BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 79

In the Matter of NW Natural, 2022 Integrated Resource Plan.	Staff Final Comments

Contents

Section 1: Introduction

The 2022 NW Natural (Company) Integrated Resource Plan (IRP) provides an informative look into many of the possibilities and challenges faced by a decarbonizing gas company. The process leading up to this IRP, including Docket No. UM 2178 and the Company's Technical Working Groups, have prepared IRP participants to have a well-informed and thoughtful discussion of the analysis the Company has presented regarding its long-term outlook. The result is an IRP that articulates the Company's near-term needs and informs a larger discussion that can help the Company refine its long-term plan for customers while also continuing to demonstrate the possibilities of decarbonization as a solid business model.

The later years of the long-term plan rely on emerging technologies with cost forecasts that are uncertain. This uncertainty about how the Company may best be able to decarbonize is so high that the long-term planning in this IRP has been a unique challenge. There may be important tradeoffs between planning on expected cost improvements for emerging technologies, and implementing lower risk solutions that are available and more certain in the near term. While the long-term modeling in the IRP is highly informative and useful in some ways, there are a few key areas where it falls short of what Staff can recommend acknowledging.

Regarding short-term Action Items, Staff has chosen to consider each Action Item separately from the long-term planning, to the extent possible. The Action Items, while interconnected with the long-term planning assumptions to some degree, can also be assessed without relying on the Company's long-term PLEXOS portfolio modeling. For this reason, Staff recommends acknowledgement of most Action Items, even while recommending non-acknowledgement of the long-term portfolio modeling.

Staff appreciates the thoughtful engagement and innovative leadership of the Company, and the insightful comments by all participants in the IRP process to date. Synapse Energy Economics provided informative analysis to support Staff's review of the IRP, and the Synapse Final Report is attached to these comments as Appendix A. Staff looks forward to further discussion about next steps that can advance decarbonization of the gas system with strategies that best protect Oregon energy customers.

Section 2: Action Items

Rose Anderson, Senior Economist

Staff's Consideration of Action Items

While Staff has concerns with the long-term planning in this IRP, and notes that stakeholders expressed concern about the long-term obligations associated with near-term action items, Staff finds that the Action Items are each adequately separable from the long-term plan to be considered somewhat independently from Staff's concerns.

Action Plan Timeframe

As a general request, Staff would like the Company to include Action Items representing a four-year timeframe in its next Action Plan.

Recommendation 1: The Commission should direct the Company to include four years of planning detail in its next Action Plan.

Action Item 1 - Mist Recall or City Gate Deal

> *Acquire 20,000 Dth/day of deliverability from either recalling Mist, a city gate deal, or a combination of both for the 2023-24 gas year. Based upon updated load forecast in upcoming IRP updates, recall Mist capacity as required for the 2024-25 and 2025-26 gas years.*

Mist Recall is a reasonable, low-cost way to meet capacity needs in the near-term. The 20,000 dth/day expected for 2023-24 is similar to the 10,000 (2020-21) and 35,000 (2021-22) from the 2018 IRP Action Plan. Staff issued discovery requesting an explanation of the circumstances when the Company would utilize citygate deals instead of Mist Recall, and the Company replied that citygate deals reflect a variety of potential contracts with varying terms and prices. Citygate deals and are generally a flexible way to meet system needs, if they are available. The Company would seek to minimize expected cost to customers in selecting citygate deals.[1]

Recommendation 2: Staff recommends acknowledgement of Action Item 1 to acquire deliverability from Mist Recall and citygate deals.

[1] NW Natural Response to Staff DR 154.

Action Item 2 - Portland Cold Box

Replace the Cold Box at the Portland liquified natural gas (LNG) facility for a targeted in-service date of 2026 at an estimated cost of $7.5 to $15 million.

Staff appreciates the Company's responses in Reply Comments to Staff Requests 37, 38, and 39 regarding the Portland Cold Box.[2] As the Company notes, supply-side non-pipeline options are limited for gas system capacity resources and those considered in the IRP did not have better economics than the Cold Box replacement. Additionally, relying on a quick rollout of demand-side resources to replace the Portland LNG facility's 130,000 Dth/day of capacity (368,776 Dth per season) by 2027 seems unrealistic, especially since the Company is already planning for 94 percent of the Technical Achievable Potential of efficiency identified by Energy Trust in its territory.

While the Cold Box replacement appears to be a least cost and risk way to meet system capacity needs, Staff has concerns with other aspects of system capacity modeling in the IRP. Specifically, future IRPs should consider the potential for non-renewal of expiring pipeline capacity contracts and the retirement of other capacity resources as appropriate. Staff recommends acknowledgement of the Cold Box. Staff further recommends that the Company must consider retirement of capacity resources as appropriate in future IRPs.

Recommendation 3: Staff recommends the Commission acknowledge the Portland Cold Box replacement.

Recommendation 4: For future IRPs, the Company's portfolio modeling must consider non-renewal of unneeded firm delivery capacity contracts upon expiration and the retirement of other capacity resources as appropriate.

Action Item 3 - Demand Response

Scope a residential and small commercial demand response program to supplement our large commercial and industrial programs and file by 2024.

NW Natural's proposal to begin the process of offering a demand response program to residential and small commercial customers is a welcome step in the right direction, and Staff recommends the Commission acknowledge this action item with one condition.

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[2] NW Natural Reply Comments. Pages 80-84.

A Residential and Commercial demand response program does not displace the need for geographically targeted approaches to peak load reduction on NW Natural's system. Geographically targeted peak load reduction can provide unique value because it helps address specific, known distribution constraints. Focusing demand response in specific locations that are nearing the capacity limits of the distribution system is more likely to result in demand response that is timely and cost-effective.

Staff expects that analysis of geographical demand response as a non-pipe alternative to distribution system upgrades will be a priority in the Company's new forward-looking distribution system planning process.

Recommendation 5: Staff recommends the Commission acknowledge Action Item 3 for residential and commercial demand response subject to the condition that the Company includes in its demand response filing a discussion of how the Company's residential and commercial demand response program will interact with and support any future locational demand response program.

Action Item 4 - Efficiency Acquisition

> *Working through Energy Trust of Oregon, acquire 5.7 – 7.8 million therms of first year savings in 2023 and 6.7 – 8.9 million therms of first year savings in 2024, or the amount identified by the Energy Trust board.*

The quantities of efficiency in Action Item 4 are the result of collaboration with Energy Trust of Oregon to reflect the avoided costs of greenhouse gas policy. In conversations with Energy Trust, Staff has learned that the 20-year forecast for this IRP includes 94 percent of all Technical Available Potential for efficiency over the planning timeframe, and additionally has pulled forward some building shell measures into the near-term to achieve a higher amount of efficiency sooner. Staff recommends acknowledgement of this Action Item.[3]

Recommendation 6: Staff recommends acknowledgement of Action Item 4 to work with Energy Trust to acquire efficiency in 2023 and 2024.

[3] NW Natural. 2022 Integrated Resource Plan. Page 148.

Action Item 5 – Senate Bill (SB) 98 Renewable Natural Gas (RNG)

> *In Oregon, to achieve SB 98 targets, seek to acquire 3.5 million Dths of renewable natural gas (RNG) in 2024 and 4.2 million Dths of RNG in 2025, representing 5% and 6% of normal weather sales load in 2024 and 2025.*

The OPUC administrative rules addressing RNG in resource planning expressly state that "all requirements concerning integrated resource plans contained in OAR 860-027-0400 and as specified by Commission Order Numbers 07-002 and 07-047" apply to RNG.[4] Orders 07-002, 07-047, and 08-339 contain the OPUC IRP Guidelines and provide that the primary goal of an IRP, "must be the selection of a portfolio of resources with the best combination of expected costs and associated risk and uncertainties for the utility and its customers."[5] To this end, Guideline 1(b)(2) requires utilities to consider risk and uncertainty, and for natural gas utilities, that includes "demand, commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions."[6] In the IRP, the utility should explain "how its resource choices appropriately balance cost and risk."[7] Significantly, an IRP "must be consistent with the long-run public interest as expressed in Oregon and federal energy policies."[8]

As Staff noted in Opening Comments, the Climate Protection Program (CPP) places stringent decarbonization requirements on the Company and creates new risks and challenges in controlling and reducing rate impacts. Under this regulatory regime, utilities should carefully weigh and appropriately model the different pathways they may take to comply with the CPP. Two tools in NW Natural's decarbonization toolbox are acquisition of RNG and Community Climate Investments (CCIs).

In 2019, the Oregon Legislature passed SB 98, which created a program for natural gas companies in Oregon to invest in RNG. As NW Natural described in its 2022 IRP:

> SB 98 sets *voluntary* targets of 5% RNG for 2020-2024 period, 10% for 2025-2029, 15% by 2030, 20% by 2035, and 30% by 2050. It enables utilities to procure RNG through offtake contracts or invest in and own cleaning and conditioning equipment required to bring raw biogas and landfill gas up to pipeline quality, as well as allowing the facilities to connect to the local distribution system. The rule does contain cost containment measure that only allow for up to 5% of the utility's revenue requirement to be used to cover the

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[4] OAR 860-150-0100(4).
[5] *In the Matter of Public Utility Commission of Oregon Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-047, Guideline 1(c), Appendix A at 1 (February 9, 2007).
[6] Order No. 07-047, Appendix A at 1.
[7] Order No. 07-047, Guideline 1(c), Appendix A at 2.
[8] Order No. 07-047, Guideline 1(c), Appendix A at 2.

incremental cost of investments in RNG infrastructure. The RNG procured under SB 98 may be acquired locally or from sources across the nation.[9]

CCIs are a feature of the Oregon DEQ's CPP designated only for projects in Oregon that reduce greenhouse gas emissions by an average of at least one MT CO_2e per CCI credit.[10]

The purposes of CCIs include:

1. Providing covered entities with an optional way to meet part of their compliance obligation;
2. Reducing other air contaminants, especially near environmental justice communities in Oregon;
3. Promoting public health, environmental, and economic benefits for environmental justice communities in Oregon; and
4. Accelerating the transition to zero or lower GHG emissions energy sources.[11]

Projects may achieve emissions reduction from transportation activity, buildings, industrial activity, and/or commercial activity.[12] A covered entity such as NW Natural can offer CCI funds to the CCI entity of its choice.[13] In summary, CCI projects are designed to bring benefits and decarbonization to Oregon, while serving as a compliance option for regulated entities.

In its 2022 IRP, NW Natural prioritized achievement of voluntary targets under SB 98 over properly analyzing the least cost and least risk strategy to meet mandatory CPP requirements. The Company configured the PLEXOS model to include SB 98 RNG by default as a hard-coded input, which made it impossible to evaluate whether RNG acquisition is the least cost/least risk method of complying with the CPP.

In Opening Comments, Staff requested that the Company run a model sensitivity to determine the PVRR improvement by acquiring CCIs up to DEQ limits, as needed, in each year that they are less expensive than other compliance options.[14] In response, the Company helpfully modeled an alternate approach to its scenarios in its Reply Comments. The modeling shows that in the near term, the PLEXOS model selects CCIs for compliance purposes instead of SB 98 RNG.

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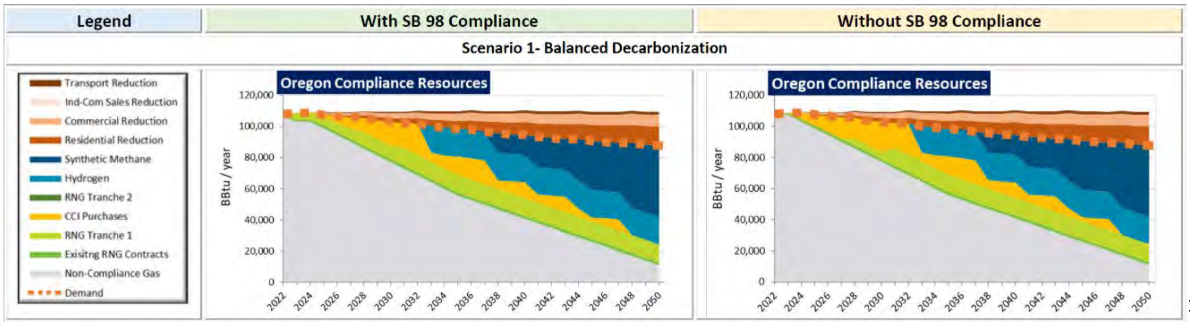
[9] NW Natural Amended IRP at 54 (emphasis added).
[10] OAR 340-271-0900.
[11] OAR 340-271-0900.
[12] OAR 340-271-0900.
[13] OAR 340-271-0930 (1)(a).
[14] *See* Staff Opening Comments at 48.



[15]

As such, NW Natural can replace SB 98 RNG with CCIs in the near term, until RNG is needed to comply with the CPP in approximately 2026, as can be seen by the later entrance of the green wedge representing tranche 1 RNG. The result in the balanced decarbonization scenario is a PVRR savings of about $150,000,000.[16] In comparison, the Company's total operating revenue (including variable costs of gas) in the UG 435 Rate Case was about $800,000,000.[17]

In Reply Comments, the Company claims that it is not seeking acknowledgment "of large investments that could substantially impact the cost of service to customers as stranded assets in the future," and that the Action Plan includes only "investments that are needed to maintain reliable service for current customers; comply with SB 98; and comply with the first three-year compliance period of the CPP with proven technologies."[18]

First, Staff notes that, unlike the CPP, there is no "compliance" aspect to the SB 98 targets. The targets set forth in statute are voluntary. Second, the Company is seeking acknowledgment of substantial investments in RNG that ratepayers will be paying for many years into the future when the modeling shows that purchasing CCIs for CPP compliance through 2026 could save ratepayers $150,000,000 in the balanced decarbonization scenario. The Company provides no explanation of how or why a choice that leads to a potential cost differential of $150,000,000 or more results in "a portfolio of resources with the best combination of expected costs and associated risk and uncertainties for the utility and its customers."

While not dispositive, it is also important to note that, so far, all SB 98 RNG has been developed only outside of Oregon. These projects include:

1. Archaea (BP) Offtake Portfolio, Eastern United States,
2. Element Markets, New York City,
3. Tyson – Dakota City (Contract not yet Executed), Nebraska,
4. Tyson – Lexington, Nebraska, and
5. Wasatch Resource Recovery, Utah.

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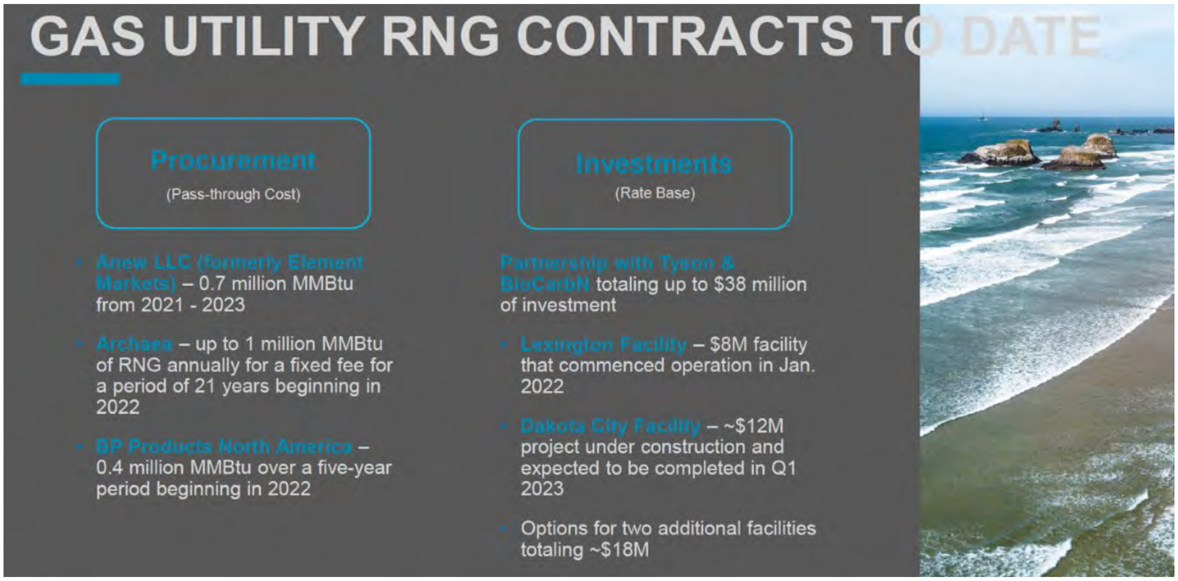
[15] NW Natural Reply Comments. Page 109.
[16] NW Natural Reply Comments. Page 52.
[17] UE 435 Exhibit 1300 Revenue Requirements Model Compliance Filing.
[18] NWN Reply Comments at 3.



[19]

Locating RNG projects in other states is allowed by SB 98 and results in overall greenhouse gas reduction. However, acquisition of RNG outside of Oregon limits other potential benefits to the public and ratepayers in Oregon which might be achieved through CCI acquisition.

Given that NW Natural must reduce its emissions significantly, which will be challenging even without additional constraints, the Company should pursue the least cost, least risk decarbonization of its system in the near term. Based on the Company's updated modeling, it appears that CCIs are the least cost option through at least 2026. This approach results in a portfolio that most appropriately balances the costs and risks that NW Natural faces with respect to decarbonization. It will benefit Oregonians through utility rate reductions and is more likely to create health and equity benefits in Oregon.

Recommendation 7: Staff recommends non-acknowledgment of the SB 98 RNG acquisition under Action Item 5 because acquisition of CCIs is a significantly less costly and risky method of complying with the CPP.

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[19] NW Natural. Investor Presentation. March 2023.

Action Item 6 - Transport Efficiency

Work with Energy Trust of Oregon, the Alliance of Western Energy Consumers and other stakeholders to develop energy efficiency programs for transportation schedule customers by 2024.

While this item is a part of our compliance strategy, NW Natural is not asking for acknowledgment from the OPUC of this item as we are already pursuing this action.

Staff thanks the Company for this update. A discussion of transportation customers, including transport efficiency, is included in Section **3.7 - TRANSPORT AND INTERRUPTIBLE CUSTOMERS.**

Action Item 7 - Community Climate Investments

In Oregon, purchase Community Climate Investments representing any additional Climate Protection Plan (CPP) compliance needs for years 2022 and 2023 in Q4 2023 and for year 2024 in Q4 2024 based upon actual emissions to ensure compliance with the 2022-2024 compliance period.

Staff recommends the Commission acknowledge this Action Item with a few clarifications. First, the Commission should discuss whether CCIs should be acquired for near-term CPP compliance in lieu of more expensive SB 98 RNG, as discussed in the section on Action Item 5 above. This IRP is an important moment for the Commission to discuss whether SB 98 RNG should be replaced with the lowest cost CPP compliance option in the near-term, and the discussion will influence acknowledgement of both Action Item 5 and Action Item 7.

If the Commission does not acknowledge the Company's plan to procure near-term SB 98 RNG, then the Company may choose to procure CCIs for CPP compliance instead. In this instance, the Company might still choose to purchase additional CCIs for compliance flexibility as contemplated in Action Item 7. While in the near term, the Company may find that reserving a portion of CCIs for unexpected compliance needs is an acceptable way to flexibly meet emissions targets, Staff has two points for consideration:

- The Company should evaluate the potential to procure a portion of Renewable Thermal Certificates (RTCs) to use instead of CCIs in case compliance needs are unexpectedly high. If the RTCs are not needed for compliance in a given period, they would still have value and could be used to benefit customers.[20,21] Further evaluation may show that slightly over-procuring RTCs for compliance flexibility could be a better value for customers than setting aside a portion of lower-cost CCIs to use just in case.

- If CCIs are used, then the amount of CCIs reserved for contingencies should reflect a reasonable amount of load variation and associated GHG emissions. For example, setting aside CCI purchases associated with about 5 percent of required emissions reductions for use in a case with load slightly higher than expected might be acceptable. But leaving 90 percent of available CCIs on the table in favor of more expensive RNG would likely not.

Recommendation 8: Staff recommends acknowledgement of Action Item 7 to purchase CCIs, conditional on the Company using CCIs and RTCs in combination in the most economical way possible to meet compliance flexibility needs, as informed by the decision on Action Item 5 and near-term SB 98 procurement.

Action Item 8 - Forest Grove Feeder

> *In Oregon, uprate the Forest Grove Feeder (also known as the McKay Creek Feeder) to be in service for the 2025 gas year at an estimated cost of $3.0 to $7.0 million.*

Staff's analysis of the Forest Grove Feeder can be found in **SECTION 3.3.1 - FOREST GROVE FEEDER UPRATE PROJECT**. In summary, the Forest Grove Feeder is experiencing low pressures at temperatures and loads experienced today. Staff's analysis has found that the Feeder uprate will be important to ensuring reliability at that location, that the alternatives studied would not be cost-effective in comparison to the uprate, and that other demand-side alternatives would not be timely considering the low-pressure issues being experienced under existing conditions. Staff recommends acknowledgement of the Forest Grove Feeder subject to certain conditions.

In response to Climate Advocates DR 3, NW Natural explained that the Forest Grove Feeder Uprate project "would not need any additional improvements to transport hydrogen blended gas through the system."[22] Staff would like the Company to engage with a third party expert to validate the uprate plans for pressure control equipment associated with the Forest Grove high pressure system. This should include an assessment of whether any further improvements would be needed for the infrastructure being installed or modified on the Forest Grove Feeder, including inlet piping for associated district regulators or any relief valves, in order to transport

[20] NW Natural's response to Staff DR 152.
[21] NW Natural's response to Staff DR 153.
[22] NWN Response to Climate Advocates DR 3, December 2, 2022.

a hydrogen concentration of up to 20 percent. The Company should include a report on this work in its request for rate recovery of the uprate.

Additionally, the Company should move ahead with its forward-looking distribution planning process and include in the next IRP any projects that it expects may need to be upgraded in three years or more. The IRP should discuss non-pipe alternatives that could be implemented in place of these possible future projects.

Recommendation 9: Staff recommends acknowledgement of Action Item 8 to uprate the Forest Grove Feeder, subject to certain conditions regarding forward looking distribution system planning and hydrogen-blend readiness.

Section 3: Action Plan Timeframe – Additional Considerations

3.1 - Risks of New Load

Rose Anderson, Senior Economist

In NW Natural's planning environment, uncertainty about the future is high and decarbonization requirements are steep. For these reasons, the risk of new distribution projects that add new load to the system is especially high. An investment that appears to be needed today could eventually prove to be unnecessary for several reasons, including if customers choose to electrify. Rate impacts for line extensions or larger distribution system upgrades will be higher than expected if planned-for customers exit the gas system. This also may create equity issues and intertemporal equity issues. Climate Advocates described these issues in Opening Comments:

> ...it is likely that customer defection will shrink the overall customer base, increasing the risk of fixed system costs shifting to those remaining. This is an equity issue; those that remain on the gas system are likely to be low-income and renter communities with fewer means to choose to electrify their households and businesses. Climate Advocates urge the Commission to do all it can to implement policies soon that will reduce additional and unnecessary investments in the gas distribution system and instead focus investments on advancing beneficial and equitable electrification solutions, particularly for these most vulnerable customers.[23]

Staff is very supportive of doing everything possible to eliminate unnecessary investments in the gas distribution system and has included several recommendations toward this goal in these comments. Advancing beneficial electrification solutions for vulnerable customers is an interesting proposal with the potential to address inequity in the future. However, Staff finds it appropriate to learn more about the costs of electrification and the extent of actual load decline before putting forth explicit recommendations on this topic in this IRP.

If new load is facilitated by distribution system projects and then clean fuels turn out to be more expensive than expected, each new therm added will be even more expensive to decarbonize than planned. In contrast, alternate approaches to distribution system constraints include options with greenhouse gas reduction costs that are certain now, not based on uncertain forecasts. Demand response, geographically targeted efficiency, and electrification could potentially offer more certainty and shorter cost recovery times in a highly uncertain time for natural gas planning.

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[23] See Docket No. LC 79, Climate Advocates Opening Comments, December 30, 2023. Page 14.

Future IRPs should strive to reduce risk to customers associated with clean fuel costs by considering proactive strategies to minimize growth related investments in the distribution system. Specifically, the Company should use a high-cost estimate of future alternative fuel prices when considering the avoided GHG compliance costs associated with non-pipe alternatives.

Recommendation 10: Future distribution system planning should include a cost benefit analysis for non-pipe alternatives that reflects an avoided GHG compliance cost element consistent with a high-cost estimate of future alternative fuels prices.

3.2 - Distribution System Transparency

Kim Herb, Utility Strategy and Planning Manager

To help IRP participants assess risks of new load, the Company should provide more detailed maps and supporting databases in future IRPs. The UM 2178 Final Report Appendix B on IRP Guidance suggests future IRPs capture mapping and infrastructure information that would help inform distribution system planning and assess options when facing risks of new load.[24]

Table 1: UM 2178 IRP Guidance

System Mapping / Infrastructure	Include planned infrastructure costs identified as new customer vs. maintenance of existing system. Identify high priority projects and 5 year planned investments with non-pipeline alternatives considered.
	Identify areas of new development / system expansion- with as much granularity as possible.
	Scenarios of load decline should include assessment of stranded asset risk.
	Include current rate base depreciation assumptions, list of assets, and amortization schedules.

Climate Advocates similarly referenced UM 2178 and an interest in NWN providing more information about its system with maps, albeit, with a specific interest in planning for "eventual pruning." Climate Advocates note that "[s]uch maps would assist the Commission in identifying "no regrets" decisions, instead of locking customers into investments that can achieve only modest emissions reductions."[25] Climate Advocates recommends the company provide publicly available maps with depreciation and other data to help assess utility infrastructure investments.

[24] UM 2178 Final Report, Appendix B – IRP Guidance, page xv.
[25] LC 79 – Climate Advocates Opening Comments, December 30, 2022, page 15.

Without taking a position on system pruning, Staff supports Climate Advocates' request for information about the age of the Company's distribution system infrastructure in various locations.

Additional information about the distribution system may help provide insight relevant to forward-looking distribution system planning and help identify opportunities for non-pipe alternatives. To help inform forward-looking distribution system planning, Staff recommends that NW Natural's future IRPs include a map of its system and associated database of feeders, locational information about the in-service date of the pipes, and the lowest recent pressures observed at those locations.

Recommendation* 11*: In future IRPs, NWN should include a system map with an associated database containing information about feeders, in-service dates of pipes, and lowest recent observed pressures.

3.3 - Distribution System Planning

Abe Abdallah, Senior Utility Analyst

Section 3.3.1 - Forest Grove Feeder Uprate Project

In its 2022 IRP, NW Natural sought acknowledgement of Action Item 8 to uprate the Forest Grove Feeder to be in service for the 2025 gas year at an estimated cost in the range of $3 million to $7 million.

Analysis

In Opening Comments, Staff concluded that additional clarification and data were needed on how the modeled pressure drop at the Forest Grove District Regulator during the coldest design day[26] would impact the intermediate and low pressure systems in Forest Grove by 2025. Exploring such level of details would help Staff explore possible short-term operational mitigation measures during peak events, in conjunction with potentially buying enough time for developing alternative non-pipe solutions.[27]

The Company provided an extensive explanation and quantitative data during several meetings with Staff, in its reply to Staff's Opening Comments, and in response to Staff information requests. Staff wishes to thank NW Natural's IRP team and other supporting staff for their sincere efforts to provide accurate and comprehensive information in a timely manner, as needed by Staff.

[26] Design day means "[a] 24-hour period of demand which is used as a basis for planning gas capacity requirements." American Gas Association Glossary, http://www.aga.org; and Ohio Adm. Code 4901:5-7-01(A).

[27] Docket No. LC 79 – NW Natural 2022 IRP, Staff Opening Comments pp. 76-77.

Stakeholders echoed concerns about long-term investments in projects, such as the Forest Grove Uprate project, and the compatibility of the outcome of such projects with CPP targets.

The Citizens' Utility Board (CUB) is concerned that if NW Natural's proposed supply-side approach to meeting the CPP's 90 percent emissions reduction is inaccurate, then a long term investment, such as Forest Grove, would add significant risks to customers.[28] CUB argues that given the uncertainties of future unproven technologies, decarbonization policies and customer choices, electrification may become the easiest and least expensive means to decarbonize. Alternatively, this scenario introduces a different risk: the diminished size of future load will make it hard for the system to pay for the amortization of this type of long-term capital investment for 40 to 50 years.

Similarly, Climate Advocates (Green Energy Institute and Coalition) states that considering that NW Natural did not provide demand-side alternatives to the Forest Grove Feeder Uprate (other than interruptible load of industrial customers) or adequately consider technology risk of alternative fuels to meet emission reduction targets, expanding the gas distribution network does not support effective decarbonization.[29] As a result, the uprate project would increase the risk of having stranded assets, increasing rate pressures and hampering electrification.

In its Reply Comments, the Company argues that any demand side solution will not decrease customer numbers and questions the reason Staff sees a "likely" scenario of decrease in number of customers, considering that the Forest Grove area has only ever seen increase in customer numbers.[30] The Company's argument implicitly assumes potentially low risk of ending up with a stranded asset in the long term. With regards to compliance to emission targets, the Company rejects the idea that demand must fall due to decarbonization.[31]

In response, Staff agrees that current trends may not necessarily decrease customer numbers. However they could, and they certainly may alter gas consumption volumes and timing both at Forest Grove and across the system as a whole. Moreover, historic trends of growth in demand may not be sustainable due to pressures around state and local decarbonization policies. As the message is clearly conveyed by CUB earlier in this section, many factors outside of the Company's control may dictate that demand must fall for emission targets to be met.

Based on the information gathered so far, Staff's understanding is that the Forest Grove distribution high pressure system has substantial pressure loss throughout the network at low temperatures, which impacts inlet pressure to the Forest Grove District Regulator. Under peak design day conditions, the inlet pressure at the district regulator is expected to experience a pressure drop exceeding the target threshold standard of 40 percent set by the Company. Driving this higher than desired pressure loss is the intermediate pressure system, which has

[28] Docket No. LC 79 - NW Natural 2022 IRP, CUB's Opening Comments, pp. 3-4.
[29] Docket No. LC 79 - NW Natural 2022 IRP, Climate Advocates' Opening Comments, pp. 16-18.
[30] Docket No. LC 79 - NW Natural 2022 IRP, NW Natural's Reply Comments, February 3, 2023, p. 61.
[31] Docket No. LC 79 - NW Natural 2022 IRP, NW Natural's Reply Comments, February 3, 2023, p. 83.

capacity issues because of the heavy large customer use on the system. When combined with high flows (typically during cold events) and reduced outlet pressure from the District Regulator, the extremities of the network suffer from low pressure.

As stated in the IRP,[32] the Company's modeling indicates that a 40 percent drop in pressure will cause the Forest Grove Feeder operating beyond 80 percent capacity, which increases the probability of outages in the event of a small increase in demand from weather or growth. According to the model, this pressure drop occurs at 25°F degrees triggered at a current design estimated demand (capacity) of 3,118 Therms/hour (Th/hr).[33]

The Company explains that most of the customers in the Forest Grove area are served in the Class B distribution system (intermediate pressure system), which operates below 60 psig.[34] Low pressures on the Class B system can cause customers to lose service. In addition, the Company stated that the other issue with low pressures is that customers with Excess Flow Vales (EFV) require a minimum inlet pressure of 10 psig for the device to operate properly.[35]

To characterize what events would trigger a 40 percent or higher drop in pressure, the Company explains how it uses the Synergi™ Gas model to incorporate the three aspects of temperature, BTU value,[36] and large customer load that impact the level of demand. In demonstrating how a pressure drop of 40 percent can occur, the Company shows scenarios of combinations of those three aspects that impact demand.[37] An instance of such event can be triggered at an average daily temperature as high as 26°F if the largest customer load is operating at maximum capacity and the BTU value is low, or at a temperature as low as 17°F with largest customer load at zero usage and BTU value is high.

Focusing on large customer load being a major contributor to the pressure drop, Waste Management is the highest usage customer on the Class B Pressure System (under 60 psig MAOP).[38] Over the last three years, Waste Management's hourly usage during the peak period during morning burn (6 AM – 10 AM) reached a maximum of 286 Th/hr. For this reason, NW Natural applies a demand of 263 Th/hr in the model to cover potential usage, which is considered quite a significant proportion of the total system demand of 3,118 Th/hr estimated to cause a 40 percent pressure drop, as mentioned earlier.[39]

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[32] Docket No. LC 79 - NW Natural's 2022 Integrated Resource Plan: Errata Filing (October 21, 2022), page 386.

[33] Docket No. LC 79 - NW Natural 2022 IRP, NW Natural's response to Staff's IR 63.

[34] Docket No. LC 79 - NW Natural 2022 IRP, NW Natural's response to Staff's IR 132.

[35] Docket No. LC 79 - NW Natural 2022 IRP, NW Natural's response to Staff's IR 145.

[36] Natural gas BTU value or the heat content of the gas supply is unpredictable and can range from 1,000 Btu/scf to 1,100 Btu/scf. The BTU value depends on the gas mixture, which in turn depends on the source of the gas and the post-processing of the gas before it enters the distribution system. A high BTU value does not require as high volume gas to serve energy needs as a low value.

[37] Docket No. LC 79 - NW Natural 2022 IRP, NW Natural's Reply Comments, February 3, 2023, p. 66.

[38] Docket No. LC 79 - NW Natural 2022 IRP, NW Natural's Reply Comments, February 3, 2023, p. 63.

[39] Docket No. LC 79 - NW Natural 2022 IRP, NW Natural's Reply Comments, February 3, 2023, p. 76.

As shown in Figure 1, comparison of actual pressure data recordings at the District Regulator with the model results confirms a close match with random scatter points around four forecasted temperature-pressure curves representing different scenarios of BTU value and largest customer load.

Figure 1 shows that if historical temperatures of 15.5°F and 9.4°F (occurring in 2017 and 1989, respectively) were to recur at present, significantly large pressure drops of the inlet pressure would be expected in accordance with any of the load combination scenarios.

Figure 1: Actual and Modeled Forest Grove Average Daily Inlet Pressure vs Temperature[40]

The Company explains that, although temperature impacts usage, variations of usage (demand) exist within a specific temperature because of other influencing factors. The Company names those factors as multiple variables that impact pressure at any given temperature including wind speeds, solar radiation, prior hour temperatures, day of the week, holidays, inclement weather, school or business closures, and unpredictable usage from industrial customers,

[40] Figure is a reproduction of Figure 10 in NW Natural's Reply Comments, February 3, 2023, p. 65.

among other factors.[41] Staff is interested to understand more about the degree by which each these factors influence demand and the extent by which pressure will be affected by the change in these variables.

Recommendation 12: Staff requests that the Company, before the next IRP, provide statistical evidence of the significance of the variables that influence demand, and hence pressure, at a specific temperature.

<u>January 30, 2023 Event</u>

A real test for the model was possible by observing the actual pressure data during the recent cold event on Monday, January 30, 2023. On that day, the inlet pressure at the Forest Grove District Regulator experienced a 53 percent drop, when the average hourly temperature went as low as 20.3°F at 5:00 AM, and the average temperature for the day was 30°F. As a mitigation measure, NW Natural's staff intervened on that day and allowed the flowing gas to bypass the district regulator to mitigate the effect of pressure 'droop' at the outlet pressure of the district regulator feeding the Class B distribution system.[42] A lower starting pressure for the Class B distribution system leads to a pressure drop that can compromise the reliability of supply throughout the pipeline network. On that day, the two large load customer interruptible loads available to NW Natural were not activated and no loss of supply to customers was reported.

Staff's analysis shows that the demand experienced at 7:00 AM and 8:00 AM of about 3,416 Th/hr that caused a 53 percent drop in pressure would have been reduced by a maximum of 105 Th/hr with the two interruptible loads being activated. Even with the highest reduction, demand would have still been quite high (3311 Th/Hr), which would cause a pressure drop of 48.6 percent, thus exceeding the 40 percent pressure criterion (a demand of 3,118 Th/Hr causes just over 40 percent drop in pressure, as per the model). Nonetheless, Staff is concerned NW Natural chose to bypass a regulator before implementing other available mitigation measures, such as calling a demand response event and activating the two large interruptible loads at its disposal. If there was a risk of outages significant enough to require a regulator bypass, why were interruptible customers not also utilized?

In summary, after collecting and analyzing all the quantitative and qualitative data provided by NW Natural, Staff appreciates the concern for how the situation on January 30, 2023, could have turned out to be a major loss of supply event considering the following factors:

- The temperature on the day did not go as low as the temperature for peak planning day when the pressure drop would have been much higher, according to the model.

[41] Docket No. LC 79 - NW Natural 2022 IRP, NW Natural's response to Staff's IR 141.

[42] Droop is the occurrence of the outlet pressure decreasing or "drooping" below the pressure setpoint as the flow increases towards the maximum capacity of the regulator. Droop is important to the user because it indicates the range of a regulator's useful capacity.

- Data provided by NW Natural indicates that the largest customer, Waste Management, used only a maximum of 13 Th/hr during the morning burn. This low demand may have been the single factor that avoided major disruptions to gas supply on the day.[43] Had Waste Management used its modeled demand of 263 Th/hr or its maximum recorded demand of 286 Th/hr during peak times (morning burn), severe pressure drops might have caused a loss of supply to customers on the Class B Distribution System.
- The interruptible customer loads on the day during the morning burn were not enough to reduce the pressure drop to acceptable levels.
- While not reflected in the model, manually bypassing the district regulator on the day helped preserve an acceptable level of pressure in the Class B Distribution System and consequently no loss of supply occurred.

February 24, 2023 Event

On February 24, 2023, there was another cold weather event where pressures dropped by 57 percent to 68.6 psig, as sited at the inlet of the Forest Grove District Regulator. The minimum temperature was 16.9 degrees and the average temperature was 27.3 degrees. Interruptible customer loads were not interrupted.[44] While this event demonstrates that significant pressure drops are occurring on the Forest Grove Feeder, it also demonstrates that NW Natural is not always interrupting its interruptible loads, even when it sees large pressure drops. NW Natural's response to Staff DR 156 indicates that a modeled scenario of interrupting these customers would have resulted in an improvement of less than 3 psig at the Forest Grove District Regulator inlet (corresponding to 55 percent drop in pressure). However, if there was a true risk of outage, Staff is concerned that the Company accepted an increased risk of customer outages by not utilizing the interruptible customers during this peak event. In essence, these customers are being given a preferred rate for accepting an interruptible status that is apparently not used during peak load events. Staff notes concern that interruptible customers are receiving a lower rate, even when their demand response is apparently not seen as particularly useful at a given location.

Conclusion

Based on Staff's analysis of the limited means available to NW Natural to solve the Forest Grove District's pressure problem, the evidence presented of pressure drops on actual cold days and the time available to develop a feasible solution, Staff concludes that the uprate project is likely the best option to maintain system reliability, given the circumstances.

Section 3.3.2 - Distribution System Projects

Staff would like to take the opportunity of the experience gained and lessons learnt from the Forest Grove District Feeder Uprate project to reflect on what improvements can be made in both the short and long terms when addressing issues with distribution system projects.

[43] Docket No. LC 79 - NW Natural 2022 IRP, NW Natural's Reply Comments, February 3, 2023, p. 68.
[44] NW Natural response to Staff IR 156.

Short Term Distribution System Planning

Analysis

During the discovery process for the Forest Grove Uprate project, Staff requested information on several short-term measures that the Company could follow to deal with low-pressure issues without requiring a feeder uprate.

One of the most prominent short-term measures that surfaced in the discussions, as an obvious solution to a problem that occurs infrequently, is the use of mobile CNG trucks injecting gas in poor pressure points in the distribution system.

In the Forest Grove situation, NW Natural states that the Company is not in favor of this measure because:[45]

- The Company's fleet of CNG or LNG trailers are only used for short-term and localized use in support of cold weather operations, or while conducting pipeline maintenance procedures.
- The portfolio of CNG trailers does not have sufficient flow rates or inventory to address the throughput limitations on the Forest Grove Feeder.
- Mobile CNG deployment carries operational risk, could require relying on large trucks to drive on icy roads during cold events, and is a far more infrastructure-heavy solution.

On the face of it, Staff accepts some of the reasoning behind the Company's rationale against the idea of mobile CNG or LNG injection. However, prior to the next IRP, Staff would like to understand when localized injection of natural gas for cold weather operations would be feasible, what operational risk it carries, and how capital intensive is the infrastructure compared to other short-term solutions. For example, given that the Company currently maintains enough infrastructure to provide 1,000 therms for 9 hours in one location, as well as multiple small trailers rated below 100 therm capacity, how would it be capital intensive to rely on this existing infrastructure to address capacity issues at Forest Grove Feeder?[46]

The other short-term measure that the Company has available but has not deployed in the Forest Grove situation is interruptible load. Staff understands that there may be operational conditions or contractual obligations that result in the Company not activating the interruptible load on a cold day. However, considering that interruptible load customers are paying preferential rates of gas usage for offering their loads for contingency events, Staff is concerned about transparency and equity issues regarding how the Company operates its interruptible load scheme. Why are these customers not being interrupted during peak events where the Company needs to bypass its regulator to maintain pressure?

[45] Docket No. LC 79 - NW Natural 2022 IRP, NW Natural's Reply Comments, February 3, 2023, p. 72.
[46] Docket No. LC 79 - NW Natural 2022 IRP, NW Natural Reply Comments, February 3, 2023, p. 72.

As part of the next IRP, Staff would like to know how often interruptible loads have been called upon to trip off to help system capacity. Staff issued discovery regarding recent interruptions on the Forest Grove distribution system, and the Company provided data that it deemed highly confidential.[47] Ratepayers, who are effectively paying for an 'ancillary service' provided by interruptible loads, are entitled to reap the benefits of the service they are paying for. Staff would also like to better understand the criteria behind how these loads are used and when they are used.

Staff is also concerned that there may be a possible extra stress on the system if there is no incentive for interruptible load providers to curtail or shift their gas usage to other times, especially if they know that they will not be called upon to drop their load during peak times. In addition, it is important to consider that in the absence of deploying interruptible loads, other non-pipe cold day measures used to compensate for pressure drops, such as deploying a team of Field Operations personnel for bypassing the District Regulator, have risks and costs that are ultimately borne by ratepayers.

Staff requests that the Company, in the IRP Update, provide rationale backed by practical examples of the deployment of CNG or LNG trailers as short-term mitigation measures, in terms of:

- Size and duration of pressure loss that make the application for CNG/LNG trailers for cold weather operations feasible,
- What operational risks CNG/LNG trailers introduce, and
- How infrastructure capital and operational costs of CNG/LNG trailers for the Forest Grove Feeder compare to other solutions.

In addition, Staff requests that the Company explore with stakeholders prior to its IRP Update the Company's Contingency Plan in preparation for cold days with a potential for detrimental events occurring. Although the following list of questions is not exhaustive, Staff seeks the following info from the Contingency Plan:

- What constitutes an emergency? What constitutes a risk event?
- What criteria should be met to trigger contingency actions (including District Regulator bypass or interruptible load)?
- Who or what would make the decision for the action? For example, is the trigger of interruptible load decided by Company personnel or automated?
- How often were these contingency actions (regulator bypassing or interruptible load) taken to alleviate the distribution system pressure in Forest Grove in the last five years? Please provide the dates and times of each action, duration of each action, and recorded temperature and district regulator inlet pressure when the action was taken.

[47] NW Natural's response to Staff IR 156.

- Are there any provisions to work with non-interruptible large load customers to constrain their flow rates to ride through peak hour events as a viable contingency option? Has the Company considered a tariff that, instead of requiring customers to be interrupted completely at peak hours, requires customers to reduce their usage by a certain amount at peak hours? Has the Company inquired as to whether customers would be open to a partial usage reduction at peak hours, instead of a complete interruption as in the current interruptible tariff?
  Is there a program to let customers, especially non-weather dependent customers, know that a cold day event is imminent to give them the chance to voluntarily reduce their gas usage?

Recommendation* 13*: Staff requests that the Company, in the IRP Update, provide rationale backed by practical examples of the deployment of CNG or LNG trailers as short-term mitigation measures, including information requested by Staff in Final Comments.

Recommendation* 14*: Staff requests that the Company explore with stakeholders prior to its IRP Update the Company's Contingency Plan in preparation for cold days with a potential for detrimental events occurring, including information requested by Staff in Final Comments.

Conclusion

Based on Staff's analysis of short-term measures to increase system capacity during times when the system is stressed, Staff concludes that in the absence of supply side measures to increase system pressure, the Company should find more ways to curtail large customers' loads during times of low pressure. Offering a partial interruptible rate that only interrupts a portion of customer load may be a step toward greater flexibility for more of the Company's large customer load.

In the forward-looking distribution system planning included in future IRPs, NW Natural should consider in its study of non-pipe alternatives whether it could develop an operational flow tariff for reductions of peak usage on the constrained portion of the distribution system. This could include constraining customer flow rates to ride through peak hour events under different price and load reduction requirements than the current interruptible tariff. This demand response option could be seen as demand reduction and/or shifting of load to off-peak times as an alternative to interruptible loads offered at lower gas usage rates. The Company should report whether it can negotiate with large, load shiftable customers to achieve reductions of peak usage, and whether such an approach could be a cost-effective way of avoiding the need for a distribution project.

Recommendation 15: In the forward-looking distribution system planning included in future IRPs, NW Natural should consider in its study of non-pipe alternatives whether it could develop an operational flow tariff for reductions of peak usage on the constrained portion of the distribution system with different price and load reduction requirements than the current interruptible tariff.

Long-Term Distribution System Planning

Analysis

Staff appreciates and supports the Company sharing its plans to deploy a forward-looking distribution system planning process.[48] A forward-looking process will help with the evaluation of non-pipe alternatives by providing more lead time in advance of distribution system constraints. This additional lead time will be essential to full consideration of alternatives that can help reduce the risks associated with new load and new distribution system capacity. These risks are further discussed in Section **3.1 - RISKS OF NEW LOAD.**

Staff stresses that two crucial factors in determining distribution system investments need to be explored more fully by the next IRP. The first factor is the timing of when evaluations and analysis need to be conducted for areas of the distribution system under observation for expected future issues. The second factor is the application of the criteria by which the Company determines that a large upgrade project may be needed.

Regarding the first factor, in the case of Forest Grove Feeder uprate project, if there had been more time available for planning to prevent low pressure events, then other alternative solutions may have been achieved. Unfortunately, neither the 2018 IRP filed in August 2018 or the IRP 2018 Update filed in March 2021 mentioned Forest Grove as an area that had been monitored and might require a system upgrade.

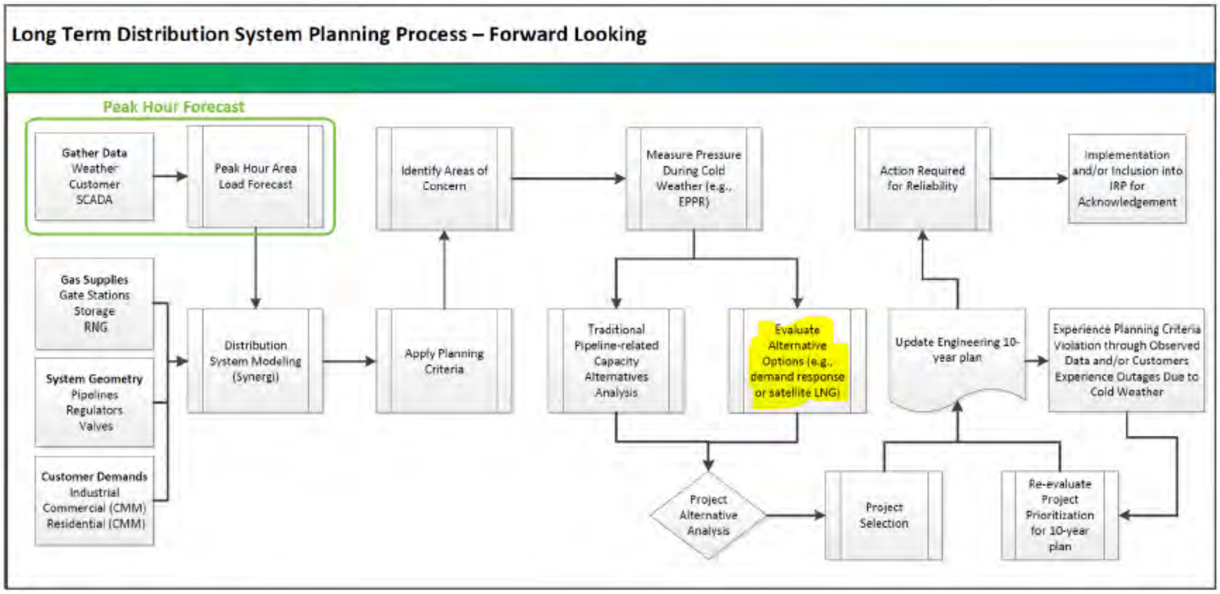
In the 2022 IRP, the 10-year distribution system plan helped the Company to prioritize areas of concern into near-term, medium term, and long-term evaluations.[49] However, for areas that need action within either the near-term or medium-term (traditionally included in an IRP), it is not clear at what point non-pipeline alternatives are considered. In the IRP, the flowchart mapping the long-term distribution system planning process shows the evaluation of alternative options being conducted alongside pipeline capacity alternative analysis:[50]

[48] NW Natural 2022 IRP. Page 355.

[49] Docket No. LC 79 - NW Natural's 2022 Integrated Resource Plan: Errata Filing (October 21, 2022), p. 358.

[50] Docket No. LC 79 - NW Natural's 2022 Integrated Resource Plan: Errata Filing (October 21, 2022), p. 359. (Emphasis added.)

Figure 8.2: Distribution System Planning Process – Peak Hour



As demand side solutions require longer time to evaluate and analyze, presenting a project 2-3 years in advance does not give enough time for those alternative non-pipeline options to be considered on an equal footing.

Regarding the second factor, the Company's system reinforcement standards described in Chapter 8 of the 2022 IRP,[51] it is important for the Company to demonstrate how meeting or exceeding the system reinforcement parameters translate to requiring a system upgrade. For example, it was not totally clear when analyzing the Forest Grove Uprate project how system capacity is deemed stressed in the model when any one of the enforcement criteria are met. In this regard, it is equally important to demonstrate the times when actual firm customer demand coincides with peak times and how it compares with modeled customer load.

In the Forest Grove case, lengthy information requests and meetings with the Company were required for Staff to understand how violating planning standards translated to capacity system issues under the assumptions made in the model. While they were appreciated, Staff believes they can mostly be avoided in the future with a better understanding of the timing of evaluations and reinforcement standards.

<u>Conclusion</u>

Based on discussion on long-term planning, Staff concluded that longer times for evaluation and analysis are needed to validate the full potential of non-pipe alternatives. Fortunately, this conclusion agrees with NW Natural's long-term plans expressed in its 2022 IRP.[52] Longer lead times will allow for the consideration of efficiency and demand response solutions, including peak-load-reduction RFPs for third parties that can help reduce locational peak load.

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[51] Docket No. LC 79 - NW Natural's 2022 Integrated Resource Plan: Errata Filing (October 21, 2022), p. 367.
[52] Docket No. LC 79 - NW Natural's 2022 Integrated Resource Plan: Errata Filing (October 21, 2022), p. 355.

In addition, when presenting large distribution system projects in advance, it is vital that the appropriate data is presented to demonstrate how breaching system reinforcement standards impacts system capacity. The Company should provide a rigorous assessment of why its current reinforcement standards, including the expectation of a 40 percent pressure drop, are sufficiently concerning to warrant new investment in pipe or non-pipe distribution system investments.

Recommendation* 16*: Toward the goal of facilitating forward-looking distribution planning, NW Natural should provide a 10-year distribution system plan in its next IRP Update, as the Company indicated it plans to do.

Recommendation* 17*: In future IRPs, Staff recommends that when NW Natural is monitoring areas in the distribution system where system reinforcements may be needed in the future, whenever possible, ample time should be allowed for evaluation and analysis of GeoTEE and Geographically Targeted Demand Response (GeoDR), among other alternative solutions.

Recommendation* 18*: In the near-term, if NW Natural's geographical load reduction programs are not available to alleviate forward-looking distribution system constraints, then a peak load reduction RFP should be issued to third-parties.

Recommendation 19: In future IRPs, for multimillion dollar upgrade projects presented, NW Natural needs to demonstrate that its system reinforcement guidelines and customer delivery requirements represent a realistic risk of loss of load. For example, given that the Company's system reinforcement guidelines are based on a 40 percent pressure drop equivalent to a pipeline at 80 percent of its capacity, under what circumstances would an unexpected weather or load event result in use of the additional 20 percent of peak capacity that could lead to a loss of load event?

3.4 - Geographically Targeted Programs

Anna Kim, Senior Utility Analyst

In Reply Comments, the Company requests direction on the "social desirability" of geographically targeted programs:

> Options such as Geographically Targeted Energy Efficiency (GeoTEE) and Geographically Targeted Demand Response (GeoDR) still need additional information on costs and reliability being gather by through [sic] the GeoTEE pilot as well as direction from the Commission on the social desirability of such targeted programs before bringing a GeoTEE or GeoDR project through an IRP.[53]

[53] LC 79—Reply Comments, p. 62.

Staff sees the locational targeting of program designs like GeoTEE to be consistent with Staff's understanding of acquiring cost-effective energy efficiency when the cost of alternative investments are shared by all customers. When the benefits of a program outweigh the costs of the program and cost less than the alternative, the program is cost-effective, even if participation is limited.

When any individual participates in a cost-effective program, such as traditional energy efficiency programs, the participant gains more benefits than the average customer, but all customers benefit through reduced resource acquisition costs. Similarly, participants in a geographically targeted program gain more from participation than the average customer, but all customers benefit from that participation through reduced distribution costs. Staff notes that Energy Trust has run other location-specific projects with Pacific Power and through Savings Within Reach. PGE also runs geographically targeted studies through the Smart Grid Testbeds.

Concerns about the appearance of fairness from geographically targeted programs have not been problematic with other utilities and should not stop the Company from developing such incentive programs as they should reduce the cost of service for all customers. These programs should be designed with a perspective of diversity, equity, and inclusion, as is the case for all traditional energy efficiency programs.

3.5 - Performance Incentive

Rose Anderson, Senior Economist

Climate Advocates suggested a Performance Incentive Mechanism (PIM) in Opening Comments. Staff is aware that NW Natural's financial incentive to construct capital projects and earn a return on investment may be counter to OPUC goals of ensuring NW Natural's resource strategy is least-cost, least-risk given all factors, including GHG reduction requirements. A PIM is a potential way to bring the Company's incentives into better alignment with OPUC goals.

Staff reached out to the Regulatory Assistance Project (RAP) to request information about PIMs that have been considered and implemented for utilities in other jurisdictions. After reviewing the examples provided, Staff found one incentive to be particularly interesting for consideration in NW Natural's long-term planning.

Among the guidance provided by RAP was that a PIM should usually not be used to incentivize compliance with a law or rule. Compliance itself is considered to be enough of an incentive. In consideration of this guidance and given that the Company is already required to significantly reduce GHG emissions, Staff did not explore incentives that encourage reduction of greenhouse gasses directly.

Instead, an incentive to compensate the utility for reducing or delaying the need for distribution system upgrades seemed interesting given the importance of avoiding unnecessary, long-lived new upgrades to the gas system in this time of uncertainty.

An example of this type of PIM is the gas incentive for non-pipe solutions implemented for ConEdison in New York. Staff proposes a discussion of a non-pipe solution incentive for NW Natural. Such an incentive should motivate the company to find alternatives to distribution system uprates that increase the amount of hard-to-decarbonize load on the system. Potentially, the incentive could apply to equipment used to electrify load as needed to avoid distribution system upgrades, which could make the utility more indifferent to electrification in the instance where it provides significant benefits in the form of distribution system savings. As Staff works with the Company and stakeholders to refine our approach to assessing non-pipe alternatives we will also explore the use of PIMs to support these activities and may seek to engage with third-parties to assist our efforts.

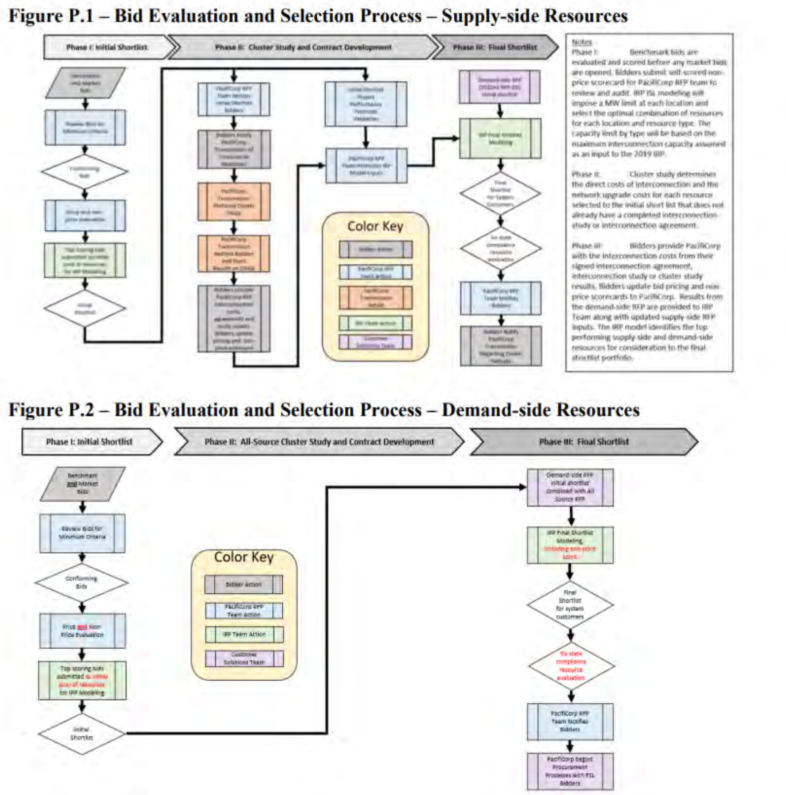
3.6 - RNG: Ownership vs. Contractual purchases

Ted Drennan, Energy Policy Analyst

In Opening Comments, Staff provided recommendations regarding RNG procurement activities. Neither the Company, nor any stakeholders, provided additional comments on this topic. Staff continues to believe there would be benefits from NW Natural publishing details of its RFP design and scoring in its IRP, similar to the approach used by investor-owned electric utilities in Oregon. This would help developers in this nascent market, and stakeholders more broadly, understand NW Natural's RNG preferences and how the Company evaluates different bids. Recent examples can be seen for both PGE and PacifiCorp. PGE's 2019 IRP, Appendix J: Renewable RFP Design and Modeling Methodology[54] and PacifiCorp's 2021 IRP, Appendix P[55] both contain details of price and non-price scoring. PacifiCorp has a very detailed bid-evaluation and selection process as shown below Figure 2: PacifiCorp's Bid Evaluation and Scoring Process:[56]

[54] *See* PGE Integrated Resource Plan at page 367 (July 2019).
[55] *See* PacifiCorp 2021 Integrated Resource Plan at page 269 (September 1, 2021).
[56] Ibid at page 277.

Figure 2: PacifiCorp's Bid Evaluation and Scoring Process



PacifiCorp's IRP also includes listing of variables[57] for price scoring, accounting for 75 percent of the bid score, and minimum bidder qualifications.[58] PacifiCorp's non-price scoring, the remaining 25 percent of a bid score, is designed so that bidders are able to self-score,[59] demonstrating the characteristics that PacifiCorp believes are most important for resource selection. Including this level of detail in the IRP is designed to tell the market what the Company wants and values.

An approach similar to that of PacifiCorp and PGE would be beneficial to market participants, NW Natural customers, and the Company overall. Recommendations included in Staff's Opening Comments remain valid today. However, Staff has updated them to provide more clarity and direction.

Recommendation 20: In future IRPs, NWN should provide an RNG procurement scoring methodology and associated modeling details, including up to date and accurate table(s) that list all sources of data inputs to the RNG acquisition model, as well as a narrative description of all updates and changes.

[57] Ibid at page 279.
[58] Ibid at page 286.
[59] Ibid at page 289.

Recommendation 21: If the Company updates its RNG procurement approach from what was included in its most recent acknowledged IRP, the Company should notify the Commission of the changes in its IRP Update. The update should include, at a minimum, where inputs and assumptions differ from those in its most recently acknowledged IRP and provide rationale for all changes.

Recommendation 22 : In the next IRP, NWN should discuss whether and how the RNG projects secured since the last IRP are in the best interest of ratepayers, including a discussion on how the various project types and associated deal structures (buy vs build) share costs, benefits, and risk across ratepayers and shareholders.

3.7 - Transport and Interruptible Customers

JP Batmale, Division Administrator

Transport & Interruptible Customers

Staff's Position from Opening Comments

Transport customers included in the DEQ's Climate Protection Program (CPP) accounts for a sizeable percent of NW Natural's covered emissions. This makes transport customers one of the largest sources of the Company's covered emissions under the CPP. How emissions are reduced from CPP covered transport customers is an important component to NW Natural's near- and long-term compliance strategy.

Further, energy efficiency (EE) is one of the three pillars of NW Natural's CPP compliance strategy. EE accounts for between approximately 5 to 9 percent of emission reductions during the first and second CPP compliance periods. Specifically, transport customers are forecasted to provide no EE savings from 2022 – 2024 and approximately 17 percent of the total EE demand reduction between 2025 – 2027.[60] Yet, currently only cost-of-service gas customers pay for EE programs; transport customers pay nothing in current rates.

To this end, Staff's Opening Comments requested two things. First, Staff sought an update regarding the accelerated launch of any energy efficiency programs directed at transport customers.[61] This inquiry echoed a key recommendation from UM 2178's Final Report.[62]

Second, Staff directed NW Natural to share with Energy Trust of Oregon (Energy Trust or ETO) a list of CPP-covered transport customers.[63] Staff surmised that the non-profit most likely had existing relationships with many of NW Natural's CPP-covered transport customers and could easily identify immediate savings/reductions.

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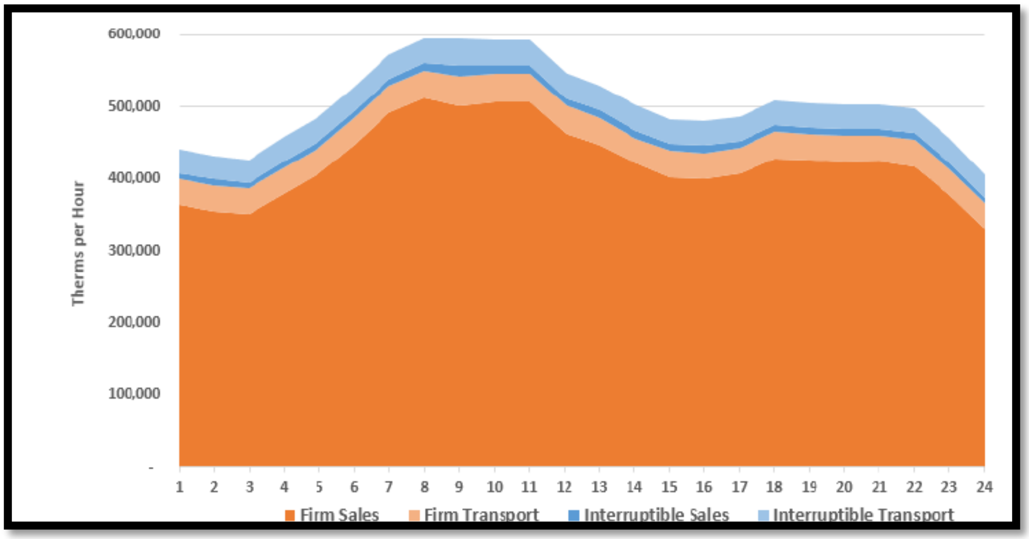
[60] *See* LC 79, IRP Workpapers, Workpaper_2022 IRP Scenario Results, Tab: Compliance Data.
[61] LC 79, Staff Opening Comments, December 30, 2022, Request 16, page 12.
[62] UM 2178, Natural Gas Fact Finding, Final Report, January 31, 2023, page 38.
[63] LC 79, Staff Opening Comments, December 30, 2022, Request 17, page 12.

In addition, Staff Opening Comments discussed interruptible customers. These customers form the entirety of NW Natural's current demand response capabilities.

Figure 3, Existing Demand Response Impact [64]



The figure above shows that approximately 2 percent of peak day sales load can be interrupted, and approximately 9 percent of total deliveries can be interrupted at peak.[65] To this end, Staff noted in its Opening Comments the extent to which future demand response capabilities naturally align with both interruptible and transport customers to control peak demand.[66]

NWN Reply Comments

The Company's reply comments detail current activities whose near-term results will be the identification of potential energy efficiency savings from CPP-covered transport customers. NW Natural's work in this regard builds on previous third-party consulting work to analyze potential savings from transport customers. It also includes offering a no-cost, time-limited, behavioral energy savings program led by Lawrence Berkley National Lab. NW Natural also expressed an openness to work and share data with ETO to launch a transport efficiency program.

And while the Company has an action item regarding the establishment of a transport customer EE program, NW Natural's reply comments also noted several, near-term programmatic and administerial hurdles to the immediate launching of a transport efficiency program. These included the revision of administrative rules related to sharing transport customer data with ETO, along with developing a Transport EE program and associated tariff with stakeholders.

With regards to demand response and transport customers, the Company made no specific arguments. However, NW Natural noted its concerns regarding the 2024 launch of a residential

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[64] LC 79, NW Natural 2022 IRP, September 23, 2022, page 108.
[65] *Ibid.*
[66] LC 79, Staff Opening Comments, December 30, 2022, page 45.

and commercial DR pilot.[67] These include concerns about modeling of such programs in PLEXOS and the general appropriateness of such programs in a policy and regulatory environment of declining load forecasts, the existence of GEOTEE pilots, and the Company's access to Mist storage recall. [68,69] NW Natural's reply comments put forth that any discussions on modeling or launching DR pilots should wait until the Company's 2022 IRP load forecast issues were resolved.[70]

Stakeholder Comments on Transport Customers in the NW Natural IRP

AWEC

The Alliance of Western Energy Consumers (AWEC) provided opening comments addressing transport customer issues in the NW Natural IRP. AWEC's filing conveyed a sense of urgency to act on several topics related to either mitigating the cost of CPP compliance or better reflecting the cost and benefit of transport customers to both the NW Natural system and GHG reduction efforts. To accomplish these goals, AWEC made five recommendations. They were:

- **Modifications to Existing Action Plan Items**
    - Action Plan Item 6: NW Natural will independently procure discrete transportation energy efficiency projects at a fixed rate equal to $14.00/dth, while continuing to develop a transportation energy efficiency program in collaboration with the ETO, AWEC, Staff and other interested parties.
    - Action Plan Item 7: NW Natural will procure the maximum amount of CCIs for CPP compliance in each compliance year and will include CCIs as a compliance alternative in PLEXOS in future IRPs.
- **Addition of New Action Plan Items**
    - Develop a method to attribute carbon savings resulting from the CPP to transportation customers since the CPP compliance instruments are obtained on transportation customers' behalf.
    - Study the impact of weather variable loads and load variability on CPP compliance for each rate class in the next IRP.
    - Study the value of interruptible throughput in the next IRP.

Staff's Transport Customer Recommendations

Staff finds AWEC's overall position and several of the subsequent recommendations to be compelling and generally aligned with Staff's thinking. In other sections of these comments Staff discusses the benefits of securing more EE and how CPP compliance resources like EE and CCIs should be treated differently in NW Natural's IRP modeling and planning. Below are Staff's recommendations related to transport customers.

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[67] LC 79, NW Natural IRP, Company Reply Comments, February 3, 2023, page 50.

[68] *Ibid,* Discussion of DR modeling concerns in PLEXOS, page 28, and discussion of DR cost-effectiveness in an era of declining load forecasts, page 51.

[69] *Ibid*, page 30.

[70] *Ibid,* page 30 and 50.

Transport Energy Efficiency Programs and Planning

We agree with AWEC that more rapidly securing EE – and thus GHG reductions – from CPP-covered transport customers should be a top priority for the Company between IRPs. Based on the IRP and NW Natural's Reply Comments, we do not believe the Company would disagree. Given NW Natural's Action Item to establish a program by 2024, the main differences seem to be around approach, not in the logic.

The magnitude of potential, near-term savings from CPP covered transport customer is meaningful to the Company's CPP compliance strategies around costs and risk reduction. Based on the estimates provided to NW Natural for this IRP, if a transport customer EE program had been in place between 2022 and 2024 then ***over one percent*** of eligible transport customers baseline load could have already been avoided.[71] Taking the 2021 OPUC stat book figure for therms distributed by NW Natural to transport customers as a theoretical "baseline," Staff estimates that approximately 3.7 million therms would have been avoided over the 2022 to 2024 timeframe.[72] While only a very broad estimate, this amounts to approximately a 10 to 20 percent increase in energy savings over that same time period. For further context, the 3.7 million therm savings could have resulted in upwards of 19,000 tons of additional emissions avoided by 2024.

Programmatically, Staff's initial intuition was to turn to Energy Trust for the immediate launch of such a program. The organization has existing and successful large commercial and industrial EE programs already covering gas and electric customers. This was the driver behind Staff's request to NW Natural in Opening Comments.

To this end, Staff is agnostic as to the organization the Company works with to acquire such savings. Much like AWEC, Staff feels that it needs to happen more quickly. Staff appreciated the Large Customer Carbon Reduction Program (LCCRP) AWEC advanced in UM 2178.[73] In re-reviewing this idea, Staff finds the concept could serve as a fruitful starting point for discussing the program design of a transport customer EE program launched in the very near future.

In terms of launching an offering immediately, AWEC raises excellent points around approaching large, transport customers for discrete, one-off EE projects that can happen very quickly.[74] Energy Trust refers to these as "custom" savings and has the programmatic infrastructure in place already for large industrial electric customers. And while Staff appreciates NW Natural's behavioral-based offering, its time-limited nature undercuts its value. Thus, given the known benefit of acquiring savings now, there would appear to be an ease to working with Energy Trust. They already have the necessary programs and already employ

[71] *See* LC 79, NW Natural 2022 IRP, September 23, 2022, page 170.
[72] *See* OPUC 2021 Stat Book, page 54.
[73] *See* UM 2178, Comments of the Alliance Of Western Energy Consumers, June 3, 2022, pages 3 and 4.
[74] *See* LC 79, AWEC Reply Comments, December 31, 2022, page 4.

industry-leading industrial efficiency engineers that have existing relationships with large facilities through their electric EE work.

To this end, Staff would also note that the urgency of acquiring low-cost and immediate transport EE savings would be sufficient grounds for Staff to support immediately waiving the rules prohibiting the sharing of transport customer information with Energy Trust. Staff would like to explore whether a potential waiver could include folding this information under the protections found for cost-of-service customers in OAR 860-086-0040(1) until the rules can be changed. Finally, if the Company should find greater benefit in not using Energy Trust for the immediate launch of a transport efficiency program by 2024, we simply ask they explain why when they bring forth the tariff to support such a route.

Recommendation 23: NW Natural should convene a stakeholder group immediately following the conclusion of the IRP to establish a transport customer efficiency program in time to be able to report on its status in the 2024 IRP update.

For planning purposes, Staff notes that the treatment of energy efficiency relative to supply-side resources needs to mature by the next IRP. Staff would simply ask that by the next IRP NW Natural have developed a deeper knowledge of its transport customers' technical, achievable potential savings. This should ensure the next load forecast better reflects these savings. Staff makes no recommendation on this topic.

Transport Energy Efficiency Avoided Cost Value

Staff agrees with AWEC's position that the avoided cost of a transport customer's emissions are mostly the avoided costs of CPP compliance.[75] However, we do not agree with the logic behind AWEC's proposed price for EE reductions.

AWEC asserts that transport customers' EE reductions should initially be compensated at the price of Tranche 1 RNG at $14.00/dth, claiming that it is the marginal cost of CPP compliance.[76] There are four reasons Staff opposes AWEC's position on incentive levels:

- A flat $14/dth is not an appropriate incentive level, because it would potentially reward transportation customers for reducing usage for any reason, which is not a least-cost incentive. An incentive for transportation customers should reward them for improving operations efficiency, like other EE programs, but the transport EE program should not pay a blanket $14/therm for reductions. It is out of line with current cost-effective approaches and, as proposed by AWEC, it could compensate transport customers for reductions due to economic conditions or other reasons. Staff is very interested in NW Natural helping develop transportation efficiency measures and programs, but the Company should not give a flat rate for any therm reduction and should base incentives on current EE incentive paradigms and best-practices.

[75] *Ibid,* page 4.
[76] *Ibid.*

- All energy efficiency, regardless of customer type, avoids CPP compliance costs. A value for one customer type in avoiding these costs, should be extended to all customer types.
- There is no evidence yet that RNG is the marginal cost of CPP compliance. A docket would be needed to establish what the cost of CPP compliance is on a per therm basis.
- The PUC's existing dockets and processes are a more appropriate forum to conduct the analysis and due diligence necessary to develop and adopt any new avoided cost value.

As part of Recommendation 23 above, Staff suggests that the process to establish a transport customer efficiency program in 2024 also include exploring an initial incentive level for CPP compliance that could be applied equally to other customer classes.

Recommendation 24: NW Natural, in the development of a transport customer efficiency program for 2024, should explore and share findings regarding an incentive that would adequately incentivize efficiency, but would not be applied as a flat, per therm rate to usage reductions for operational, economic, or other reasons.

Community Climate Investments

Staff and AWEC's position on the value, use, and modeling of Community Climate Investments (CCIs) for CPP compliance are very similar. AWEC states:

> All other things equal, CCIs are a more cost-effective means of CPP compliance than RNG, and therefore, it is prudent for NW Natural to acquire the maximum amount of allowable CCI investments in each year, before acquiring any RNG.[77]

Staff further discusses the use of CCIs relative to RNG in these comments in the Section on **ACTION ITEM 5 – SENATE BILL (SB) 98 RENEWABLE NATURAL GAS (RNG).**

Attribution of GHG Reductions

Staff supports AWEC's request that transport customers know how much carbon these customers have paid to reduce. Staff encourages NWN to work with AWEC to better understand how to implement this request and how to provide reliable estimates of carbon reduction paid for by transportation customers. It will be important to consider that transport customers should only receive credit for those reductions that can be verified as being paid for by those same customers.

Required Studies for the Next IRP

AWEC makes two study recommendations for the next IRP. The first study would cover weather-related load variability and the associated risks. The second study would seek to better value the benefits of interruptible loads.

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[77] *Ibid*, page 5.

With regard to the first study, AWEC requests a study of weather-variable load, arguing that that NW Natural has to over-comply with CPP because of weather variability. Staff notes that this is not necessarily true as long as the Company has some flexible compliance options that can be adjusted at the end of the compliance period. It is Staff's understanding that compliance options such as RTCs from RNG can be used for flexible compliance in future compliance periods. Additionally, NW Natural has indicated in discovery that if the Company has over-complied in a given compliance period, it will likely be able to sell any excess RTCs on the market.[78] This should help avoid significant costs of over-compliance to customers, especially while RTC/RIN value remains high. For these reasons, Staff sees cost burden associated with NW Natural's over-compliance with CPP as unlikely in the near term. Staff does not see a strong need for a study of weather-variable load.

As for studying the value of interruptible loads, Staff is supportive. However, any such study that NW Natural would choose to undertake should be designed to better inform the value of any program that shifts customer load away from peak, including residential and small commercial customers. Further, such a study should capture how often interruptible loads are actually called upon during peak events. Evidence uncovered by Staff and discussed in SECTION 3.3.2 - DISTRIBUTION SYSTEM PROJECTS leads Staff to believe that interruptible loads are not always called up during peak events and thus calls into question their tariff design. Regardless, we encourage NW Natural to reach out to AWEC to discuss their concerns. Additionally, in their next IRP or rate case NW Natural should provide a better understanding of the intersection of interruptible programs and transport customers as a demand response resource and for NW Natural, AWEC, and Staff to then determine the extent to which their compensation appropriately reflects their benefits.

Recommendation 25: Staff recommends the Company reach out to AWEC to discuss whether the value of interruptible customers is being adequately represented in the IRP and make any appropriate updates in the 2022 IRP Update.

[78] NW Natural's Reply to Staff DR 153.

Section 4: Long Term Plan

NW Natural has worked hard to plan for a future that is uncertain and changing rapidly. The IRP is a commendable and exciting effort to adapt to a rapidly changing policy environment with emerging low-carbon technologies. The low-carbon fuels and technologies considered in the IRP may indeed be an important part of the future of decarbonization on the gas system.

However, in this challenging planning environment the costs and risks of the long-term plan have not yet been adequately explored, and unfortunately Staff can not recommend acknowledgement of the long-term plan at this time because the long-term plan does not yet adequately assess or mitigate risk, and does not include reasonably accurate estimates of all relevant inputs.

The areas of risk evaluation and input accuracy that need to be improved in future IRPs are as follows:

1. Assess all top portfolios for risk, not just preferred portfolio.
2. Assess severity and variability of risk in top portfolios.
3. Provide adequate information on all relevant costs to evaluate the comparative costs and risks of portfolios.
4. More thoroughly assess the risk of relying on steep cost declines for technologies that are either emerging or not yet available on the market (syngas and gas heat pumps).
5. Work toward consideration of electrification as a resource option.
6. Include a reference case customer forecast that better reflects current trends and policies.
7. Provide additional support for cost and availability estimates of emerging technologies.

4.1 - Representation of All Costs

Rose Anderson, Senior Economist

Include All Relevant Gas System Costs

An important goal for future IRPs should be to accurately reflect all costs that change between portfolios, especially portfolios with very different load forecasts, to allow for comparison of NPVRR between portfolios. These costs include:

- “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."[79]

Line extension costs have been on the order of $30 million per year, or about $2.5 million per year in revenue requirement.[80,81] This is a substantial amount, and it should be reflected in IRP modeling as a cost that varies between portfolios with different amounts of new customers.

In a scenario with load decreasing, the number of new distribution system upgrades needed would also decrease as compared to a scenario with load growth. This difference is not reflected in current IRP scenarios.

The current modeling in PLEXOS does not allow unneeded capacity, such as pipeline contracts, Mist Recall, and LNG facilities to 'retire' economically. Retirement of these resources when they become uneconomic would be essential to providing service to customers at reasonable cost, and IRP analysis needs to include these retirement decisions.

As a first step toward complete and comparable portfolios, the Company should work toward reflecting appropriately the varying levels of these costs in portfolios with different load and peak load forecasts.

Recommendation 26: The next IRP should include modeling of all relevant distribution system costs and capacity costs, including additional projects that would be needed in high load scenarios as well as costs that would not be incurred in lower load scenarios.

Electrification Costs

While the IRP was an impressive first assessment of how to meet the challenging goal of decarbonization of the gas system, one of the elements which should be considered in gas and electric utility planning moving forward is the variety of costs and risks associated with electrification.

The Company makes it clear that it does not profess to know how these costs and risks manifest for the electric utilities with which it shares territory. While it is understandable that the Company has not yet been able to estimate electric system costs, looking at these costs in IRPs moving forward will be an important way to facilitate consideration of which decarbonization pathways result in the lowest cost and risk for households. The Commission will be better able to ensure just and reasonable rates if it can look holistically at the effects of various

[79] Synapse Energy Economics. Review of Northwest Natural Gas 2022 Integrated Resource Plan – Final Report. Page 41.
[80] Synapse Energy Economics. Review of Northwest Natural Gas 2022 Integrated Resource Plan – Final Report. Page 43.
[81] Docket No. UG 435. NW Natural's Response to CUB DR 84a.

decarbonization pathways on households as gas and electric customers, rather than just their gas bills.

Moving forward with the consideration of these costs in gas utility IRPs will take careful study and collaboration between utilities, stakeholders, the Commission, and third-party experts. To begin the conversation, Staff is engaging Synapse to provide an initial, high-level study of electrification costs. Synapse has taken a first look at the question of how to compare electrification costs between portfolios, and this study is described in the Synapse report attached to this Staff Report as Appendix A. The Synapse study is not definitive and does not address many of the important questions raised by stakeholders in comments filed March 8, including the potential electric rate impacts of increased demand on the electric system and building-specific electrification costs in Oregon. The study has a large margin of error and is intended as a framework for discussion rather than as a full answer to questions about electrification costs. It will hopefully spur a conversation around how to improve the estimate and eventually include these costs as a consideration in the comparison of IRP portfolios.

Regarding electrification modeling next steps, in comments, Climate Advocates wrote:

> As a starting point, the Commission should review Appendix B of the UM 2178 Draft Report for improvements that could be made to the IRP process. Specifically, Appendix B includes a recommendation for the gas utility to develop beneficial electrification assumptions in coordination with the electric utility. Taking this recommendation one step further, Climate Advocates recommend that the Commission explore developing a formal planning partnership between NWN and electric utilities in which the electric and gas utilities model key scenarios and sensitivities from the other fuel utility. In this proposal, electric utilities would develop models using the inputs of NWN's scenarios from its next IRP.[82]

Staff appreciates this connection to the dialogue from UM 2178.

To this end, Staff has engaged The Cadmus Group to help inform and consider the possibilities of increased coordination between gas and electric utility planning to help reduce the cost and risks of decarbonization to customers. The research objectives of the Cadmus study are to:

- Understand current challenges for achieving GHG emission reductions within existing planning framework. It will consider (1) the regulatory decision-making framework, (2) data needs (e.g., market price forecasts, load forecasts, customer growth forecasts), and (3) modeling needs.

[82] See Docket LC 79, Climate Advocates' Opening Comments, December 30, 2022. Page 8.

- Identify best practices that could be implemented to resolve these challenges and facilitate systemwide (gas + electric) planning to achieve least-cost, least-risk carbon reductions for Oregon's regulated gas and electric utilities.
- Identify key challenges and opportunities for systemwide (gas and electric) planning to inform agenda development for upcoming workshops to define actionable next steps.

The study will culminate in Summer 2023 with a report summarizing findings, including outlining information, tools, and evaluation framework elements needed to begin making connections between electric and gas utility IRPs. Staff anticipates that this study, along with Synapse's development of electrification costs, will help inform how electrification is modeled in future IRPs.

Once the Synapse and Cadmus studies are complete, it may be helpful to open a discussion forum for all gas IRP participants. The discussion can include ways to improve and refine electrification cost estimates for better comparison between gas IRP portfolios' NPVRR, and whether electrification should be modeled as a greenhouse gas reduction compliance option in gas IRPs. Staff supports Climate Advocates' recommendation to engage participants in UM 2178 on the question of how to proceed.

While the Commission could, of course, choose to make a decision regarding this matter in this docket, as it applies to NW Natural's IRP, it may be better to wait. In the near future the Commissioners will be able to see the results from these studies and then request feedback from stakeholders on the questions of how to proceed and what the scope of work and qualifications for any third-party should be. Commissioner interests and priorities regarding next steps for collaborative gas/electric utility planning and the calculation of electrification costs and benefits are welcome in this docket or other planning dockets going forward.

Transparent Cost Categories

In addition to the total NPVRR of each portfolio, information about the components of NPVRR should be available for review with the IRP. Staff requests the Company provide a clear breakout of costs by type and by year in the next IRP. For example, categories could include distribution LEA, distribution system upgrade, supply side resources, capacity resources, and demand response. This should include a summary table of cost category NPVRR by portfolio.

Recommendation 27: The Company should provide NPVRR for each portfolio in the next IRP and a breakdown of portfolio NPVRR into cost categories in workpapers filed with the IRP.

4.2 - Portfolio Evaluation: Stochastic Analysis

Curtis Dlouhy, Senior Economist & Policy Analyst

Stochastic Analysis Within Each Scenario Rather Than Across All Scenarios

In Opening Comments, OPUC Staff Request 7 asked NW Natural to do stochastic analysis *within* multiple scenarios in future IRPs, rather than *across* all scenarios like the Company did in its initial LC 79 filing. Performing stochastic analysis within scenarios means that each scenario has its own stochastic analysis. This allows risks to be compared between scenarios. In comparison, NW Natural's IRP foregoes stochastic analysis for each scenario and instead combines a variety of inputs from the different scenarios into one stochastic analysis.

Additionally, Staff's request for stochastic analysis within scenarios is intended to address Staff's concern that NW Natural's "stochastics across scenarios" approach imposes assumptions over uncertainty, which, if not addressed, could paint an inaccurate picture of the risk associated with each portfolio.[83] Similarly, Climate Advocate's Opening Comments noted that the Company's IRP does not "perform an adequate quantitative and qualitative assessment of the risk of each scenario" and suggests the Company could address this with sensitivities or other means.[84] Although the Company stated in Reply Comments that it would not oppose doing stochastic analysis within each scenario, the Company claims that doing stochastic analysis within each scenario 1) still leads to bias, and 2) requires that all scenarios be deemed equally likely to occur. Staff disagrees with the Company's characterization of Staff's suggested approach and maintains that it would bring additional clarity to the risk analysis.

NW Natural's current framework of "stochastics across scenarios" does not adequately quantify the costs and risk of each scenario. Staff noted that this approach imposes assumptions over uncertainty, which, if not addressed, could paint an inaccurate picture of the risk associated with each portfolio. For example, the Company's current approach makes it difficult to analyze how the NPVRR of a portfolio resulting from a low RNG price scenario would respond to an unexpected change in load or the adoption of gas heat pumps. Having this visibility into the risks of one scenario, and the ability to compare its risks with the risks of a different scenario, provides the ability to compare risks associated with different pathways. If only one stochastic analysis is done, it becomes more difficult to think about the comparative risks of decisions such as incentivizing dual fuel heat pumps (Scenario 3, for which there is no risk analysis in the IRP).

The Company claims that moving to a "stochastics within scenarios" approach does not solve the bias problem of the "stochastics across scenarios" approach and could in fact lead to a

[83] Staff Opening Comments. Pages 24-26.

[84] See Docket No. LC 79 Climate Advocates Opening Comments, December 30, 2022 pg. 7.

different bias, noting that the true underlying distribution is unknowable.[85] Staff finds this critique to be an unproductive distraction from the overall recommendation to use the "stochastics within scenarios" approach. While it is true that the underlying distribution of *every* real-world instance of randomness is unknowable, some are well enough understood, such as price dynamics, customer choice absent policy nudges, or weather, that they are worth modelling as stochastic processes for planning purposes. On the other hand, issues of policy implementation or Company choices that characterize many of the Company's scenarios have such high levels of uncertainty that Staff finds it either unproductive or actively detrimental to the planning process to perform an analysis that uses them to inform an overall stochastic distribution. As Staff has described in its Opening Comments, the Company's characterization of Staff's suggested approach is incorrect because abstracting away from uncertainty removes a source of bias rather than assigning a probability to it in a model.

The Company also claims that Staff's suggested "stochastics within scenarios" analysis requires that the analysis be conducted in a way that assumes all scenarios are equally likely.[86] Staff disagrees with this claim. The Company's claim is equivalent to saying that merely discussing different outcomes makes them equally likely to occur. Rather, Staff's recommended "stochastics within scenarios" approach allows the Company to avoid modeling the impossible to model items Staff identified in its Opening Comments, such as appetite for policy choices made in a different regulatory climate. By employing a "stochastics within scenarios" approach, the Company need not even assign a probability between scenarios and can keep analysis of each scenario entirely separate from each other. As stated in Staff Opening Comments, this allows the Company and stakeholders to better understand the risk within each scenario. In the next IRP, Staff recommends that the Company be required to do a Monte Carlo analysis of the top scenarios rather than across scenarios.

While Staff used the example of 50 Monte Carlo runs within each scenario and the reference case in Staff's initial comments, Staff does not want this to be interpreted as a mandate for how a "stochastics within scenarios" analysis should be run. Staff understands that new analysis techniques or ideas may arise as the Company's IRP analysis evolves and wants to leave some degree of flexibility to incorporate new ideas where appropriate. However, Staff wants to make it clear that it expects to see the resource portfolio and NPVRR of multiple stochastic futures, evaluated within at least the top few scenarios identified by Staff and stakeholders, when the Company files its next IRP. For more discussion on stochastic analysis and reporting see Section **4.3 - Portfolio Modeling: Risk Severity and Variability.**

Recommendation 28: In the next IRP, Staff recommends that the Company be required to do a Monte Carlo analysis of the top scenarios rather than across scenarios.

[85] Company's Reply Comments, Page 43.
[86] Company's Reply Comments, Page 43.

Revisit the stochastic modelling used in NW Natural's gas price forecast in a future IRP

In Staff Request 8, Staff requested that the Company explore alternative ways to do its stochastic modeling in its gas price forecast in a future IRP. In Opening Comments, Staff specifically highlights Vector Autoregressive (VAR) models or other time-series cointegrated models, noting that these allow for stochastic shocks to enter into the model through more than just the Alberta Energy Company (AECO) hub, which appeared to be all the Company's current method would do. The Company states that its current method still has the ability to incorporate the stochastic shocks at any hub but stated that it would be willing to explore alternative modeling approaches in a future IRP.[87] Staff finds this to be acceptable and looks forward to seeing how the Company's gas price forecast evolves.

4.3 - Portfolio Modeling: Risk Severity and Variability

Rose Anderson, Senior Economist

Staff thanks NW Natural for its reply regarding severity of risk in Reply Comments. However, the Company's interpretation of Staff's concern does not seem to capture Staff's intention. Staff is not concerned about stochastic distributions being generated outside of PLEXOS, and Staff is not concerned with severity only in the preferred portfolio as NW Natural states. Staff agrees with NW Natural that assessing the severity of risks associated with decisions being made in this IRP is an important part of risk assessment in an IRP. However, Staff would like to see in future IRPs an evaluation of risk in multiple portfolios that represent decisions the Company could make and potentially even decisions that various entities in the region could make collaboratively. Section **4.2 - Portfolio Evaluation: Stochastic Analysis** contains more discussion of the Company's stochastic analysis and why it should be performed within multiple scenarios, instead of across all scenarios.

PGE and PacifiCorp both provide stochastic assessments for top portfolios that represent different utility decisions. For example, PGE's most recent IRP looked at a variety of scenarios representing different potential approaches to resource planning. Each scenario was analyzed under 810 different futures, and PGE reported risk severity metrics for each scenario.[88,89,90] PGE considered scenarios with different methods of optimizing cost and risk, different rates of new resource acquisition, and different greenhouse gas reduction trajectories. The study of a variety of potential decisions allowed for a discussion of potential paths forward for the Company and the risks associated with each.

[87] Company's Reply Comments, page 45.
[88] PGE 2018 IRP. Appendix H. Summary of Portfolios.
[89] PGE 2018 IRP. Chapter 3. Page 85.
[90] PGE 2018 IRP. Executive Summary. Page 31.

PacifiCorp's recent IRP looked at scenarios with varying coal retirement decisions and selected one with favorable cost and risk metrics. After selecting one scenario, PacifiCorp ran eight sensitivities that looked at additional decisions the Company might make around transmission, near-term resource acquisition, and longer-term major resource decisions.[91] PacifiCorp reported the following stochastic metrics for each sensitivity:

- Stochastic mean PVRR,
- Upper-tail Mean PVRR,
- 5th, 90th and 95th percentile PVRR,
- Standard deviation, and
- Risk-adjustment (5% of the 95th percentile).[92]

NW Natural should model its IRP after these approaches that evaluate the risks of various decisions the utility could make. Although the range of options available to NW Natural may not be as wide as for electric utilities, the Company should consider different pathways that it could pursue to reduce cost and risk for customers, and it should evaluate the risks of each pathway using stochastics.

For example, the Company should look at key decisions to study. This could be a decision to aggressively pursue dual fuel heat pumps in collaboration with the Commission, ETO, and electric utilities; a regional decision to pursue gas heat pumps; or a decision to more aggressively pursue efficiency and ask Energy Trust to search for new sources of Technical Achievable Potential for efficiency. By assessing ways the Company can actively shape the future and the risks associated with each path, the IRP can become a more useful planning tool.

Recommendation 29: NW Natural's next IRP should provide metrics comparing the severity and variability of risk in key portfolios.

4.4 - Dual Fuel Heat Pump Pilot

Anna Kim, Senior Utility Analyst

In Reply Comments, the Company asked about Staff's perspective and goals for a dual fuel heat pump pilot.[93] This is a pilot proposed by Energy Trust. Staff fully supports Energy Trust's efforts to design and conduct a pilot project on dual fuel heat pumps.

The purpose of the pilot proposed by Energy Trust is to learn and evaluate the potential benefits of a dual-fuel heating system. Energy Trust operates energy efficiency programs for electric utilities and natural gas utilities. Staff understands that Energy Trust has gained verbal agreement from all five funding utilities (PAC, PGE, NW Natural, Avista, Cascade) to fund the

[91] PacifiCorp 2021 IRP. Page 245.
[92] PacifiCorp 2021 IRP. Appendix J. Pages 211-213.
[93] LC 79—Reply Comments, p. 30-34.

dual fuel heat pump pilot. The information that Energy Trust intends to gather from this pilot will inform the role of dual-fuel systems in meeting Oregon's clean energy goals, and the goals of all five funding utilities. Energy Trust's dual fuel heat pump pilot proposal does not set precedent or include assumptions about how a future program will be paid for or compensated. Rather, this activity gathers information that would inform whether a future offer should be created and how such an offer could be designed. Without additional information about performance and usage, it is not possible to speculate on what would be appropriate for this technology.

Staff understands that Energy Trust proposed this pilot in order to collect new information that is currently not available through existing energy efficiency measures with which Energy Trust works or publicly available measurements from the region. Staff understands that while Energy Trust has ideas for research questions and learning objectives, Energy Trust also wants to work with all the funding utilities to collaborate on identifying these objectives.

The dual fuel heat pump pilot is not designed to be scalable but to collect information that could enable a future opportunity. Generally, Staff appreciates NW Natural's forward-thinking about the need to work towards sustainable offers.

Staff appreciates the thoughtful consideration the Company put into its "Appendix D: Hybrid Heating Pilot" of Reply Comments. Staff reiterates that the current pilot is proposed by Energy Trust and that it will involve participation from five different funding utilities. There are many aspects in Appendix D that sound interesting and useful that may be outside the scope of Energy Trust's pilot or Energy Trust's current funding sources. For example, Energy Trust is not currently funded to research or run demand response programs. Energy Trust is a collaborative partner to utility-led demand response programs but does not currently run any demand response directly. Staff encourages the Company to work with Energy Trust to determine what aspects of Appendix D fit within the scope of the proposed pilot that can be incorporated. If there is additional research outside of Energy Trust's scope, Staff encourages the Company to consider what additional information is worth pursuing with alternative funding options.

For further discussion of dual fuel heat pumps and other studies that may help inform their value, see Section **4.5 - DUAL FUEL POTENTIAL.**

4.5 - Dual Fuel Potential

Rose Anderson, Senior Economist

When considering electrification of the gas system, the extent to which new electric generation and transmission capacity would be needed to accommodate an increase in seasonal heating load is unknown. Increases in peak-hour load are a major driver of costs to the electric system, and the amount of new capacity needed would likely be significant.

NW Natural's Reply Comments note that Hydro Quebec (a state-run electric company) and Energir (a privately owned gas company) have worked together to study the potential of dual fuel space heating to help decarbonize the gas and electric systems, while also reducing the need for new capacity on the electric system. The result is striking, as shown in the chart below. The utilities found that in a dual-fuel heat pump scenario, as compared to a full electrification scenario, there is a 2 GW reduction in peak electrical demand from targeted customers on the electric system by 2030:

Table 6. Comparative 2030 energy use impact of full electrification and dual-energy scenarios

	Full electrification	Dual-energy	Difference
Natural gas sale (Mm^3)	-401	-287	-28%
Electrical energy (GWh)	2,957	1,837	-38%
Peak electrical demand (MW)	2,070	63	-97%

Figures represent the total 2030 technical potential for replace-on-burnout in the targeted buildings and end-uses, assuming an available market of 1/15th of the total market each year. *Source*: Hydro-Québec and Énergir, 2021a [94]

Given the uncertainty around alternative fuels, electrification, and the interaction of decarbonization policies on the state's energy system broadly, a closer look at dual fuel heating may be a valuable way to understand how this innovative approach to heating may be operated to maximize the benefit to the gas system, the electric system, ratepayers, and the state. The Commission should encourage collaboration between gas and electric utilities in understanding the costs and benefits of dual fuel heat pump scenarios, as compared to electrification scenarios, under decarbonization requirements.

Staff learned in conversations with the Company that NWN looked at incentivizing dual fuel heat pumps in this IRP by providing a credit equal to an estimate of the difference between the cost of a heat pump with electric backup and the cost of a heat pump with gas backup. The company estimated this cost difference at $400. For the next IRP, Staff hopes the Company will continue to explore the possibilities around dual fuel heat pump incentives and provide more information about the technology, as well as providing support for the estimate of dual fuel heat pump costs in comparison to heat pumps with electric back up.

Additionally, in the next IRP, NW Natural should study the effect of dual fuel systems on gas system peak load, storage needs during cold weather periods, and gas system daily average load. It will be important to gain insight into what types of resource decisions today have the lowest regrets in a dual fuel heat pump future. Staff recommends the next IRP more fully explore the potential of dual fuel heat pumps and ensure that some dual fuel futures are

[94] ACEEE. Heating Electrification without Peak? A Unique Electric-Gas Collaboration Shows a Third Way is Possible. Page 6-228.

represented in any Monte Carlo risk analysis. These types of low load, high peak load scenarios do not appear to be represented in the present IRP's Monte Carlo.

In addition, dual fuel potential should be among the topics in any discussion of coordination between gas and electric utilities long-term planning that may take place in another venue as directed by the Commission.

Recommendation 30: To explore the potential benefits of dual fuel heat pumps, the Company's next IRP should include an in-depth study of dual fuel heat pump potential and the effects of dual fuel technology on peak and average load on the gas system.

4.6 - Load Forecast

Ryan Bain, Senior Utility Analyst

The Company's load forecast is principally the product of two components, the number of customers and their expected usage. In various IRP scenarios, the Company's load forecast is impacted by activities that NW Natural notes are exogenous to this IRP's portfolio modeling process: incremental energy efficiency and electrification.

Regarding the use per customer forecast, Staff appreciates the Company's responses regarding the performance of their modelling of usage per customer by class and the Company's reported out-of-sample forecast performance statistics for their Peak Day Firm Sales model. Broadly, Staff finds that the Company's models for usage per customer are reasonable and perform adequately in forecasting. However, the Company should be more forthcoming with their modelling inputs in future engagements.

Where Staff finds concern is with the assumptions used to estimate the first component of the load forecast, the customer count. In six of the nine scenarios used to illustrate how varying policy, technology, and cost assumptions could affect the load forecast, the "current expectations" for customer growth are one in the same with the "business as usual" reference case scenario. However, the "business as usual" reference case is an econometric forecast that only picks up historical customer count trends. The forecast does not consider any recent policy changes, simply because recent policies, including the new gas moratoriums and electrification incentives, have not been in effect long enough to be reflected in historical data. As noted by CUB,[95] two Oregon cities passed resolutions to ban new natural gas hookups for certain building types.

NW Natural's Reply Comments imply that Staff's concerns about the reference case load forecast are misplaced because the Company performs a stochastic Monte Carlo analysis in the

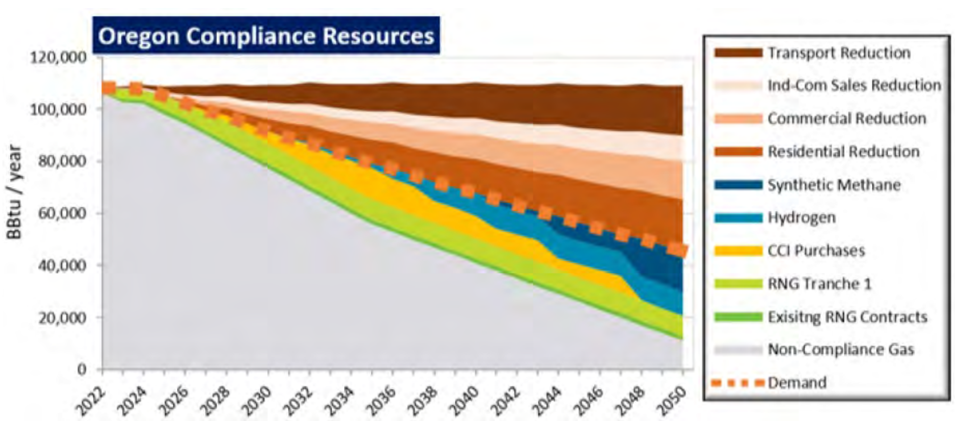
[95] https://edocs.puc.state.or.us/efdocs/HAC/lc79hac145936.pdf.

IRP that considers a variety of different load forecasts.[96] However, the Monte Carlo analysis is not the only important analysis in the IRP. Scenario analysis also informs the conversation about the Company's long-term plan. Much of the scenario analysis in this IRP is based on an unrealistic customer count forecast and is therefore less useful than it could be. Staff recommends that in the next IRP, the Company's reference case load forecast should better reflect current local, state, and federal policies. This action will better inform the Company's customer count forecasts by scenario and provide more reliable references for contrasting to their new stochastic load forecasting technique. This will better inform stakeholders and potentially protect ratepayers against imprudent expenditure.

While the reference case forecast should not be relied upon in this IRP for planning purposes, the Monte Carlo analysis in the IRP better reflects recent trends and policy. However, Staff reiterates that the use of a "business as usual" customer count forecast in six IRP scenarios distorts this IRP. In future IRPs, most scenarios should reflect the Company's best estimate of the future with individual sensitivities diverging from that expected forecast to inform the Company's planning decisions.

Additionally, in future IRPs when NW Natural represents electrification and energy efficiency as reductions to forecasted load, the Company should share the assumptions and/or modeling methodology used to represent the impact of these activities on forecasted load. For example, the figure below showing Oregon compliance resources could show residential electrification and residential efficiency, instead of just residential reduction.

Figure 4: Oregon Compliance Resources



[97]

Recommendation* 31*: In the next IRP, the Company's reference case load forecast should better reflect current local, state, and federal policies.

[96] NW Natural. Reply Comments, pages 8 - 10.
[97] NW Natural 2022 IRP. Page 319.

Recommendation 32: In the next IRP, NW Natural should clearly show which load reductions are because of efficiency and which are because of electrification.

4.7 - Energy Efficiency in PLEXOS

Rose Anderson, Senior Economist

Modeling Efficiency as Selectable in PLEXOS

In Opening Comments, Staff recommended the Company model energy efficiency as a selectable option in PLEXOS. Staff has looked further into this concept in conversations with NW Natural and Energy Trust and found that now may not be the ideal time to implement this modeling change.

First, NW Natural's 2022 IRP already includes about 94 percent of the efficiency in Energy Trust's Technical Achievable Potential. There does not appear to be a large amount of efficiency that could be added, even if PLEXOS found additional efficiency to be a cost-effective option. Second, both NW Natural and Energy Trust have noted that such a study will require a significant amount of work. Adding efficiency to PLEXOS modeling may not be an optimal use of time and resources at this time given the small amount of efficiency available to add.

In the future, it may be helpful to model increased amounts of efficiency as a selectable option in PLEXOS. This study could be performed as a sensitivity to inform a conversation about whether pursuing additional efficiency could be valuable. For example, in the leadup to PGE's 2023 IRP, PGE studied an additional 10 MWa of efficiency per year in its IRP model and found that amount of additional efficiency to reduce total NPVRR, even though it had been identified as 'non-cost-effective' using avoided cost calculations.[98]

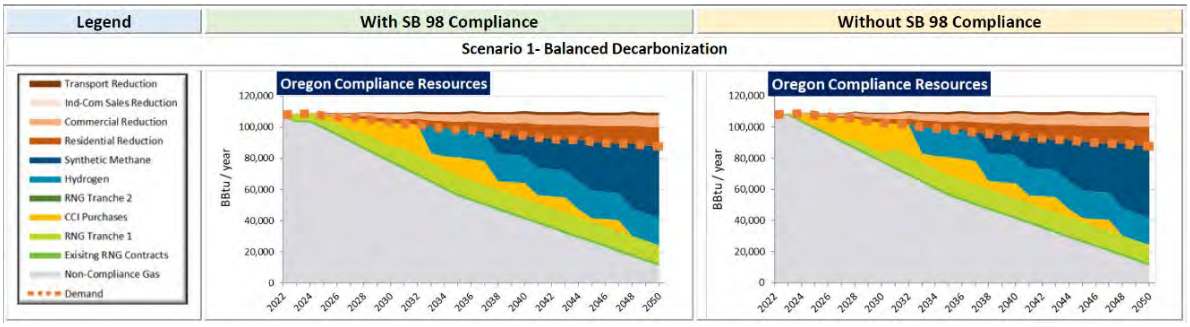
If future conversations with Energy Trust demonstrate that evaluating additional efficiency in NW Natural's IRP model could provide valuable information, then that study may be an informative starting point for conversation about whether and how Energy Trust should go about increasing its efficiency for NW Natural.

In the present IRP, rather than include efficiency modeling in PLEXOS, Staff requests the Company update its avoided costs to reflect that SB 98 RNG is voluntary and can be avoided with efficiency. The Company in its Reply Comments argued that modeling SB 98 RNG as voluntary would not change avoided costs. However, the Company's argument assumes that SB 98 RNG will continue to be treated as mandatory. Staff notes that once SB 98 RNG is modeled as non-mandatory, any RNG acquired for CPP purposes will become the avoided compliance resource for avoided cost calculations, instead of CCIs. NW Natural's Reply

[98] PGE Roundtable Presentation. January 2023. Page 57.

Comments show that this is expected to occur in about 2027 in its Balanced Decarbonization scenario.[99]

Figure 5



Recommendation 33: The Company should update its avoided costs to reflect that SB 98 RNG is voluntary and can be avoided with efficiency.

[99] NW Natural Reply Comments. Page 109.

4.8 - RNG Modeling and Appendix K

Ted Drennan, Energy Policy Analyst

Appendix K

Staff appreciates the Company's response to Staff Request 24 from Opening Comments and the additional detail provided to describe the differences between the RNG Evaluation Methodology provided in UM 2030 and methodology ultimately presented in the IRP. Staff requests that future IRPs include a clear report of any key changes in the methodology similar to that included in the Company's Reply Comments.[100]

When the Company filed its IRP on September 23, 2022, it did so without including Appendix K. The Company subsequently filed Appendix K on October 21, 2022. The Company then met with Staff to discuss its modeling of RNG on January 20, 2023, in response to Staff Request 25, which requested a meeting with the Company to discuss questions about the RNG workbook. At that time NW Natural indicated it would file a corrected version of Appendix K in February, which, as of March 23, 2023, has not been filed.

Staff has been unable to resolve all concerns as it has yet to see an updated version of Appendix K the Company had indicated it would provide. Further, Staff continues to see opportunities to improve risk inputs and modeling. However, Staff is comfortable enough with the current RNG modeling in this IRP to recommend continued use of the methodology and delay discussion of workbook improvements until future proceedings. Staff's willingness to address these issues in a future proceeding does not imply prudence for projects selected using the method.

Recommendation 34: The Company should provide an updated Appendix K which correctly describes the Company's modeling for RNG projects.

RNG Workbook

The issues regarding the RNG workbook that were discussed at the January 20 meeting included: 1) selection of "Type of Project" and associated outboard modeling, and 2) risk inputs and associated modeling.

In its response to Staff's Data Request 13, the Company explained that the "Project Type" in the RNG models submitted by the Company might not reflect the actual project because there had been additional outboard modeling, i.e., modeling that occurs outside of the RNG workbook. This outboard modeling was used in a number of ways. One way was to determine the total revenue requirement to input in the RNG model, which was derived in a cost-of-service model. The Company also used outboard models to calculate the value associated with the sale of brown gas in some of its earlier models. Where this occurred, the Company selected

[100] NW Natural Reply Comments at 53.

"Unbundled Environmental Attribute Purchase" for the project type, when the actual project was "RNG with Sale of Brown Gas." The Company addressed Staff's concern about this discrepancy between modeled projects and actual projects at the January 20 meeting. Staff understands this to be an issue with earlier models and likely will not be an issue going forward.

Staff's concerns with NW Natural's risk modeling for the RNG model in opening comments remain. In summary, these include the choice of risk distribution, the lack of inclusion of downside risk, and the lack of information on how the risk bands are selected by internal experts. For risk distribution, the Company uses a lognormal distribution for asymmetric risks but has offered no foundation for this approach.[101] Staff raised a question regarding the approach using a hypothetical example in opening comments[102] of a +/-20 percent risk band versus one with -19 percent and +20 percent. The risk distribution for the former would be assumed normal, the latter assumed lognormal. At the January 20 meeting, the Company explained under this hypothetical that the results would be similar under either lognormal or normal distributions. While this may be true in the hypothetical posed, it still does not provide rationale for the assumptions of a lognormal risk distribution. For reference, an example of the hypothetical risk data for a project included with the Company's RNG Incremental Cost Workbook is included below.

Risk Analysis Key Inputs		
RNG Volume Uncertainty		
Annual Prob RNG Supply Ceases		0.5%
Prob of Delay (1 and 2 year)	30%	5%
% Δ From Base Case	5th %	95th %
Project Volume Output	-20%	10%
Project Cost Uncertainty		
% Δ From Base Case	5th %	95th %
Carbon Intensity	-15%	15%
Payments to Investments	-5%	30%
Other non-output costs	-3%	5%
Non-offtake Variable Costs	-20%	30%
Offtake/Biogas Price	0%	0%
Other Offsetting Revenues	-12%	30%

[103]

The Company did not provide additional information on the reasons for ignoring downside risk (i.e., risks that could lower expected costs) in their modeling. Staff provided a hypothetical in opening comments for this as well.[104] In Staff's hypothetical there should be a clear preference for one project over another, but due to the Company's modeling approach the Company would be indifferent between the projects.

[101] RNG Incremental Cost Workbook.
[102] See Staff Comments at 56-57.
[103] RNG Incremental Cost Workbook, RNG Dashboard Tab.
[104] Ibid at 57.

Finally, there is a lack of a standardized approach to risk modeling, or selection of risk bands, which is still concerning to Staff. Here the Company's internal experts assess risks associated with various factors included in Table k.2 Project Evaluation Component Description.[105] There are no formal rules or processes for assigning risks, so it is not clear that results of the analysis would be the same under two different subject-matter experts. Comments from CUB highlight concerns about relying on internal experts with regard to gas heat pump adoption rates which were more optimistic than adoption rates from NEEA experts.[106] NW Natural's RNG modeling likewise relies on internal experts to assess risks associated with different projects. It is not clear to Staff whether there are policies in place at the Company to assure modeling of risks related to RNG projects are standardized, or if expert biases might systemically favor one type of project versus another. As discussed in Section **3.6 - RNG: OWNERSHIP VS. CONTRACTUAL PURCHASES**, the approach of the electric utilities, especially PacifiCorp which allows self-scoring for non-price attributes, would bring standardization and transparency to this process. Appendix K, when corrected, could also allow for additional information related to RFP modeling and scoring.

Recommendation 35: In the next IRP, the Company should provide support for risk modeling approach (i.e. lognormal vs normal risk distributions, ignoring upside risks) and ensure this topic is discussed in a technical working group meeting for the next IRP.

Recommendation 36: In the next IRP, the Company should standardize their approach to selecting risk values such that modeling could be duplicated and ensure this topic is discussed in a technical working group meeting for the next IRP.

Recommendation 37: The Company should provide an explanation for why it does not consider downside risks in its models and demonstrate that this approach results in least-cost, least-risk resources.

[105] See NW Natural IRP, Appendices at 199.
[106] See CUB comments at 10.

4.9 - RNG, Hydrogen, and Syngas

4.9.1 - RNG Availability and Cost

Ted Drennan, Energy Policy Analyst

As discussed in Opening Comments, NW Natural is placing a heavy reliance on non-emitting supply-side resources for decarbonizing their system. Staff appreciates the additional information provided by the Company regarding its cost assumptions for RNG, hydrogen, and synthetic methane. The Company's experience with RNG development and its exposure to market prices and availability helps support its near-term assumptions. However, Staff still has some concerns with how the Company's RNG costs compare to other forecasts and with the longer-term cost and availability trends. In particular, Staff has concerns regarding availability assumptions that rely on 'all-hands-on-deck' approach to RNG and the Company's minimal consideration to competition for RNG.

Staff has looked more in depth at the Company's reliance on a study from ICF. This further dive into the study has not alleviated concerns of the appropriateness of relying on the study.

The study was discussed in the Company's third technical workshop on March 28, 2022. At the discussion, it was reported the values are dependent on a deep decarbonization scenario that "requires aggressive deployment of emission reduction measures across the country."[107] This is also called an "all-hands-on-deck approach." While this approach helps demonstrate the role decarbonized fuel could play under a best-case scenario, Staff does not believe it provides a reasonable foundation for understanding potential availability because it is premised on a flawed policy assumption. Recent legislative actions in the US challenge the assumption that all groups are working together regarding emission reductions from natural gas. A few simple illustrative examples follow.

On January 6, 2023, a law in Ohio was signed that declared natural gas is green energy. From HB 507:[108]

> (43) "Green energy" means any energy generated by using an energy resource that does one or more of the following:
> (a) Releases reduced air pollutants, thereby reducing cumulative air emissions;
> (b) Is more sustainable and reliable relative to some fossil fuels.
> "Green energy" includes energy generated by using natural gas as a resource.

[107] See Supply Side Resources Technical Working Group No. 3 Presentation, slide 72 (March 28, 2022).
[108] See Sub. H.B. No. 507, 134th Ohio General Assembly (Effective Date April 7, 2023).

The Wyoming legislature considered a resolution titled "Phasing out new electric vehicle sales by 2035." While Senate Joint Resolution SJ004[109] died in committee, it was not in line with the 'all hand-on-deck" approach in the ICF study.

The Kentucky Senate approved a bill SB 4,[110] that will, "prohibit the Public Service Commission from approving a request by a utility to retire a coal-fired electric generator unless the utility demonstrates that the retirement will not have a negative impact on the reliability or the resilience of the electric grid or the affordability of the customer's electric utility rate".

More locally, parties need look no farther than the situation with the Colstrip generating plants. Here the Montana legislature passed laws that were designed to stop the majority owners from closing the power plant. The laws were found to be unconstitutional,[111] although it looks like the plant will continue to operate.

Besides the issues raised above, the methodology of the study is a concern. As discussed by ICF, the 2021 study was based off of ICF's 2019 study. The 2019 study had two scenarios, a low-resource and high-resource approach. The 2019 study contained one price curve, for the high-resource scenario. The costs were less in this scenario than the low-resource scenario.

For the 2021 update relied on by NW Natural, ICF eased the constraints on what was available to produce RNG but kept the same cost curves. Thus, the supply increased, at constant costs, which does not seem reasonable. Table 2 below shows the assumptions between the two cases in ICF's 2019 study, along with the updated assumptions in the 2021 study. The latest assumptions are substantially greater than the earlier ones.

Table 2: ICF Study Comparisons

RNG Feedstock	ICF 2019 Study: Low Resource	ICF 2019 Study: High Resource	ICF Updated Study
LFG	50% of EPA's candidate landfills	80% of EPA's candidate landfills	95% of eligible landfills
Animal Manure	30% of technically available animal manure	60% of technically available animal manure	75% of technically available
WRRF	30% of WRRFs with a capacity greater than 7.25 million gallons per day	50% of WRRFs with a capacity greater than 3.3 million gallons per day	95% of facilities w/>3.5MGD
Food Waste	40% of the food waste available at $70/dry ton	70% of the food waste available at $100/dry ton	95% @ $100/ton

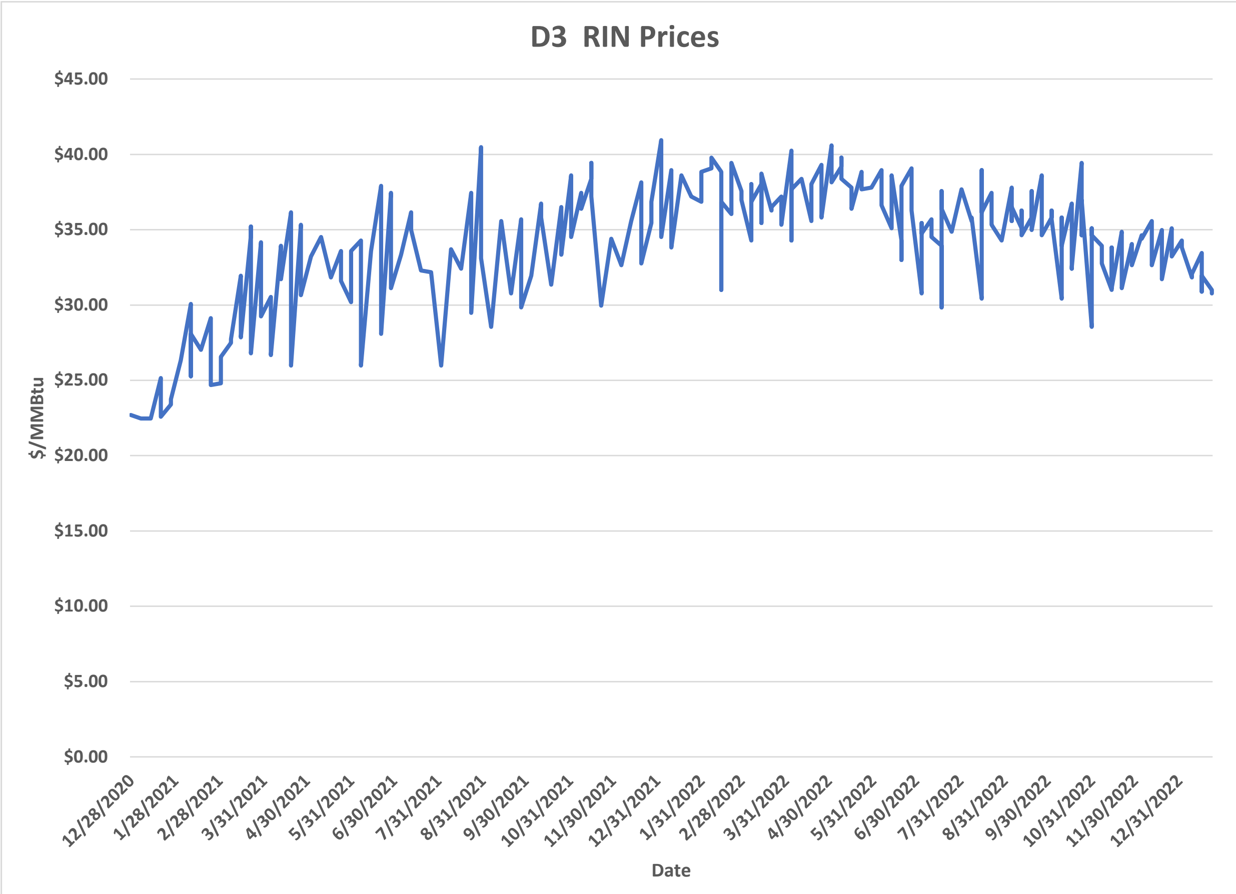
109 See Wyoming Senate Joint Resolution No. SJ0004, Phasing Out New Electric Vehicle Sales by 2035 (last accessed March 11, 2023).
110 See Kentucky Senate Bill 4, (adopted March 16,2023).
111 See Tom Lutey, "Newly-passed Colstrip laws unconstitutional, court rules," Billings Gazette, October 10, 2022.

Agriculture Residue	20% of the agricultural residues available at $50/dry ton	50% of the agricultural residues available at $50/dry ton	80% @ $50/ton
Forestry and forest product residue	30% of the forest and forestry product residues available at $30/dry ton	60% of the forest and forestry product residues available at $60/dry ton	80% @ $50/ton
Energy crops	50% of the energy crops available at $50/dry ton	50% of the energy crops available at $70/dry ton	60% @ $50/ton
Municipal solid waste (MSW)	30% of the non-biogenic fraction of MSW available at $30/dry ton	60% of the non-biogenic fraction of MSW available at $100/dry ton	80% @ $50/ton
P2G	50% capacity factor for dedicated renewables	80% capacity for dedicated renewables	NA

Staff continues to have concerns with the price forecasts for RNG used by the Company. Competition for RNG is high in the renewable fuel market. Transportation RNG, with its environmental attributes represented by D3 Renewable Identification Numbers (RINs), receives premium rates. Figure 6 below highlights the historic prices for D3 RINs as reported by the EPA for 2021 through February 10, 2023. The D3 RIN prices [112] have been higher than NW Natural's current RNG projections for Tranche 2, which is estimated at $19/MMBtu. This means that NW Natural could have difficulty finding large quantities of RNG at prices much below prices of RIN RNG. In a recent filing, NW Natural discusses how the RNG market is driven by the fuels markets, including D3 RINs.[113] The Company points out that while volatile, "the overall value or RNG in these markets remain strong, with a 2-year average of over $33/mmbtu.[114]

[112] Data selected from https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information last accessed March 11,2023. Prices are reported at the RIN level, which were converted to $/MMBtu. One MMBtu of RNG is approximately 11.7 RINs.
[113] See UG 462, NW Natural 100, Chittum/Page 25-26, lines 14-1. The current market for D3 RINs, which is the type of RNG the majority of resources we would purchase for RNG Statute and CPP Rule compliance would generate, is quite strong.
[114] See UG 462, NW Natural 100, Chittum/Page 26, lines 3-5.

Figure 6: D3 RIN Prices2021-Feb 10, 2023



Others looking at the RNG market have differing views than those in NW Natural's IRP as well. A recent article by S&P Global[115] addresses the current market for RNG, including the competing markets for RNG, i.e., use in transportation or by utilities:

> Transportation RNG -- which is typically priced around the value of conventional gas, plus D3 RIN credits -- is currently marketable between $30-$35/MMBtu, while RNG sold to utilities, manufacturers and other end users in the voluntary market is marketable between $20-$25/MMBtu, with normal production costs around $15/MMBtu and under, Kinder Morgan's Holsapple told S&P Global.

These estimates conflict with NW Natural's RNG projections. The same S&P Global report notes that producers are expecting prices for RNG around $20/MMBtu for long-term projects:[116]

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[115] See https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/121622-rng-industry-expects-us-voluntary-customers-to-spur-demand-after-early-transport-boom last accessed March 11,2023.
[116] Ibid.

A recent survey of 450 RNG producers by US clean energy consultancy EcoEngineers found that many companies are beginning to draw around $20/MMBtu for RNG sold into voluntary markets on a long-term basis.

Table 3 below compares the historic maximum and minimum EPA values in Figure , the values from S&P, and NW Natural's values for Tranche 1 and 2. Even NW Natural's projections for the higher-cost Tranche 2 are lower than historical and expected costs.

Table 3: RNG Cost Comparison

	Price
Tranche 1 (1/3 of NWN RNG Supply)	Portfolio cost of $14/MMBtu
Tranche 2 (2/3 of NWN RNG Supply)	Portfolio cost of $19/MMBtu
S&P long-term utility purchase of RNG	$20-25/MMBtu
S&P Transportation RNG	$30-35/MMBtu
Historic EPA D3 Cost – minimum (1/4/2021)	$22.46/MMBtu
Historic EPA D3 Cost – maximum (1/3/2022)	$40.95/MMBtu

Request 28 from Staff's opening comments requested further discussion supporting and providing justification for RNG, hydrogen, and synthetic [methane] cost assumptions. In the Company's response, it explains that "larger and larger scale RNG projects are being developed."[117] Further, the Company suggests, "if the utility developed RNG projects become a larger percentage of the utility's RNG portfolio, then costs for NW Natural customers will trend toward production costs."[118]

Staff agrees that utility-developed RNG projects will result in prices that trend toward production costs, as utility projects are generally provided to ratepayers at cost (plus rate-of-return). However, even the Company's Tranche 1 costs are lower that production costs noted by Kinder Morgan. Thus, it does not alleviate Staff's concerns with current long-term RNG price forecasts used in the IRP. Further, in the same section NW Natural cites World Resource Institute, which forecasts project costs from $3 to $30/MMBtu. The $30 is much higher than the Tranche 2 estimates, which top out at under $20/MMBtu. Overall, Staff is not persuaded by the Company's response regarding RNG price assumptions.

Staff understands that the Company provided a scenario with higher RNG costs in the 2022 IRP, however in the next IRP Staff would like to see a sensitivity with costs based on the higher end of recent, relevant publicly available forecasts. Additionally, given the wide range of forecast RNG prices, utilizing more than two tranches may help improve accuracy for costs and availability at different price ranges.

[117] See NW Natural reply comments at 59.

[118] *Ibid*.

Prior to the Company's next IRP technical working groups, Staff plans to explore engaging an independent third party to review the reasonableness of key technology and market assumptions for use in the next IRP.

Recommendation 38: For the next IRP, the Company should provide an analysis that would examine high-cost RNG, hydrogen, and synthetic gas as a sensitivity. The cost estimates should be on the higher end of recent, relevant publicly available forecasts, and the Company should provide the sources used for each cost forecast.

Recommendation 39: For the next IRP, the Company should provide a literature review of RNG price and availability forecasts.

4.9.2 - Hydrogen and Syngas Cost and Availability

Rose Anderson, Senior Economist

As discussed in Staff Opening Comments, NW Natural's estimates for hydrogen costs appear to be on the low end of available forecasts. NW Natural's hydrogen cost trajectory, based on advice from third party consultants, is among the lowest forecasts for hydrogen prices that Staff has reviewed. However, aggressive cost declines for green hydrogen are a real possibility given that renewable energy is ever-more abundant in the region and recent policies have taken aim at significantly reducing the cost of green hydrogen.

In Opening Comments, CUB argues that NW Natural's hydrogen cost estimates are concerning in part because the Company's IRP described hydrogen electrolyzers as dispatching opportunistically based on wholesale market prices. CUB argues that any electric rate paid by NW Natural to an electric utility is not likely to reflect opportunistic wholesale market prices. Staff agrees with this assessment. However, in NW Natural's Reply Comments, the Company explains that IRP hydrogen costs include the cost of a dedicated renewable resource and are not based on opportunistic wholesale market purchases.[119,120]

Staff reviewed the sources provided by the Company for its hydrogen cost estimates and finds that the materials provided offer only minimal support for the Company's estimates. While consultants provided cost estimates for a variety of hydrogen projects, NW Natural provided no clear documentation of its process for translating the third-party studies to a hydrogen price forecast that reflects NW Natural's unique circumstances. Electrolyzer size, capacity factor, and the manner of obtaining renewable energy are all important to the cost of hydrogen, and it is unclear what assumptions were used in this IRP. For example, **[Begin Confidential]** [redacted]

[119] NW Natural Reply Comments. Page 15.
[120] NW Natural Reply to Staff DR 151.

[redacted]

[End Confidential]. It's not clear whether NW Natural could achieve either those utilization rates or energy prices with dedicated renewable resources. The other third-party estimate of hydrogen costs was provided without the appendix listing its full set of assumptions, so Staff cannot say whether the Company might be able to achieve the utilization and energy price assumptions from that study.

Recommendation* 40*: In the next IRP, the Company should refine its cost estimate for green hydrogen by modeling a resource with a precise capacity, utilization rate, and a precise quantity of renewable energy available to it at a given price. These assumptions should be shared in the Technical Working Group process and in the IRP itself.

Syngas Cost and Availability

While the Company's hydrogen price forecast is lacking in transparency, it at least appears to approximate certain third-party forecasts based on materials provided by the Company. However, transparency for the Company's syngas (methanated hydrogen) cost forecast is much more limited. The cost of syngas is a significant contributor to NPVRR in later years of the planning timeframe, and the limited transparency into the forecast is concerning.

While transparency was generally low, Staff is aware that the Company provided information responsive to a request about syngas costs is in its Reply Comments. The comments state the Company has seen a price quote for syngas equivalent to $22/MMBtu. Staff has further questions about this price quote including whether the syngas is from verifiably renewable energy. Staff issued a discovery request about this quote, but the Company's reply was not due yet at the time of writing these Final Comments.[121]

Setting aside for a moment the impressive price quote NW Natural has received, it is important to discuss the rigor and transparency of the syngas price forecast in the IRP. For example, Staff requested in discovery that the Company explain what the source for its CO2 feedstock was assumed to be and to provide an estimate of the cost of CO2 feedstock to the methanation process. The Company did not provide an answer to either question. Instead, the Company provided data about methanation costs in general and made the vague assurance that "NW Natural developed its cost assumptions from methanation by looking across numerous estimates of costs for different methanation processes and technologies."[122,123]

Similarly, when Climate Advocates requested information about electrolyzer, CO2 feedstock, and methanation costs, the Company provided information about electrolyzer costs only, ignoring the questions about syngas.[124]

[121] Staff DR 165.

[122] NW Natural's reply to Staff DR 137.

[123] NW Natural's reply to Staff DR 138.

[124] NW Natural's reply to Climate Advocates IR 7.

The Company says that it modeled its syngas costs on “new electric renewable generation resources.” However, Staff’s initial review of the literature provided by NW Natural on syngas costs does not support that the Company’s cost estimate is consistent with third-party study estimates for syngas from new, dedicated renewable resources, which the Company states it is modeling for green hydrogen and syngas production.[125,126]

The Company has provided participants very little support for its methanation forecast in this IRP, and the lack of transparency around its assumptions makes it difficult to take the Company’s estimate at face value. Especially in response to a direct discovery request, the Company should be able to produce workpapers in support of its cost estimate for syngas. The Company’s cost estimates appear to need more work, as well as third-party review or support.

Recommendation 41: For the IRP Update, NW Natural should engage a third-party expert to assist in estimating the cost of syngas. Workpapers supporting the updated estimate should be filed with the IRP Update.

CO2 Availability and Eligibility

CUB aptly points out in its Opening Comments that the emissions and costs of syngas may depend on the financial and legal framework around carbon sequestration.[127] If an industrial plant is capturing carbon to comply with an emissions reduction policy, it seems unlikely that the plant will be allowed to sell the CO2 to NW Natural for use in methanation, while still claiming emissions reductions for itself. This creates competition between using CO2 for sequestration and using it for syngas production. CUB and Climate Advocates also point out that if industrial sources are required to reduce emissions moving forward into 2050, industrial point sources of CO2 gas may become rarer, making this important feedstock more difficult to procure.

CUB argues that because syngas is an emerging technology with inputs that are not certain to be available at a low cost, the syngas availability forecast should be subject to an emerging technology discount. Staff suggests that more information is needed before applying any discount to the availability of syngas. Staff recommends the Company provide details about its syngas input assumptions before its next IRP. This should include an estimate of the capacity of electrolyzers, renewable generation, and methanation equipment in MW selected in key portfolios and the quantity of CO2 needed in each year to support syngas production. The Company should request feedback from participants on expectations about the availability of these resources. This information will give stakeholders a sense of the magnitude of resource needed in each portfolio. Informed by this data, the Company and stakeholders can have a

[125] NW Natural reply to Advocate DR 5.
[126] NW Natural reply to Staff IR 137.
[127] CUB Opening Comments. Pages 16-17.

grounded discussion of availability and the potential for a relevant emerging technology discount.

Recommendation 42: In the next IRP Technical Working Group process, NW Natural should provide an estimate of the capacity in MW of electrolyzers, renewable generation, and methanation equipment needed in each year for several key portfolios. The Company should also provide the cost and quantity of CO2 needed in each year in key portfolios to support syngas production. The Company should request feedback from participants regarding the likelihood of these resources being readily available and consider applying any emerging technology availability discount at that time.

4.10 - Risk Management and Sharing

In Opening Comments, Climate Advocates discussed ways to modify the allocation of risk between ratepayers and shareholders, including Multi-Year Rate Plans (MYRP), fuel cost sharing, and performance incentive mechanisms.

Staff is open to further conversation around fuel cost sharing and MYRP. However, these conversations should be a second priority at this time to efforts that help reduce risk associated with new investments in the distribution system, as discussed in Section **3.1 - Risks of New Load**. Staff's comments on performance incentives are in Section **3.5 - Performance Incentive.**

Staff also suggests a discussion of risk sharing for the costs of any SB 98 RNG the Company pursues in lieu of more cost-effective options like CCIs. If the Company continues to pursue near-term SB 98 RNG, then a conversation should take place around risk sharing. Given that these investments create potential benefits for shareholders around capital costs, yet they are not the lowest cost way to meet CPP requirements for customers, there are ways to place more of the risks of these investments on shareholders. This could include measures to place the risk of cost overruns on shareholders, as the Commission has discussed doing for certain renewable electricity investments.[128] For example, the Company could be limited to recovering the amount of the cost estimate used to select a project in its RNG workbook.

Recommendation 43: The Commission should indicate whether risk sharing will be considered at cost recovery for any future SB 98 RNG projects.

4.11 - Natural Gas Price Forecast

Sudeshna Pal, Senior Energy Policy Analyst

[128] Order No. 20-321.

Staff Final Comments

In Opening Comments, Staff made three requests to NW Natural regarding natural gas price forecasts. These requests are documented as Requests 43-45 in Staff Opening Comments. In these final comments, Staff summarizes its evaluation of gas price forecasts based on NW Natural's response to Staff requests. Staff also addresses stakeholder comments around natural gas price forecasting in NW Natural's 2022 Integrated Resource Plan (IRP).

Staff Requests and NW Natural Responses

Staff Request 43 asked for more visibility into supply and demand factors as well as assumptions around alternative fuel availability that were considered in the IHS Markit price forecasts used in NW Natural's IRP. NW Natural provided a copy of the IHS Markit Report and summarized key insights from the report in its confidential reply comments, which Staff found helpful.[129] Staff now has a better understanding of various factors considered in the forecasting model and finds it reasonable.

Staff Request 44 asked whether NW Natural could work with IHS to obtain a forecast with assumptions about RNG and electrification specific to the West, as that would be most relevant for the Company's customers. NW Natural responded that specific analyses of this sort are costly and will not add enough value to its analysis. The Company also pointed out that the model risk analyses account for a wide range of prices, thus potentially capturing conditions in the West that could result in higher or lower than average prices. Staff agrees that prices at the gas hubs will be influenced by changes in gas market dynamics both at the national and global level. Staff retracts its request for a West specific analysis.

Finally, Staff Request 45 asked for clarification around the impact of price variations across hubs in general and higher and more volatile prices at Sumas in particular, on avoided cost calculations. NW Natural explained that avoided costs already account for price volatility seen at specific hubs through two components, namely, the natural gas purchase and shipping costs and the commodity price risk reduction values.[130] Staff appreciates the explanation and now has a better understanding of how price variations are reflected in avoided cost calculations and does not have further concerns at this time.

Stakeholder Comments

In their Opening Comments, the Climate Advocates point out that gas prices may not return to historically low levels as the IRP seems to suggest. Staff believes that NW Natural forecasts are consistent with other gas and electric utilities in the region. Staff also appreciates the range of different price forecasts considered in the Monte Carlo analysis. The uncertainty is addressed by the low and high gas prices that NW Natural considers in its risk analysis. Staff also notes that the WACOG (weighted average cost of gas) is not the relevant price forecast to consider when comparing NW Natural's gas price forecasts to others in the region. The inclusion of

[129] NW Natural Confidential Reply Comments, Page 99-100.
[130] For detailed explanation, see NW Natural Reply Comments, Page 101 of 119.

WACOG was a demonstration of price impacts on customer bills based on NW Natural's share of purchases from different hubs rather than the overall market price forecasts.

Conclusion

NW Natural's price forecasts are consistent with those seen in peer utility IRPs. The natural gas market is subject to a wide range of uncertainties that makes forecasting a challenging task. NW Natural uses forecasts from a third-party, and Staff found these forecasts to be based on a wide array of factors that could possibly impact future natural gas prices. Staff appreciates that NW Natural considers a wide range of prices and performs risk analyses to address these uncertainties in a reasonable manner.

Section 5: List of Recommendations

5.1 - Action Plan

Regarding the 2022 IRP Action Plan, Staff has nine basic recommendations:

> ***Recommendation 1: The Commission should direct the Company to include four years of planning detail in its next Action Plan.***
>
> ***Recommendation 2: Staff recommends acknowledgement of Action Item 1 to acquire deliverability from Mist Recall and citygate deals.***
>
> ***Recommendation 3: Staff recommends the Commission acknowledge the Portland Cold Box replacement.***
>
> ***Recommendation 4: For future IRPs, the Company's portfolio modeling must consider non-renewal of unneeded firm delivery capacity contracts upon expiration and the retirement of other capacity resources as appropriate.***
>
> ***Recommendation 5: Staff recommends the Commission acknowledge Action Item 3 for residential and commercial demand response subject to the condition that the Company includes in its demand response filing a discussion of how the Company's residential and commercial demand response program will interact with and support any future locational demand response program.***
>
> ***Recommendation 6: Staff recommends acknowledgement of Action Item 4 to work with Energy Trust to acquire efficiency in 2023 and 2024.***
>
> ***Recommendation 7: Staff recommends non-acknowledgment of the SB 98 RNG acquisition under Action Item 5 because acquisition of CCIs is a significantly less costly and risky method of complying with the CPP.***
>
> ***Recommendation 8: Staff recommends acknowledgement of Action Item 7 to purchase CCIs, conditional on the Company using CCIs and RTCs in combination in the most economical way possible to meet compliance flexibility needs, as informed by the decision on Action Item 5 and near-term SB 98 procurement.***
>
> ***Recommendation 9: Staff recommends acknowledgement of Action Item 8 to uprate the Forest Grove Feeder, subject to certain conditions regarding forward looking distribution system planning and hydrogen-blend readiness.***

5.2 - Action Plan Timeframe – Additional Considerations

This section lists short-term recommendations that were not covered in the Action Plan.

Recommendation 10: Future distribution system planning should include a cost benefit analysis for non-pipe alternatives that reflects an avoided GHG compliance cost element consistent with a high-cost estimate of future alternative fuels prices.

Recommendation 11: In future IRPs, NWN should include a system map with an associated database containing information about feeders, in-service dates of pipes, and lowest recent observed pressures.

Recommendation 12: Staff requests that the Company, before the next IRP, provide statistical evidence of the significance of the variables that influence demand, and hence pressure, at a specific temperature.

Recommendation 13: Staff requests that the Company, in the IRP Update, provide rationale backed by practical examples of the deployment of CNG or LNG trailers as short-term mitigation measures, including information requested by Staff in Final Comments.

Recommendation 14: Staff requests that the Company explore with stakeholders prior to its IRP Update the Company's Contingency Plan in preparation for cold days with a potential for detrimental events occurring, including information requested by Staff in Final Comments.

Recommendation 15: In the forward-looking distribution system planning included in future IRPs, NW Natural should consider in its study of non-pipe alternatives whether it could develop an operational flow tariff for reductions of peak usage on the constrained portion of the distribution system with different price and load reduction requirements than the current interruptible tariff.

Recommendation 16: Toward the goal of facilitating forward-looking distribution planning, NW Natural should provide a 10-year distribution system plan in its next IRP Update, as the Company indicated it plans to do.

Recommendation 17: In future IRPs, Staff recommends that when NW Natural is monitoring areas in the distribution system where system reinforcements may be needed in the future, whenever possible, ample time should be allowed for evaluation and analysis of GeoTEE and Geographically Targeted Demand Response (GeoDR), among other alternative solutions.

Recommendation 18: In the near-term, if NW Natural's geographical load reduction programs are not available to alleviate forward-looking distribution system constraints, then a peak load reduction RFP should be issued to third-parties.

Recommendation 19: In future IRPs, for multimillion dollar upgrade projects presented, NW Natural needs to demonstrate that its system reinforcement guidelines and customer delivery requirements represent a realistic risk of loss of load. For example, given that the Company's system reinforcement guidelines are based on a 40 percent pressure drop equivalent to a pipeline at 80 percent of its capacity, under what circumstances would an unexpected weather or load event result in use of the additional 20 percent of peak capacity that could lead to a loss of load event?

Recommendation 20: In future IRPs, NWN should provide an RNG procurement scoring methodology and associated modeling details, including up to date and accurate table(s) that list all sources of data inputs to the RNG acquisition model, as well as a narrative description of all updates and changes.

Recommendation 21: If the Company updates its RNG procurement approach from what was included in its most recent acknowledged IRP, the Company should notify the Commission of the changes in its IRP Update. The update should include, at a minimum, where inputs and assumptions differ from those in its most recently acknowledged IRP and provide rationale for all changes.

Recommendation 22 : In the next IRP, NWN should discuss whether and how the RNG projects secured since the last IRP are in the best interest of ratepayers, including a discussion on how the various project types and associated deal structures (buy vs build) share costs, benefits, and risk across ratepayers and shareholders.

5.3 - Long Term Plan

This section lists the recommendations regarding the Company's long-term planning.

Recommendation 23: NW Natural should convene a stakeholder group immediately following the conclusion of the IRP to establish a transport customer efficiency program in time to be able to report on its status in the 2024 IRP update.

Recommendation 24: NW Natural, in the development of a transport customer efficiency program for 2024, should explore and share findings regarding an incentive that would adequately incentivize efficiency, but would not be applied as a flat, per therm rate to usage reductions for operational, economic, or other reasons.

Recommendation 25: Staff recommends the Company reach out to AWEC to discuss whether the value of interruptible customers is being adequately represented in the IRP and make any appropriate updates in the 2022 IRP Update.

Recommendation 26: The next IRP should include modeling of all relevant distribution system costs and capacity costs, including additional projects that would be needed in high load scenarios as well as costs that would not be incurred in lower load scenarios.

Recommendation 27: The Company should provide NPVRR for each portfolio in the next IRP and a breakdown of portfolio NPVRR into cost categories in workpapers filed with the IRP.

Recommendation 28: In the next IRP, Staff recommends that the Company be required to do a Monte Carlo analysis of the top scenarios rather than across scenarios.

Recommendation 29: NW Natural's next IRP should provide metrics comparing the severity and variability of risk in key portfolios.

Recommendation 30: To explore the potential benefits of dual fuel heat pumps, the Company's next IRP should include an in-depth study of dual fuel heat pump potential and the effects of dual fuel technology on peak and average load on the gas system.

Recommendation 31: In the next IRP, the Company's reference case load forecast should better reflect current local, state, and federal policies.

Recommendation 32: In the next IRP, NW Natural should clearly show which load reductions are because of efficiency and which are because of electrification.

Recommendation 33: The Company should update its avoided costs to reflect that SB 98 RNG is voluntary and can be avoided with efficiency.

Recommendation 34: The Company should provide an updated Appendix K which correctly describes the Company's modeling for RNG projects.

Recommendation 35: In the next IRP, the Company should provide support for risk modeling approach (i.e. lognormal vs normal risk distributions, ignoring upside risks) and ensure this topic is discussed in a technical working group meeting for the next IRP.

Recommendation 36: In the next IRP, the Company should standardize their approach to selecting risk values such that modeling could be duplicated and ensure this topic is discussed in a technical working group meeting for the next IRP.

Recommendation 37: The Company should provide an explanation for why it does not consider downside risks in its models and demonstrate that this approach results in least-cost, least-risk resources.

Recommendation 38: For the next IRP, the Company should provide an analysis that would examine high-cost RNG, hydrogen, and synthetic gas as a sensitivity. The cost estimates should be on the higher end of recent, relevant publicly available forecasts, and the Company should provide the sources used for each cost forecast.

Recommendation 39: For the next IRP, the Company should provide a literature review of RNG price and availability forecasts.

Recommendation 40: In the next IRP, the Company should refine its cost estimate for green hydrogen by modeling a resource with a precise capacity, utilization rate, and a precise quantity of renewable energy available to it at a given price. These assumptions should be shared in the Technical Working Group process and in the IRP itself.

Recommendation 41: For the IRP Update, NW Natural should engage a third-party expert to assist in estimating the cost of syngas. Workpapers supporting the updated estimate should be filed with the IRP Update.

Recommendation 42: In the next IRP Technical Working Group process, NW Natural should provide an estimate of the capacity in MW of electrolyzers, renewable generation, and methanation equipment needed in each year for several key portfolios. The Company should also provide the cost and quantity of CO2 needed in each year in key portfolios to support syngas production. The Company should request feedback from participants regarding the likelihood of these resources being readily available and consider applying any emerging technology availability discount at that time.

Recommendation 43: The Commission should indicate whether risk sharing will be considered at cost recovery for any future SB 98 RNG projects.

This concludes Staff's Final Comments.

Dated at Same, Oregon, this 30th day of March, 2023.

Rose ANDERSON

Rose Anderson
Senior Economist
Energy Resources and Planning Division

Appendix A - Synapse Report

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

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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

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[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.

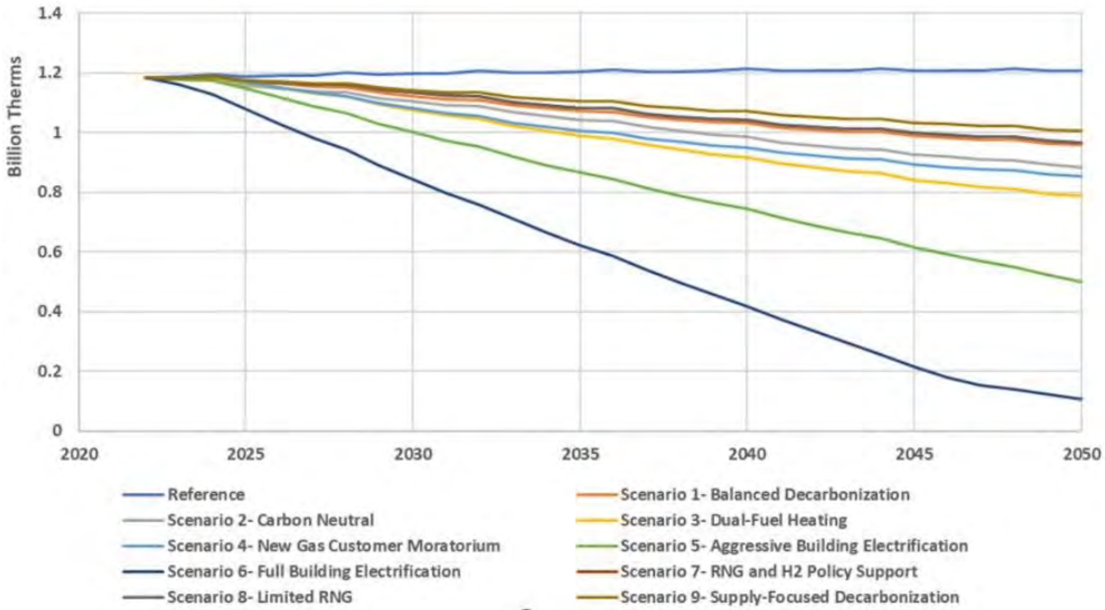
The scenarios allow for a range of input assumption variations, but they do not represent all possible permutations. We note the following:

- 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

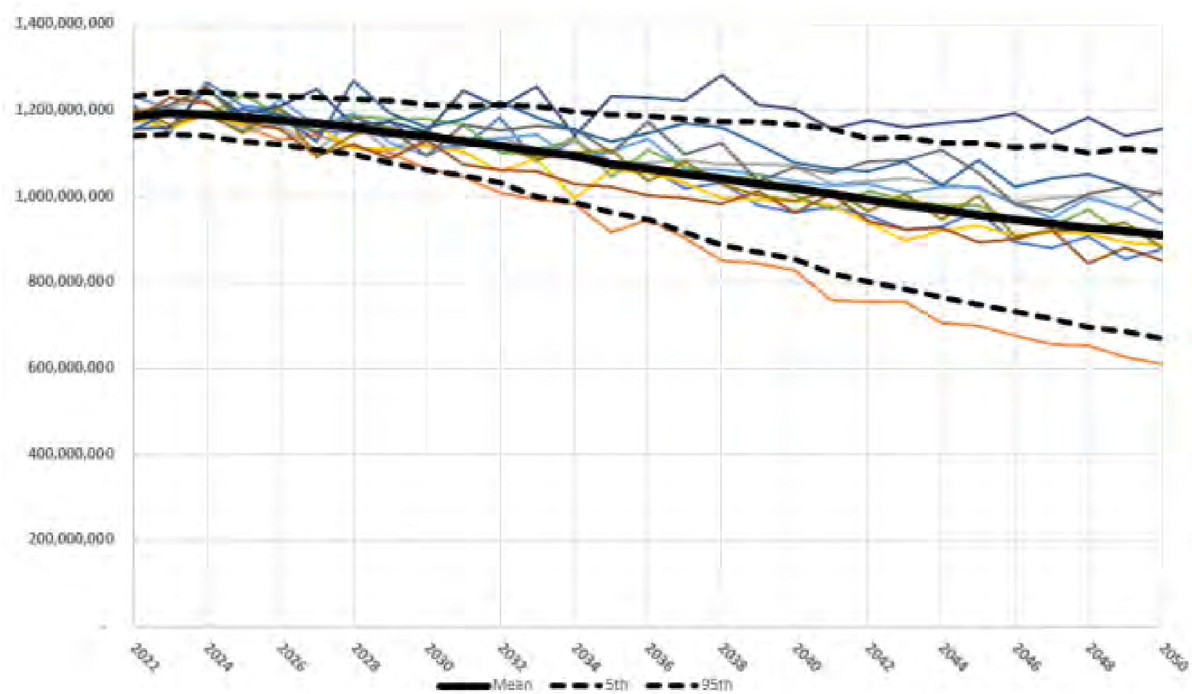
The following four figures (Figure 2 through Figure 5) from NWN's IRP show the variation in annual gas load (deliveries) and peak demand (peak day demand) for the deterministic scenarios and Monte Carlo draws.

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



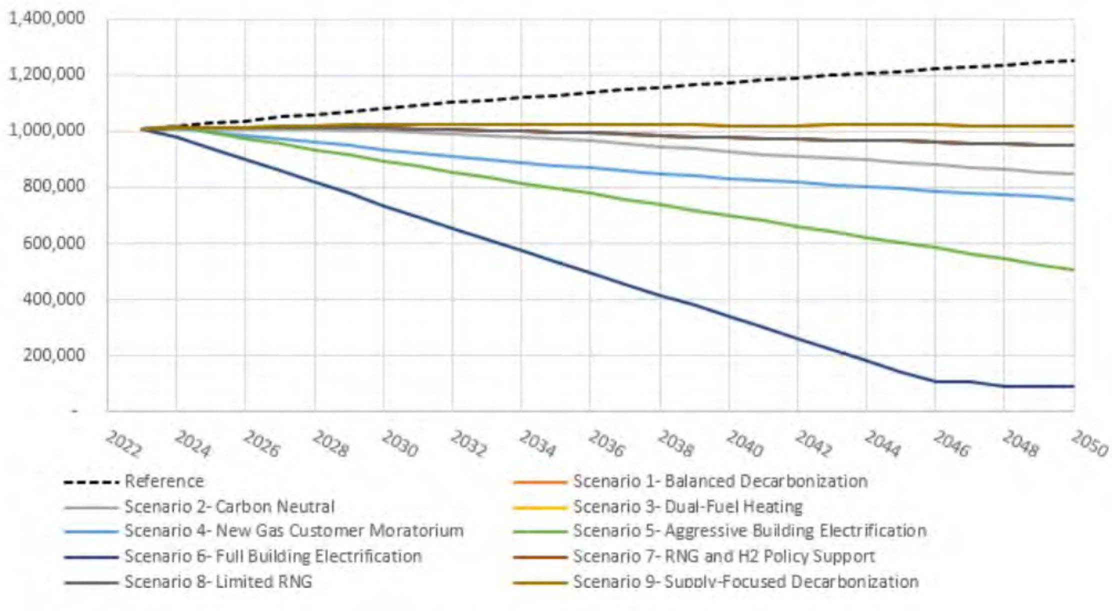
Source: NWN Figure 3.38, page 105.

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



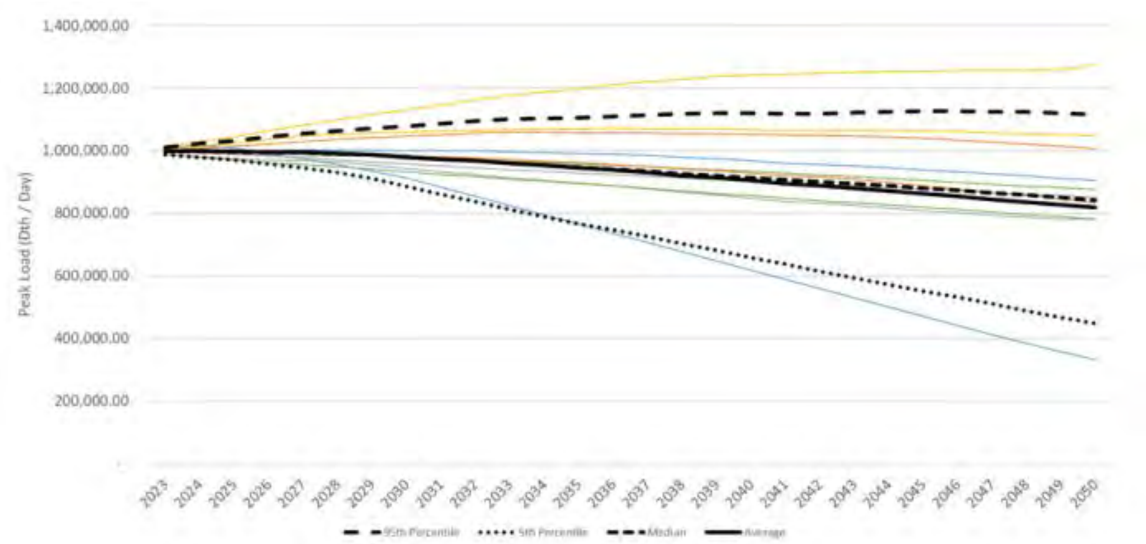
Source: NWN Figure 3.40, page 107.

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."

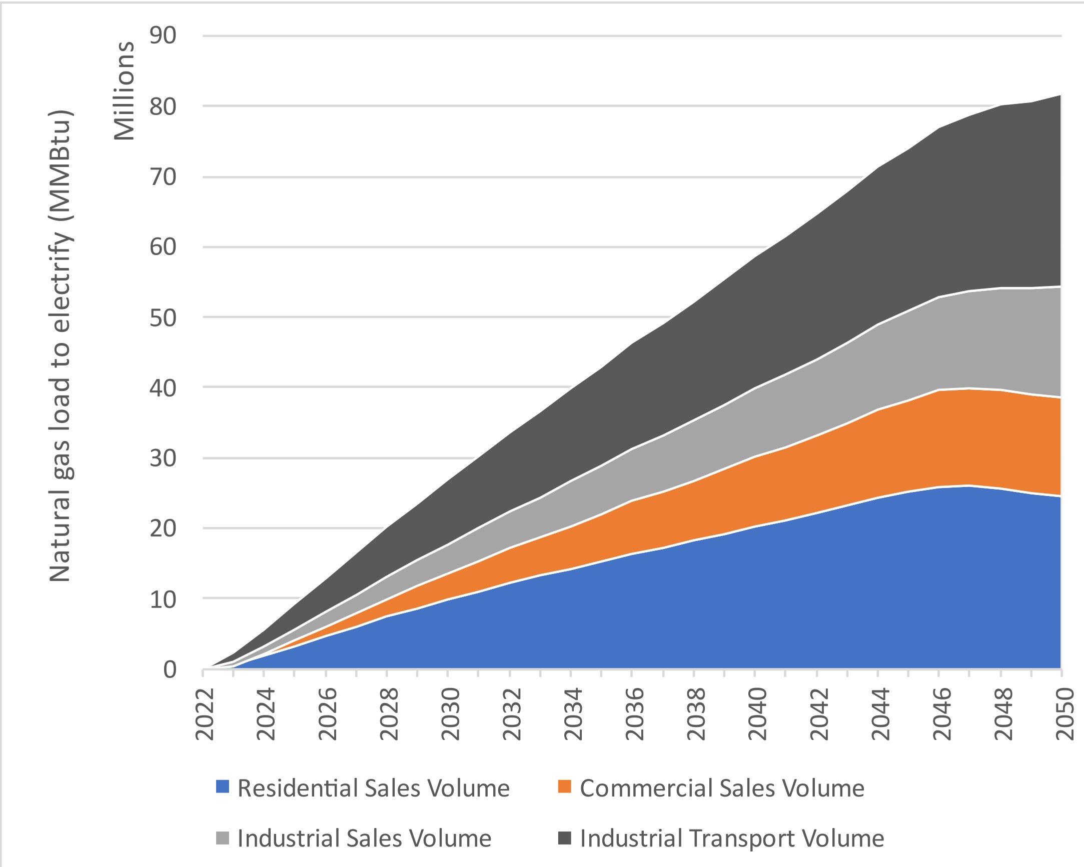
The following five graphs, Figure 6 through Figure 10, reproduced from the analysis contained in full in Appendix C, show the following:

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

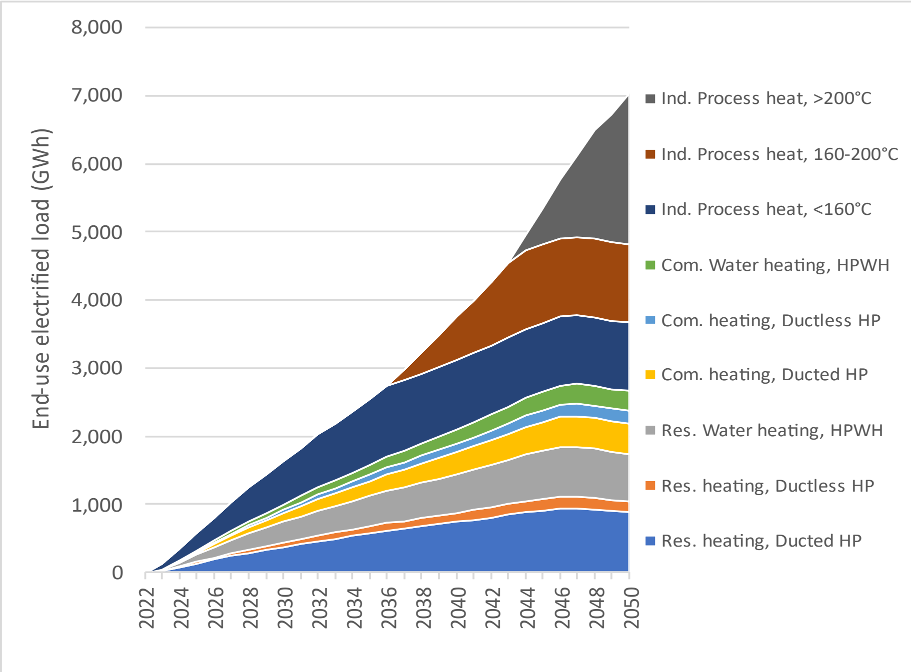
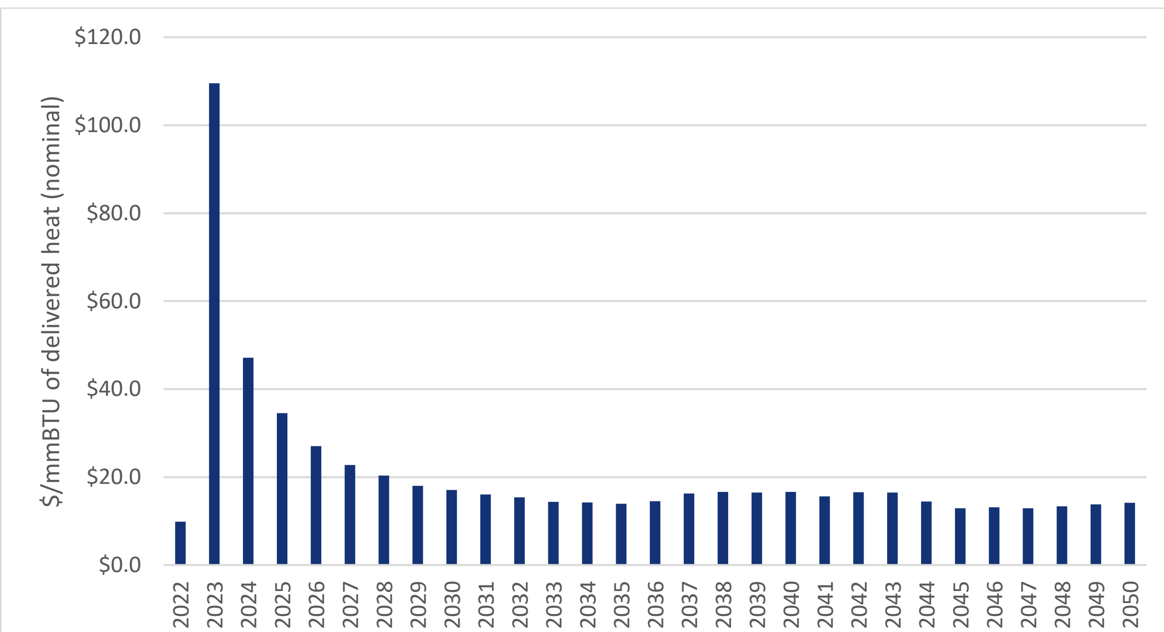


Figure 8. Estimated/proxy per unit costs of electrification, Scenario 6



Total Costs of Electrification

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

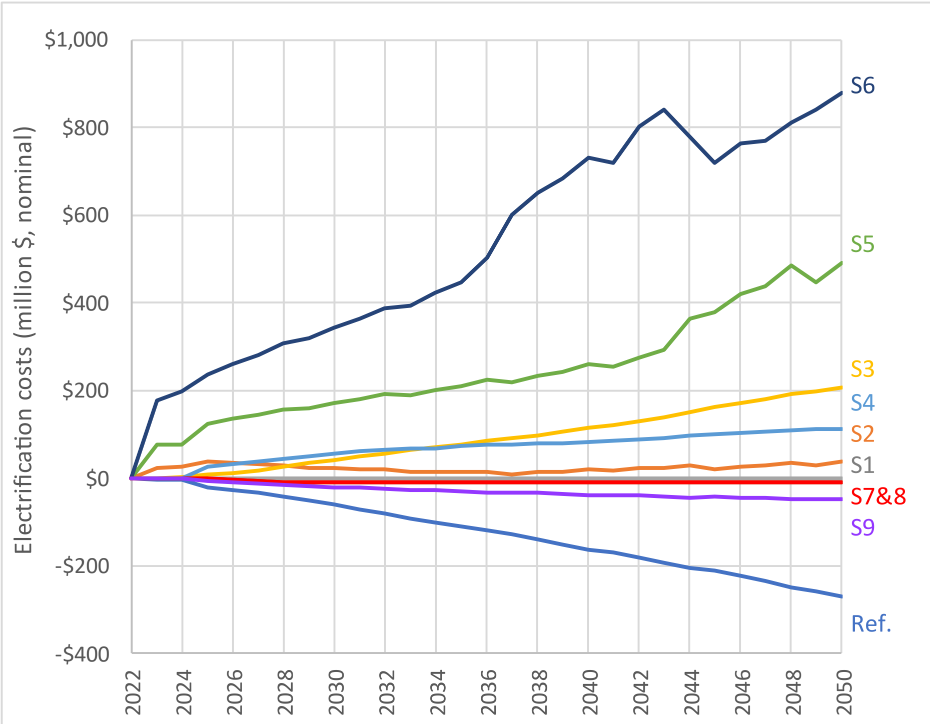
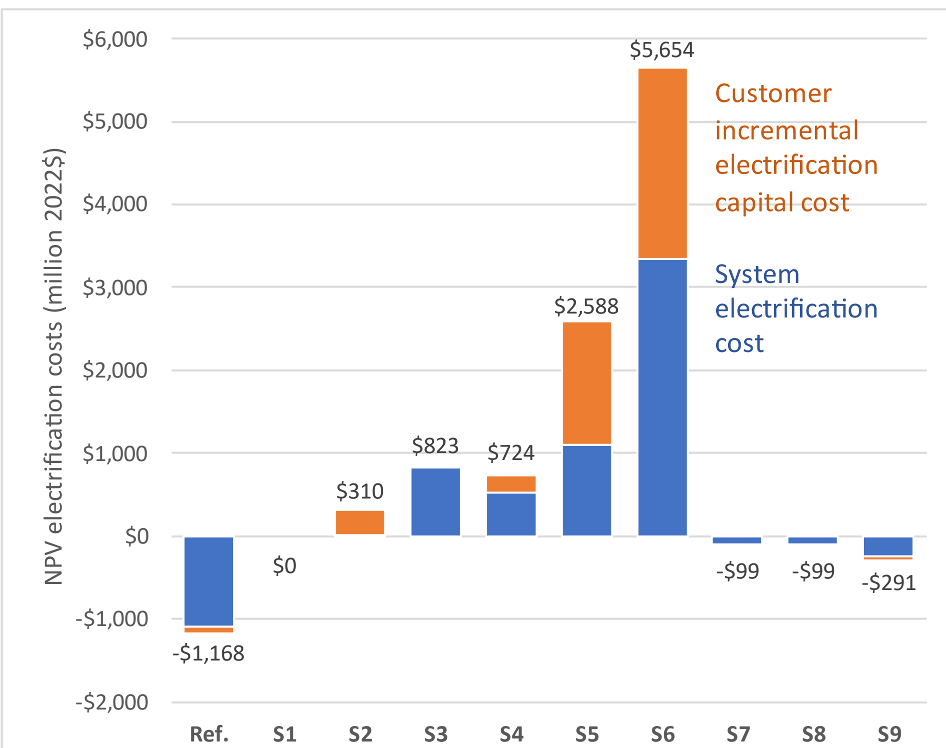


Figure 10. Net present value system and customer electrification costs, all scenarios relative to Scenario 1



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

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[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

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[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]

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[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

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[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.

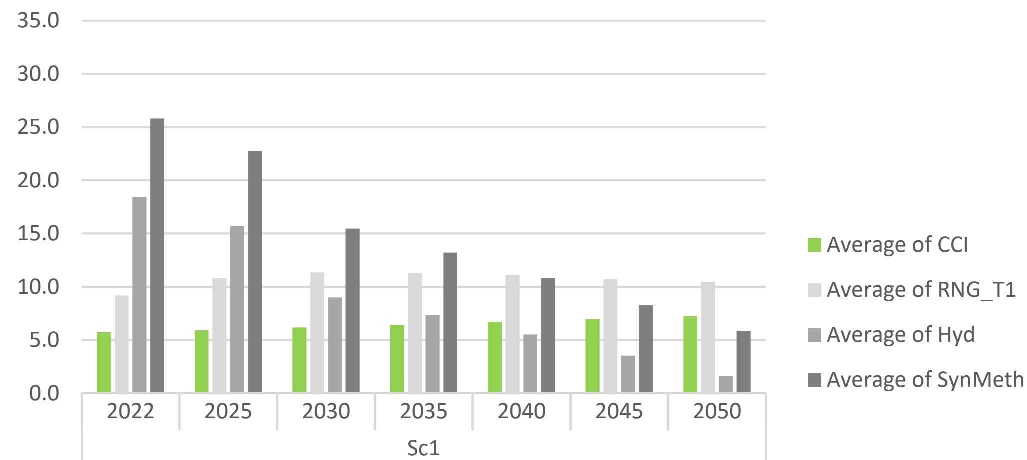
[38] NWN IRP page 212. Portfolio costs are also in Table 6.6 (page 217) and represent the bundled price of RNG including its renewable thermal certificate (RTC). Costs for compliance purposes (unbundled costs of the RTC) are in the "Compliance Data" tab of the summary results workpaper.

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

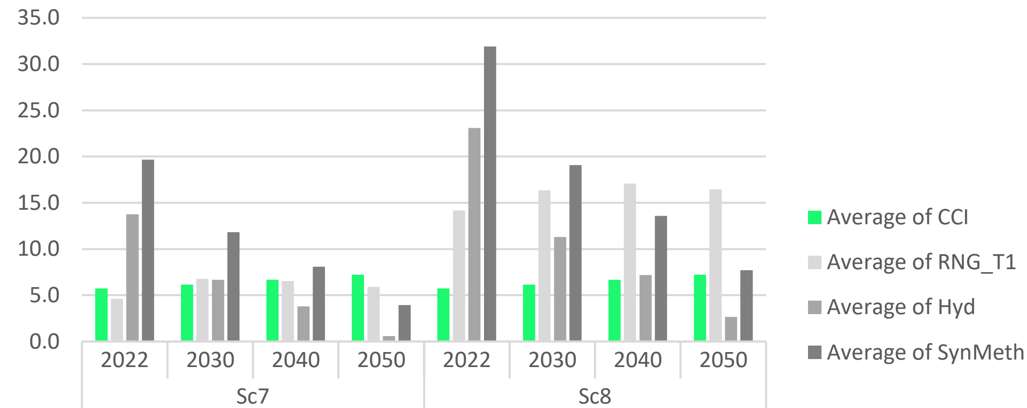


	2022	2025	2030	2035	2040	2045	2050
Average of CCI	5.7	5.9	6.2	6.4	6.7	7.0	7.2
Average of RNG_T1	9.2	10.8	11.3	11.3	11.1	10.7	10.5
Average of Hyd	18.4	15.7	9.0	7.3	5.5	3.5	1.6
Average of SynMeth	25.8	22.7	15.5	13.2	10.8	8.3	5.8

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]

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[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).

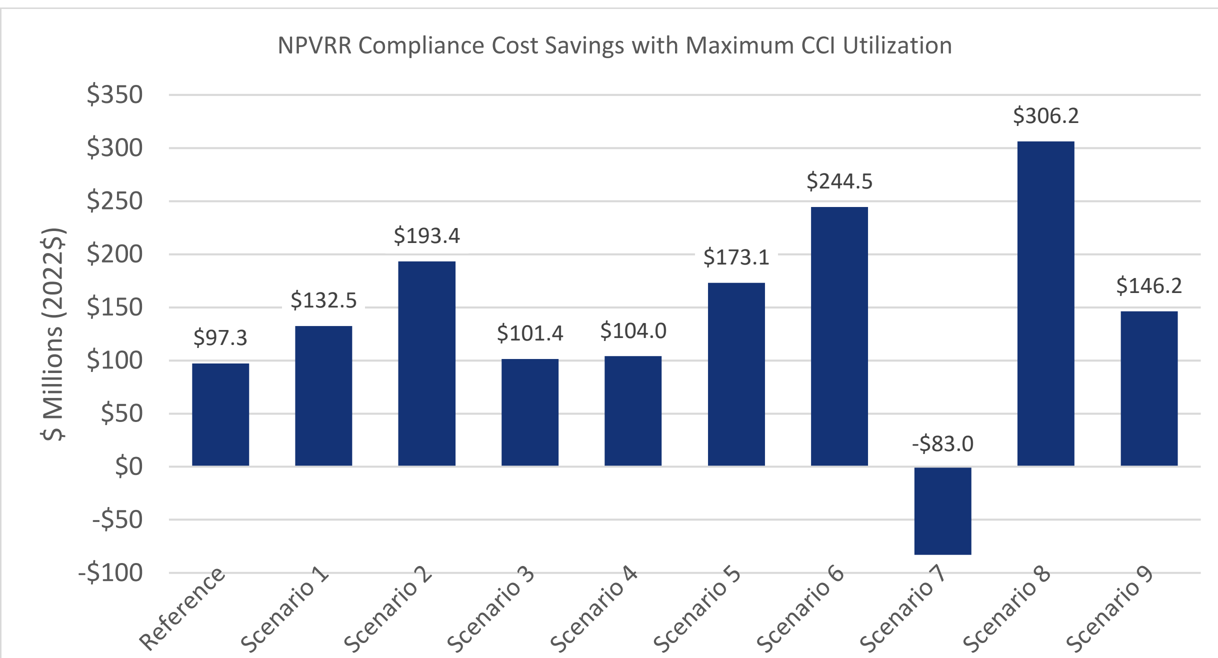
Table 5. NPV compliance cost savings using a maximum level of CCI credits, vs. RNG

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]

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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.

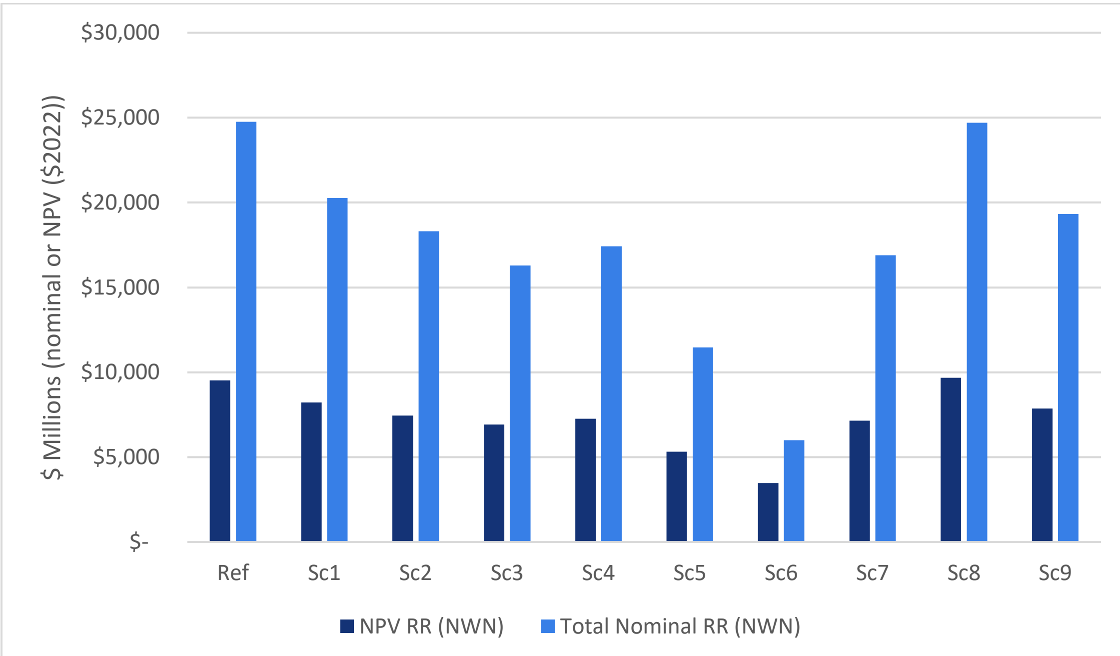
[64] NWN response to OPUC DR1.

[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.

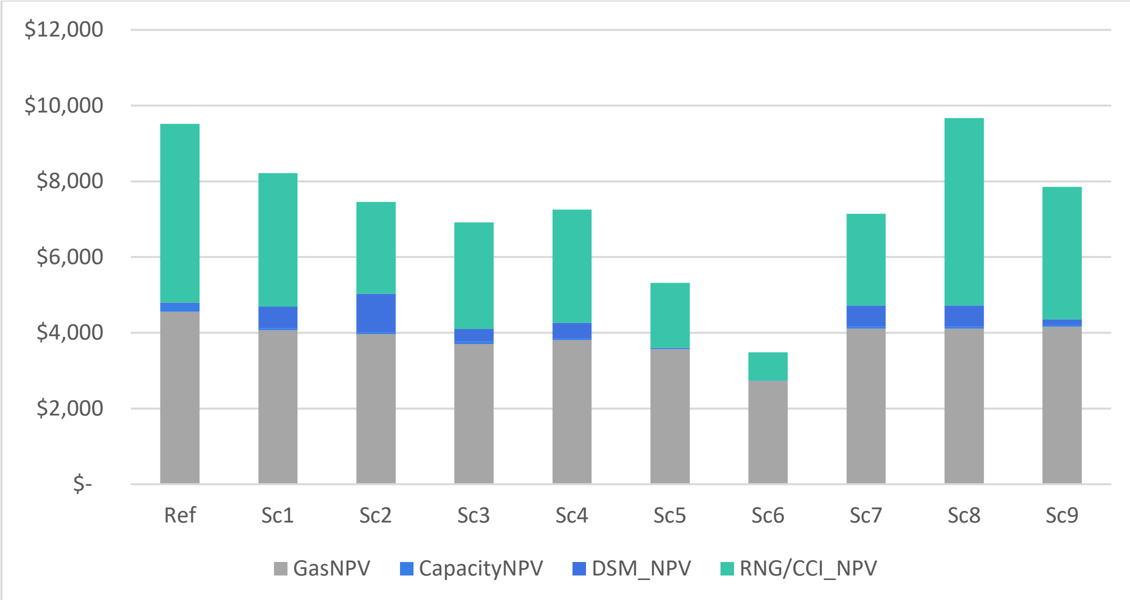
Figure 14. Magnitude of 29-year stream of revenue requirements used in NWN PLEXOS modeling



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

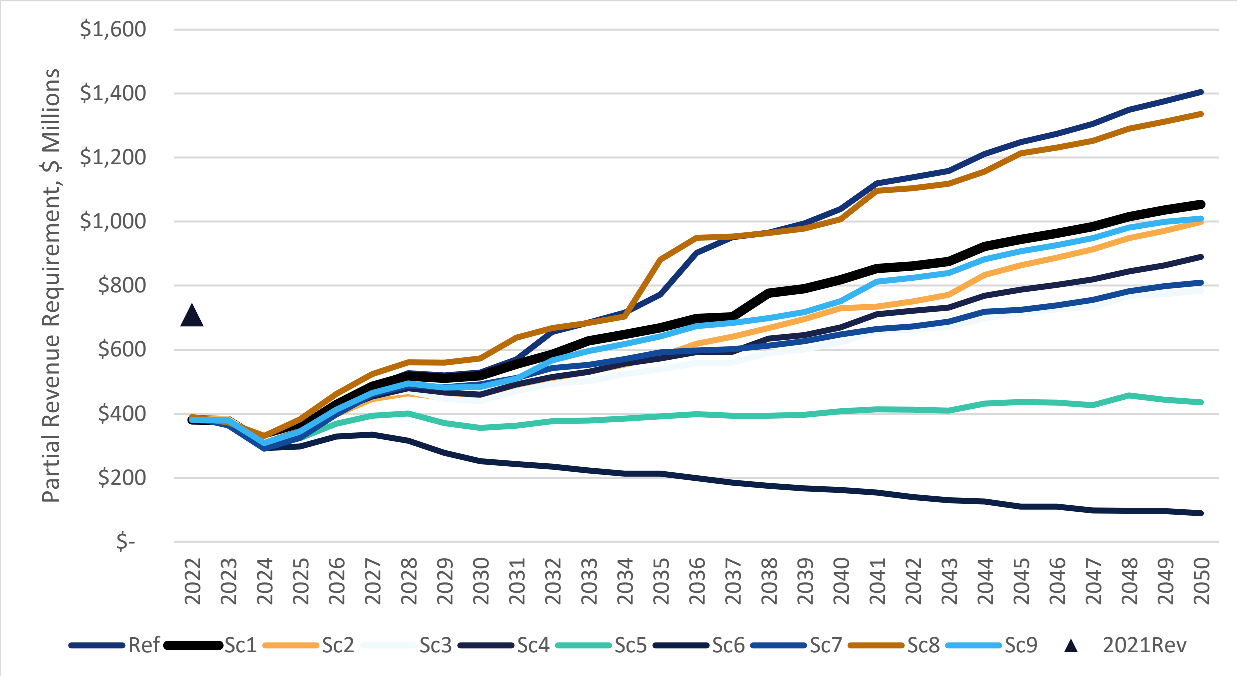


Source: NWN Scenario Results Workpaper.

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

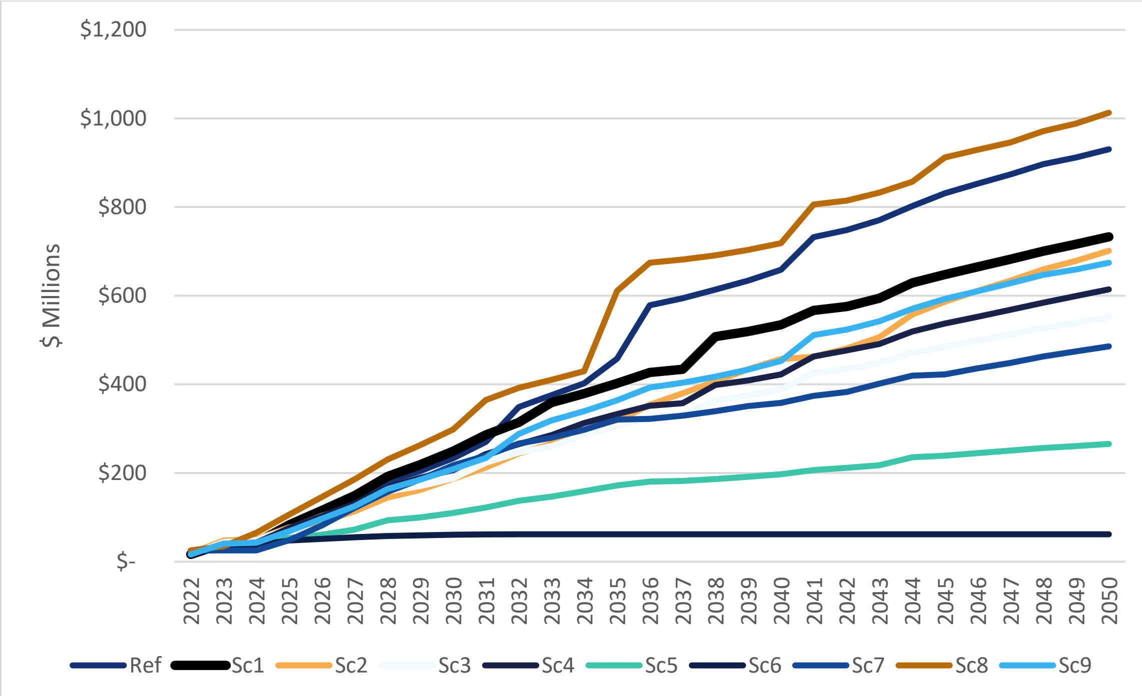


Source: DR 105 (2021 revenue requirement), and NWN Workpaper IRP 2022 Scenario Results. Graphing by Synapse.

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

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[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]

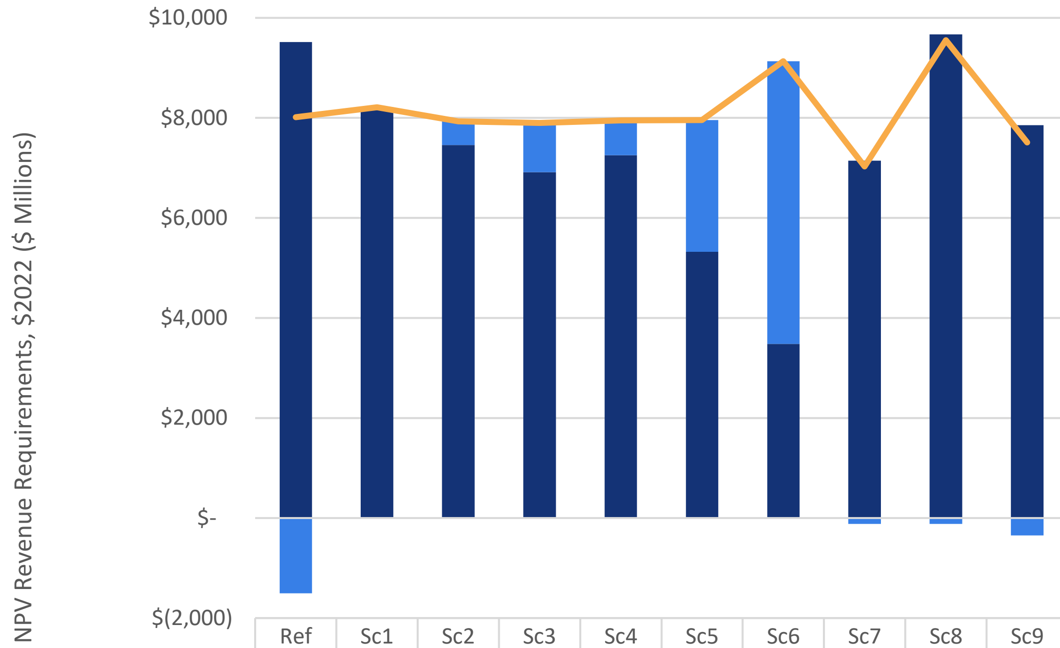
PVRR Comparisons Across Scenarios with Different Levels of Gas Load

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



	Ref	Sc1	Sc2	Sc3	Sc4	Sc5	Sc6	Sc7	Sc8	Sc9
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 w/ Electrification	$8,012	$8,215	$7,934	$7,897	$7,953	$7,959	$9,135	$7,030	$9,553	$7,509

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.

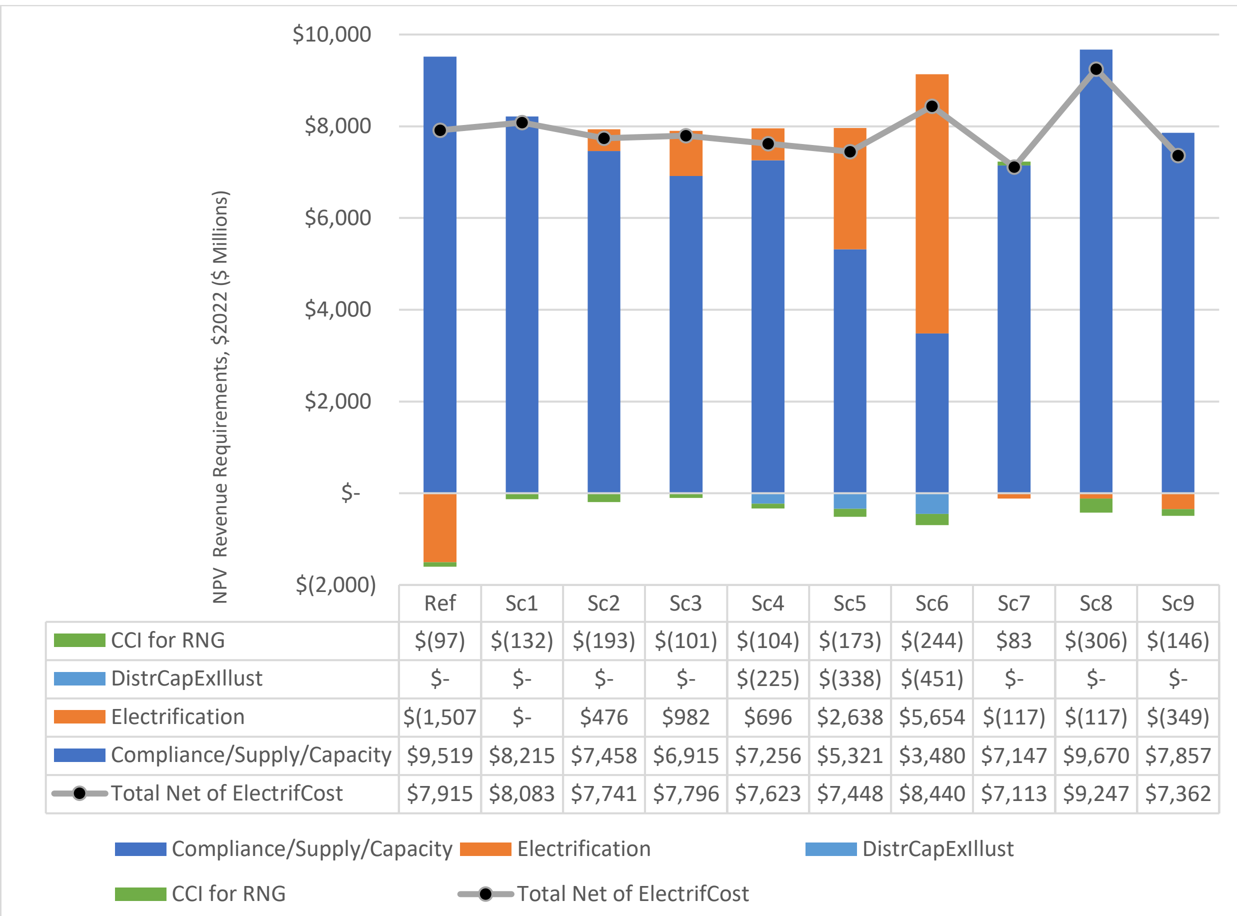
Figure 18 above illustrates the following:

- 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

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.

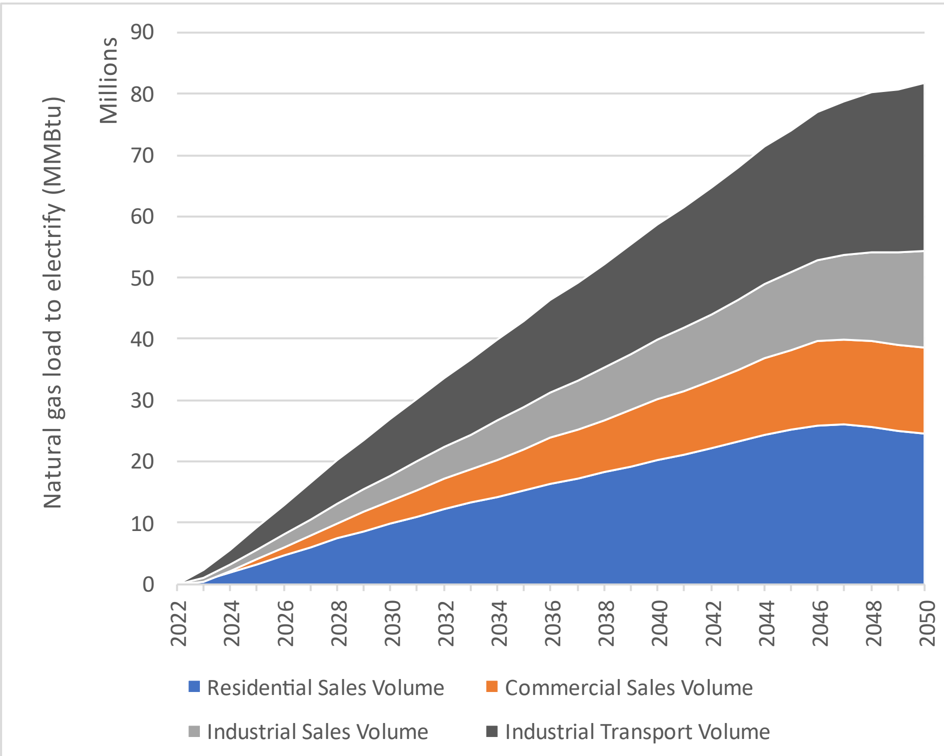
[89] Rightor, E., Whitlock, A. and Elliott, R.N. 2020, July. Beneficial electrification in industry. American Council for an Energy Efficient Economy. Available at: https://www.aceee.org/sites/default/files/pdfs/ie2002.pdf.

[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

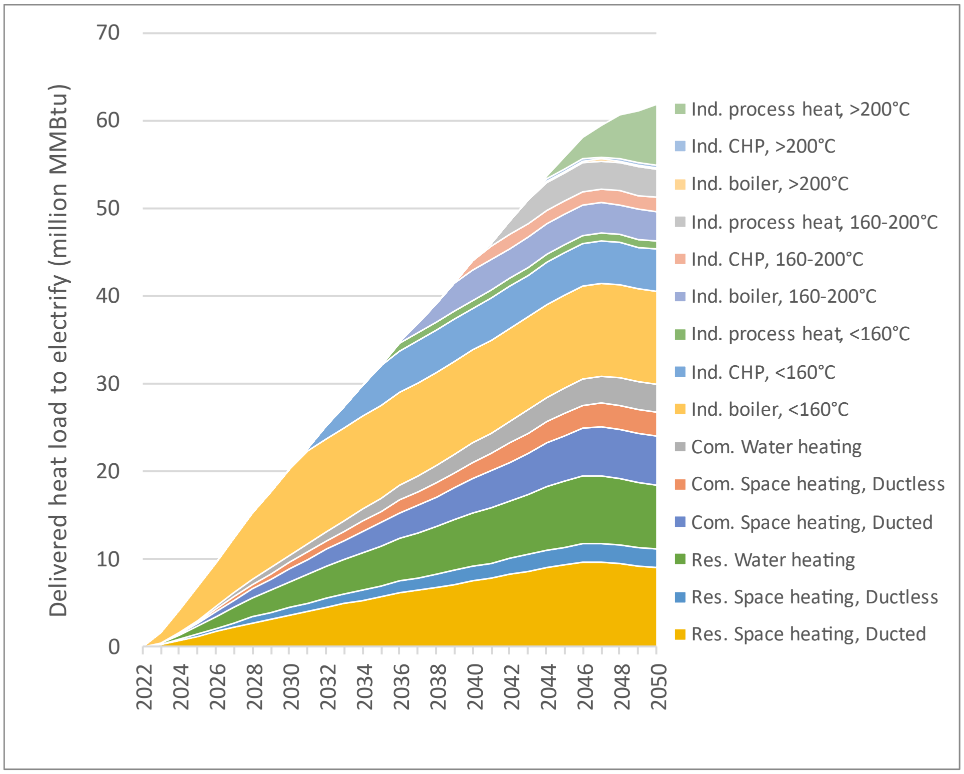


For some scenarios and in some years, natural gas load is less than in Scenario 1, resulting in a "negative load to electrify." This results in a cost savings in Synapse's analysis.

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

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[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.

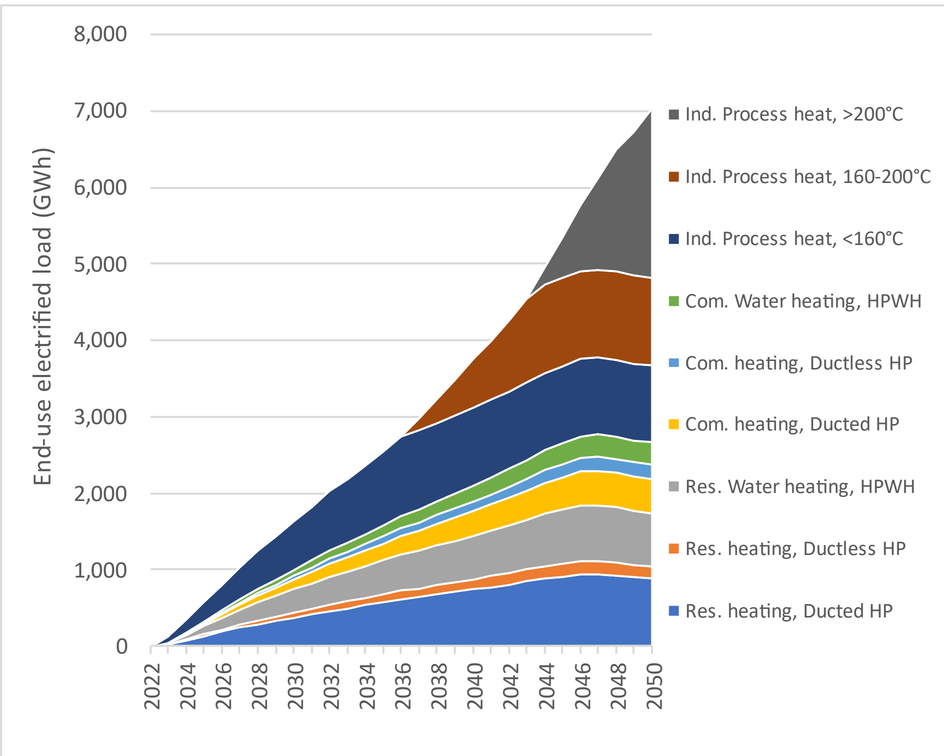
[105] Jadun, P., McMillan, C., Steinberg, D., Muratori, M., Vimmerstedt, L. and Mai, T. 2017. *Electrification futures study: End-use electric technology cost and performance projections through 2050.* National Renewable Energy Lab. Available at: https://www.nrel.gov/docs/fy18osti/70485.pdf.

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).

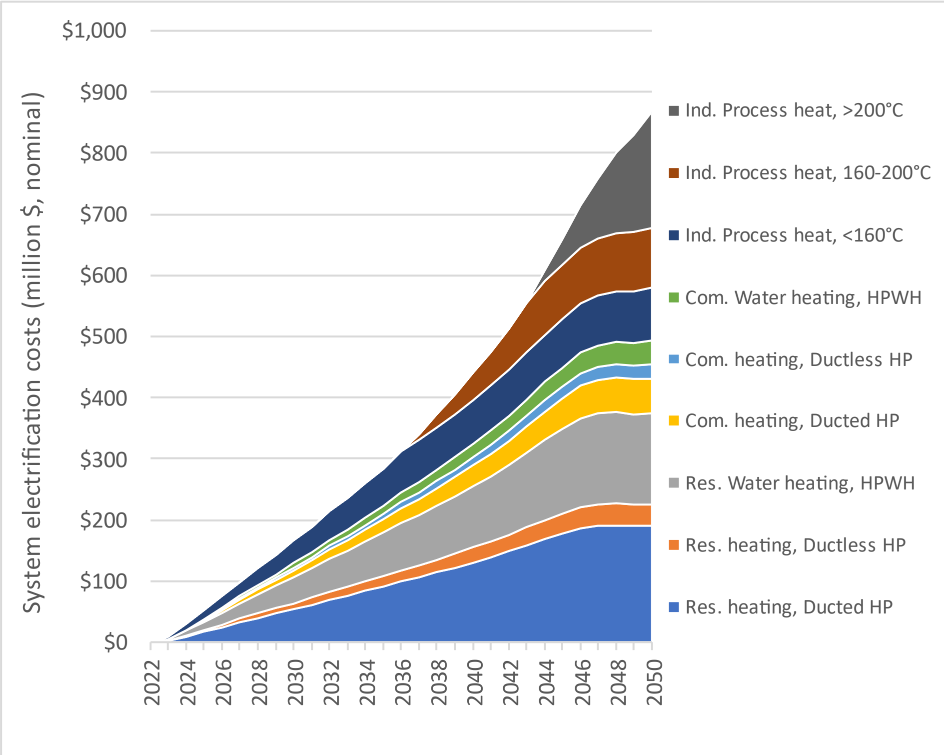
Table 12. Rates for major electric utilities that serve NWN's service territory

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.

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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

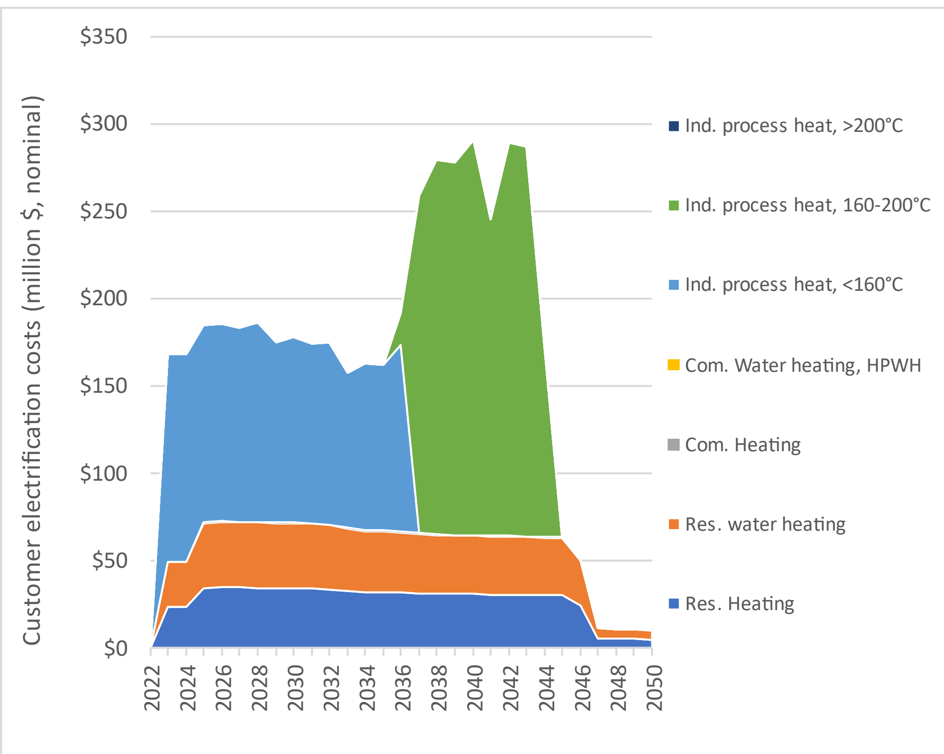
[113] California Electronic Technical Reference Manual (eTRM), http://www.caltf.org/etrm-overview.

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

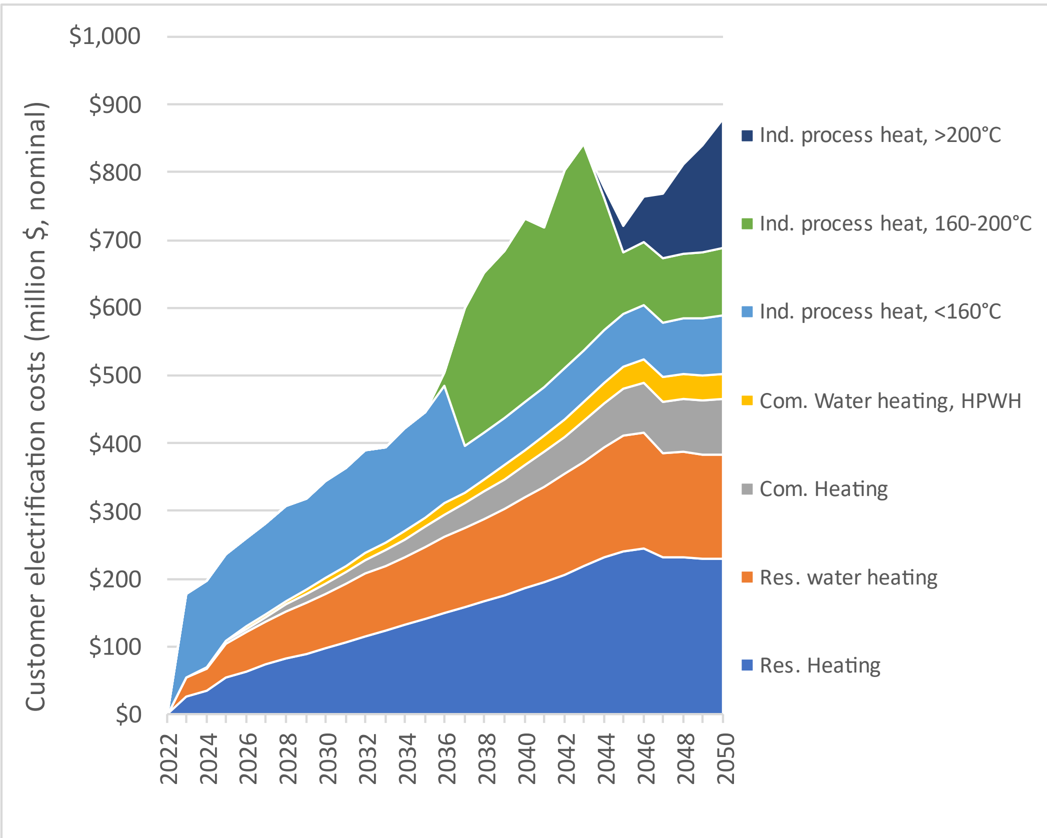


Figure 26. Annual system and customer electrification costs, all scenarios relative to Scenario 1

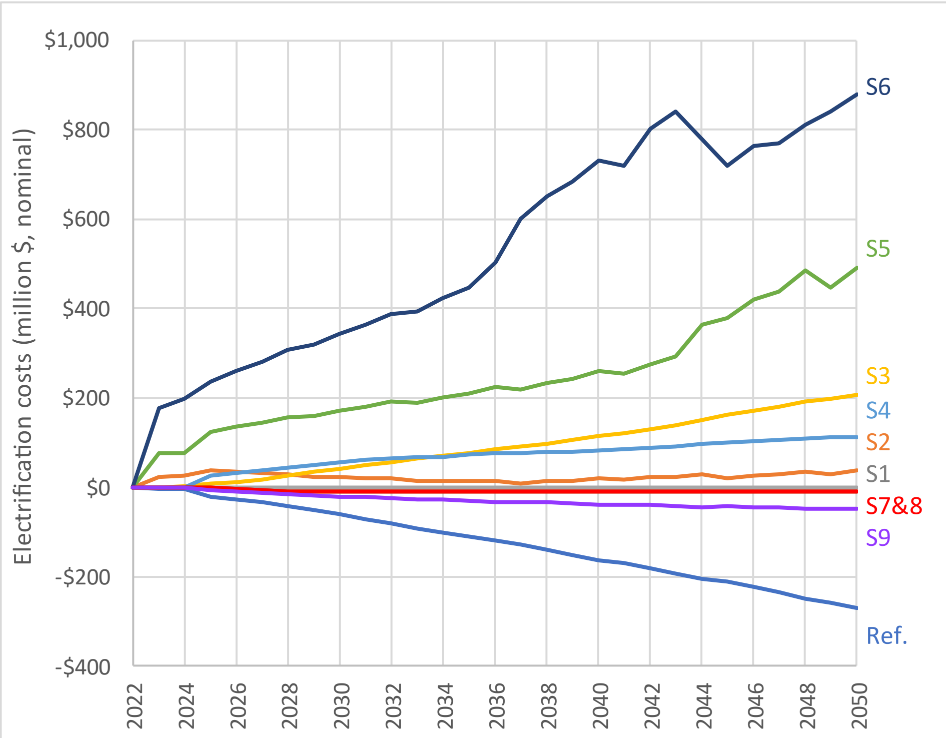
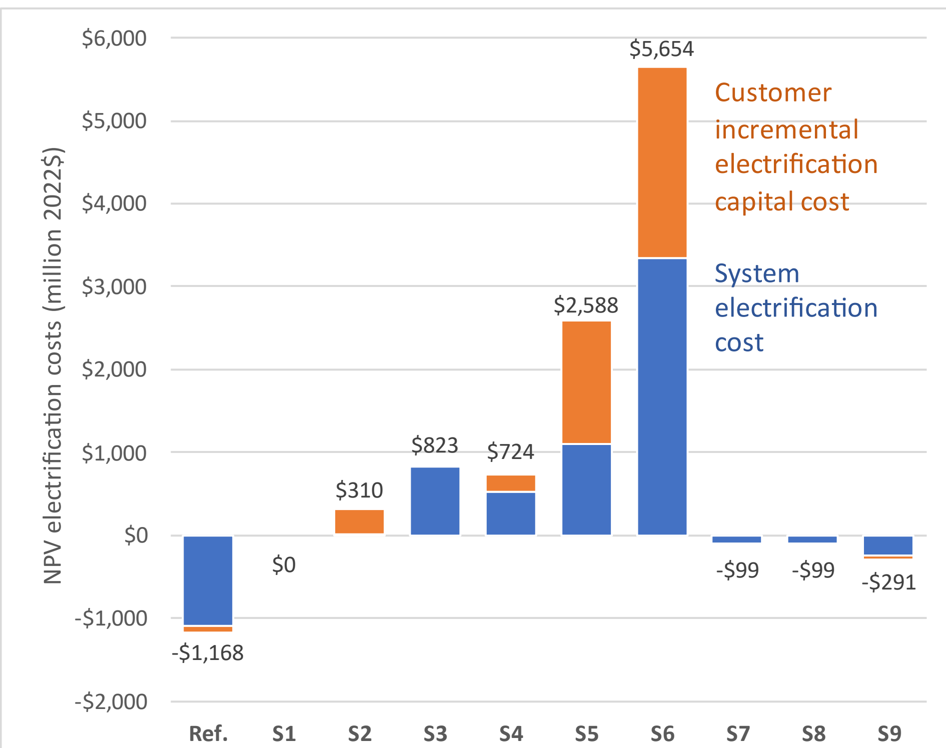


Figure 27. Net present value system and customer electrification costs, all scenarios relative to Scenario 1



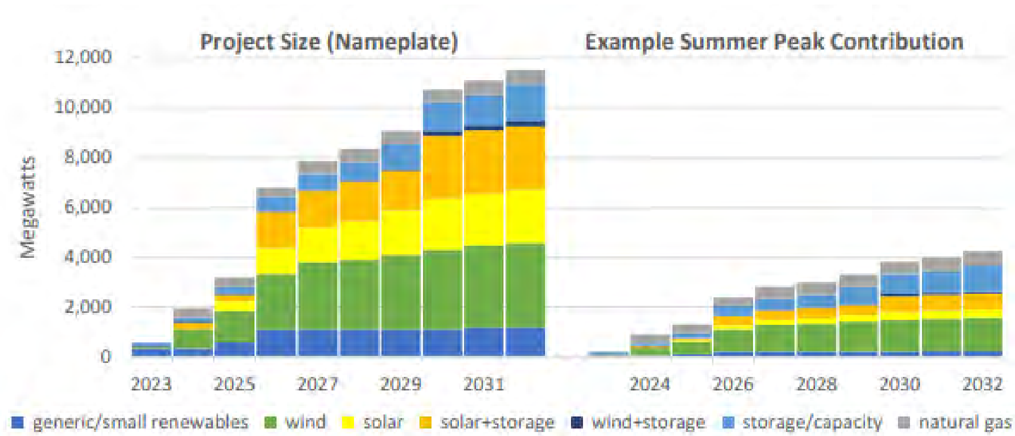
Appendix D. PACIFIC NORTHWEST ELECTRIC SYSTEM TRAJECTORY

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]

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[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.

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CERTIFICATE OF SERVICE

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I certify that I have this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 30th day of March, 2023 at Salem, Oregon.

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Mark Brown
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