, CCI credit prices are significantly lower than RNG prices through 2037. However, NWN selects the use of RNG to meet CPP compliance requirements within its PLEXOS modeling[39] rather than allowing all of the available lower cost CCI credits to be first fully selected by the optimization model.

Figure 11. CCI credit and supply resource compliance price, all scenarios except Scenarios 7 and 8

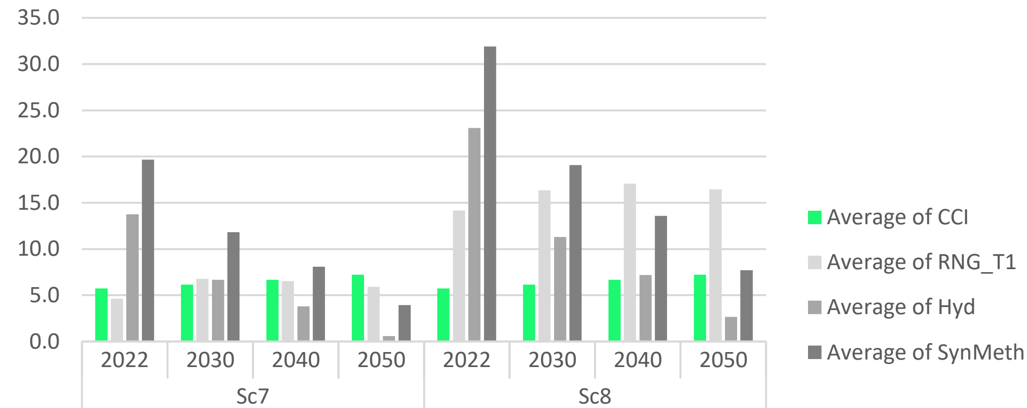


	2022	2025	2030	2035	2040	2045	2050
Average of CCI	5.7	5.9	6.2	6.4	6.7	7.0	7.2
Average of RNG_T1	9.2	10.8	11.3	11.3	11.1	10.7	10.5
Average of Hyd	18.4	15.7	9.0	7.3	5.5	3.5	1.6
Average of SynMeth	25.8	22.7	15.5	13.2	10.8	8.3	5.8

Note: Scenario 1 price is the same as that of all other scenarios except Scenarios 7 and 8, for RNG sources (RNG_T1, Hydrogen, Synthetic Methane). RNG prices are unbundled prices reflecting compliance price. CCI credit prices are the same for all scenarios. Source: NWN 2022 IRP Scenario Results Workpaper.

[39] See the IRP 2022 Scenario Results workpaper, "Compliance Resources by State" tab with the PLEXOS output for compliance resources across all scenarios.

Figure 12. CCI credit and supply resource compliance price, Scenarios 7 and 8



	Sc7 2022	Sc7 2030	Sc7 2040	Sc7 2050	Sc8 2022	Sc8 2030	Sc8 2040	Sc8 2050
Average of CCI	5.7	6.2	6.7	7.2	5.7	6.2	6.7	7.2
Average of RNG_T1	4.6	6.8	6.5	5.9	14.2	16.3	17.1	16.5
Average of Hyd	13.8	6.7	3.8	0.6	23.1	11.3	7.2	2.7
Average of SynMeth	19.7	11.8	8.1	4.0	31.9	19.1	13.6	7.7

Note: Scenario 1 price is the same as that of all other scenarios except Scenarios 7 and 8, for RNG sources (RNG_T1, Hydrogen, Synthetic Methane). RNG prices are unbundled prices reflecting compliance price. CCI credit prices are the same for all scenarios. Source: NWN 2022 IRP Scenario Results Workpaper.

NWN states that it "internalized as its own RNG targets"[40] the established volumetric targets of SB 98, although such procurement is voluntary, not mandatory. Independent of the pricing of RNG, hydrogen, or synthetic methane resources, NWN constrains the PLEXOS model and "selects"[41] the use of an initial quantity of a mix of these resources in close accordance with a procurement schedule for SB 98 gas.[42] NWN lists SB 98 target volumes as a percentage of retail sales in the workpaper and includes them in the PLEXOS constraint file.

Compliance Resources

For the first compliance period (2022–2024), NWN indicates that a majority of the compliance obligation in most scenarios primarily utilize biofuel RNG.[43] NWN uses less than the maximum amount allowed for CCI credits in the beginning of the planning horizon (through 2030) across most scenarios. In all years, for all scenarios except Scenario 8, the level of RNG is only from Tranche 1; in later years, the availability

[40] IRP, page 181.

[41] Response to DR 104.

[42] The workpaper includes the output from PLEXOS for compliance resources but does not transparently show the exact algorithm that produces the mix of CCI and RNG tranche 1 resource allocation for the early years of the planning period when 100 percent of available CCI credits would be expected to be selected.

[43] IRP page 26.

of synthetic methane or hydrogen leads to procurement of those resources for compliance, in addition to Tranche 1 RNG.[44]

NWN acknowledges that depending on weather conditions or "other load developments," a small amount of CCI credits (the "lowest cost incremental option") could be needed during the first compliance period.[45] However, NWN also states that "in the near[ ]term biofuel RNG is the cheapest option and is used to meet SB 98 targets."[46]

Cost of Compliance

RNG supply comprises the largest component of compliance obligation costs across all scenarios. On average across all scenarios, RNG makes up 77 percent of total compliance costs, and CCI credits only account for 13 percent.[47]

Even though CCI credits are a cheaper compliance option than incremental RNG, NWN underutilizes them because it procures "biofuel RNG to meet SB 98 targets."[48] As shown in Table 3 below, in every scenario, NWN does not select the maximum amount of CCI credits for the first two compliance periods (through 2027) and selects the maximum in the next compliance period only in the Reference scenario.[49,50] As a result, across all scenarios, NWN uses only 60 percent of total available CCI credits. Only by the fifth compliance period (starting in 2034) does the model use 100 percent of available CCI credits in all scenarios (except Scenario 6).[51]

44 Appendix G: Portfolio Selection, and NWN Workpaper "2022 IRP Scenario Results", "Compliance Data" tab.

45 IRP, page 26.

46 IRP, page 26.

47 NWN Workpapers_2022 IRP Scenario Results, "Compliance Data" tab.

48 IRP, page 26.

49 NWN Workpapers_2022 IRP Scenario Results, "Compliance Resources by State" tab.

50 NWN 2022 IRP PLEXOS Input Data Files: "Constraint_CCI Compliance Period Limit"

51 In Scenario 6 ("Full Building Electrification"), no CCIs are used, only RNG is used for compliance due to decreased loads.

Table 3. Percent of maximum available CCI credits used in scenarios for CPP compliance

Compliance period	Maximum CCI credits (Bbtu)	Ref	S1	S2	S3	S4	S5	S6	S7	S8	S9
2022-2024	32,248	3%	1%	0%	0%	1%	0%	0%	0%	1%	1%
2025-2027	42,567	46%	31%	4%	23%	24%	3%	0%	15%	34%	35%
2028-2030	49,016	100%	75%	30%	58%	59%	21%	0%	42%	84%	83%
2031-2033	41,277	100%	100%	71%	100%	100%	57%	0%	100%	100%	100%
2034-2036	33,801	100%	100%	100%	100%	100%	100%	0%	100%	100%	100%
2037-2039	28,171	100%	100%	100%	100%	100%	100%	0%	100%	100%	100%
2040-2042	22,805	100%	100%	100%	100%	100%	100%	0%	100%	100%	100%
2043-2045	17,439	100%	100%	100%	100%	100%	100%	0%	100%	100%	100%
2046-2048	12,073	100%	100%	100%	100%	100%	100%	0%	0%	100%	100%
2049-2051	7,304	0%	0%	0%	0%	0%	0%	0%	0%	95%	0%

Source: NWN Compliance Data and CCI Maximum Limit values. Tabulation by Synapse.

On a per MMBtu basis, it is less expensive for NWN to comply with the CPP by purchasing CCI credits rather than renewable fuels during the first three, or four, compliance periods. If NWN used the maximum amount of CCI credits available to it in each year, NWN would need less RNG supply to comply with the CPP, which would reduce total compliance costs. To illustrate the magnitude of this difference, Table 4 below shows the cost savings potential for each scenario by year if NWN reduced total RNG volumes by using the maximum available CCI credits.

Table 4. Net savings by year of replacing RNG with CCI credits up to maximum level allowed

Compliance year	Reference	Scenario								
		1	2	3	4	5	6	7	8	9
Years	*$ (millions)*	*$*	*$*	*$*	*$*	*$*	*$*	*$*	*$*	*$*
2022	12.69	12.55	12.39	12.47	12.55	12.63	11.94	(6.23)	24.55	12.55
2023	12.69	12.55	12.39	12.47	12.55	12.63	11.94	(6.23)	24.55	12.55
2024	12.69	12.55	12.39	12.47	12.55	12.63	11.94	(6.23)	24.55	12.55
2025	26.19	25.06	24.49	24.38	24.41	24.24	20.85	(6.57)	57.80	25.33
2026	26.19	25.06	24.49	24.38	24.41	24.24	20.85	(6.57)	57.80	25.33
2027	26.19	25.06	24.49	24.38	24.41	24.24	20.85	(6.57)	57.80	25.33
2028	-	19.57	34.04	4.58	5.75	33.01	23.55	(0.27)	51.86	26.28
2029	-	19.57	34.04	4.58	5.75	33.01	23.55	(0.27)	51.86	26.28
2030	-	19.57	34.04	4.58	5.75	33.01	23.55	(0.27)	51.86	26.28
2031	-	-	21.26	-	-	9.93	23.30	-	-	-
2032	-	-	21.26	-	-	9.93	23.30	-	-	-
2033	-	-	21.26	-	-	9.93	23.30	-	-	-
2034	-	-	-	-	-	-	22.36	-	-	-
2035	-	-	-	-	-	-	22.36	-	-	-
2036	-	-	-	-	-	-	22.36	-	-	-
2037	-	-	-	-	-	-	21.42	-	-	-
2038	-	-	-	-	-	-	21.42	-	-	-
2039	-	-	-	-	-	-	21.42	-	-	-
2040	-	-	-	-	-	-	20.41	-	-	-
2041	-	-	-	-	-	-	20.41	-	-	-
2042	-	-	-	-	-	-	20.41	-	-	-
2043	-	-	-	-	-	-	1.03	-	-	-
2044	-	-	-	-	-	-	1.03	-	-	-
2045	-	-	-	-	-	-	1.03	-	-	-
2046	-	-	-	-	-	-	6.36	(76.86)	-	-
2047	-	-	-	-	-	-	6.36	(76.86)	-	-
2048	-	-	-	-	-	-	6.36	(76.86)	-	-
2049	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-

Source: Synapse, tabulating Compliance Data from NWN.

As seen in Table 5 below, the net present value of potential compliance cost savings (2022 dollars) ranges from $97 million to $300 million dollars over the entire IRP planning horizon. Only in Scenario 7 (RNG and H2 Policy Support) would replacing RNG with unused CCI credits increase total compliance costs; this is the scenario with the lowest RNG compliance costs ($4 to $6 per MMbtu). In contrast, the cost savings are the greatest for Scenario 8 Limited RNG, which has the highest average cost of RNG of all scenarios ($13 to $15 per MMbtu).

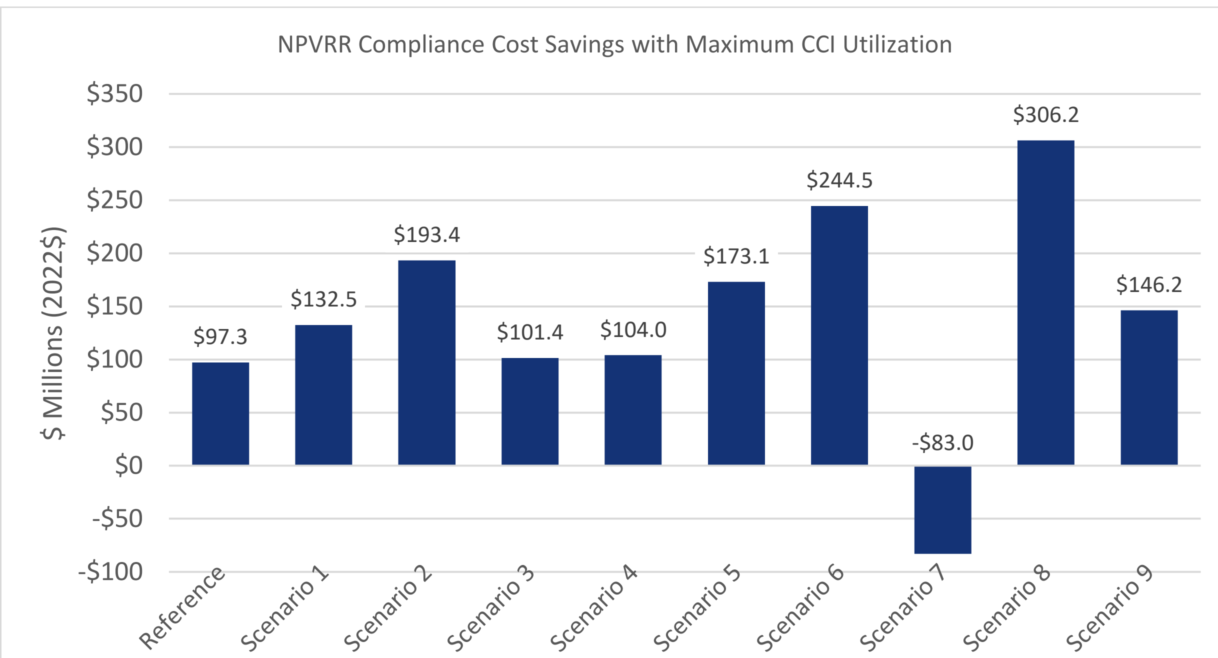
Table 5. NPV compliance cost savings using a maximum level of CCI credits, vs. RNG

Scenario	NPV Compliance Cost Savings (2022 $)
Reference	97.3
Scenario 1- Balanced Decarbonization	132.5
Scenario 2- Carbon Neutral	193.4
Scenario 3- Dual-Fuel Heating	101.4
Scenario 4- New Gas Customer Moratorium	104.0
Scenario 5- Aggressive Building Electrification	173.1
Scenario 6- Full Building Electrification	244.5
Scenario 7- RNG and H2 Policy Support	-83.0
Scenario 8- Limited RNG	306.2
Scenario 9- Supply-Focused Decarbonization	146.2

Source: Synapse, based on computations from "Compliance Data" tab of the Scenario Results workpaper.

As seen in Table 4 and Table 5 above, the value of using CCI credits instead of procuring RNG to meet CPP compliance is at its highest when RNG costs are high, in Scenario 8. But in all scenarios except the low-cost RNG Scenario 7, using CCI credits at their maximum levels results in ratepayer savings.

Figure 13. NPV RR effect by scenario of substituting CCI credits for RNG, up to Allowed level of CCI credits



Source: NWN Workpapers IRP Scenario Results, "Compliance Resources by State" tab, NWN IRP PLEXOS Input Data Files "Constraint_CCI Compliance Period Limit."

Price and Availability Trajectories for Hydrogen and Synthetic Methane

The IRP addresses the uncertainty of availability and price of hydrogen and synthetic methane by running a Monte Carlo simulation that tests the price of hydrogen, which is tied to estimates for the price of renewables.[52] NWN uses third-party sources to estimate the trajectory of costs for hydrogen, which also informs the trajectory of costs for synthetic methane. Scenario 8 assumes higher prices relative to the other scenarios for hydrogen and synthetic methane by the end of the planning horizon. NWN bounds the availability of hydrogen at 20 percent of total energy deliveries in most scenarios, with higher levels (35 percent) in Scenario 9 and lower levels (12 percent) in Scenario 8.[53] NWN does not limit the availability of synthetic methane. The pricing of hydrogen and its effect on the pricing for synthetic methane must also be considered when reviewing the direct effect of the cost of renewable electricity on electrification measures. NWN does not compare the costs of hydrogen or synthetic methane to the costs of electrification as a direct competing decarbonization option.

Summary of RNG and CCI Credits as CPP Compliance Solutions

Absent a clear analysis of the cost of electrification and its impact on the cost of a decarbonization pathway with lower demand (such as seen in Scenarios 3, 4, 5, or 6), and considering NWN's constraints in the model targeting SB 98 gas procurement (even though it is more expensive than CCI credits throughout the first half of the planning horizon), NW's analysis is incomplete. It is difficult to determine the quantitative extent to which RNG (biofuel), hydrogen, or synthetic methane solutions are part of a least-cost solution for compliance with the CPP. We note the following:

- The economically optimal mix of RNG, CCI credits, and load reduction through electrification is not assessed under NWN's construct.
- To lower overall ratepayer costs, NWN should fully utilize CCI credits that cost less than RNG solutions in the first part of the planning horizon.
- There is limited sensitivity testing of the costs of RNG, hydrogen, and synthetic methane across the scenarios. IRP Guideline 1(c) includes a call for the testing of the "severity of bad outcomes." In some sense, using Scenario 8 can help illustrate the effect on ratepayers if a high supply-side renewable fuel path is chosen, as prices would be higher than what NWN projects for Scenario 1. However, a more comprehensive analysis is required to better explore the different combinations of high RNG cost and lower gas load trajectories. Notably, only one scenario addresses the use of hydrogen at a concentration lower than 20 percent in the pipeline system. Given the potential limitations of using hydrogen (vs. synthetic methane) in large volumes in the pipeline

---

[52] IPR, page 190, "...this IRP only considers hydrogen produced through electrolysis (green hydrogen) and synthetic methane (described below) using renewably-generated electricity."

[53] IRP, Section 7 table "Compliance Resource Options", "Quantity Available". It is our understanding that the percentage of hydrogen "by energy" reflects the share of hydrogen as a compliance resource, not the blending percentage, which is considered to be 20% (IRP, Table 6.6).

system,[54] additional sensitivity testing is needed to better understand the projected costs and eventual ratepayer impacts of considering a hydrogen-heavy resource path if its allowed share in the pipeline system is reduced from the 20 percent assumption that NWN uses in most scenarios.

2.5. Integrated Resource Planning Revenue Requirements Construct

In this section we use the information from the prior three sections and consider it in the context of the use of the PVRR ("present value of revenue requirements") construct for gas IRP planning.

Overview

Oregon IRP Guideline 1(c) states that utilities should use the present value of ratepayer revenue requirements (PVRR) as the key cost metric, when conducting resource planning.[55] According to the guideline, the revenue requirements considered in gas resource planning should include short- and long-lived resources including pipelines, gas supply, and gas storage. Generally, total revenue requirements for planning purposes include the costs to buy gas and operate the system, the costs to pay for past capital investments, the costs for new capital investments as needed, and (new in 2022) the costs to comply with the CPP.[56] Capital investment costs include asset depreciation and return on investment for NWN.

The guideline also states that the planning horizon should be at least 20 years, end effects[57] should be considered, and utilities should "include all costs with a reasonable likelihood of being included in rates over the long term."[58] Some of the costs likely to be included in rates over the long term will vary depending on the system load, and some of those costs will remain fixed independent of the level of system load.[59]

---

[54] See, for example, a recent California Public Utilities Commission report on hydrogen blending on the natural gas system. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.

[55] Included in 1(c): "Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases."

[56] See NWN response to OPUC DR 105, which contains NWN's Annual Report of Operations for the past 10 years. This includes costs recovered through rates for distribution assets and operations, gas supply commodities, gas supply transportation, gas storage, and other component costs (e.g., taxes).

[57] End effects are the accounting mechanism used in a model such as PLEXOS to address the fact that planning decisions have long-term impacts beyond the last year of the modeled planning horizon. A common approach is to presume a continuing trajectory of operational cost patterns beyond the last year of the planning horizon. NWN in response to OPUC DR 106 states that testing the end effects optionality in PLEXOS in two ways did not impact the resource selection.

[58] Guideline 1(c).

[59] For example, scenarios with no new customers after 2025 (Scenarios 4, 5 and 6) or with dual-fuel heating (Scenario 3) will lead to different needs for service lines and distribution system investments, compared to the other scenarios with higher

NWN states that it "uses PVRR as the key cost metric in this IRP and includes analysis of current and estimated future costs of both long- and short-lived resources."[60] NWN's application of this guideline (the way in which it "uses PVRR as the key cost metric") affects the selection of input assumptions, its methodological approach to finding resource solutions, and the ultimate outcomes from the IRP exercise.

In Section 7.2 of the IRP, NWN states that its use of the PLEXOS model "triangulates a least cost solution of resource acquisition and dispatch that minimizes net present value of total system costs over a specified planning horizon" and it further states that this means "the model solves for a solution that minimizes the summed net present value (NPV) of all costs incurred each day in the planning horizon; from 2022 to 2050."[61]

Transparency

There is limited transparency in NWN's presentation of revenue requirements components and the present value of those revenue requirements over the planning horizon in the IRP. Section 7 of the IRP and the accompanying workpapers contain detailed input assumptions and results data; but there is no direct inclusion of a PVRR computation, or a tabulation of the components of the revenue requirements used in the objective function. Given that the introduction of the CPP gives rise to significant compliance resource costs, more direct presentation of compliance resource costs (in the context of overall revenue requirements) and variation of those costs across scenarios would allow for a more transparent display and comparison of how the different scenarios result in different compliance outcomes. IRP Table 7.5, containing the frequency with which the model selects certain capacity resource solutions, is useful but insufficient.

Revenue Requirements Included in NWN Modeling

NWN did not present a table showing total planning horizon revenue requirements, the components of those revenue requirements, or their present value for any of the scenarios or any of the Monte Carlo simulation draws within the body of the IRP. NWN includes the revenue requirement components used in the PLEXOS model in the workpapers[62] but does not tabulate them in combination for any of the scenarios.

annual loads and higher peak day demands. Lower future year peak day demand scenarios will also have lower requirements to meet firm peak delivery requirements from existing and/or new storage and transmission pipeline contracts.

[60] NWN IRP, Appendix A, page 12.

[61] NWN IRP, page 249.

[62] Specifically, "Gas Supply Commodity Cost," "Compliance Data," and "Incremental Capacity Cost" tabs in the Summary Scenario results workpaper.

NWN is correct[63] that comparisons between any two scenarios must be undertaken carefully, especially for scenarios with different load trajectories. Yet, it is still valuable, and perhaps invaluable, to see how and understand why the stream of revenue requirements varies over time; to see how and understand why the PVRR across the 29-year planning horizon varies across scenarios; and to see the components of the revenue requirements stream used in the modeling. This is particularly useful at a time of relative system transformation as past cost trends do not predict future cost trends, and compliance costs to meet CPP requirements make up a large share of total revenue requirements.

NWN lists the categories of decision variables, or “selection variables,” it uses in the model in Table 7.1 of the IRP. NWN states that the “PVRR of the costs that are included in the PLEXOS resource planning model is the metric that PLEXOS minimizes by selecting the least-cost resource portfolio needed to serve demand and meet compliance obligations throughout the planning horizon.”[64]

In response to OPUC DR44, NWN lists the components of the revenue requirement that “are the relevant costs needed to evaluate resources for a least-cost selection to achieve the objectives, described in Section 7.1, for meeting compliance, energy and capacity requirements.” Those costs include the following, which NWN states are contained in the workpapers:[65]

- Gas costs (WACOG tab);[66]
- Compliance resource costs (Compliance Data tab);
- Capacity resource costs (Incremental Capacity Costs tab); and
- Demand-side costs (Oregon DSM Scenario Costs and Washington DSM Scenario Costs tabs).

The “Compliance Data” tab also contains a summary of the total incremental demand-side costs as one portion the total compliance costs computed and presented by NWN in this file.

While NWN presents a summary of compliance costs in the workpaper—and the different tabs contain the capacity, gas costs, and additional demand-side cost details—NWN does not present a summary table of these revenue requirements or the present value of these revenue requirements anywhere in the IRP. NWN does not directly compare (across scenarios) any of the revenue requirement streams; NWN states in response to OPUC DR1 that it “is not appropriate to use the PVRR of the costs in the PLEXOS model alone to compare scenarios,” particularly for those with different levels of energy requirements or gas load.

[63] NWN, response to Staff DR1.

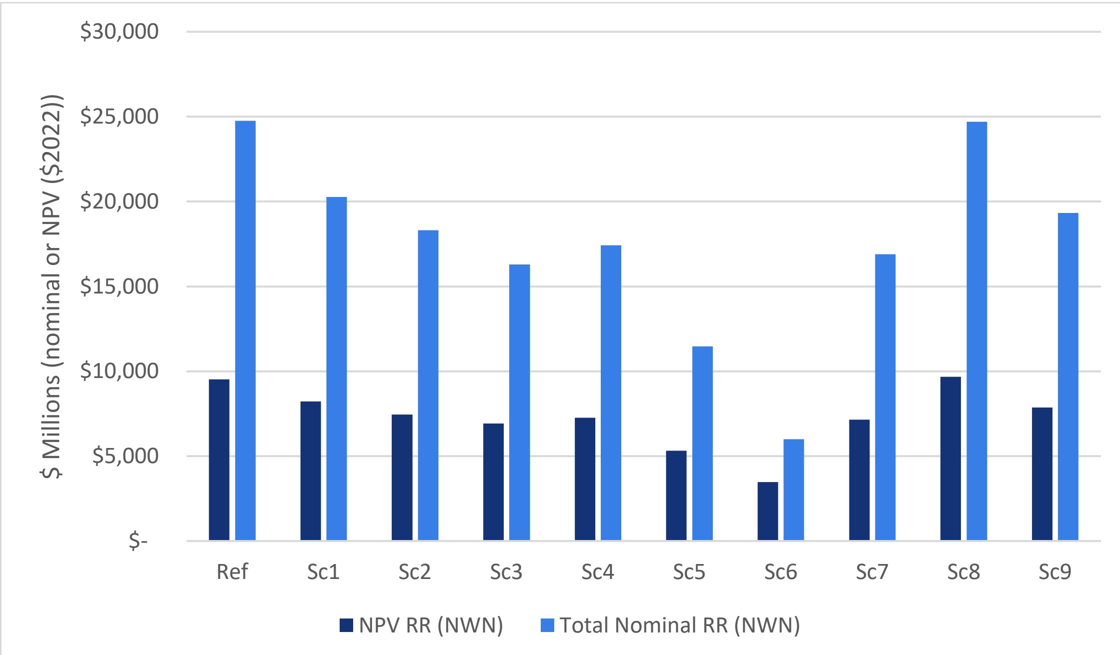
[64] NWN response to OPUC DR1.

[65] Workpapers_2022 IRP Scenario Results.

[66] There is a “WACOG Calc” tab, and a “Gas Supply Commodity Costs” tab. The WACOG calc tab contains the prices and per unit costs for gas commodities, and the other tab contains the total annual costs by scenario for the gas commodity supply.

Figure 14 below is a summary of the revenue requirements for NWN scenarios 1 through 9, plus the reference scenario, using NWN's cost components. The chart shows both nominal and NPV values. The costs shown are those "partial" revenue requirement costs that NWN includes in its modeling approach. NWN does not include in its modeling the remaining revenue requirements, including those arising from past and projected capital investments in the distribution system.

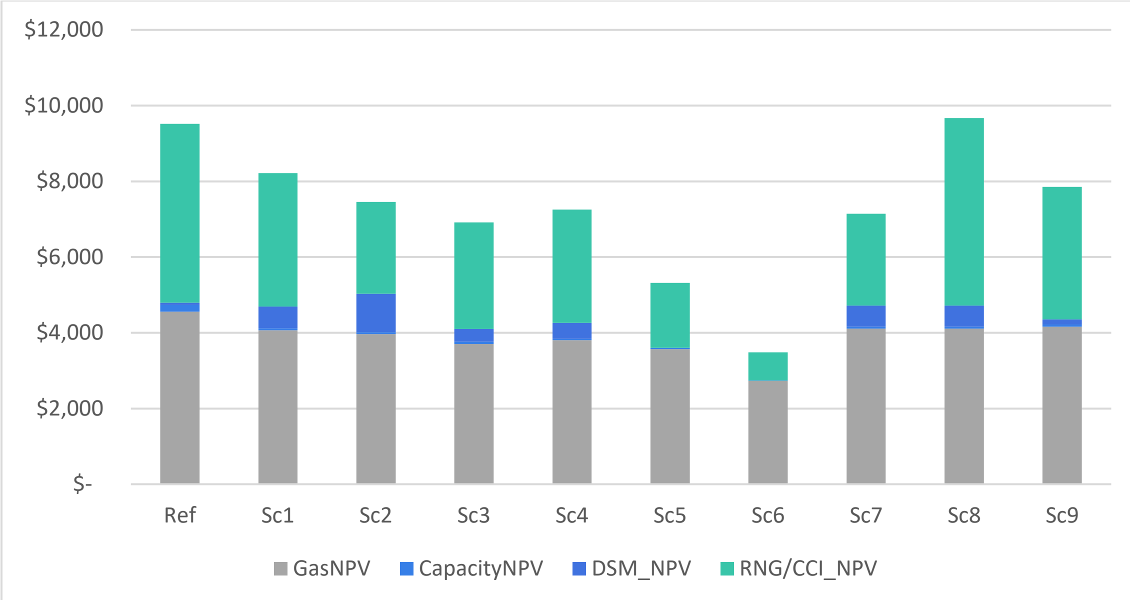
Figure 14. Magnitude of 29-year stream of revenue requirements used in NWN PLEXOS modeling



Source: NWN Workpaper 2022 IRP Scenario Results: Compliance Data, Gas Supply Commodity Costs, Incremental Capacity Costs tabs. Tabulation by Synapse.

Figure 15 below shows the NPVRR cost categories by scenario. Gas supply and compliance costs dominate total costs. Incremental capacity and DSM costs represent a marginally small share of costs.

Figure 15. Net present value of 29-year stream of revenue requirements by scenario and by component

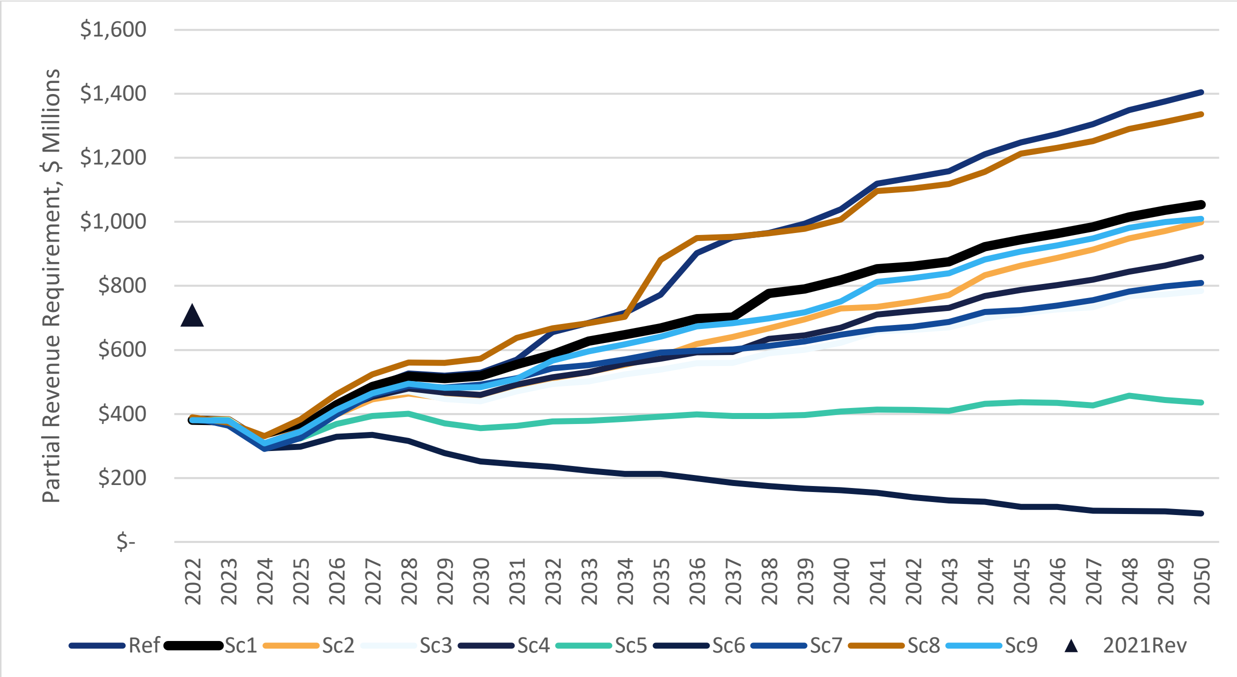


Source: NWN Scenario Results Workpaper.

The total revenue requirements analyzed in the PLEXOS model in each year are on the order of roughly one-half of NWN's total revenue requirements, based on the 2021 actual revenue requirement value from NWN [67] as shown in Figure 16.

[67] The response to OPUC DR 105 included attachments that contained the total revenue requirements for the 2012 through 2021 periods.

Figure 16. NWN's Partial revenue requirements by year by scenario in PLEXOS model

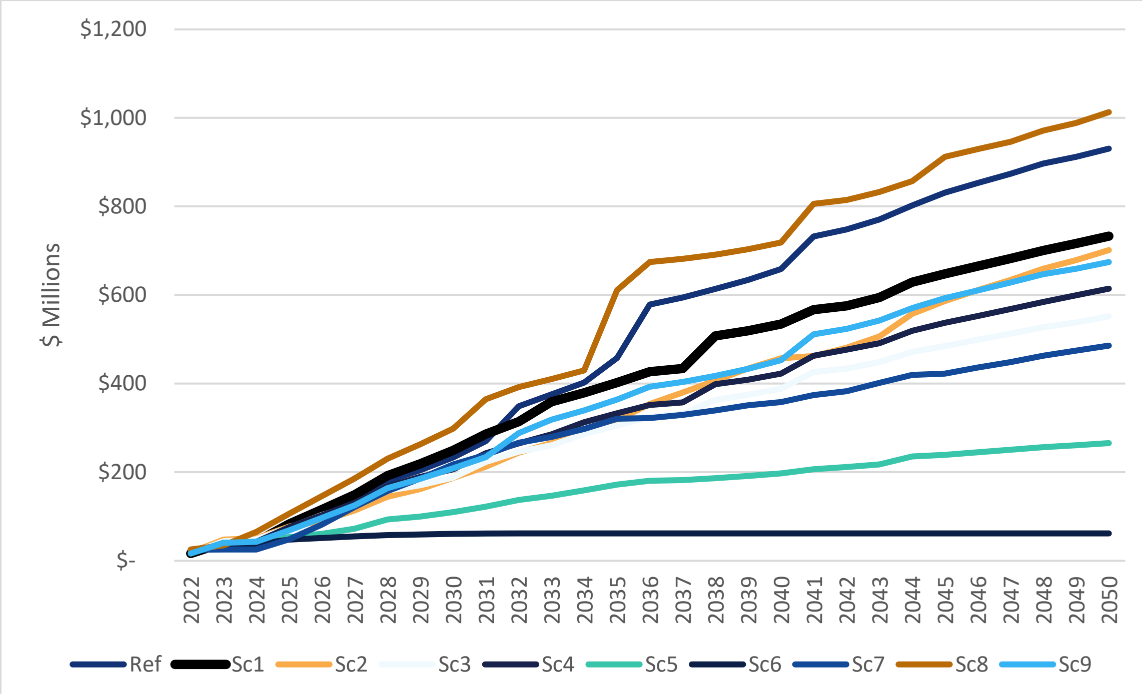


Source: DR 105 (2021 revenue requirement), and NWN Workpaper IRP 2022 Scenario Results. Graphing by Synapse.

NWN presents compliance data on the "Compliance Data" tab of it summary workpaper file.[68] The format allows the user to select different scenarios and see the resulting accounting of costs for CPP compliance for Oregon (and for Washington compliance under the CCA). The compliance cost streams seen in Figure 17 below illustrate the significant variation in compliance costs across the scenarios over time.

[68] Workpapers_2022 IRP Scenario Results.

Figure 17. Oregon CPP compliance costs by year by scenario (NWN)



The lowest compliance costs are seen in Scenario 6, which contains the lowest level of gas load. The highest level of compliance cost is seen in Scenario 8, which is the only scenario that reflects a higher cost for RNG (biofuel, hydrogen, and synthetic methane fuels). The compliance cost streams are composed of RNG, CCI, and incremental demand-side management costs that in combination meet the CPP requirements for total emissions from the sales and transport sectors.

In addition to the compliance costs, which are for both sales and transport customers, the workpaper also contains the projected cost of gas for its sales customers and the cost of capacity resource expansion (required for delivery to sales and transport customers) across the scenarios. For those revenue requirements that NWN includes when optimizing its resource plan, the cost of gas comprises the bulk of remaining costs after compliance costs. Capacity resource requirement costs are incremental to the existing transmission and distribution costs.

NWN's optimization includes neither existing transmission and distribution costs nor projected distribution costs as part of the revenue requirement cost trajectory.

Revenue Requirements Excluded from NWN Modeling

NWN states that not all revenue requirements are considered or included in IRP objective function formulations in IRPs,[69] and it gives examples of the types of costs that are not included: "For example, employee compensation and IT costs not associated with energy supply resources are not included in

[69] NWN Response to OPUC DR1.

the costs shown from the resource planning model."[70] However, there are *other* costs associated *with* energy supply resources that are *not* included in NWN's revenue requirements formulation.

NWN does not include the following revenue requirement components in its PLEXOS modeling:

- Distribution system expansion costs, including service and mains investment, which logically would vary depending on system customer additions and overall gas load;
- Distribution system operation and maintenance costs, which also would vary depending on the gas demand; and
- Existing fixed costs for firm delivery from upstream pipelines. These costs could vary in the future for any scenarios that would require lower amounts of firm capacity delivery.

Critically, for those scenarios that include the effect of electrification on lowering gas demand, electrification costs are also not directly considered within NWN's construct for resource planning solutions.

Incremental Distribution System Capital Expenditures and Operations and Maintenance Costs Excluded from PLEXOS Analysis

NWN's annual revenue requirements include costs associated with distribution and transmission system capital investment. As with all prudently incurred capital investment required for the system, those costs include the asset depreciation and the return on investment afforded NWN. Incremental operations and maintenance costs associated with new plant investment are also incurred. NWN provides the total capital investment and operations and maintenance costs for the distribution and transmission system in its Annual Report of Operations. NWN provided these data in this IRP as part of a discovery response.[71] Table 6 below summarizes salient aspects of the data.

[70] NWN Response to DR1.

[71] NWN, response to OPUC DR 105, Attachments 1-10 (annual earnings review data) and Attachment 11 (operating costs).

Table 6. Annual operating data with distribution system operating cost and plant investment

	Total Operating Revenues	Distribution System Operations and Maintenance Costs	Total NWN System Capital Investment Additions	Distribution System Capital Investment Additions	Distribution share of total	Illustrative revenue requirement increase from new Capital Addition, Based on Imputed Value from Rate Case Stipulation (9% of capital investment)	
	$ millions	$ millions	$ millions	$ millions	Percentage	Total System $ millions	Distribution System $ millions
2012	664.7	39.4					
2013	666.4	43.1	77.5	42.4	55%	6.9	3.8
2014	711.0	41.6	96.6	51.9	54%	8.6	4.6
2015	715.6	42.3	57.0	45.2	79%	5.1	4.0
2016	647.6	45.1	65.1	60.4	93%	5.8	5.4
2017	670.8	48.0	64.8	58.9	91%	5.8	5.2
2018	625.8	46.9	76.8	70.4	92%	6.8	6.3
2019	617.5	46.4	92.5	77.0	83%	8.2	6.9
2020	647.5	49.5	121.1	113.5	94%	10.8	10.1
2021	709.5	52.3	112.5	103.2	92%	10.0	9.2

Source: Synapse Tabulation and revenue requirement calculation. Response to OPUC DR 105, and Multi-Party Stipulation Regarding Revenue Requirement, Rate Spread and Certain Other Issues, UG 435 and UG 411, May 31, 2022. Page 6, lines 5-10. Notes: The 9 percent factor to estimate revenue requirements for distribution system capacity investment is based on the ratio of the net revenue requirement for capital additions for new customers ($2.195 million) and the capital addition amount ($24.65 million), as seen in the noted Stipulation document.

Table 6 above shows the magnitude of capital expenditures for the NWN system in total, and NWN's distribution system investment during the 2012–2021 period. In 2020 and in 2021, NWN capital investment in the distribution system was over $100 million in each year. Over the past five years, the investment has averaged almost $85 million per year. The table also illustrates a rough magnitude of annual revenue requirement for each year's investment, which reflects a 9 percent multiplier on the annual capital investment to account for financing, asset life, depreciation, return, and related factors. The 9 percent value used was based on the 2022 rate case stipulation document cited in the Table 6 notes.[72]

Of the total shown in Table 6, a portion of the distribution system investment is for new customer connections. The portion of the total distribution system capital investment due to new customers in the 2022 rate case test year was $24.6 million. A discovery question response in that rate case indicated

[72] The stipulation noted that the portion of the total distribution system capital investment due to new customers in the test year was $24.6 million, and the stipulation indicated that the revenue requirement associated with that investment was $2.2 million, or roughly 9 percent of the capital spending.

that over the past five years, new customer additions led to roughly $30 million per year in capital investment.[73]

Thus, generally, new customer additions at the historical level may result in roughly $2.2 to $2.7 million per year increased revenue requirement (reflecting 9% of a range of investment between $24.6 million and $30 million per year), accumulating each year over the life of the investment. Depending on the assumptions made for the number of new customers,[74] and the level of projected capital investment (which was not done by NWN in this IRP), the accumulating 29-year stream of costs for just the new customer investment portion of the distribution system could be on the order of $800 million (nominal) and a present value of $450 million.[75] To illustrate the effect of considering this cost component in the NPVRR computations, Figure 19 in the next sub-section includes this effect for Scenario 6 in the graphic comparing NPVRR across scenarios, and uses proportionally lower levels for Scenarios 5 and 4, for which NWN also assumed declining customer counts over time.

NWN *excluded* from its PLEXOS modeling the cost components associated with existing and new distribution assets, and existing transmission system plant investment.[76] This is particularly noteworthy for potential new distribution system capital expenditures because the magnitude of this increase in annual revenue requirements is material to PVRR totals for different resource solution pathways. Thus, the impact of reduced, or increased, revenue requirements (by scenario) associated with these assets is not part of NWN's overall assessment of a least-cost scenario, for planning purposes. The costs associated with new pipeline transmission or storage costs *are* included as incremental capacity costs in the PLEXOS model.[77]

NWN references the rate impacts across scenarios in response to OPUC DR1. NWN states that "[e]xisting rate base is also not something that is traditionally included in the resource planning models." NWN also states that "the more appropriate comparison across scenarios is the rate impacts to customers," in reference to a question concerning comparisons across the PVRR of different scenarios.[78] We note that NWN provides bill impacts graphs in its Section 7, and it directly shows bill impacts in the Scenario

[73] Response to CU-NWN DR 84a in case UG 435.

[74] NWN's new customer projections for Oregon residential customers for Scenario 1 slows over time, but is always positive, reaching roughly 55% of the level of new customer additions (compared to 2023) by the end of the planning horizon in 2050 ("customer count" tab of Scenario Results summary workpaper. For Scenarios 4, 5 and 6, customer counts drop steadily, at different rates, reflecting the attributes of the scenario.

[75] This is based on a simple stream of real costs starting at $2.2 million per year for 10 years, reducing to $1.5 million per year for 9 years, and further reducing to $1.0 million per year for 10 years. NWN's real discount rate of 3.4% is then applied to this stream, to compute a NPVRR component amount of $450 million.

[76] Response to OPUC DR 107, OPUC DR 103, OPUC DR 1.

[77] IRP, Table 1.2 Capacity Resource Options, page 22.

[78] NWN Response to OPUC DR 1.

Results workpapers; but NWN actually does not directly provide a measure of the relative customer rates across scenarios.

In response to OPUC DR 103(a), which asked about the "Oregon Bill Impacts" tab and data included in the workpapers, and specifically the non-WACOG costs (which are not in the PLEXOS modeling),[79] NWN confirmed that the costs used to generate the bill impacts listed in the IRP in Section 7 and in the IRP workpapers include an estimated trajectory of non-WACOG costs, which would include costs not yet incurred for new capital investment for the distribution system. The workpaper itself indicates that the cost trajectory for non-WACOG costs is based on a regression analysis of historical trends.

The costs of non-WACOG revenue requirements decline slightly over time, based on NWN's methodology.[80] However, there are no differences in non-WACOG cost trajectories over time across the scenarios. For scenarios with less load, and for scenarios with fewer customer additions over time, the expected distribution costs, including sizable capital investments and potentially including ongoing operation and maintenance cost, would be materially lower.

Going forward, IRP analysis should include estimates of how distribution system costs would change under scenarios with lower load and/or lower new customer counts. While this form of analysis is new for gas IRPs, it is essential in order to gauge the magnitude of non-WACOG costs avoided under scenarios of increasing electrification of end uses currently served by gas, or potential new customer load that may not arise due to electrification trends.

Supply-Side Firm Capacity Costs Excluded from PLEXOS Model

NWN's Appendix E contains tabulations of the firm pipeline contract and storage volumes required to meet peak day demands.[81] In the "capacity data" tab of the Summary Results workpaper, NWN shows the existing and new capacity capabilities of resources, a totalization of the information in Appendix E tables. These firm capacity capabilities sum to just under 1,000,000 Dekatherms/day (Table E.6).

The PLEXOS model does not incorporate the capability for any of these peak day capability resources to "retire," or for contracts for their capacity to be terminated instead of renewed, on the upstream pipeline systems. In response to OPUC DR 107, NWN states that it "does not allow" existing capacity resources to retire in the PLEXOS model. Under low-load scenarios, peak day requirements fall across the planning horizon. For example, Section 7 of the IRP contains "System Peak Day Load" trajectories graphs that show falling peak day needs in Scenarios 4, 5, and 6. While Scenario 3 (Dual-Fuel Heating) shows roughly flat peak day demand over the planning horizon, the actual peak day needs for scenarios

---

79 See the response to OPUC DR 103. Non-WACOG is the term used by NWN in its UM 2178 workpaper that includes an estimate of the cost of gas not tied to the commodity "weighted average cost of gas" or WACOG component costs. It includes historical (and, projected) costs for carrying distribution plant investment revenue requirements and operating and maintenance costs.

80 See UM 2178 workpaper, response to DR 103, "Historical Data and Rate Detail" tab.

81 IRP Appendix E, Tables E3, E.4, E.5, E.6.

with dual-fuel heating will depend on the ultimate performance of electric heating systems during peak periods.

NWN should configure the PLEXOS model such that it could "retire" firm capacity resources when not needed, while maintaining sufficient firm capacity under the peak planning standard.

Electrification Costs

The PLEXOS model does not include any electrification costs for any of the scenarios that are modeling (at least in part) end uses served through electrification. In this report, estimated electrification costs for scenarios relative to Scenario 1 are shown in Section 2.3 above, and in Appendix C.

Optimization of Resource Plan and Comparisons Across Scenarios

NWN's resource plan optimization determines combinations of energy, capacity resources, and compliance resources for each of its scenarios, and for each of its 500 draws in its Monte Carlo simulation analysis. The resulting resource combinations for each scenario or draw arise from the PLEXOS model's objective function minimizing the present value of a subset of NWN's total revenue requirements.

While NWN's objective function[82] considers key going-forward costs (the cost of gas, the cost of new capacity resources, and the cost of CPP compliance) it excludes some material costs that will vary depending on the system gas load. NWN states that "the model solves for a solution that minimizes the summed net present value (NPV) of all costs incurred each day in the planning horizon; from 2022 through 2050."[83] However, "all costs" that are relevant to solutions with varying load inputs are not included in NWN's assessment.

Distribution system expenditures (new capital expenditures and operations and maintenance costs associated with that new plant) are excluded from consideration. NWN used an assumed set of distribution system additions across all scenarios, with no variation. Distribution system investments that will differ across NWN's scenarios should be included as part of the revenue requirements formulation, to meet the essence of this guideline. The guideline is intended to capture those costs that may vary depending on different resource solutions, yet NWN did not include those varying costs in the PLEXOS formulation.

As noted, NWN's modeling configuration maintains supply-side firm capacity costs from existing upstream pipeline contracts. Under any scenario of reductions in load, NWN would not need to renew these contracts and the costs should be "removed" as part of the optimization process in PLEXOS. Currently, NWN retains these costs in all its scenarios.

[82] NWN IRP, page 249, PLEXOS objective function equation.

[83] IRP, page 249.

Optimization Process

NWN conducts an optimization process within the PLEXOS modeling environment to produce outcomes for both resource options (e.g., physical supplies) and CPP compliance actions (e.g., CCI credits and RNG) for each of its nine working scenarios, for its Reference scenario, and for each of the 500 draws in its stochastic assessment. The optimization seeks a least-cost resource solution over a 20-year timeframe given the parameterization of the scenario or the draw. The optimization process produces a least-cost portfolio result given the inputs and the constraints associated with each scenario or draw. The outcome includes the makeup of CPP compliance actions, and physical resources for capacity and energy.

NWN determines its preferred portfolio—the average of its Monte Carlo draw outcomes[84]—based on the optimization results across its 500 draws. The preferred portfolio is reflected in the capacity and compliance resource acquisition summaries, the compliance instruments purchase, and the demand reduction investment totals seen in Figures 7.5 through 7.9 of the IRP.

While the deterministic scenario analyses present a picture of different (though overlapping) resource outcomes due, for example, to different gas demand levels, NWN does not directly use those results when determining its preferred portfolio.[85]

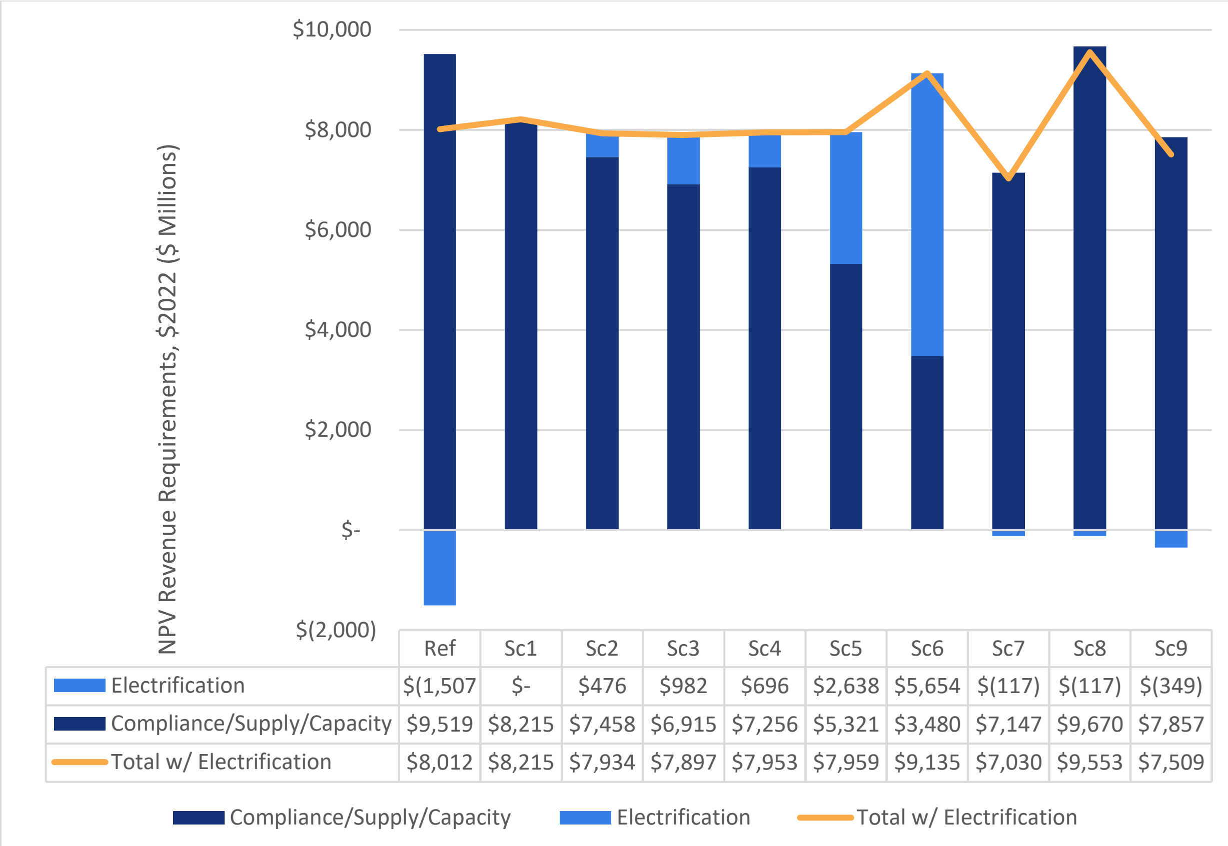
PVRR Comparisons Across Scenarios with Different Levels of Gas Load

Section 2.3 above described our approach to estimate the cost of electrification for Scenario 6 compared to Scenario 1, and then to presume proportional electrification costs for other scenarios relative to the difference in gas load forecast by NWN for each scenario. To illustrate how those costs could be combined with the remaining costs for each scenario modeled by NWN, and to show how the resulting scenario PVRRs can be compared, we add the NPVRR of the electrification costs to the NPVRR of the underlying commodity, resource capacity and compliance costs computed by NWN. Figure 18 below shows a comparison of the total costs across scenarios.

[84] NWN response to Staff DR 69 (c). “the preferred portfolio is the average of the outcomes from the stochastic Monte Carlo risk analysis detailed throughout the IRP with the results being shown in Chapter 7, Section 6.”

[85] NWN response to OPUC DR 69 (d).

Figure 18. Comparison of NPVRR across all scenarios, inclusive of electrification cost estimate, 2022-2050



Source: Synapse using NWN Compliance, Supply and Capacity Costs, and Synapse electrification costs. Note: Scenario 1 is considered the base load scenario (zero electrification costs) for the purpose of this comparison. The Reference scenario and Scenarios 7, 8, and 9 contain more gas load than Scenario 1, and thus are "credited" with electrification savings at the same level as the other scenarios see for incurred electrification cost.

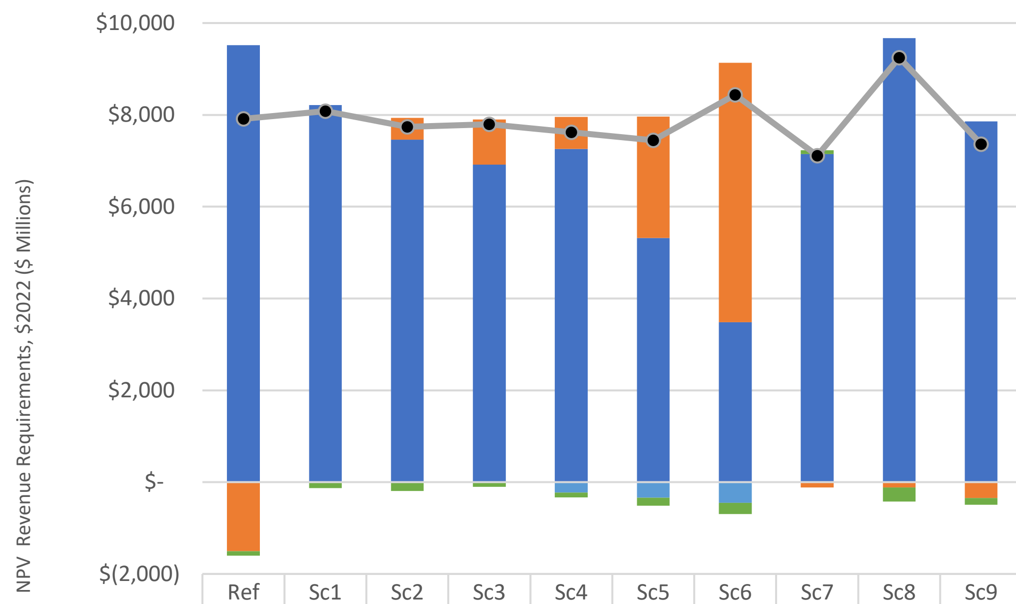
Figure 18 above illustrates the following:

- Scenario 7, which assumed low RNG costs, is the lowest-cost of all scenarios.
- Scenario 8, which assumes higher RNG costs, is the highest-cost scenario, exceeding the costs of Scenario 6 (highest level of electrification).
- All other scenarios assumed NWN's reference trajectory of RNG costs. Scenarios 3 through 5, which assume increased electrification relative to Scenario 1, are all lower-cost than Scenario 1.
- Scenario 2, which assumed increased energy efficiency (with increased costs for that load reduction based on the same costs as seen for electrification) is roughly the same total cost as Scenarios 3, 4, and 5 with electrification.

The figure demonstrates primarily that making comparisons across scenarios with different levels of gas load is possible when using an estimate of the costs of the electrification (or increased energy efficiency) required to reduce the gas loading. It also begins to illustrate the importance of sensitivity testing of scenarios to help understand the relative economic impact of a planning path that potentially relies on RNG. Under scenarios of higher RNG costs, even the most aggressive of the electrification scenarios (Scenario 6) costs less.

The analytical mechanism can be used to further illustrate the effect on NPVRR if other components of cost are considered, or if additional sensitivity testing is used. Figure 19 below shows the effect of utilizing lower-cost CCI credits to their maximum capability, instead of higher-cost RNG, and considering further NPVRR savings of reduced distribution system investment for lower-load scenarios.

Figure 19. NPVRR comparison with electrification costs, CCI-for-RNG substitution, and distribution capex savings, 2022-2050



	Ref	Sc1	Sc2	Sc3	Sc4	Sc5	Sc6	Sc7	Sc8	Sc9
CCI for RNG	$(97)	$(132)	$(193)	$(101)	$(104)	$(173)	$(244)	$83	$(306)	$(146)
DistrCapExIllust	$-	$-	$-	$-	$(225)	$(338)	$(451)	$-	$-	$-
Electrification	$(1,507	$-	$476	$982	$696	$2,638	$5,654	$(117)	$(117)	$(349)
Compliance/Supply/Capacity	$9,519	$8,215	$7,458	$6,915	$7,256	$5,321	$3,480	$7,147	$9,670	$7,857
Total Net of ElectrifCost	$7,915	$8,083	$7,741	$7,796	$7,623	$7,448	$8,440	$7,113	$9,247	$7,362

Compliance/Supply/Capacity Electrification DistrCapExIllust
CCI for RNG Total Net of ElectrifCost

Source: Synapse, using NWN underlying costs plus Synapse estimate of electrification costs. Sensitivity testing of CCI credits for RNG Substitution from Synapse.

Figure 19 above illustrates that consideration of revenue requirement cost savings from alternative resource pathways can be used to compare outcomes against NWN's preferred scenarios, in this case using Scenario 1 to reflect NWN's preference.

The two figures shown above, Figure 18 and Figure 19, demonstrate how directly considering the costs of load not served by gas, but served by electricity, allows for a rough comparison across scenarios to gauge the relative value of planning solutions using RNG versus solutions with electrified load. These two paths result in the same, or at least analytically similar, levels of decarbonization. Uncertainty associated with the level of decarbonization resides in each pathway. For electrification pathways, there is uncertainty with the marginal greenhouse gas emissions associated with increased electrification-derived load. For RNG pathways, there is uncertainty associated with the true level of net emissions associated with the combustion of RNG. NWN does not directly address this risk in its analysis.

NWN discusses correlations in its Monte Carlo analysis.[86] NWN does not directly examine the relation between the cost of RNG and the cost of electrification. If renewable energy costs to create RNG are low, the "competing" electrification pathways will also cost less, because production of hydrogen and synthetic methane use that same renewable energy. If electrification costs are high because of a high cost of electricity, then it is reasonable to assume that hydrogen and synthetic methane costs will also be high, as green hydrogen costs would also be high. Any cost comparison must be made carefully and account for this correlation. NWN has not examined these patterns in this IRP because it has not considered the cost of electrification in its modeling. We recommend future IRPs use a more thorough analysis to account for these correlations, and the overall RNG vs. electrification competition.

Normalized NPVRR Comparisons Across All Scenarios with Electrification Costs and Including Relevant Cost Components in the Revenue Requirements Streams

Failing to analytically consider electrification costs is a weakness of NWN's analysis, as is using partial revenue requirements that exclude cost components likely to vary based on gas demand. NWN's analysis misses the opportunity to directly compare the economics of the most important alternative solution options for decarbonization—RNG vs. electrification options—and it excludes consideration of cost components that could vary significantly over the planning horizon between these two scenarios (gas distribution system investments).

NWN does not directly address the comparison of NPVRR across any of its scenarios. This form of comparison can be complex, as varying input assumptions such as gas demand render a direct comparison less useful across any scenarios with different gas demands. However, mechanisms exist to normalize the results across scenarios in such a way as to render comparisons valuable. For example, differences in load inputs due to varying levels of energy efficiency or electrification load loss can directly consider the costs of the energy efficiency or the electrification, allowing for an apples-to-apples comparison, at least roughly.

[86] IRP Section 7, page 256.

While historically the costs that NWN excludes in its optimization may not have varied considerably across different outcomes, under the wide range of gas demand analyzed in this IRP, there could be substantial differences in such expenditures or investments.

The figures above show how NWN can make the NPRR analyses more transparent, fostering discussion and consideration of the best pathways to achieve least-cost compliance with CPP requirements.

3. Conclusions and Recommendations

Conclusions

- NWN's analysis fails to provide a robust economic comparison across resource solution alternatives that meet the CPP requirements. NWN does not provide a sufficient quantitative evaluation at this time of the costs of a resource solution consisting of greater levels of electrified end uses and lower levels of gas load, versus a resource solution that achieves decarbonization through the use of RNG (biofuel), hydrogen, and synthetic methane.

- The analysis performed by NWN is incomplete. It does not appropriately trade off across the costs of RNG, the lower costs of CCI credits, and the costs of electrification as a means of lowering gas demand. The combination of prioritizing RNG (per SB 98 targets) and reducing use of CCI credits, and not allowing for electrification cost in the model to enable comparison is a key shortcoming. This is particularly impactful in the early years of the planning horizon when CCI credits are underutilized.

- While the overall effect of demand response alternatives (and incremental energy efficiency) beyond that contained in the various scenarios may be uncertain, the resource solution options must at least include demand response options as a means of reducing future peak day needs. This would better allow for tradeoffs in the model between demand-side and supply-side firm capacity alternatives.

- NWN's partial revenue requirements construct could constitute a valid analytical approach, as some costs are likely to remain fixed over time; but NWN does not include those revenue requirement components (that vary with load) necessary for a true optimization across all CPP compliance options. Distribution capital investments and their associated costs are critical components of a trajectory of future revenue requirements; they are excluded from NWN's analysis, as are the potential cost savings arising under lower peak day loading scenarios if upstream pipeline or other firm capacity resources were allowed to be economically "retired" as part of the PLEXOS modeling.

- The Monte Carlo simulation is based on a sampling approach across the 500 draws that is biased towards high-load outcomes. This is an underlying weakness of the Monte Carlo exercise. When coupled with the exclusion of modeled costs that may vary with load (i.e., distribution system expansion), the exclusion of electrification options as a means towards meeting CPP requirements, and the treatment of RNG vs. CCI credit solutions, we find that the simulation does not sufficiently evaluate the risks of moving ahead with resource solutions that plan on a dependence of RNG supply sources.

- There is no direct inclusion of electrification as a demand-side resource option in the PLEXOS model, with associated costs and peak and annual gas load reduction effects. This undermines the optimization process by excluding a leading and realistic resource option that will influence ultimate gas load over the planning horizon and would directly influence the optimal resource path for both CPP compliance and physical resource (capacity) options needed for the system.

- While the overall effect of demand response alternatives (and incremental energy efficiency) beyond that contained in the various scenarios may be uncertain, the resource solution options must at least include demand response options as a means of reducing future peak day needs, to better allow for tradeoffs in the model between demand-side and supply side firm capacity alternatives.

- The overall exercise includes minimal risk assessment. There is minimal direct sensitivity testing on the CPP compliance outcomes under higher costs/prices for RNG, hydrogen, and synthetic methane. Given the reliance on these alternatives for future compliance, the IRP analytical structure should better reflect a testing of "severity of bad outcomes" by posing more scenarios of higher-cost trajectories for RNG resources.

- There are significant PVRR analytical transparency issues. NWN should provide direct computations of revenue requirements used in its model.

- Including a relatively high peak day planning standard while excluding demand response resource options results in Portland Cold Box inclusion in all but one scenario. The need for the Portland Cold Box replacement or refurbishment is uncertain. If and when its capacity is assured, this inexpensive resource could enable "retirement" of upstream pipeline firm capacity.

Recommendations

- We recommend an Action Plan that includes maximum use of less-expensive CCI credits for the first few CPP compliance periods and fully excludes planned procurement of incremental RNG resources until NWN performs a more rigorous economic assessment.

- As long as future IRP exercises clearly include the ability for the model to "retire" unneeded firm delivery capacity from contracted upstream pipelines importing to NWN's territory, we recommend considering acknowledgement of the retention of the Portland Cold Box peak-shaving capacity. It is a relatively inexpensive peak day capacity resource available to support needs across the entire system,[87] and it is not dependent on RNG solution pathways.

- We also recommend expedited scoping of a demand response program and deployment (if needed) to help meet peak day demands. The inclusion of a fairly stringent peak day

[87] See, for example, NWN IRP Table 6.14 "Capacity Resource Cost and Deliverability," page 243.

planning standard logically implies a need to include, in the optimization modeling for capacity needs, all resources that can contribute towards meeting (or reducing or avoiding) the peak day load.

- We do not recommend acknowledgment of the longer-term resource paths arising out of NWN's preferred portfolio, which consists of a mix of biofuel RNG, hydrogen, and synthetic methane. NWN's analysis is far too limited, as it excludes even rudimentary economic analysis of key electrification alternatives.

- We recommend acknowledging the value of the Cold Box resource. NWN could invest in the Portland Cold Box to attain peak shaving at a relatively low cost. It serves as an insurance policy and it is unlikely to become a stranded cost, as long as other firm service options (e.g., upstream pipeline contracts) are only used as necessary. It will be useful even if there are ongoing reductions to peak day load, as it is a broad system resource.

- We recommend acknowledgment of NWN's plan to file a demand response program. We recommend that NWN scope out the specifics of such a program and file it as soon as possible. We recommend accelerated deployment of demand response resources for the Forest Grove feeder and further recommend geo-targeting of efficiency, and potentially electrification, for this feeder.

- For this IRP, we recommend NWN re-run PLEXOS for one new scenario, Sc. 1 load, and fully remove all hard-coded RNG (except, perhaps, the five existing contracts) from the solution set. This would allow the model to choose CPP compliance based on the cost of RNG vs. the cost of other options, in particular CCI credits. If necessary (depending on model parameter configuration that may limit CCI credits to less than the maximum allowed), run at least one scenario/sensitivity to this option with maximum utilization of CCI credits as first pass.

- For this IRP, we recommend NWN re-run PLEXOS for one new scenario, Sc. 1 load, with additional electrification and demand response alternatives included as solution options to reduce both peak day demand and annual load (energy). NWN can use a simplified, aggregate Price/Quantity pair construct to represent resources (1 for demand response, 1 for electrification) in fairly broad strokes, each with attendant annual energy reduction (minimal or zero for demand response) and peak day capacity reduction.

- For future IRPs, we recommend the following:

    - Scope out the timing of contracts for upstream pipeline firm delivery, as a potential for "retirement" in the model's configuration and allow such potential cost savings to be in the model.

    - Add to the total costs (to be optimized) the revenue requirement components associated with new customer and new load growth, which reflect distribution plant investment. And, add distribution operations and maintenance costs that vary with load. Vary these cost trajectories to distinguish between scenarios with different load trajectories.

- Consider the results of the pilot program using geo-targeted energy efficiency, but also considering geo-targeting demand response and electrification.
- Consider the policy impacts on IRP analysis under different forms of joint planning, cost allocation, incentives for electrification, and other forms of coordination across gas and electric utility planning. This may first require stakeholder/policy discussions and reflections on joint planning, incentives for decarbonization, cost allocation between electric and gas utility customers of solutions that most economically support decarbonization initiatives, and overall consideration of incentive issues.
- Consider how Energy Trust of Oregon is involved in fuel-switching-related services, in addition to its historical role in gas or electric utility efficiency planning and service deployment.

Appendix A. Checklist of Specific IRP Guideline Areas and Review Indications

G#	Essence of Guideline	Review Indication
1a	Evaluate resources – consistent and comparable basis	Yes, with some exceptions to comparability – e.g., RNG vs. CCI credits
	Consider all resources—supply- and demand-side	No, lacking some demand-side: demand response and electrification options only narrowly considered in scenario analysis
	Compare resources in portfolio risk modeling	Yes, but insufficient risk assessment
	Use consistent methods and assumptions for evaluation	Yes, with exceptions, e.g., RNG priority for compliance though higher cost.
	WACC to discount future resource costs	Yes, 6.35% nominal, 3.40% real
1b	Risk and uncertainty to be considered	Yes, considered but not adequately; minimal sensitivity assessment
	Gas demand – baseload, peak, and swing	Yes, peak day standard very high
	Commodity supply	Yes
	Commodity price	Yes
	Transportation availability	Yes
	Transportation price	Yes
	Greenhouse gas regulation cost of compliance	Yes
	Identify additional sources of risk, uncertainty	Yes, identified but not fully analyzed
1c	Goal: select portfolio "best cost / risk"	Unclear at best; insufficient risk analysis / minimal sensitivity testing
	At least 20-year planning horizon plus end effects – include all costs likely to be in rates over the long term	No, excludes effect of costs likely to be in rates for capital investment and expense tied to gas demand
	PVRR as key cost metric – costs for all resources – storage, pipelines, gas supply, purchases	No, insufficient application of PVRR solution comparisons (some demand-side resources excluded, future pipeline investment and expense potentially avoided is excluded); not transparent in presentation; no costing for electrification; no clear cost comparison across resource portfolio options.
	Risk metric: (1) variability of cost, (2) severity of bad outcomes, (3) discussion of hedging	1-Yes, but with exceptions (not all costs included); 2-No, not directly; 3 – Yes, with exceptions
	Explain how resource choices balance cost and risk	No
1d	Consistent with long-run public interest – state and federal	Partially, CPP directly addressed but inconsistent without affirming portfolio as addressing cost and risk requirements
2	Process requirements – public involvement, confidentiality, draft IRP for review	Synapse - did not address.
3	Filing, review, update	Synapse - did not address.
4	Plan components	
	High, low, and stochastic load risk analysis, explain major assumptions	Yes
	Identification of supply, transport, storage needs to bridge gap between expected loads and existing resources	Yes
	Identify and estimate costs of all supply- and demand-side options accounting for anticipated advances in technology	No, demand-side options excluded
	Measures to provide reliable service	Yes, but some demand-side excluded

G#	Essence of Guideline	Review Indication
4	Identify key assumptions about future: environmental compliance costs, fuel prices, alternative scenarios considered	Yes
	Portfolios: construct, evaluate, analyze uncertainties, and rank different resource portfolios	Yes, with exception – insufficient analysis of uncertainties and effect on portfolio robustness
	Select portfolio	Yes, but with caveats
	Identify and explain: selected portfolios, if any inconsistencies with state/federal policies, barriers to implementation	Yes
	Action Plan	Yes
5	Transmission costs for fuel (gas), transmission as resource option	Yes
6	Conservation	Yes, some exceptions
	Periodic potential study	Yes
	Specify annual savings targets / include best cost/risk energy efficiency resources	Unclear if best cost/risk energy efficiency resources always included
	ETO: check that Action Plan consistent with ETC projections	Yes, with exceptions
7	Demand Response – evaluate demand response to meet supply and/or transportation needs	Partially. Some included but key R/C demand response excluded even though in Action Plan
8	Environmental Costs – greenhouse gas reduction and CPP compliance	Yes
9	Direct access loads – NWN transportation service	Synapse did not address
10	Multi-state plans on integrated basis	Yes
11	Reliability – meet peak, swing, and baseload	Yes
	Portfolio achieves stated reliability, cost, risk objectives	Yes, reliability; unclear – cost, risk
12	Distributed generation - electric	Not applicable
13	Resource acquisition – bid practices for supply, transport	Synapse did not address.

Appendix B. REFERENCED DISCOVERY RESPONSES

All of the following referenced responses were from questions submitted by the Oregon Public Utilities Commission.

1. DR 1. Annual revenue requirements for PVRR for scenarios
2. DR 13. Hydrogen price
3. DR 44. Components of revenue requirements / computation
4. DR 69. Regulatory compliance future
5. DR 88. Monte Carlo simulation draws, and how gas demand distribution was considered
6. DR 102. Monte Carlo simulation overview
7. DR 103. Oregon bill impacts, non-WACOG gas costs
8. DR 104. Supply must take. RNG quantities for selection
9. DR 105. Annual revenue requirements, company wide
10. DR 107. Firm capacity resources / pipeline capacity resources
11. DR 108. Demand response

Appendix C. ELECTRIFICATION COST ASSESSMENT

This appendix assesses the cost of electrification in the scenarios NWN presents in its 2022 IRP. Electrification costs—while omitted in NWN's assessment—are critical to understanding and comparing the cost of various IRP scenarios. Market trends, contemporary demand-side policies, and the imperative for economy-wide decarbonization suggest a transition to electric equipment that NWN cannot ignore within the structure of its IRP modeling.

We present detailed results from Scenario 6- Full Building Electrification, and high-level results for all other scenarios. Synapse selected Scenario 6 to show the upper bound of electrification costs. Comprehensive results for all scenarios are shown in *Workpaper_2022 IRP electrification cost analysis.xlsx*.

NWN IRP

Electrification Costs and Planning Absent in NWN IRP

NWN's 2020 IRP does not directly include electrification as a demand-side resource option, with associated costs and peak and annual gas load reduction effects. NWN's omission inhibits least-cost resource planning by excluding a prominent and realistic resource option that influences gas load and optimal resource planning over the study period.

Electrification Cost Assessment Critical to Scenario Comparison

NWN considers a diverse complement of scenarios in the IRP, reportedly to evaluate various pathways for CPP compliance as well as infrastructure and supply resource options. However, without including the cost of electrification—both electric system and customer-side investments—it is impossible to compare scenario costs on an equal basis. Scenario 6 is the least-cost scenario for NWN, considering the cost of compliance, capital investment, and supply resources; but prudent planning merits comparing the cost of Scenario 6 compare against a scenario that includes electrification.

Market Trends and Climate Policies Dictate Need for IRP Electrification Cost Assessment

Recent building sector policies and market trends point toward an increasing rate of fuel-switching from natural gas appliances and equipment to electric alternatives. Relevant policy examples include local actions to restrict new gas connections in Eugene and Salem; Portland's commitment to advance building performance standard legislation; building electrification incentives included in the *Inflation Reduction Act*; institutional and district energy system commitments to decarbonization; and policies intended to reduce industrial emissions such as House Bill 4139 (Oregon "Buy Clean" policy for embodied carbon).

Market trends toward electrification are due in part to electric equipment and appliances improving in performance and cost in recent years, making them viable low- or zero-carbon alternatives to fossil fuel equipment.[88,89,90] In metropolitan cities in Oregon such as NWN's core customer base of Portland, over the period 2015–2021 natural gas lost 2.9 percent market share in residential heating, while electricity gained 4.4 percent.[91] Taken together, these policy and market trends signify a need to understand the impact, costs, and benefits of electrification and its effect on NWN and ratepayer costs.

Synapse Electrification Cost Modeling

Approach

For each scenario and sector, Synapse prepared the following series of calculations through Year 2050:

1. Quantify the natural gas load to electrify, as identified in NWN's IRP scenarios
2. Estimate the delivered heat load to electrify
3. Forecast equipment performance for heat pumps
4. Estimate the resulting electricity use from fuel-switching
5. Assess electric system costs
6. Quantify the number of customers to electrify
7. Estimate the quantity or capacity of new electric end-use equipment
8. Estimate incremental end-of-life equipment capital costs for electrification measures relative to installing like-for-like gas equipment
9. Sum the electric system and incremental customer capital costs

The subsections that follow describe these calculations in greater detail.

Natural Gas Load to Electrify

We begin by quantifying the natural gas load to electrify under each of NWN's IRP scenarios. Sector by sector, we subtract customer natural gas load from the load in Scenario 1- Balanced Decarbonization,

---

[88] Jadun, P., McMillan, C., Steinberg, D., Muratori, M., Vimmerstedt, L. and Mai, T. 2017. *Electrification futures study: End-use electric technology cost and performance projections through 2050.* National Renewable Energy Lab. Available at: https://www.nrel.gov/docs/fy18osti/70485.pdf.

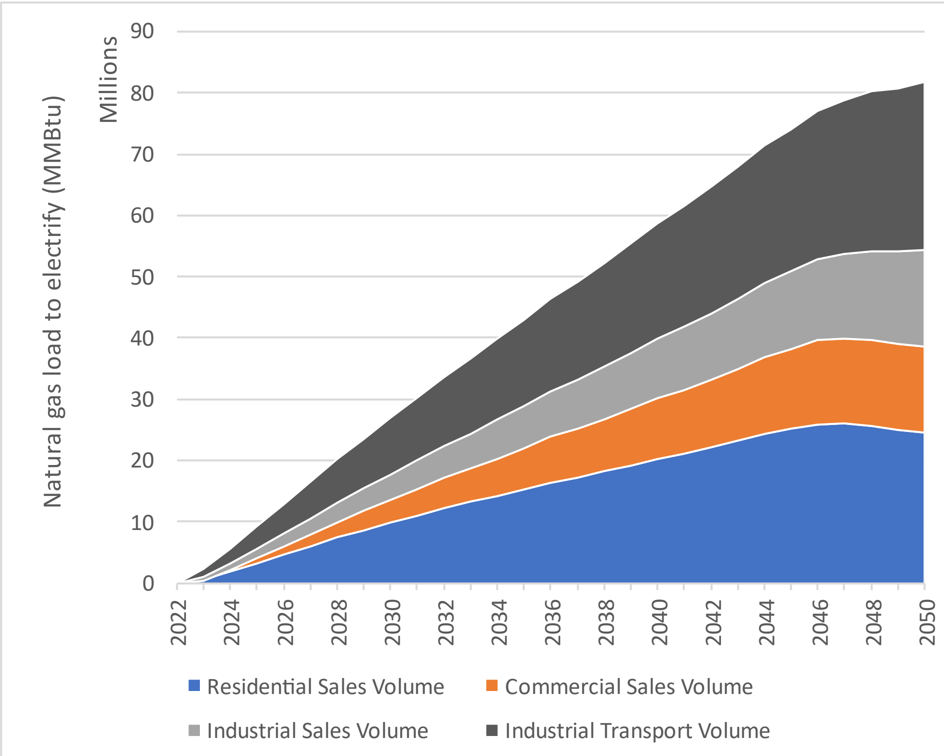
[89] Rightor, E., Whitlock, A. and Elliott, R.N. 2020, July. Beneficial electrification in industry. American Council for an Energy Efficient Economy. Available at: https://www.aceee.org/sites/default/files/pdfs/ie2002.pdf.

[90] Rightor, E., Hoffmeister, A., Elliott, N., Lowder, T., Belding, S., Cox, J., Gluesenkamp, K.R., Shen, B., Nawaz, K. and Scheihing, P. 2021. *Industrial Heat Pumps: Electrifying Industry's Process Heat Supply*. Oak Ridge National Lab. Available at: https://www.aceee.org/research-report/ie2201.

[91] U.S. Census Bureau. 2023. *American Community Survey*. Available at: https://www.census.gov/data.html.

NWN's preferred pathway to meeting its climate obligations. Figure 20 presents example results from Scenario 6- Full Building Electrification.

Figure 20. Natural gas load to electrify, Scenario 6 relative to Scenario 1

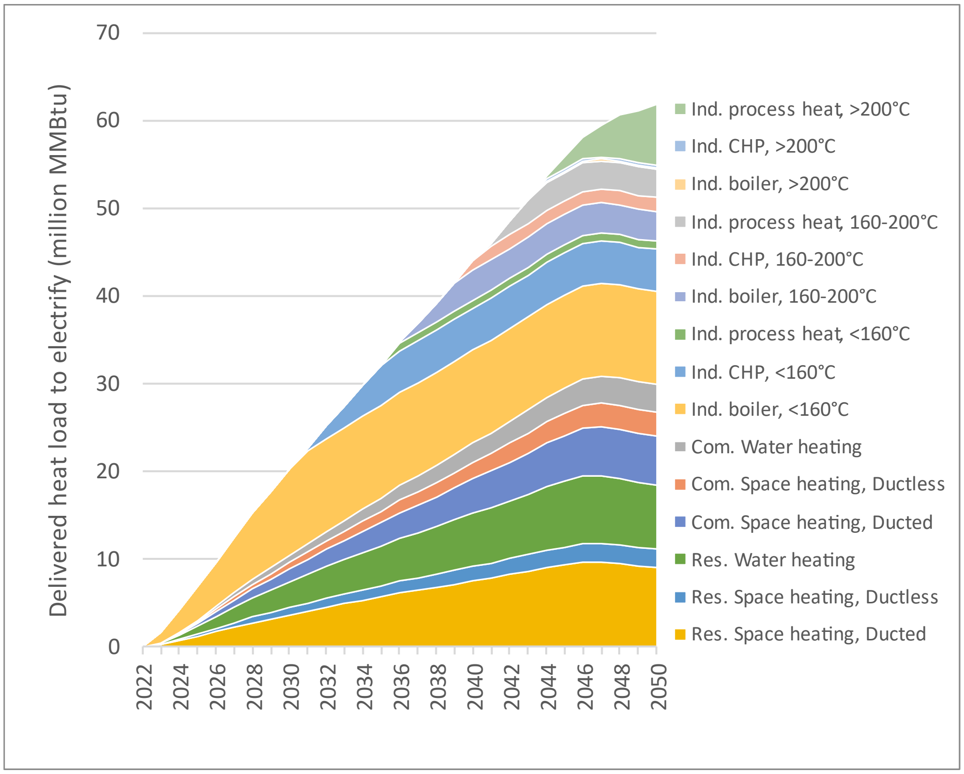


For some scenarios and in some years, natural gas load is less than in Scenario 1, resulting in a "negative load to electrify." This results in a cost savings in Synapse's analysis.

Delivered Heat Load to Electrify

To estimate the heat load that must be electrified in each NWN's IRP scenario, Synapse first estimated end-use consumption of natural gas for each sector. Then, we derived estimates of useful energy (e.g., heat delivered to buildings and hot water systems) by dividing the natural gas end-use load by equipment efficiency factors. Figure 21 below shows sample results for Scenario 6. Note that the total useful energy to be electrified is less than the total natural gas load, as combustion equipment is less than 100 percent efficient. The subsections below describe our assumptions and approach in greater detail.

Figure 21. Delivered heat load to electrify, Scenario 6 relative to Scenario 1



Residential and commercial buildings

For the residential and commercial sectors, space heating and water heating are the dominant natural gas loads in the region.[92,93,94,95] This analysis assumed that all end use of natural gas in these buildings is for space heating and water heating. This simplifying assumption may somewhat underestimate the cost of electrification, as electrifying other end uses (e.g., cooking, dryers, process heat, etc.) would incur additional capital costs. Space heating represents the largest use of natural gas in buildings in Oregon, at 78 and 30 percent of residential and commercial fossil fuel use, respectively.[96,97,98] Water heating

[92] U.S. EIA. 2022. *Commercial Building Energy Consumption Survey, 2018*. Available at: https://www.eia.gov/consumption/commercial/data/2018/index.php.

[93] U.S. EIA. 2015 Residential Energy Consumption Survey. Available at: https://www.eia.gov/consumption/residential/index.php.

[94] NREL. *ComStock End Use Load Profiles for the U.S. Building Stock*. Available at: https://comstock.nrel.gov/datasets.

[95] NREL. *ResStock End Use Load Profiles for the U.S. Building Stock*. Available at: https://resstock.nrel.gov/datasets.

[96] Residential end-use consumption estimate based on comprehensive residential building sector modeling by NREL for Oregon: NREL. *ResStock End Use Load Profiles for the U.S. Building Stock*. Available at: https://resstock.nrel.gov/datasets.

[97] Commercial end-use consumption estimate based on comprehensive commercial building sector modeling by NREL for the major counties in NWN's service territories (Marion, Lane, Multnomah, Washington, and Clackamas): NREL. *ComStock End Use Load Profiles for the U.S. Building Stock*. Available at: https://comstock.nrel.gov/datasets.

[98] NREL. *ResStock End Use Load Profiles for the U.S. Building Stock*. Available at: https://resstock.nrel.gov/datasets.

comprises 19 percent of the total natural gas consumption in both residential and commercial buildings.[99]

We assumed representative baseline natural gas space heating and water heating equipment as well as electric alternatives, as identified in Table 7. We assumed baseline equipment that reflects the current market. For example, we selected packaged units as the representative technology for commercial space heating; packaged units hold the largest market share for commercial heating equipment in the Pacific region and the United States at large.[100]

Table 7. Residential and commercial end-use equipment assumptions

Sector	End use	Baseline Natural Gas Equipment	Electric Replacement Equipment
Residential	Water heating	Storage natural gas water heater, 50 gal, UEF = 0.63	Heat pump water heater, >=45 to <=55 gal, UEF = 3.75
Residential	Space heating	Res DXGF SEER 14 and TE 80%, SFm	Air-source heat pump, DXHP SEER >= 17 and HSPF >= 9.4,
Commercial	Water heating	Natural gas storage water heater, 75 gal, UEF = 0.59,	Heat pump water heater, 80 gallon, UEF = 3.75
Commercial	Space heating	Commercial SpltPkg - 135 - 239 kBtu/hr AC with gas furnace - code compliant	Commercial IEER-rated package heat pump, 135 to 239 kBtu/hr, IEER15.5 COP3.2,

Industrial sector

Synapse's analysis assumed that all natural gas use for industrial transport customers and industrial sales customers is consumed in one of three industrial processes: conventional boiler use, combined heat and power (CHP) and/or cogeneration process, and process heating. This is a simplifying assumption, which may somewhat overestimate cost of electrification, as lower temperature end uses (e.g., space heating) are more economical to electrify than industrial process heat.[101,102,103] In Table 8, we disaggregated natural gas use in NWN's service territory by industry and by temperature, based on detailed, county-level analysis of industrial survey data from 2014.[104] Using the same data, we also

---

[99] Ibid.

[100] US EIA. 2022. *Commercial Building Energy Consumption Survey, 2018*. Available at: https://www.eia.gov/consumption/commercial/data/2018/index.php.

[101] Jadun, P., McMillan, C., Steinberg, D., Muratori, M., Vimmerstedt, L. and Mai, T. 2017. *Electrification futures study: End-use electric technology cost and performance projections through 2050.* National Renewable Energy Lab. Available at: https://www.nrel.gov/docs/fy18osti/70485.pdf.

[102] Rightor, E., Whitlock, A. and Elliott, R.N. 2020, July. Beneficial electrification in industry. American Council for an Energy Efficient Economy. Available at: https://www.aceee.org/sites/default/files/pdfs/ie2002.pdf.

[103] Rightor, E., Hoffmeister, A., Elliott, N., Lowder, T., Belding, S., Cox, J., Gluesenkamp, K.R., Shen, B., Nawaz, K. and Scheihing, P. 2021. *Industrial Heat Pumps: Electrifying Industry's Process Heat Supply*. Oak Ridge National Lab. Available at: https://www.aceee.org/research-report/ie2201.

[104] NREL. 2019. *Manufacturing Thermal Energy Use in 2014*. Available at: https://data.nrel.gov/submissions/118.

disaggregated natural gas use by temperature and process and identify alternative electric technologies in Table 9. We allocated NWN's industrial supply in proportion to these tabular data.

Table 8. Annual natural gas load by industry and temperature, counties in NWN service territory, 2014

Industry	Gas consumption (MMBtu)			
	<160°C	160-200°C	>200°C	Total
Textile Mills	14,434	745	1,377	16,556
Textile Product Mills	123,819	123,819	0	247,639
Apparel Manufacturing	18	203	0	220
Plastics and Rubber Products Manufacturing	112,645	714,776	0	827,421
Primary Metal Manufacturing	16,099	404,575	2,997,365	3,418,040
Fabricated Metal Product Manufacturing	119,339	0	671,628	790,966
Machinery Manufacturing	62,244	5,647	43,650	111,541
Furniture and Related Product Manufacturing	0	22,497	0	22,497
Miscellaneous Manufacturing	8,064	272,843	0	280,907
Food Manufacturing	4,386,438	0	0	4,386,438
Beverage and Tobacco Product Manufacturing	285,038	0	0	285,038
Wood Product Manufacturing	0	2,582,174	0	2,582,174
Paper Manufacturing	9,864,992	2,440,199	6,116,001	18,421,192
Petroleum and Coal Products Manufacturing	0	503,227	24,713	527,940
Chemical Manufacturing	445,247	0	1,638,718	2,083,965
Nonmetallic Mineral Product Manufacturing	6,634	518,771	3,152,218	3,677,623
Transportation Equipment Manufacturing	18,595	0	721	19,316
Total	**15,463,606**	**7,589,475**	**14,646,391**	**37,699,472**

Source: NREL. 2019. Manufacturing Thermal Energy Use in 2014. Available at: https://data.nrel.gov/submissions/118.

Table 9. Annual natural gas load by temperature and technology, counties in NWN service territory, 2014

Temp.		Existing Natural Gas Technologies	MMBtu	%
<160°C	Industrial heat pumps	Conventional Boiler Use	9,883,422	26%
		CHP and/or Cogeneration Process	4,796,154	13%
		Process Heating	784,030	2%
160-200°C	Industrial heat pumps (emerging technologies)	Conventional Boiler Use	3,186,862	8%
		CHP and/or Cogeneration Process	1,576,418	4%
		Process Heating	2,826,196	7%
>200°C	Various (e.g., electric boiler, resistance heating, direct arc melting, induction heating)	Conventional Boiler Use	151,693	0%
		CHP and/or Cogeneration Process	290,843	1%
		Process Heating	14,203,855	38%
Total	--	--	**37,699,472**	**100%**

Source: NREL. 2019. Manufacturing Thermal Energy Use in 2014. Available at: https://data.nrel.gov/submissions/118.

Equipment performance

Next, we estimated equipment performance. For combustion equipment we used values shown in Table 10 and assumed these do not change over time. For all heat pump technologies, we applied a performance improvement trajectory based on the "moderate advancement" scenario in the NREL

Electrification Futures study.[105] For air source heat pumps, we estimated the actual equipment performance using typical hourly meteorological data for the region and temperature-varying equipment performance curves, differentiating performance by ducted and ductless models. For industrial heat pumps, we identified a range of appropriate technologies with varying performances, as shown in Table 11. For high-temperature process heat, we assumed electric technologies with an efficiency of 0.99.

Table 10. Combustion equipment performance data

Sector	End use	Technology	Combustion efficiency
Residential	Space heating	Ducted	0.86
Residential	Space heating	Ductless	0.86
Residential	Water heating		0.63
Commercial	Space heating	Ducted	0.80
Commercial	Space heating	Ductless	0.80
Commercial	Water heating		0.85
Industrial	Process heat	Conventional boiler	0.75
Industrial	Process heat	CHP/Co-gen	0.70
Industrial	Process heat	Process heating	0.80

Sources: DOE Furnace Appliance Standards Technical Support Document/Supporting Spreadsheets
EERE: 2015-10-06 Direct Final Rule Life-Cycle Cost (LCC) Analysis Spreadsheet: Commercial Furnace Life-Cycle Cost and Payback Period Analysis. https://www.regulations.gov/document?D=EERE-2013-BT-STD-0021-0051
EERE: NOPM Commercial Packaged Boiler Life-Cycle Cost and Payback Period Analysis Spreadsheet (CB_Prelim_LCC_2014-12-17) https://www.regulations.gov/document?D=EERE-2013-BT-STD-0030-0031
Council of Industrial Boiler Owners, Energy Efficiency & Industrial Boiler Efficiency.
ACEEE. 2022. Industrial Heat Pumps: Electrifying Industry's Process Heat Supply. Available at: https://www.aceee.org/research-report/ie2201.

Table 11. Industrial heat pump performance data

Industrial heat pump type	Coefficient of performance: existing technologies (<160°C)	Coefficient of performance: emerging technologies (160-200°C)
Mechanical vapor compression (MVC), closed cycle	5.10	2.50
Mechanical vapor recompression (MVR Semi), semi-open cycle	5.90	2.60
Mechanical vapor recompression (MVR Open), open cycle	7.10	2.80
Thermal vapor recompression (TVR), open cycle	N/A	N/A
Heat activated Type 1 (HA Type 1), closed cycle	2.40	1.20
Heat activated Type 2 (HA Type 2), closed cycle	0.10	0.00
Average across technologies	4.12	1.82

Source: ACEEE. 2022. Industrial Heat Pumps: Electrifying Industry's Process Heat Supply. Available at: https://www.aceee.org/research-report/ie2201.

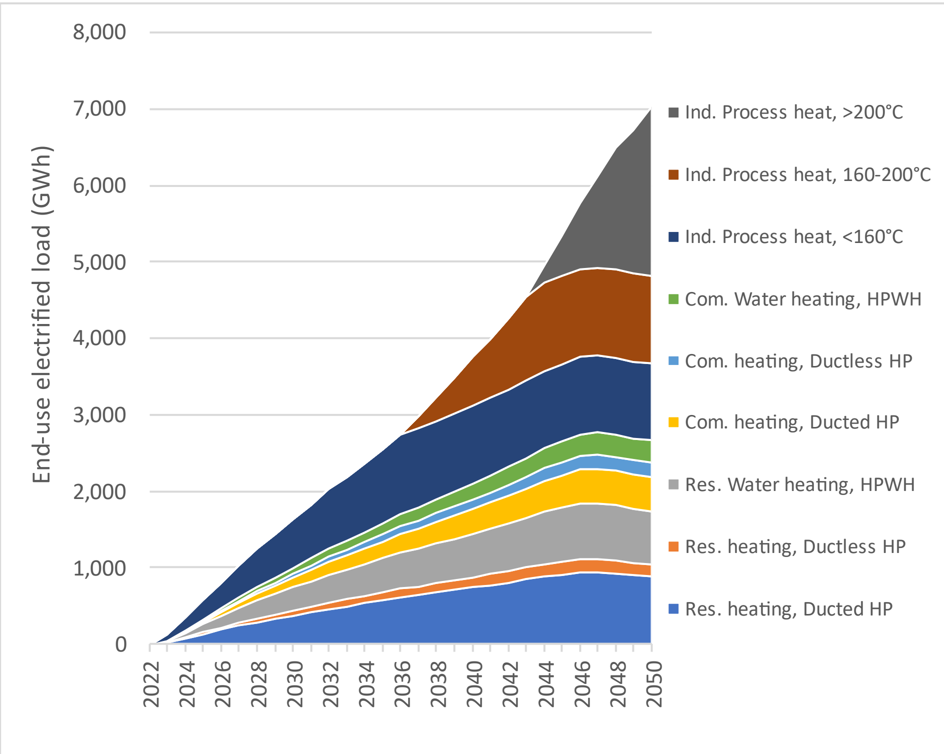
[105] Jadun, P., McMillan, C., Steinberg, D., Muratori, M., Vimmerstedt, L. and Mai, T. 2017. *Electrification futures study: End-use electric technology cost and performance projections through 2050.* National Renewable Energy Lab. Available at: https://www.nrel.gov/docs/fy18osti/70485.pdf.

Finally, we derived estimates of useful energy (e.g., heat delivered to buildings and hot water systems) shown in Figure 21 above by dividing the natural gas end-use load by equipment efficiency factors.

End-Use Electrified Load

Next, we applied the electric equipment performance factors shown above to the Synapse-estimated useful energy load. The result, shown in Figure 22 for Scenario 6, is the electrical demand of the electrified customers.

Figure 22. End-use electrified load, Scenario 6 relative to Scenario 1



System Electrification Costs

Next, we assessed the system costs of electrifying customer load, using electric utility rates as proxy for system costs.[106] Table 12 presents electric utility rates representative of the NWN service territory, which we derive from local utility tariffs for PGE, Eugene Water & Electric Board (EWEB), and PacifiCorp. For commercial and industrial customers, Synapse derived blended rates per kilowatt-hour that include

[106] This assumption may hold true if heating electrification does not dramatically increase the overall electric system peak load. Given the high prevalence of resistive heating technologies in the Pacific region—26 percent of households (EIA. 2020. Residential Energy Consumption Survey)—converting resistive heating equipment to heat pumps could substantially lower winter peak loads relative to a scenario that does not.

demand-related charges; we estimated the demand charges using modeled end-use load profile data.[107] We assumed electric utility rates stay constant in real terms (increase at the same rate as inflation, which we assumed to be 2 percent per year).

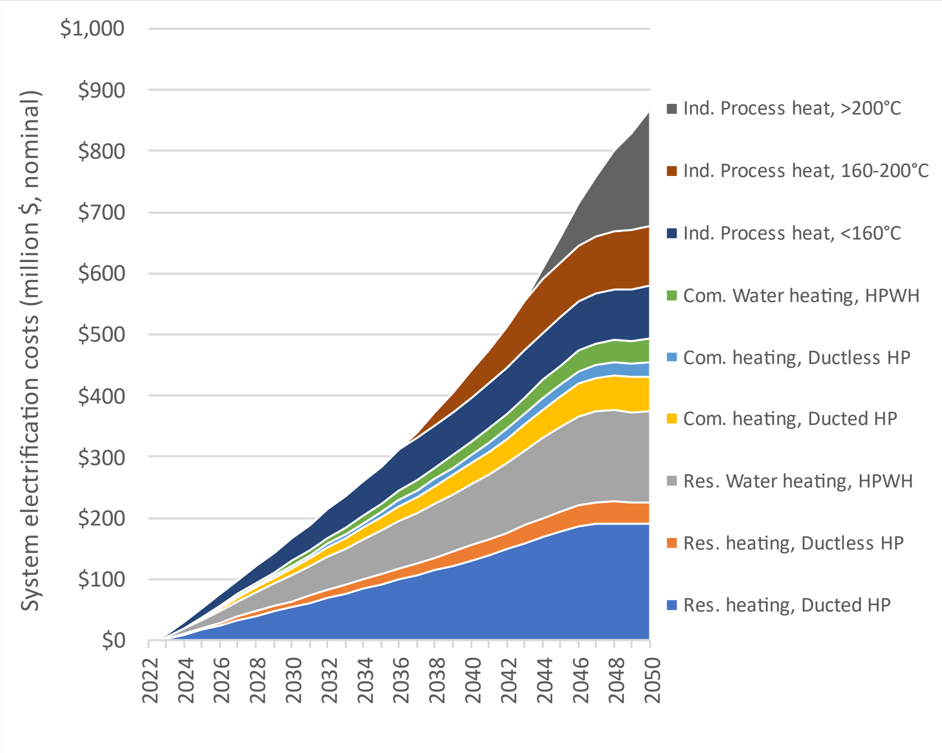
Table 12. Rates for major electric utilities that serve NWN's service territory

City	Counties	Area Population		Utility	Residential rate ($/kWh)	Commercial rate ($/kWh blended)	Industrial rate ($/kWh blended)
Portland	Multnomah, Washington, Clackamas	1,876,155	68%	PGE	$0.130	$0.072	$0.046
Salem	Marion, Polk	432,925	16%	PGE	$0.130	$0.072	$0.046
Eugene	Lane	381,365	14%	EWEB	$0.095	$0.086	$0.074
Coos Bay	Coos	63,315	2%	PacifiCorp	$0.077	$0.046	$0.040
Total/ blended		**2,753,760**	**100%**		**$0.124**	**$0.073**	**$0.049**

We applied the electric utility rates to the electrified end-use load to estimate total system costs, shown in Figure 23 for Scenario 6.

[107] Commercial electric demand estimate based on comprehensive commercial building sector modeling by NREL for the major counties in NWN's service territories (Marion, Lane, Multnomah, Washington, and Clackamas): NREL. *ComStock End Use Load Profiles for the U.S. Building Stock*. Available at: https://comstock.nrel.gov/datasets.

Figure 23. System electrification costs, Scenario 6 relative to Scenario 1



Customers to Electrify

In addition to electric system costs, the other major cost of electrification is end-use equipment at customer properties. We began to quantify these costs by estimating the number of customers that will electrify each year; specifically, we subtracted the customer counts in each scenario from the counts in Scenario 1.[108] Table 13 presents the results for Scenario 6.

Table 13. Electrified customers (cumulative), Scenario 6 relative to Scenario 1

Customers	2025	2030	2035	2040	2045	2050
Residential	82,098	255,754	421,817	578,927	732,378	777,130
Commercial	7,353	22,691	37,533	51,937	66,226	70,497
Industrial sales	133	347	568	808	1,048	1,306
Industrial transport	20	51	79	106	130	153
Total	**89,604**	**278,842**	**459,997**	**631,778**	**799,781**	**849,086**

108 NWN did not include counts of industrial sales and transport customers in its 2020 IRP workpapers. Synapse projected these counts through 2050 using EIA-176 customer counts for 2021, which we scale in proportion to the industrial load over time.

Customer Electrification Capacities

Table 14 shows the equipment capacities to be electrified each year for Scenario 6: count of water heaters, tonnage of air source heat pumps, and million British thermal units per hour (kBtu/hr×10^3 or MMBH) for industrial heat pumps. We assume one water heater, on average, per customer. We used building characteristic data and load to estimate an average heat pump capacity of 2.5 tons for homes in Oregon.[109] We estimated the commercial heat pump capacity based on the commercial heating load to be electrified each year and the end-use natural heating load profile for commercial buildings in NWN's service territory.[110] We estimated industrial capacities based on the industrial process heat load to be electrified each year and estimated load factors, segmented by temperature. We derived the industrial load factors using based on detailed, county-level analysis of industrial survey data from 2014 and average annual typical production hours by industry.[111,112]

Table 14. Customers electrification capacities, Scenario 6 relative to Scenario 1

Sector	End use	Technology	Units	Incremental capacities (annual)						Cumulative capacities (2022-2050)
				2025	2030	2035	2040	2045	2050	
Residential	Space heating	ASHP	tons	86,464	86,233	80,759	77,496	76,131	12,401	1,942,824
Residential	Water heating	HPWH	each	34,586	34,493	32,303	30,999	30,452	4,960	777,130
Commercial	Space heating	ASPH	tons	17,767	22,229	24,966	25,778	22,293	3,375	549,438
Commercial	Water heating	HPWH	each	43	43	45	54	43	53	1,306
Industrial	Process heat, <160°C	IHP	MMBH	80	76	72	81	60	70	2,067
Industrial	Process heat, 160-200°C	IHP, emerging	MMBH	45	42	40	45	33	39	1,148
Industrial	Process heat, >200°C	Various	MMBH	84	79	76	84	63	73	2,163

Abbreviations: air-source heat pump (ASHP), heat pump water heater (HPWH), industrial heat pump (IHP)
Notes: "Various" high-heat industrial technologies include electric boilers, resistance heating, direct arc melting, induction heating, and more.

---

109 NREL. *ResStock End Use Load Profiles for the U.S. Building Stock*. Available at: https://resstock.nrel.gov/datasets.

110 Based on comprehensive commercial building sector modeling by NREL for the major counties in NWN's service territories (Marion, Lane, Multnomah, Washington, and Clackamas): NREL. *ComStock End Use Load Profiles for the U.S. Building Stock*. Available at: https://comstock.nrel.gov/datasets.

111 NREL. 2019. *Manufacturing Thermal Energy Use in 2014*. Available at: https://data.nrel.gov/submissions/118.

112 U.S. DOE. 2003. Industrial Assessment Center: IAC Database. Available at: https://iac.university/download.

Customer Incremental Capital Costs

Next, Synapse estimated the incremental capital cost to electrify customers. We identified appropriate baseline and replacement measures with costs using data from the California Electronic Technical Reference Manual (eTRM). [113] We adjust material and labor costs to major cities in NWN's service territory using RSMeans locational factors. Note that heating and cooling equipment costs were included in the baseline measures for heat pumps, as heat pumps can replace both. Table 15 presents baseline measures and Table 16 presents electrification measures with the calculated incremental cost. Table 17 presents industrial electrification measure costs.

Table 15. Baseline measure capital costs

End use	Baseline Name	Base Labor	Base Material	Full Base Cost	Units
Res. water heating	Storage natural gas water heater, 50 gal, UEF = 0.63	$323	$1,131	$1,454	each
Res. space heating	Res DXGF SEER 14 and TE 80%	$238	$839	$1,077	per ton
Com. water heating	Natural gas storage water heater, 75 gal, UEF = 0.59	$433	$2,377	$2,810	each
Com. space heating	Commercial SpltPkg - 135 - 239 kBtu/hr AC with gas furnace	$253	$923	$1,176	per ton
Ind. process heat	Process heat	$1	$22	$23	per MBH

Table 16. Electrification measure capital costs and incremental costs

End use	Measure Name	Measure Labor	Measure Material	Full Measure Cost	Incre-mental Cost	Units
Res. water heating	Heat pump water heater, >=45 to <=55 gal, UEF = 3.75	$471	$2,057	$2,528	$1,073	each
Res. space heating	Res DXHP SEER >= 17 and HSPF >= 9.4	$341	$1,134	$1,475	$398	per ton
Com. water heating	Heat pump water heater, 80 gallon, UEF = 3.75	$605	$3,391	$3,996	$1,186	each
Com. space heating	Commercial IEER-rated package heat pump, 135 to 239 kBtu/hr, IEER15.5 COP3.2	$394	$796	$1,190	$14	per ton
Ind. process heat	Various	Various	Various			Per MBH

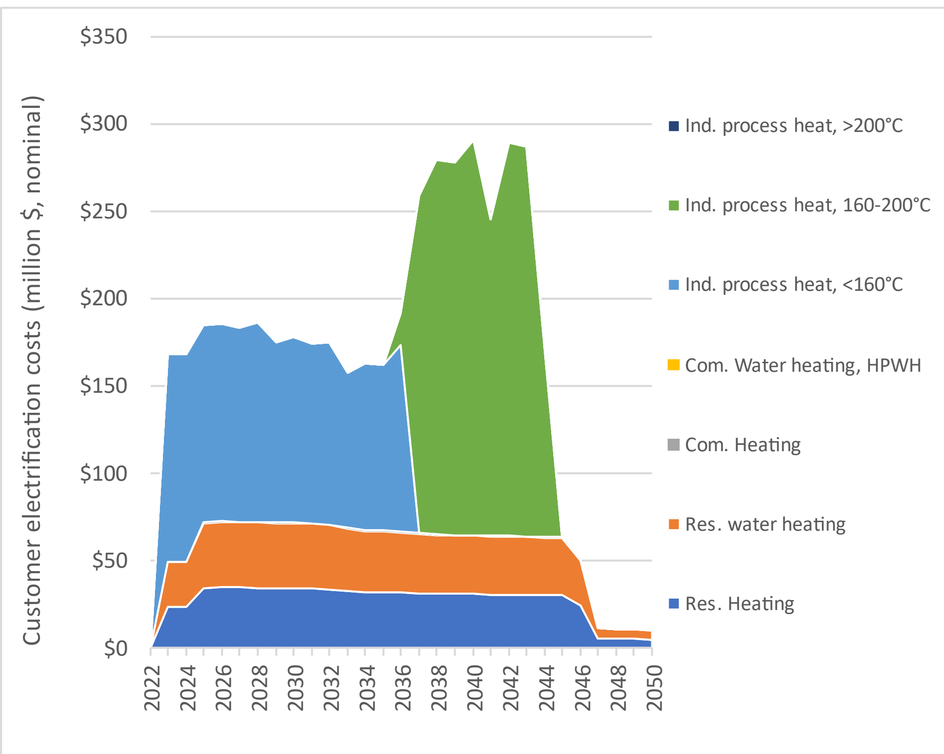
113 California Electronic Technical Reference Manual (eTRM), http://www.caltf.org/etrm-overview.

Table 17. Industrial electrification measure capital costs

Industrial heat pump type	Capital cost: existing technologies, <160°C ($/MBH)	Capital cost: emerging technologies, 160-200°C ($/MBH)
Mechanical vapor compression (MVC), closed cycle	$428	$856
Mechanical vapor recompression (MVR Semi), semi-open cycle	$348	$696
Mechanical vapor recompression (MVR Open), open cycle	$268	$535
Thermal vapor recompression (TVR), open cycle	$161	NA
Heat activated Type 1 (HA Type 1), closed cycle	$1,070	$1,605
Heat activated Type 2 (HA Type 2), closed cycle	$1,338	$2,007
Average across technologies	$602	$1,140

Figure 24 presents the Scenario 6 customer electrification capital investment, which we computed using the above incremental unit costs and the electrification equipment capacities. Note that high-temperature process heat (>200°C) has nearly zero incremental cost to electrify but incurs high system costs due to the lower efficiency relative to industrial heat pumps. Incremental commercial heating customer electrification costs are also nearly zero, as commercial air-source heat pumps are near cost parity with the combined cost of baseline heating and cooling equipment.

Figure 24. Customer electrification costs, Scenario 6 relative to Scenario 1



Combined System and Customer Electrification Costs

Finally, Synapse computed the total cost of electrification by summing the electric system costs and customer electrification costs. Figure 25 presents total electrification costs for Scenario 6, segmented by end use. In Figure 26 and Figure 27, we identify total electrification costs across all NWN IRP scenarios—annual and net present values, respectively.

Figure 25. System and customer electrification costs by end use, Scenario 6 relative to Scenario 1

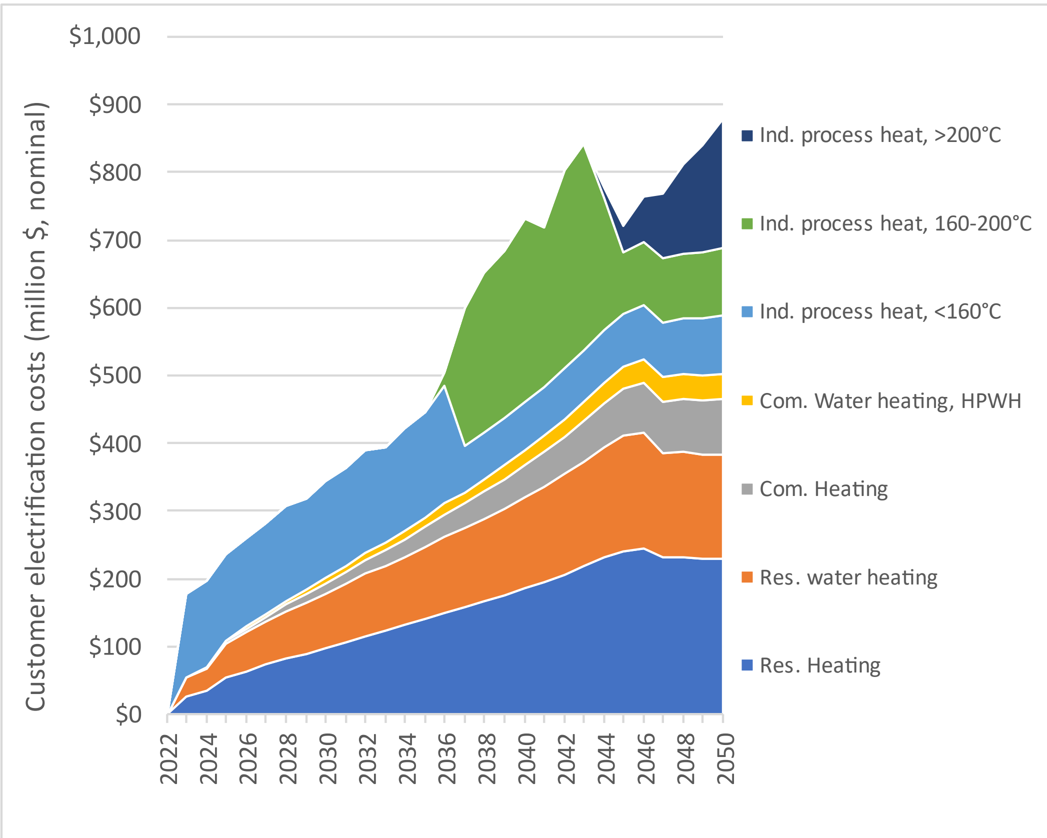


Figure 26. Annual system and customer electrification costs, all scenarios relative to Scenario 1

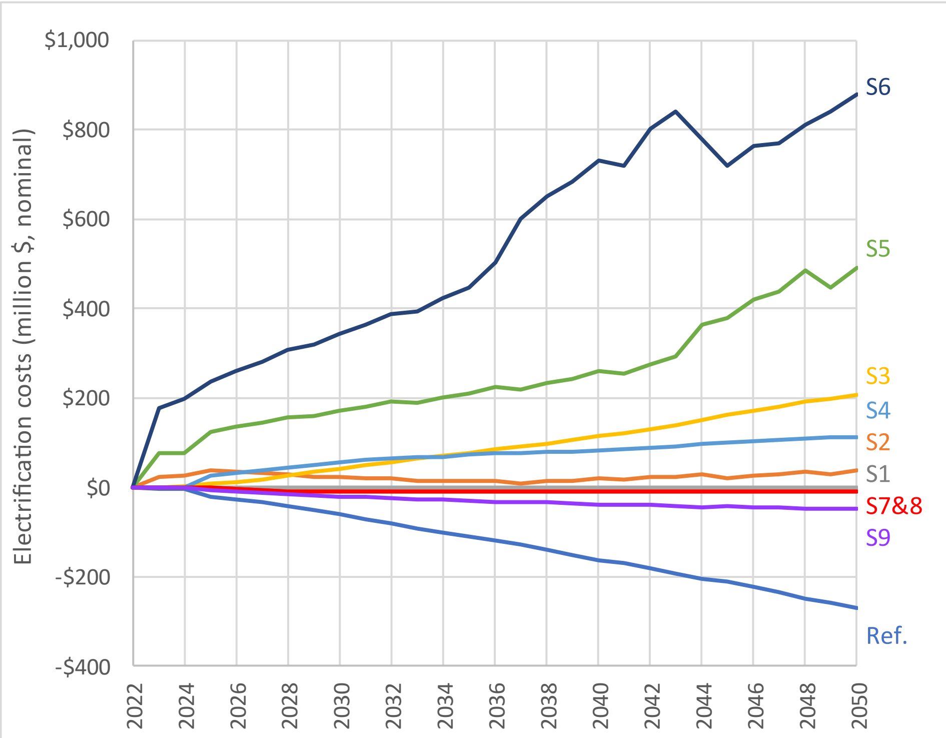
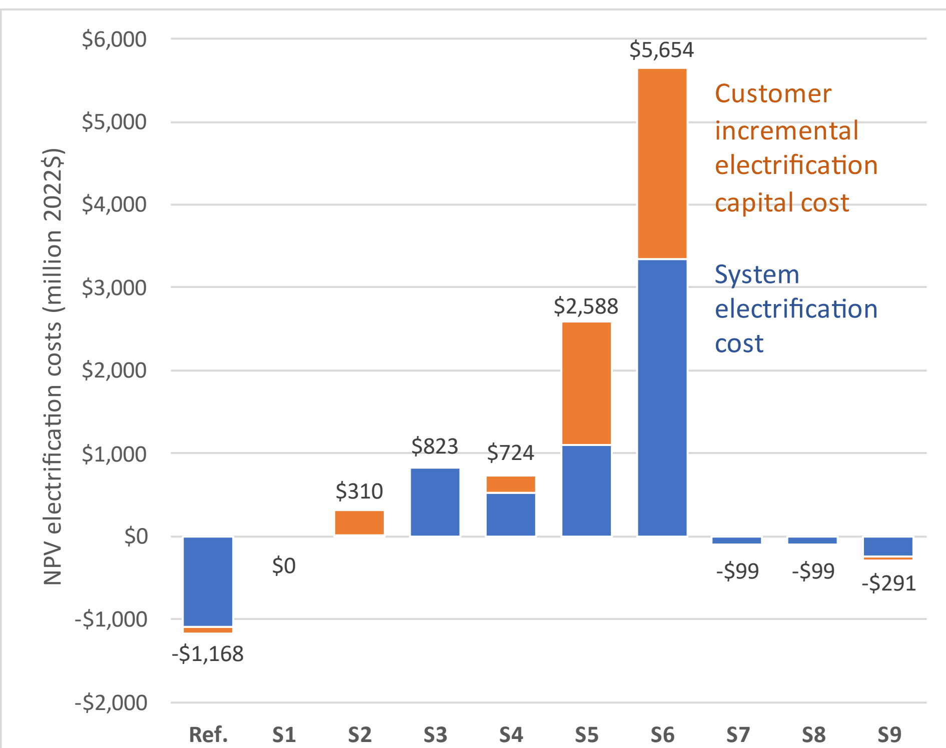


Figure 27. Net present value system and customer electrification costs, all scenarios relative to Scenario 1



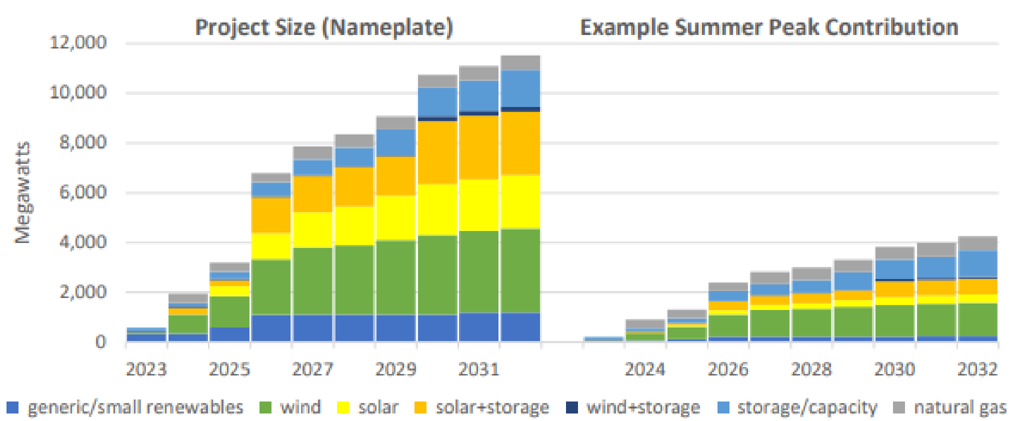
Appendix D. Pacific Northwest Electric System Trajectory

Electric Energy Sources in the Pacific Northwest Electric System

The electric sector in the Pacific Northwest is mostly comprised of emission-free electricity production and continues to increase its share of emission-free generation.[114] On the margin, new load from electrification over the next few decades will be supported by new resources while continuing to rely on electricity production from the existing resource base. The new resources are almost all zero-carbon renewable or storage resources.

The 2022 PNUCC forecast[115] illustrates the fundamental transformation occurring within the region's electric systems. In addition to coal plant retirement, planned/preferred resources are primarily wind, solar and battery energy storage. Figure 28 below reproduces a graphic from the forecast illustrating the pattern of new renewable resources planned for the region.

Figure 28. Pacific Northwest Utilities Conference Committee planned/preferred future new electric system resources



Source: PNUCC, Northwest Regional Forecast of Power Loads and Resources, 2022-2032. April 2022. Figure 6.

[114] PNUCC (Pacific Northwest Utilities Conference Committee), Northwest Regional Forecast of Power Loads and Resources, 2022-2032, April 2022. "**Majority of Northwest Generation is Carbon Free.** With hydropower as the foundation of the region's power supply, the share of non-emitting resources meeting the region's needs is steadily growing. Measured by project size, Figure 3 shows that the share of carbon-free resources in the Northwest grew from 76% in 2018 to 79% in 2022 and is expected to be at or above 83% by 2026," page 7.

[115] PNUCC (Pacific Northwest Utilities Conference Committee), Northwest Regional Forecast of Power Loads and Resources, 2022-2032, April 2022.

Accompanying the graphic seen in Figure 28 above is the following synopsis of planned resource development:

> "**Innovative Combinations of Resources on the Drawing Board**. Over the next 10 years, utilities have identified more than 11,000 MW of nameplate capacity made up of generic renewables and other unnamed solar, wind and storage projects in their integrated resource plans' preferred portfolios to meet their growing need. Innovative combinations of wind with storage, solar with storage, or a mix of all three are showing promise and being planned for several utilities.
>
> Wind power and solar generation make up the largest portion of potential new resources in this year's report shown in Figure 6. To help meet peak capacity needs more batteries and storage projects are finding their way into the mix. Other resources and technologies such as small modular reactors are in utilities' plans beyond the horizon of this study".[116]

The forecast report continues:

> "With the addition of over 9,400 MW of renewable energy over the 10-year study horizon, the continued transition to clean energy will rely on sufficient transmission to get new generation to load. Utilities have included upgrades and additions to transmission in their preferred portfolios. They are counting on these changes to the regional infrastructure to ensure an adequate reliable power supply. In summary, the shifts in this year's Northwest Regional Forecast are capturing the clean energy transition the industry is making. The Forecast demonstrates how the power system is evolving to meet society's goals to address climate change with load forecasts picking up, variable energy resources replacing thermal generation and new innovative technologies and programs on the horizon."[117]

PGE's current draft IRP portfolio results show only renewable resources, storage resources, and new transmission in its preferred portfolio. There are no new gas-fired resources included across the planning horizon.[118]

---

[116] Ibid., pages 9-10.

[117] Ibid., page 11.

[118] PGE 2023 IRP draft results, https://assets.ctfassets.net/416ywc1laqmd/2gMJyEW312ALrVIPPh7b1c/e0fcd76b2a645dbd4f9ac6c51615c5eb/IRP_Roundtable_January_23-1__1_.pdf#page=68, slide 70.