BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 79

In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, 2022 Integrated Resource Plan	OPENING COMMENTS BY GREEN ENERGY INSTITUTE AT LEWIS & CLARK LAW SCHOOL, CLIMATE SOLUTIONS, COLUMBIA RIVERKEEPER, COMMUNITY ENERGY PROJECT, ELECTRIFY NOW, METRO CLIMATE ACTION TEAM, NATURAL RESOURCES DEFENSE COUNCIL, and SIERRA CLUB

Climate Advocates' Opening Comments

Redacted Public Version

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I. Introduction and Recommendations

The Climate Advocates[1] appreciate the opportunity to provide comments in response to NW Natural's (NWN) Integrated Resource Plan (IRP or the Plan). This is the first IRP NWN has submitted to the Oregon Public Utility Commission (Commission) since the passage of the Climate Protection Program (CPP)[2] in Oregon and the Climate Commitment Act (CCA)[3] in Washington. Both state regulatory programs set a declining cap on greenhouse gas (GHG) emissions to reach the states' climate targets, including from the sale of natural gas from local distribution companies. As a first step to understanding how natural gas utilities might comply with these requirements, the Commission opened the Natural Gas Fact Finding process in docket UM 2178. Although still in progress, the Draft Report provided recommendations to the state's three gas utilities in preparing their IRPs. Indeed, to properly reveal the "best combination of expected costs and associated risks and uncertainties,"[4] the Commission needs an IRP that meaningfully advances compliance with these climate policies—in a realistic and least risk manner—and it should consider implementing recommendations from the draft UM 2178 report to achieve that goal.

NWN submitted an IRP that protects its profits today while disregarding expert recommendations—risking the futures of its customers and Oregon's ability to meet its decarbonization goals. NWN's IRP does not present a realistic and justifiable least cost, least risk path towards decarbonization. The plan delays the bulk of its emissions reductions until late in the planning horizon, at which point it relies on unproven, risky technologies that support investment in fossil fuel infrastructure in the hope that there will be a series of radical shifts in the cost and feasibility of these technologies. Essentially, it is using unrealistic assumptions from this IRP to defend its business model in conversations with local governments and state legislators, assuring public servants[5]

[1] The Climate Advocates include the Green Energy Institute at Lewis & Clark Law School, Climate Solutions, Community Energy Project, Columbia Riverkeeper, Electrify Now, Metro Climate Action Team, NRDC, and Sierra Club.
[2] Climate Protection Program, OAR Ch. 340, Div. 271, https://www.oregon.gov/deq/ghgp/cpp/pages/default.aspx
[3] Climate Commitment Act (CCA), https://ecology.wa.gov/Air-Climate/Climate-Commitment-Act
[4] Oregon Public Utility Comm'n, Order Nos. 07-002, 07-047, Guideline 1(c) (hereinafter, IRP Guidelines).
[5] NWN Comments to REBuilding Task Force, Nov. 15, 2022, https://olis.oregonlegislature.gov/liz/2021I1/Downloads/CommitteeMeetingDocument/257434; Milwaukie City Council meeting, Nov. 11, 2022, https://www.youtube.com/watch?v=SAm7T8OV-NU.

that its decarbonization plan is not only viable but is preferable to building electrification—a decarbonization solution that relies on decades-old, proven technologies resulting in actual, verifiable emissions reductions and public health benefits.

Recognizing that the Commission has an obligation to ensure the IRP is "consistent with the long-run public interest as expressed in Oregon and federal energy policies,"[6] the Climate Advocates urge the Commission to use this pivotal moment to leverage its authority and demand responsible action from the Company. The Climate Advocates make the following four recommendations.

1. **The Commission should implement new regulatory practices, consistent with many of the tools identified in its UM 2178 Draft Natural Gas Fact Finding Report.**

As an investor-owned utility whose business model hinges on maintaining and expanding the gas system, NWN does not have the incentive to maximize public interest outcomes in its GHG emissions compliance strategies. The Company's incentives are not at all aligned with its customers' interests nor the public good. This IRP provides a critical opportunity for the Commission to implement necessary regulatory measures that catalyze the energy transition while protecting ratepayers and realigning the utility's incentives. The Climate Advocates ask the Commission to:

(1) require NWN to assess the risks of its scenarios, including stranded asset risks, and identify the specific approach it chose in its Action Plan;

(2) direct integrated utility planning to compare proven, low-cost decarbonization technologies today, including residential and commercial electrification;

(3) explore and consider implementing performance based regulatory tools to help achieve state decarbonization goals; and

(4) mandate NWN map its distribution system in preparation for eventual pruning.

2. **The Commission should not acknowledge the Forest Grove uprate project.**

The Plan provides faulty reasoning for the need to uprate a Forest Grove feeder and does not explore alternatives that may be less costly and better align with long-term decarbonization goals, while protecting ratepayers from unnecessary investments that

[6] IRP Guideline 1(d).

may become stranded assets. The Commission should not acknowledge the Forest Grove feeder project at this time; the Company should conduct additional analysis that fully examines if there is a portfolio of non-pipeline alternative resources that can reduce, defer, or eliminate the need for the project.

3. **The Commission should not acknowledge the adoption of alternative fuels in NWN's IRP**

NWN's decarbonization plan relies on unrealistic, rapid cost reductions in electrolysis, methanation, and carbon capture, without addressing safety concerns. In fact, NWN's decarbonization scenarios bank on multiple technology breakthroughs, going to remarkable lengths to avoid employing proven decarbonization measures like electrification over the next ten years—when emissions reductions are most necessary and fruitful.

4. **The Commission should require NWN to refile its IRP to overhaul its heat pump technology availability forecast, load forecast, and fuel prices to reflect realistic projections.**

NWN includes a number of speculative, unsupported assumptions about the future. NWN's bases its gas heat pump assumptions on wishful widespread adoption of a technology that is not commercially available. The Company's natural gas price forecasts are unrealistically optimistic and skew alternatives away from energy efficiency and electrification. The Company's load forecast was out-of-date at the time of the filing as it did not include a number of significant policy changes that will affect their near- and long-term load forecast. For example, the load forecast does not include changes to the Washington state residential and commercial building codes, the Commission's order reducing the Company's line extension allowance, and the passage of the Inflation Reduction Act, as well as local resolutions to pursue electrification in new construction. The load forecast impacts each of the Company's action items including its demand- and supply-side resource acquisition compliance costs and the need for distribution project upgrades. Finally, the Company's fuel price forecast is significantly lower than comparable forecasts, which biases traditional supply investments at the expense of demand-side resources. As the impacts of these factors are so significant, the Commission should require the utility to refile its IRP.

II. NWN's IRP demonstrates the need for reformed planning at the Commission

The IRP planning process does not properly account for transformative state policies and the evolution of the energy sector to a lower carbon future. The CPP's GHG emissions caps will require significant change, not just from the Company but also from the Commission. NWN needs to provide an emissions-compliant IRP that considers risks of various investment strategies and fairly evaluates electrification. To facilitate this change, the Commission must do two things. First, create a planning process that enables the utility to assess fairly the cost and benefits of electrification. Second, the Commission should consider exploring whether performance-based ratemaking tools will better align the utility's incentives with public policy and customer outcomes.

Accordingly, the Climate Advocates recommend the following four regulatory improvements. First, NWN should assess scenario risks and identify its preferred approach. Second, the Commission must consider mechanisms for integrated energy system modeling. Third, the Commission is in an ideal position to assess risk sharing and limit gas ratepayer obligations. Finally, the Commission should mandate that NWN publish maps of its system as a first, incremental step to assessing the usefulness of strategically pruning segments of its distribution system in order to protect ratepayers from additional potentially imprudent investments.

A. NWN's IRP should identify its preferred approach to meeting CPP compliance requirements

NWN's decision to model a multitude of scenarios, without identifying its preferred pathway, results in a plan that fails to yield sufficient information about *which* of NWN's investments (or none) will result in better and more cost-effective emissions reductions. NWN evaluates nine scenarios against a reference case and estimates the cost of each approach.

Figure 1: NWN's Total Compliance Cost by Scenario and by State

Scenarios	Total Compliance Cost- Oregon	Total Compliance Cost- Washington	Total Cost
Balanced Decarbonization	$ 11,784,953,068	$ 975,159,202	$12,760,112,270
Carbon Neutral	$ 10,132,588,348	$ 1,136,375,944	$11,268,964,292

Dual-Fuel Heating	$ 8,933,992,992	$ 730,233,360	$9,664,226,352
New Gas Customer Moratorium	$ 9,759,811,761	$ 741,360,503	$10,501,172,264
Aggressive Building Electrification	$ 4,650,326,827	$ 465,383,527	$5,115,710,354
Full Building Electrification	$ 1,660,619,327	$ 283,550,076	$1,944,169,403
RNG and H2 Policy Support	$ 8,303,069,304	$ 765,431,788	$9,068,501,092
Limited RNG	$ 16,105,398,278	$ 1,204,526,712	$17,309,924,990
Supply Focused Decarbonization	$ 10,555,557,429	$ 867,552,779	$11,423,110,208

Despite detailed evaluations of these scenarios, NWN does not assess the risk of any scenario. The Company does not perform an adequate quantitative and qualitative assessment of the risk of each scenario. Such an inquiry could be handled in a variety of ways, one of which is to conduct sensitivity analyses. For example, what is the cost of each portfolio, and consequently the cost to customers, if the utility's price forecast for RNG and hydrogen are 50 percent, 100 percent, or 200 percent below actual costs? What is the cost of each portfolio if the utility's peak load begins to decline?

Nor does the Company identify a specific scenario for developing its Action Plan. The lack of clarity as to what actions produce the least risk scenario undermines the value of this exercise and obfuscates the Company's decision-making process.

B. The Commission should coordinate the gas and electric planning processes and ensure consistent assumptions and best available data are used across utilities

Climate Advocates recognize that NWN is limited in its ability to model electric utility costs and risks as they pertain to its electrification scenarios. As NWN explains in its Plan:

> *NW Natural does not know the full cost to serve that customer on the electric system inclusive of the incremental generation, transmission, distribution cost, which are in addition to the incremental equipment and installation costs for customers to switch to an all-electric home. As such NW Natural*

is not able to validate that electrification would be is a least cost, least risk option for customers that have chosen gas end-use equipment. [7]

Due to these limitations, the Commission cannot be confident that the Company identified the least cost, least risk Plan. For example, the total compliance cost values measure the cost to serve the gas network while meeting state goals. In its balanced approach (Scenario 1), the total cost of this approach through 2050 is roughly $11.78 billion.[8] The costs for the two electrification scenarios, Aggressive Electrification and Full Electrification, are significantly lower—$4.65 billion and $1.66 billion, respectively.[9] However, these values are not representative of the total costs of electrification scenarios, making it impossible to compare the scenarios' total costs. Electrification costs excluded from NWN's scenarios include the cost of replacing gas appliances with electric models, any accompanying building improvements like sealing pipes and upgrading electrical panels, and electric utility investments in renewable energy to accommodate the load growth and continue the decarbonization of the grid.

We recognize that NWN will need information and analysis from electric utilities to account fully for the costs associated with electrification in its own IRPs. Without electric utility contributions to the forecasting and planning work, the scenario analysis will remain incomplete and inadequate. 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.[10] 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. The resulting analysis would provide a holistic understanding of energy requirements and provide enough data

[7] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, p. 182.
[8] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Workpapers, October 24, 2022, "Scenario Results," "Compliance Data" tab.
[9] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Workpapers, October 24, 2022, "Scenario Results," "Compliance Data" tab.
[10] Docket No. UM 2178, Natural Gas Fact Finding Draft Report, Appendix B, p. xv. Available at https://edocs.puc.state.or.us/efdocs/HAH/um2178hah155046.pdf.

to determine the least cost, least risk scenario. This recommended approach is similar to one recently adopted by the British Columbia Utilities Commission (BCUC). In January 2022, the BCUC required British Columbia Hydro and Power Authority (BC Hydro) and Fortis BC Energy Inc. to share the data required to file load forecast results based on each other's scenarios contained in their respective resource plan.[11] The Climate Advocates' recommendation builds upon the BCUC's requirement to share information to develop load forecasts and would require the Oregon utilities to share cost and other relevant assumptions to better inform each other's scenarios.

The viability of electrification as the core of a least cost, least risk approach makes this change warranted. There is significant reason to believe that, even after accounting for the costs associated with electrificiation, the electrification scenarios will be lower-cost and lower-risk than alternative scenarios. For example, an analysis by Synapse Energy Economics indicates that electrification scenarios in Oregon could result in billions of dollars in net present savings.[12] Moreover, fuel price shocks and continued reductions in renewable generation costs further enable the viability of electrification. Costs of renewables, such as solar and wind, have rapidly declined over the past decade such that even new natural gas plants in Europe do not appear cost-effective.[13]

The increasing prevalence of policies supporting all-electric new construction indicates that the risks associated with the electrification approach are low. Replacing a gas appliance with a similar model often still has lower upfront costs than installing an electric appliance due to costs associated with sealing pipes, wiring, and panel upgrades, but recent policies are tackling these incremental costs. Through the Inflation Reduction Act (IRA), the Federal government has expanded residential tax credits for the purchase of heat pumps and provided additional rebates on electric appliances such as heat pumps, electric ranges, and electric clothes dryers.[14] Additionally, many states have instituted

[11] British Columbia Utilities Commission, Energy Scenarios for BC Hydro and FEI, Re: FortisBC Energy Inc. – British Columbia Hydro and Power Authority – Energy Scenarios, January 21, 2022. Available at https://docs.bcuc.com/Documents/Arguments/2022/DOC_65400_2022-01-21-FEI-BCH-Energy-Scenarios-Request.pdf.
[12] Synapse Energy Economics, *Toward Net Zero Emissions from Oregon Buildings* at iv, 38, 41-42 (June 2022), https://www.synapse-energy.com/sites/default/files/Net-Zero-Emissions-from-Oregon-Buildings-21-127.pdf.
[13] IRENA (2022), Renewable Power Generation Costs in 2021, International Renewable Energy Agency, Abu Dhabi.
[14] "Text - H.R.5376 - 117th Congress (2021-2022): Inflation Reduction Act of 2022." Congress.gov, Library of Congress, 16 August 2022, https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

residential energy efficiency and electrification programs, such as California, which will provide $84.7 million in incentives for heat pump water heaters in 2023.[15] Oregon and Washington may each develop new energy efficiency programs, or expand programs, that would further reduce the incremental costs of electric appliance adoption, thus making electrification more cost-competitive for customers.

With beneficial electrification comes the reduction in household gas use, which improves health outcomes. Natural gas use results in hazardous air pollutants such as nitrogen oxides (NOx) released during combustion, which are linked to childhood asthma. Stoves leak even when turned off, releasing harmful particles, such as benzene, which is a carcinogen for which there is no safe exposure level.[16] These societal health costs, which NWN does not include in its analysis, do not exist in an all-electric household.[17]

Nevertheless, whether as a result of reductions in throughput or increased electrification, an unmanaged transition could pose significant risks to gas-system ratepayers. Each gas customer that electrifies their household is one less customer that can contribute to a gas utility's fixed charges. The smaller pool of customers could raise rates for those that remain on the gas network, which could spur more customers to exit. NWN estimates these rate increases, but their values are not credible given the omission of Federal legislation, such as the Inflation Reduction Act, and changes to State building codes.

Policy measures can mitigate shareholder and ratepayer risk by managing the transition from gas to electric service for residential and commercial ratepayers. For example, reducing depreciation schedules could allow NWN to invest in maintaining existing networks while providing greater certainty to shareholders. Policies discouraging further expansion of the gas system, such as elimination of line extension allowances and pursuit of non-pipeline alternatives, can avoid unnecessary spending on infrastructure that is incompatible with achieving decarbonization targets. Also, approaches like

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[15] *CPUC provides additional incentives and framework for Electric Heat Pump Water Heater Program*, California Public Utilities Commission, April 7, 2022, https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-provides-additional-incentives-and-framework-for-electric-heat-pump-water-heater-program.
[16] Jeffrey Kluger, *Your gas stove may be leaking benzene into your kitchen*, Time, October 20, 2022, https://time.com/6223219/gas-stove-leaking-benzene/
[17] A Review of the Evidence Public Health and Gas Stoves, Multnomah County, 2022. https://multco-web7-psh-files-usw2.s3-us-west-2.amazonaws.com/s3fs-public/gas-stoves-health-risk-report-2022_0.pdf

strategic pruning of the gas system can decommission infrastructure, reducing fixed costs at the same time that customers are removed from the system.

The Commission must adopt guidelines to reflect the realities of the energy transition. That starts with an IRP process that includes a complete evaluation of compliance scenarios by both gas and electric utilities and extends to a transition in regulatory practices.

C. The Commission should explore new regulations to align utility, ratepayer, and decarbonization interests

The challenge and significance of the Commission's role in this proceeding cannot be overstated. Not only is it appropriate for the Commission to consider risk allocation between ratepayers and shareholders, but the Commission also has a fundamental responsibility to direct utilities toward a managed transition that avoids stranding ratepayers and assets. Climate Advocates recognize that risk allocation is complex and includes every aspect of the regulatory framework. However, without an evolution in regulatory oversight, the gas utility's incentives will continue to work against the public interest and the Commission risks inviting a turbulent and costly decarbonization of the gas distribution network. Fortunately, the Commission possesses a number of regulatory tools to modify the existing risk allocation, including Multi-Year Rate Plans (MYRP), fuel cost sharing, and performance incentive mechanisms. If implemented carefully, these devices can incentivize cost-effective decarbonization, and better allocate the risk of the utility's decisions between the company and its customers.

1. MYRP

MYRPs permit utilities to operate for several years without a traditional, general rate case and incentivize cost containment. This performance-based measure calculates revenue requirements using forecasted CAPEX, formula rates, or an index, such as inflation. The length of the plans and the use of forecasting could help control operational costs. Loosening the link between cost and revenue could allow utilities to operate more efficiently by allowing companies to share in savings from reduced operating costs.

2. Fuel Cost Sharing

Fuel cost sharing shifts a portion of feedstock risk to utilities to better align incentives. Such policies stipulate a percentage cap that the utility could pass through to customers when fuel prices vary from baselines. For example, in 2018 the Hawaii Public Utilities Commission approved a 2 percent risk share for Hawaii Electric so that it had some incentive to limit fuel use and comply with decarbonization targets.[18] Portland General Electric and Green Mountain Power (Vermont) both have 10 percent risk sharing mechanisms, operating since 2007 and 2006, respectively.[19] Although these are electric utilities, instituting such a policy for a gas utility could also promote energy efficiency and reduce energy burdens.

3. Performance Incentive Mechanisms (PIMs)

PIMs can either directly target GHG reduction or do so indirectly through proxy measures, such as electrification and peak demand reductions. PIMs can effectively complement state decarbonization targets by incentivizing utilities through financial rewards for meeting targets and, in some cases, applying penalties for missing minimum goals. A number of states have passed some form of PIM, some with multiple metrics.

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[18] Trabish, Herman K. "Hawaii's New Fuel Price Performance Incentive Gives Heco 'Skin in the Game'." Utility Dive, 6 Aug. 2018, https://www.utilitydive.com/news/hawaiis-new-fuel-price-performance-incentive-gives-heco-skin-in-the-game/528329/.

[19] Trabish, Herman K. "Hawaii's New Fuel Price Performance Incentive Gives Heco 'Skin in the Game'." Utility Dive, 6 Aug. 2018, https://www.utilitydive.com/news/hawaiis-new-fuel-price-performance-incentive-gives-heco-skin-in-the-game/528329/.

Figure 2: Sample Selection of State PIM[20]

State	Key design features	Maximum available incentive*
Hawaii	Initial, one-time incentive based on achievement of peak demand reduction target through direct procurement.	Lesser of 5% of aggregate annual contract value or $500,000
Michigan	Up to 15% of demand response costs on a sliding scale based on demand response capacity, achieved growth rate, and nonwires alternatives assessment costs	15% of demand response spending
Texas	1% of net benefits for every 2% of demand reduction goal exceeded	10% of net benefits
Vermont	Percentage of total approved budget based on performance on several outcomes, including winter/summer peak demand reduction	2.5% of total approved budget
Rhode Island	Cash reward based on achievement of peak demand reduction, structured as a shared savings mechanism exempt from utility return-on-investment cap	45% of net benefits
New York	Up to 100 basis points added to ROE for PIMs in aggregate; peak demand reduction achievements receive a portion	A portion of 100 basis points for SDR performance (currently approved at 65–70 total basis points)
Massachusetts	Portfolio-wide incentive based on performance from 75–125% of the PIM goals	5.4% of cumulative budget for program costs

Although PIMs are more common for electric utilities, they present an opportunity for gas utilities to reduce their GHG emissions while earning a fair return and, more importantly, without expanding pipeline solutions. The Commission should consider exploring a PIM that encourages NWN to electrify end customer appliances by allowing a rate of return on investments that help meet the set target. Such a PIM presents an opportunity to align climate goals with utility goals.

4. Minimizing stranded assets

Meeting decarbonization targets will require significant and rapid changes to the gas system in any scenario. Ratepayers ultimately bear the cost and the risk associated with stranded assets, and the time to begin planning to mitigate these risks is now. The first step in minimizing ratepayer burdens is for the Commission to evaluate all new investments more critically to assess the possibility of stranding.

[20]Gold, Rachel. et al., "Performance Incentive Mechanisms for Strategic Demand Reduction." *American Council for an Energy-Efficient Economy*, Feb. 2020, https://energyinnovation.org/wp-content/uploads/2020/02/Performance-Incentive-Mechanisms-for-Strategic-Demand-Reduction.pdf.

Next, the Commission must adopt regulatory changes to reduce risk for existing gas customers moving forward, anticipating that both fuel throughput and overall customer count will decline over time. With regulatory reassessment of the value of gas line extension allowances, the health and economic benefits of electrification, and a nationwide trend of local governments taking action to phase out gas in new construction, 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.

For example, the Commission can accelerate depreciation schedules, securitize assets, and change the return on equity (ROE) to proactively maintain utility revenues while spreading costs to the widest set of ratepayers. Accelerated depreciation seeks to pay off assets before their intended useful life, which also frees capital for compliance investments. Securitization allows the state to own an asset that may not be used and useful for its intended life and issue bonds to cover its cost. With a lower interest rate than debt, bonds lower the total cost of a gas investment. Reducing the ROE on certain investments reduces ratepayer obligations on pipeline solutions and steers gas utilities towards compliance investments. The Commission should explore whether any of these tools, or a c combination, are appropriate to reduce the risk of stranding assets.

Ultimately, if NWN fails to meet emissions targets because it does not seriously explore realistic opportunities to decarbonize, any future incremental infrastructure costs, as well as costs for failure to comply with the targets, should be borne by NWN's shareholders and not by ratepayers.

D. The Commission should require NWN to make maps of its system publicly available

Finally, to impose some order on this energy transition, the Commission must position itself so that it understands all of its options and can identify measures that are protective of ratepayers. To do this, it needs to have a clear understanding of the age and depreciation schedules of the existing pipe. The Commission could easily accomplish this goal by requiring NWN to produce publicly available maps overlayed with depreciation data as well as other critical data for assessing the utility's infrastructure. Such maps would assist the Commission in identifying "no regrets" decisions, instead of locking customers into investments that can achieve only modest emissions reductions. NWN should provide this type of information as an incremental first step to arm the Commission with the information it needs when considering whether strategic system pruning is a useful means of controlling costs and risks. Strategically resizing the gas system where it is aging, inefficient, or requires significant and expensive upgrades is a "no regrets" option.[21]

III. The Commission should not acknowledge the Forest Grove Feeder Uprate

The Commission's new regulatory approach should begin with rejecting the Forest Grove Feeder uprate. NWN does not weigh electrification as an alternative and risks deploying an asset that is not compatible with CPP goals and stranding the investment.

NWN forecasted the need for upgrades related to the Forest Grove Feeder, stating that the feeder is operating over the original design capacity and that a severe pressure drop occurs on a segment of the feeder during peak conditions.[22] During cold weather periods, demand increases which results in a drop of pressure and, when the drop exceeds 40 percent, the chance of outages is greater.[23] Specifically related to the Forest Grove Feeder, an average temperature of 25 degrees Fahrenheit would lead to a pressure drop of over 40 percent. NWN estimates that such a cold event occurs every three years on average.[24] NWN's solution to this problem is to increase the pressure of the Feeder by

[21] Docket No. UM 2178, Natural Gas Fact Finding Draft Report, p. 23 and Appendix B, p. xv. Available at https://edocs.puc.state.or.us/efdocs/HAH/um2178hah155046.pdf
[22] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, page 384.
[23] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, IRP 386.
[24] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, IRP 387.

uprating it, which will prevent pressure drops of 40 percent or greater.[25] The net present total cost of the uprate is between $3 and $7 million dollars.[26]

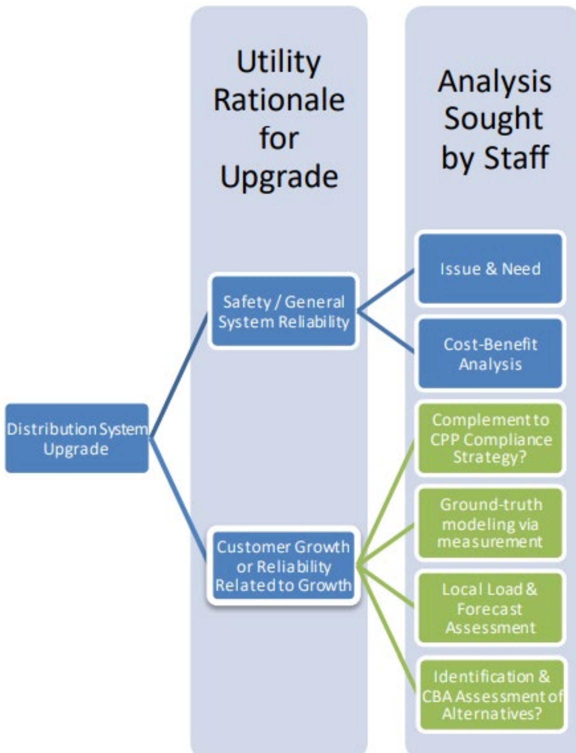
NWN's IRP does not provide demand-side solutions other than targeted interruptible schedules from large industrial customers. Climate Advocates are concerned that NWN's conclusion to uprate the feeder is due in part to flawed load forecasts. In a discovery response, NWN states that the Customer Management Module "incorporated customer growth in the area that was not captured in the legacy models used in 2019."[27] As discussed in Section V.B, with the proper assumption that customer counts will decrease due to rising electrification, it may be possible for NWN to alleviate the issue by investing in demand-side solutions[28] and other non-pipeline alternatives. Non-pipeline alternatives are not theoretical—PG&E's proposed zonal electrification pilot project at California State University Monterey Bay will electrify 620 customers with behind the meter investments and retire an existing gas line, at lower projected costs to ratepayers than making otherwise-necessary upgrades to the pipeline.[29] PG&E determined that electrification was more cost-effective than repairing the gas network.[30] Additionally, the project would help reduce emissions and ensure long-term, affordable rates. NWN should use learning from this pilot to model the impact of $3 million and $7 million in demand-side investments (the bounds NWN provides for the cost of the uprate), with no increase in customers. Another option is to scale the pilot of NWN's demand-side program, the Geographically Targeted Energy Efficiency program (GeoTEE), for this service area. These investments would also lower total ratepayer costs, unlike the uprate, which would saddle ratepayers with costs that will not be useful in the long term. If these measures cannot curb the demand of gas enough, NWN should model the cost of injecting gas into the Forest Grove Feeder during the peak period using trucks.

Furthermore, in response to the CPP, Commission staff recently unveiled new criteria by which to assess gas utility IRPs. As part of the directive, "investments and activities

[25] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, IRP 389.
[26] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, IRP 394.
[27] LC 79 Advocate DR 2 NWN Response (provided as Attachment A).
[28] Demand-side solutions include energy efficiency and various load management techniques aimed at minimizing peak and net demand.
[29] Application of Pacific Gas and Electric Company for Approval of Zonal Electrification Pilot Project. August 10, 2022. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M496/K451/496451495.PDF
[30] Application of Pacific Gas and Electric Company for Approval of Zonal Electrification Pilot Project. August 10, 2022. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M496/K451/496451495.PDF

found in preferred portfolios and IRP Action Plans must demonstrate both how they achieve long-run GHG emission reductions ***and*** avoid near-term penalties during each three-year compliance period."[31] The Commission staff put forward a high-level framework for evaluating distribution system upgrades, seen below in Figure 3.

Figure 3:Staff's Proposed Approach to Distribution System Project Analysis Post-CPP Adoption[32]



In its final report on the Cascade Natural Gas IRP, the Commission staff used this framework to decide whether to acknowledge several distribution projects. The Prineville Gate experienced "impaired flow and outlet pressures due to undersized components" causing issues during peak periods.[33] However, the Commission staff recommended did not acknowledging the project because the main source of issues was the forecasted growth.[34]

The application of this framework should result in the Commission not acknowledging the Forest Grove Feeder uprate at this time. Following the process depicted in Figure 2, the uprate must complement the CPP Compliance Strategy.

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[31] Docket No. LC 76, Acknowledgement of the 2020 Integrated Resource Plan Update, October 7, 2022
[32] Docket No. LC 76, Acknowledgement of the 2020 Integrated Resource Plan Update, October 7, 2022
[33] Docket No. LC 76, Acknowledgement of the 2020 Integrated Resource Plan Update, October 7, 2022
[34] Docket No. LC 76, Acknowledgement of the 2020 Integrated Resource Plan Update, October 7, 2022

Considering the technology risk detailed in Section IV.A, expanding the gas distribution network does not support effective decarbonization. Even if there are short-term concerns during peak periods, the process stipulates that NWN should provide a cost benefit analysis of alternatives. Those alternatives should be non-pipeline solutions that help achieve CPP targets.

Moreover, acknowledging the uprate would be antithetical to every measure discussed in these comments. The Forest Grove feeder uprate would be at risk of stranding assets, increasing rate pressures, and hampering electrification.

IV. The Commission should not acknowledge the adoption of alternative fuels in NWN's IRP

NWN's IRP results in a strategy that is highly risky in both the short-term and long-term due to unreasonable technology costs, policy assumptions, and forecast assumptions. Despite state and local movements to electrify buildings, state decarbonization policies, and natural gas prices that are presently increasing and inherently unstable and unpredictable, NWN assumes a steady growth in customers and marginal fuel price increases. These assumptions allow NWN to propose pipeline solutions to decarbonize its network. However, the Company's proposed solutions are not commercially viable and cannot be implemented in the next decade.

For NWN's decarbonization plan to succeed while maintaining affordable rates, the costs of electrolysis, methanation, and carbon capture must decrease significantly and rapidly. Future studies must also indicate that hydrogen blending at the levels necessary to achieve meaningful emissions reductions is safe and requires neither end customer retrofits nor distribution upgrades—neither of which appears likely based on current research, as explored in section IV.A.1. NWN should also examine the capacities of existing main distribution pipelines to deliver—without substantial added investment—the less thermally-dense hybrid gas in sufficient quantities to meet customer needs. The need for cost reduction across each input and process compounds long-term risk; the failure of only one technology to materialize in a cost-effective way can derail NWN's entire strategy due to the interdependence of the technologies. This strategy has equity impacts on ratepayers; even if technology costs decrease substantially, hydrogen and synthetic methane prices will likely be greater than electric alternatives over the next couple of decades. Wealthier customers have more resources to transition to electricity and, without policy interventions, will be the first to exit the gas network. Customer exits could increase rates for the remaining, lower-income gas customers that must fund NWN's alternative fuel costs investments and fixed costs. Households with the fewest resources could face the greatest energy burdens and bear the most risk under this strategy.

Pursuing this strategy also enables NWN to continue operating as usual for the next decade with minimal decarbonization efforts—a strategy that has been aptly named "tech-crastination."[35] This exposes NWN to short-term compliance risk. NWN relies on unrealistic RNG supply estimates, allowances, and credits to meet targets until it believes hydrogen and synthetic methane will become commercially viable. Short-run inaction and policy changes, such as excluding Renewable Thermal Credits (RTCs) as a CPP compliance mechanism, or changes in RNG emissions accounting, increase the risk of non-compliance and higher rates. As a publicly regulated utility, NWN must pursue decarbonization measures that reduce ratepayer risk in both the short- and long-term and this IRP does not provide valid reasoning that operating in a "business as usual" manner is the least cost, least risk approach to decarbonization. Therefore, Climate Advocates recommend that the Commission not acknowledge the use of hydrogen and synthetic methane in NWN's IRP.

A. NWN's IRP overly relies on unproven technology.

To meet its required emissions reduction targets, NWN relies heavily on unproven technologies, including synthetic methane and hydrogen blended into distribution pipelines. These alternative fuel sources account for at least 50 percent of 2050 energy consumption in seven of NWN's nine scenarios. Such overreliance on unproven technology is unreasonable and excessively risky. The production and distribution of hydrogen and synthetic methane are innovative solutions that can reduce emissions if deployed strategically in certain sectors. However, these resources are not currently commercially viable, have practical, technical, and economic limitations, and their use

[35] Borgeson, M., and Fakhry, R., *Hydrogen in Buildings: The Poster Child of Tech-Crastination*, September 7, 2021. https://www.nrdc.org/experts/rachel-fakhry/hydrogen-buildings-poster-child-tech-crastination

will provide greater value in other applications than blending into the gas distribution system. Such other applications, finding higher value-added uses for the cleaner gas, may well drive market-clearing prices above what the utility has assumed. As with many technologies, funding can lead to cost reductions, but it does not guarantee cost competitiveness. Relying too heavily on innovation that is not yet commercially viable to resolve decarbonization challenges poses significant risk and can lead to greater ratepayer costs.

1. Hydrogen

At low quantities, hydrogen can blend with natural gas in the distribution system to offset gas consumption. Hydrogen cannot entirely replace natural gas, though, due to safety reasons and appliance constraints. First, hydrogen has a far greater risk of ignition and leakage than natural gas in the current gas network. Hydrogen is three times less energy intensive than methane by volume.[36] Introducing hydrogen without a reduction in energy output requires an increase in pipeline capacity (pressure-associated or volumetric), leading to additional leaks and safety concerns, and costs. A recent California Public Utilities Commission study shows that the greater the hydrogen concentration in the gas network, the more significant the leaks become.[37] Research also shows these risks increase significantly in service lines when hydrogen blends exceed 20 percent, with smaller distribution networks most vulnerable.[38] These hazards increase operational costs, since additional leak detection technology and more frequent maintenance inspections are necessary.

Additionally, while hydrogen blends can erode some gas distribution pipes, the greater concern is their impact on appliances. Studies suggest that some appliances cannot tolerate even the slightest blends.[39] Even if most appliances are compatible with hydrogen, it could only account for a small percentage of fuel until modifications to end

[36] Docket R.13-02-008, Ruling, Attachment 2. Hydrogen Blending Impacts Study, July 18, 2022.
[37] Docket R.13-02-008, Ruling, Attachment 2. Hydrogen Blending Impacts Study, July 18, 2022.
[38] Melaina, M. W., et al. "Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues." *National Renewable Energy Laboratory*, U.S. Department of Energy, Mar. 2013, https://www.nrel.gov/docs/fy13osti/51995.pdf.
[39] Melaina, M. W., et al. "Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues." *National Renewable Energy Laboratory*, U.S. Department of Energy, Mar. 2013, https://www.nrel.gov/docs/fy13osti/51995.pdf.

use appliances are required.[40] The widespread blending of hydrogen in gas lines could thus require the abrupt retrofit of home appliances as soon as blending reaches the requisite level, likely well before the end of many installed appliances' useful lives. Given gas utilities' service mandates, hydrogen's incompatibility with appliances poses a genuine risk to NWN's decarbonization strategy.

Hydrogen production is also dependent on substantial water availability. Electrolysis studies estimate that one kg of hydrogen requires between 18 and 24 liters of water.[41] And since 1 kg of hydrogen has an energy density equal to 33.6kWh,[42] each liter of water results in only 1.4 to 1.867 kWh. Replacing piped natural gas with locally produced hydrogen will thus substantially increase water consumption. Climate change has significantly altered weather patterns across Oregon over the last two decades, leading to the driest conditions in over a thousand years in some parts of the state.[43] Long-term reductions in precipitation threaten to eliminate the Oregonian wet season, affecting water supply. High-volume production of hydrogen will exacerbate the effects of drought conditions in the region and competition for water resources will intensify. Water scarcity may pose challenges to hydrogen production in NWN's service territory.

Hydrogen blending also exposes customers to unknown and potentially severe air pollution and health risks. Hydrogen blending is likely to increase NOx pollution because hydrogen burns hotter than methane, and NOx is formed under high temperature conditions during combustion. A 2022 meta-analysis of NOx emissions from equipment analogous to domestic burners operating on hydrogen/natural gas blends found "a huge range of possible changes in NOx emissions from H2-[natural gas] fuel blends."[44] In a mean case that reflects the results across the relevant literature, hydrogen blends of over 5%–20% led to NOx emission increases of 7%–30%. Pollution, health, and safety risks

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[40] Melaina, M. W., et al. "Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues." *National Renewable Energy Laboratory*, U.S. Department of Energy, Mar. 2013, https://www.nrel.gov/docs/fy13osti/51995.pdf.
[41] Blanco, Herib. *Hydrogen Production in 2050: How Much Water Will 74EJ Need?* Energypost.eu, 22 July 2021, https://energypost.eu/hydrogen-production-in-2050-how-much-water-will-74ej-need/.
[42] Molloy, Patrick. Run on Less with Hydrogen Fuel Cells. RMI, 2 Oct. 2019, https://rmi.org/run-on-less-with-hydrogen-fuel-cells/.
[43] *Oregon Drought*. Oregon.gov, https://www.oregon.gov/owrd/programs/climate/droughtwatch/pages/default.aspx.
[44] Madeleine L. Wright & Alastair C. Lewis, Emissions of NOx from blending of hydrogen and natural gas in space heating boilers, at 7, 11, Elementa: Science of the Anthropocene (May 31, 2022), https://doi.org/10.1525/elementa.2021.00114.

were among the concerns that led community members and climate, health, and environmental organizations to oppose a recent hydrogen blending proposal by NWN, ultimately resulting in withdrawal of the proposal.[45] NOx emissions from existing gas appliances are already a health concern and a threat to indoor and outdoor air quality.[46] Rather than exacerbating this threat by introducing hydrogen blends, NWN should pursue opportunities to eliminate these emissions through electrification.

Hydrogen has limited potential to reduce gas distribution emissions. Since safety, infrastructure, and end customer appliance issues may limit hydrogen blending to between 5 and 20 percent by volume, fossil fuels will continue to account for a significant majority of the gas network energy. Even if green hydrogen blends can reach the 20 percent upper bound, this will only result in about a 7 percent reduction in emissions. To accommodate the same load with a 20 percent blend would require a substantial increase in pressure and capacity, while exacerbating potential leakage issues. It is unclear if NWN can accommodate such a capacity increase without significant capital upgrades. Moreover, for hydrogen blending to play a role in decarbonization, green hydrogen will have to overcome significant barriers to becoming cost-competitive, as discussed in Section IV.A.2.a below.

2. Synthetic Methane

NWN's decarbonization scenarios rely on not just one technology breakthrough, but multiple, increasing the risk that NWN does not meet Oregon and Washington emissions targets. The failure of one of these technologies to materialize or be cost competitive threatens NWN's overall strategy. In NWN's Balanced Decarbonization scenario, Synthetic Methane is produced through a process called methanation that combines hydrogen, produced from renewable-powered electrolyzers (called green hydrogen), with carbon dioxide, sourced from carbon capture technology. None of these processes is commercially viable today, only a handful of methanation pilots exist worldwide, and we

[45] NW Natural Withdraws Application for Controversial Hydrogen Blending Experiment Following Community Uproar. Sierra Club, 2 Nov. 2022, https://www.sierraclub.org/press-releases/2022/11/nw-natural-withdraws-application-controversial-hydrogen-blending-experiment.; UM 2251, NW Natural's Application for Approval of Eugene Hydrogen Project, November 1, 2022.
[46] *A Review of the Evidence Public Health and Gas Stoves*. Multnomah County, https://multco-web7-psh-files-usw2.s3-us-west-2.amazonaws.com/s3fs-public/gas-stoves-health-risk-report-2022_0.pdf.

are extremely skeptical the technology will be commercially viable during the IRP's planning horizon. Yet, NWN's Balanced Decarbonization strategy (scenario 1) proposes sourcing 12,665 billion Btu of synthetic methane in Oregon by 2038 and 46,014 billion Btu in 2050, corresponding to 13 percent and 52 percent of total demand, respectively.[47] The Company relies on five assumptions about synthetic methane that, taken together, demonstrate that a plan relying on the fuel is speculative, risky, and likely unrealistic. The five assumptions are:

a. Green hydrogen becomes cost competitive
b. Carbon capture becomes cost competitive
c. Methanation process becomes cost competitive
d. There is sufficient excess renewable energy to enable green hydrogen
e. Electricity prices are low

Climate Advocates address each of these challenges below.

a. *Green hydrogen*

Hydrogen is produced in a number of ways: "gray" hydrogen is produced from methane and releases CO_2; "blue" hydrogen is similar to gray hydrogen but is paired with carbon capture to reduce emissions; and "green" hydrogen produces zero-carbon energy by using renewables such as solar and wind to power electrolyzers. Costs of gray and blue hydrogen vary with natural gas prices, but estimates suggest that gray hydrogen costs roughly $0.50-$1.70/kg and blue hydrogen costs $1-$2/kg.[48] Green hydrogen is the most expensive to produce, at an estimate of $3-$8/kg.[49] Due to the incremental cost over blue and gray hydrogen, low-carbon hydrogen (green) accounted for less than 1 percent of total hydrogen production in 2021.[50] Cost reductions in green hydrogen depend on electrolyzer technology, which separates hydrogen from water. According to the International Renewable Energy Agency (IRENA), electrolyzer technology needs low

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[47] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Workpapers, October 24, 2022, "Scenario Results," "Compliance Data" tab.
[48] IEA (2021), *Global Hydrogen Review 2021*, IEA, Paris https://www.iea.org/reports/global-hydrogen-review-2021
[49] IEA (2021), *Global Hydrogen Review 2021*, IEA, Paris https://www.iea.org/reports/global-hydrogen-review-2021
[50] https://www.iea.org/reports/hydrogen

electricity costs, supportive regulation, greater efficiency, and a longer useful lifespan to become cost-competitive.[51]

Backed by favorable policies, adequate funding, and cheap electricity, the IRENA estimates that a long-term cost reduction of 80 percent is possible.[52] BloombergNEF, the third-party NWN hired to estimate green hydrogen prices, projected nominal US hydrogen prices to be [Begin Confidential] [redacted] [End Confidential]/MMBtu for Alkaline Electrolysis and [Begin Confidential] [redacted] [End Confidential]/MMBtu for PEM Electrolysis in 2050.[53] In 2050, BloombergNEF's forecasted natural gas prices are [Begin Confidential] [redacted] [End Confidential] than green hydrogen prices despite the assumption that, [Begin Confidential] [redacted]"[54] [End Confidential] Lazard, the other third-party consultant NWN hired to estimate hydrogen cost, forecasted a range of [Begin Confidential] [redacted] [End Confidential]/MMBtu to [Begin Confidential] [redacted] [End Confidential]/MMBtu based on an electricity price range of [Begin Confidential] [redacted] [End Confidential]/MWh and [Begin Confidential] [redacted] [End Confidential] MWh.[55] Conversely, in its Balanced Approach, NWN assumes a 91.2 percent reduction in costs from $18.43/MMBtu in 2021 to $1.63/MMBtu in 2050.[56]

Figure 4: Hydrogen Cost Forecasts

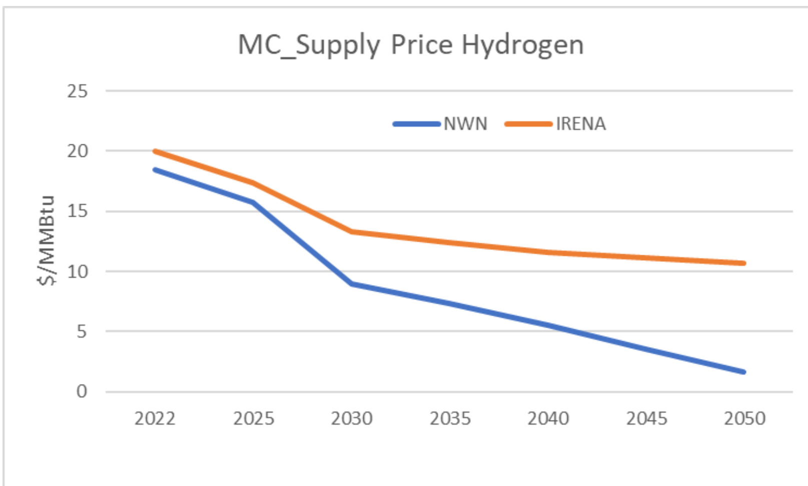
	2022	2030	2050
NWN Balanced Decarbonization Scenario[57]	$18.43	$8.99	$1.63

[51] IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal, International Renewable Energy Agency, Abu Dhabi.
[52] IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal, International Renewable Energy Agency, Abu Dhabi.
[53] LC 79 Advocate DR 7 Attachment 3 NWN Response, p. 17 (provided as Confidential Attachment D).
[54] LC 79 Advocate DR 7 Attachment 2 NWN Response, p. 17 (provided as Confidential Attachment C).
[55] LC 79 Advocate DR 7 Attachment 1 NWN Response, p. 2-3 (provided as Confidential Attachment B). [Begin Confidential] [redacted] [End Confidential]
[56] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Workpapers, October 24, 2022, "Scenario Results," "Compliance Data" tab
[57] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Workpapers, October 24, 2022, "Scenario Results," "Compliance Data" tab

BloombergNEF[58]	[Begin Confidential] [redacted] [End Confidential]	Begin [Confidential] [redacted] [End Confidential]	[Begin Confidential] [redacted] [End Confidential]

According to Figure ES2 in the IRENA report referenced above, electrolytic hydrogen production costs are expected to decrease from about $20/MMBtu in 2020 to about $10/MMBtu in 2050. NWN's predictions starkly contrast to the projected 2050 value by IRENA, which is based on expected learning curves for electrolyzes similar to that achieved by solar PV modules. The figure below compares the IRENA and NWN cost projections.

Figure 5: Northwest Natural and IRENA Hydrogen Cost Comparison



To meet its decarbonization targets, NWN relies on unrealistically greater cost reductions than what the IRENA and its third-party consultants modeled under favorable circumstances. The Company provides no explanation for the discrepancy between its modeled hydrogen costs and industry reports. Thus, NWN's hydrogen cost forecast appears to be unreasonable.

b. *Carbon Capture*

The second feedstock needed to produce methane is CO_2. While CO_2 is abundant, its economic viability as a feedstock depends on the concentrations of CO_2 in the source

[58] LC 79 Advocate DR 7 Attachment 3 NWN Response, p. 16-17 (provided as Attachment D).

stream. Sourcing CO_2 from an ethylene oxide stream, a byproduct in chemical manufacturing, costs between $25-$35/ton due to the high concentration of CO_2.[59] NWN could acquire its CO_2 from a number of high-concentration sources, but these supplies must be co-located with methanation plants for maximum cost effectiveness. Piping CO_2 from chemical or power plants to a methanation plant increases total costs, therefore location is an important consideration. Conversely, direct air capture costs between $134-$342/ton due to low concentrations in the air and can more easily be built near methanation plants.[60] These high costs currently make direct air capture unviable, and this is likely to remain the case absent significant policy support that is unlikely to materialize, such as a carbon tax of at least $200/ton.[61] Even if policy support for decarbonization significantly increases, that support will likely benefit electrification as much if not more than carbon capture, doubling down on electrification's status as the lowest-cost, lowest-risk approach to building decarbonization.

Securing carbon from industrial sources is the more cost-efficient alternative, but this strategy also carries significant risk; there must be enough non-fossil CO_2 supply in the region. To reach state emissions targets, each industry will need to decarbonize, meaning that there will be fewer sources of CO_2. Fossil fuel plants provide a reliable and consistent source of CO_2, but climate goals will force the retirement of fossil generation in favor of renewables. Other industries that manufacture products with carbon, such as chemical production, will rely on carbon capture. But there may not be enough total supply nor a consistent enough supply to produce the synthetic methane quantities NWN projects. Even if there is sufficient supply, NWN will have to secure the contractual rights to the "environmental attribute," which in a carbon constrained world will be a valuable commodity. Relying on carbon capture to cost-effectively provide a feedstock is thus risky and unreasonable.

Furthermore, NWN appears to omit the cost of carbon feedstocks from its analysis. NWN states that "[synthetic methane] prices represent the unbundled price of synthetic methane, which includes the price of hydrogen plus the price to methanate that hydrogen

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[59] IEA (2021), *Is carbon capture too expensive?*, IEA, Paris https://www.iea.org/commentaries/is-carbon-capture-too-expensive

[60] IEA (2021), *Is carbon capture too expensive?*, IEA, Paris https://www.iea.org/commentaries/is-carbon-capture-too-expensive

[61] Beaumont MLL (2022) Making Direct Air Capture Affordable; Technology, Market and Regulatory Approaches. *Front. Clim.* 4:756013. doi: 10.3389/fclim.2022.756013

via methanation."[62] Based on our understanding of this sentence, the Company appears to imply that it considers carbon feedstocks to be a free resource. Carbon has numerous applications in industry and will likely be sought after as policy limits the extraction of fossil fuel sources of carbon. Factoring in uneconomical carbon capture into synthetic methane cost would greatly increase customer rates. Considering that neither synthetic methane nor carbon capture is commercially viable, NWN has not demonstrated due diligence in its cost assumptions.

c. *Methanation*

Methanation combines hydrogen and CO_2 feedstocks into methane. Only a handful of methanation pilot projects exist worldwide, and this is for good reason; as discussed earlier, both feedstocks are not commercially viable. Since the requisite inputs are costly, research and development in methanation is thus extremely expensive. As a result, current pilot projects are quite small, such as Uniper's plant in Germany, which only produces 600kW of methane.[63] It is challenging to forecast the reduction in methanation costs since the technology is nascent. While this process may eventually be cost-effective, relying on unknowns significantly increases the risk that NWN's decarbonization strategy will not succeed.

d. Sufficient Excess Renewable Energy

The production of carbon neutral synthetic methane requires significant renewable energy. Electrolyzers, carbon capture, and methanation each rely on electricity. For synthetic methane to be carbon neutral, renewables must be the source of electricity. Renewables used for alternative fuel production must be dedicated resources, to ensure that using renewables for alternative fuels does not result in increased fossil generation elsewhere on the electric grid. Scaling synthetic methane will therefore require significant investments in renewable energy. For methane production and delivery to be constant, renewable energy must be available not just at peak periods, but at all times. This means

[62] LC 79 Advocate DR 14 (provided as Attachment E).
[63] "'Green' Methane Pilot Plant Starts Up." Chemical Processing, 3 July 2018, https://www.chemicalprocessing.com/processing-equipment/reaction-synthesis/article/11312596/green-methane-pilot-plant-starts-up.

that energy storage and renewables must pair. Reliance on the growth of renewable energy and storage to meet not just existing electricity demand, but significant new demand from the gas sector adds another challenge and further risk. Direct electrification makes much more efficient use of renewable electricity than electrolysis and methanation, especially when electrification uses highly efficient heat pump technology.[64]

e. *Electricity Prices*

Since each part of the production of synthetic methane process relies on electricity, the cost-competitiveness of the fuel is highly dependent on the price of electricity. According to IRENA, "The largest single cost component for on-site production of green hydrogen is the cost of the renewable electricity needed to power the electrolyser unit… A low cost of electricity is therefore a necessary condition for producing competitive green hydrogen."[65] This dependency on electricity is confirmed by BloombergNEF, the third-party NWN hired to estimate hydrogen costs. In its levelized costs estimate in Australia, it projected that, in 2030, electricity costs would account for [Begin Confidential] [redacted] [End Confidential] percent and [Begin Confidential] [redacted] [End Confidential] percent of total hydrogen costs when sourced with onshore and solar energy, respectively.[66] NWN did not conduct any sensitivity analysis testing the impact of electricity prices on the overall cost of the portfolio. In essence, the Company is delaying a significant amount of its emissions reduction requirements for 10-15 years, and the cost-effectiveness of that plan is heavily dependent on the price of electricity. This is highly problematic as NWN fails to explore the risk of this strategy.

[64] Cara Bottorff, *Hydrogen: Future of Clean Energy or a False Solution?*, Sierra Club (Jan. 4, 2022) (noting that "[u]sing renewables to produce hydrogen is about 20 to 40 percent less efficient than using renewable energy directly," even before accounting for the additional energy input for methanation and the comparative efficiency of heat pumps over combustion furnaces).
[65] IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal, International Renewable Energy Agency, Abu Dhabi.
[66] LC 79 Advocate DR 7 Attachment 2 NWN Response, p. 15 (provided as Attachment C).

3. Technology Review

a. *The Plan's reduction in Power-to-Gas costs is unreasonable*[67]

The Company's plan to rely on decarbonization through the abundant use of synthetic methane is a high-risk strategy because it assumes technological improvements, available dedicated renewable electricity, and low electricity prices. To satisfy the conditions of its Balanced Decarbonization scenario, NWN assumes a sharp decrease in technology costs in hydrogen, methanation, and carbon capture.

Figure 6: NWN's Balanced Approach Scenario Normal Fuel Costs per MMbtu

	Natural Gas	Hydrogen	Synthetic Methane*
2022	$4.50	$18.43	$25.80
2035	$3.55	$7.31	$13.21
2050	$4.99	$1.63	$5.83

*It is unclear what factors into this cost. If this includes carbon feedstock costs, then the total costs of piping hydrogen, methanation, and carbon capture costs are the cost of synthetic methane minus hydrogen; $7.37/MMBtu in 2022, $5.9/MMBtu in 2035, and $4.2/MMBtu in 2050. If it does not include carbon feedstock costs, the true synthetic methane costs would be much greater.

Significant cost reductions are not without precedent; energy sector technology innovations supported by funding and associated learning curves have produced considerable results, such as with Solar Photovoltaics (PV) technology. When solar power was in its infancy in 1980, the cost of solar power stood at $30/watt.[68] Solar PV costs dropped to around $2/watt in 2010 and to $0.20 per watt in 2020.[69]

NWN expects the new technologies to follow a similar trajectory in order to meet its 2050 targets. However, assuming that energy technologies will inevitably become cheaper is misguided. Solar PV is an example of the successful reduction in cost, but there are counter-examples that are more comparable to the technologies NWN is banking on. Tidal power has produced electricity since 1966, when France developed La Rance station to harness power from an estuary at a cost of $918 million (adjusted for

[67] Power-to-gas refers to the conversion of electric power into a gas and typically refers to electrolysis and methanation.
[68] IEA, *Evolution of solar PV module cost by data source*, 1970-2020, IEA, Paris https://www.iea.org/data-and-statistics/charts/evolution-of-solar-pv-module-cost-by-data-source-1970-2020.
[69] IEA, *Evolution of solar PV module cost by data source*, 1970-2020, IEA, Paris https://www.iea.org/data-and-statistics/charts/evolution-of-solar-pv-module-cost-by-data-source-1970-2020.

inflation through 2019).[70] Despite its history, tidal power currently accounts for a fraction of global electricity supply. The DOE estimates that tidal power costs between $130-$280/MWh,[71] far exceeding the $37/MWh cost of land-based wind power.[72] Despite government investments, tidal power is still not a competitive source of electricity generation.

Similarly, the development of nuclear power, which accounted for 28 percent of low carbon electricity in 2019 has not coincided with a reduction in cost.[73] In fact, as global production increased in the late 20th Century, nuclear costs "skyrocketed."[74] Concerns related to safety and enhanced regulation following nuclear incidents such as Chernobyl and Three Mile Island contributed significantly to this change. Decades after the incidents, final construction estimates of the still-unfinished Vogtle nuclear plant in Georgia exceed $34 billion, more than double the initial cost estimate and years behind schedule.[75] What was once believed to be the future of low carbon energy is now one of the most expensive forms of power generation.[76]

Tidal and nuclear power are two examples that demonstrate that not all learning curves progress as expected and are highly context dependent. Both tidal and nuclear power are examples of nonmodular technologies, which do not benefit from the same manufacturing cost decreases as modular technologies, such as solar PV and electric appliances like heat pumps. The manufacturing economies of scale that allowed solar PV, in part, to become cost competitive is not applicable to customized tidal and nuclear plants. Total cost reductions are thus more limited for nonmodular technologies. Methanation and carbon capture are both nonmodular technologies; the plants and piping

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70 Unwin, Jack. "Potential vs. Expense: Is Tidal Energy Worth the Cost?" Power Technology, 21 Mar. 2019, https://www.power-technology.com/analysis/tidal-energy-cost/.
71 Appendices. U.S. Department of Energy, Apr. 2019, https://www.energy.gov/sites/default/files/2019/09/f66/73355-Appendices.pdf.
72 Stehly, Tyler, Philipp Beiter and Patrick Duffy. 2020. 2019 Cost of Wind Energy Review. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5000-78471. https://www.nrel.gov/docs/fy21osti/78471.pdf.
73 "Nuclear Power in the World Today." World Nuclear Association, Oct. 2022, https://world-nuclear.org/information-library/current-and-future-generation/nuclear-power-in-the-world-today.aspx.
74 Jessica R. Lovering, Arthur Yip, Ted Nordhaus, Historical construction costs of global nuclear power reactors, Energy Policy, Volume 91, 2016, Pages 371-382, ISSN 0301-4215, https://doi.org/10.1016/j.enpol.2016.01.011.
75 Proctor, Darrell. "Vogtle Nuclear Expansion Price Tag Tops $30 Billion." POWER, POWER Magazine, 9 May 2022, https://www.powermag.com/vogtle-nuclear-expansion-price-tag-tops-30-billion/.
76 Bertel, E., and P. Wilmer. Nuclear Power: A Competitive Option? OECF Nuclear Energy Agency, https://www.osti.gov/etdeweb/servlets/purl/20256609.

must be built based on the availability of feedstocks in a given location. Concentrated CO_2 streams from industrial facilities vary in concentration and quantity. The capture solution must be custom built and piped to a methanation plant that can accommodate the CO_2 stream. Moreover, electric appliances have already achieved significant and accelerating adoption and cost reductions, making it unlikely that synthetic methane will catch up and become cost-competitive. Synthetic methane cost reductions are ultimately much more limited than solar PV.

b. Reliance on Power-to-Gas is riskier than electrification

NWN's strategy to pursue synthetic methane is especially risky when compared to electrification. At a high level, the two major factors that could derail the cost competitiveness of synthetic methane are: (1) technological innovations do not materialize, and (2) electricity prices and supply render synthetic methane production uncompetitive. Neither of these factors affect electrification to such an extent; to be cost-competitive, electrification does not need technological breakthroughs at the scale needed for NWN's decarbonization solutions, and electrification supplies power to customers directly.

First, due to technologies such as electric heat pumps, new building electrification is already cost competitive.[77] In fact, Washington has already passed an all-electric space and water heating requirement for new commercial, multifamily, and residential construction.[78] Heat pumps can serve all of NWN's customer base as the technology's performance continues to improve. Tests on new models indicate that heat pumps are capable of performing in as low as negative 23 degrees Fahrenheit, effectively meeting the needs of NWN's customer base.[79]

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[77] Takahashi, Kenji, et al. *Toward Net Zero Emissions from Oregon Buildings*. Sierra Club, 23 June 2022, https://www.synapse-energy.com/sites/default/files/Net-Zero-Emissions-from-Oregon-Buildings-21-127.pdf.

[78] DiChristopher, Tom. *Washington State to Require Electric Heating in Building Code Update*. S&P Global, 25 Apr. 2022, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/washington-state-to-require-electric-heating-in-building-code-update-69960737. Donofrio, Joel. *Heat Pumps Will Be Required in New Construction in WA State Starting in 2023*.Yakima Herald-Republic, 8 Nov. 2022, https://www.yakimaherald.com/news/local/business/heat-pumps-will-be-required-in-new-construction-in-wa-state-starting-in-2023/article_e5c1d908-5f96-11ed-8848-9b28dec639ad.html.

[79] "Trane Technologies Surpasses U.S. Department of Energy Requirements for High-Efficiency, Cold Climate Heat Pump." Business Wire, 3 Nov. 2022,

Second, the grid sends electricity directly from generation sites to customer end uses unlike power-to-gas. NWN's solution requires electricity as an input to create another form of energy for customer use. NWN's strategy thus expends electrical energy to solve an issue already solved much more efficiently by electrification. The electrolysis, carbon capture, and methanation processes would need to be at least 100 percent energy efficient to provide the same amount of energy as what the current electrical system provides (to say nothing of the two- to four-fold increases in efficiency achievable by switching from fossil fuel or resistance heating to electric heat pumps), but energy conversions lead to energy loss. For comparison, Uniper's power-to-gas pilot achieved a 53 percent efficiency.[80] It is far cheaper and less risky to use the existing electric system to decarbonize than to rely on technological breakthroughs. Moreover, synthetic methane is even more susceptible to electricity prices since the three critical processes (electrolysis, carbon capture, methanation) rely on electricity and experience energy conversion losses. Considering electrification is an established and cost competitive alternative to achieve decarbonization, relying so heavily on synthetic methane is unreasonable. Pursuing a decarbonization strategy reliant on synthetic methane increases the risk that NWN does not meet its targets.

Third, the technological advances needed to make a 100% clean and renewable electric grid reliable and resilient have multiple possible solutions, compared to the serial breakthroughs required by the power-to-gas plan. Long-term storage, regional power markets, and new transmission lines are all solutions that will increase reliability and resiliency as the electricity grid moves to 100% clean.

Finally, NWN's scenarios clash with its narrative explanation of the use of power-to-gas. The IRP states, "[f]or a direct-use natural gas system, P2G is essentially an opportunistic resource — by taking advantage of transitory surpluses in electricity markets, a gas utility can produce low-cost, carbon-neutral fuel for its customers. Thus, the availability of low-cost (or no-cost) electricity directly affects a P2G facility's utilization factor and overall economics."[81] According to NWN, the most cost-efficient

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https://www.businesswire.com/news/home/20221103005955/en/Trane-Technologies-Surpasses-U.S.-Department-of-Energy-Requirements-for-High-Efficiency-Cold-Climate-Heat-Pump.

[80] Mahajan, D.; Tan, K.; Venkatesh, T.; Kileti, P.; Clayton, C.R. Hydrogen Blending in Gas Pipeline Networks—A Review. Energies 2022, 15, 3582. https://doi.org/10.3390/ en15103582

[81] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, page 197.

use of these alternative fuels will be to draw power from the grid when there is excess supply (usually in the middle of the day) and to provide demand response during peak periods. While this appears to be a sound strategy, NWN forecasts significant hydrogen and synthetic methane supply in its scenarios, the Company fails to demonstrate that electrolyzers and methanation plants can operate only during "opportunistic" periods while also supplying 50 percent of NWN's energy supply. We are skeptical that NWN can rely on curtailed electricity to supply the 63.57 trillion Btu of annual power-to-gas it projects to supply by 2050 in the Balanced approach.[82] BloombergNEF, NWN's third-party hydrogen consultant, assumed a [Begin Confidential] "[redacted][83] [End Confidential] meaning that it did not expect electrolyzers to use curtailed energy. While using curtailed energy could lower electricity costs, lower operational capacity also increases levelized costs of electrolyzers. NWN does not demonstrate how it could harness enough curtailed electricity to supply the power-to-gas nor does it provide assumptions related to the cost impact of lower capacity factors. Moreover, developers may pair renewables with battery storage, reducing or greatly diminishing excess electrical supply. NWN assumes that hydrogen and synthetic methane will be cost-competitive in part due to the unrealistic expectation that it can source low-cost electricity.

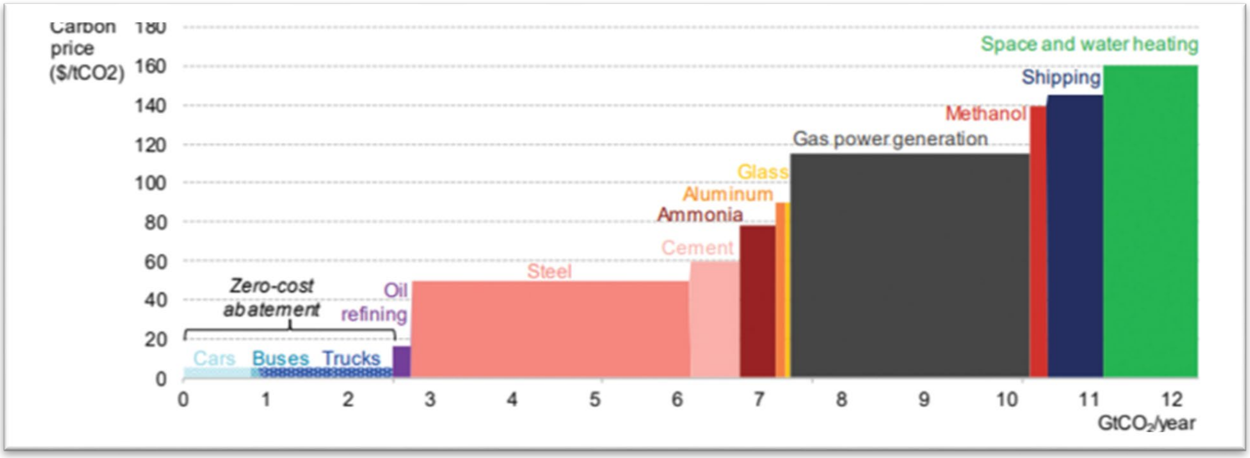
c. *Competition from other sectors*

NWN will face competition in accessing hydrogen for blending and as a feedstock for synthetic methane. In its 2050 net-zero report, the IEA states that "hydrogen and hydrogen-based fuels will need to fill the gaps where electricity cannot easily or economically replace fossil fuels."[84] Considering the abundance of low-cost hydroelectric power in the Pacific Northwest, electrification proves a cost-effective way in which to replace the gas distribution system. Other sectors that face greater decarbonizations challenges, such as heavy industry and transportation, will likely be players in the

[82] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Workpapers, October 24, 2022, "Scenario Results," "Compliance Data" tab
[83] LC 79 Advocate DR 7 Attachment 2 NWN Response, p. 15 (provided as Confidential Attachment C).
[84] IEA (2021), Net Zero by 2050, IEA, Paris https://www.iea.org/reports/net-zero-by-2050.

hydrogen market. Figure 7 details the results of a BloombergNEF study that evaluated the impact of $1/kg hydrogen on emissions reductions.

Figure 7: 2050 Marginal Abatement Cost Curve Assuming $1/kg Hydrogen by Sector[85]



The results show that it is much more cost effective to use hydrogen for emissions reductions in vehicles and industrial applications like steel and cement production. Conversely, space and water heating (distribution pipeline uses) are the least effective uses of hydrogen due to the availability of cost-effective electrified alternatives. Considering that Oregon and Washington have two of the cleanest grids, the relative price of hydrogen-based CO_2 abatement for space and water heating in NWN's service territory is higher than what is shown in Figure 7. As emission compliance targets increase, transportation and industrial sectors will compete for hydrogen, driving up prices. Ultimately, hydrogen's versatility will render it more challenging to procure for pipeline uses, and a hydrogen-focused gas system decarbonization strategy increases risks to ratepayers.

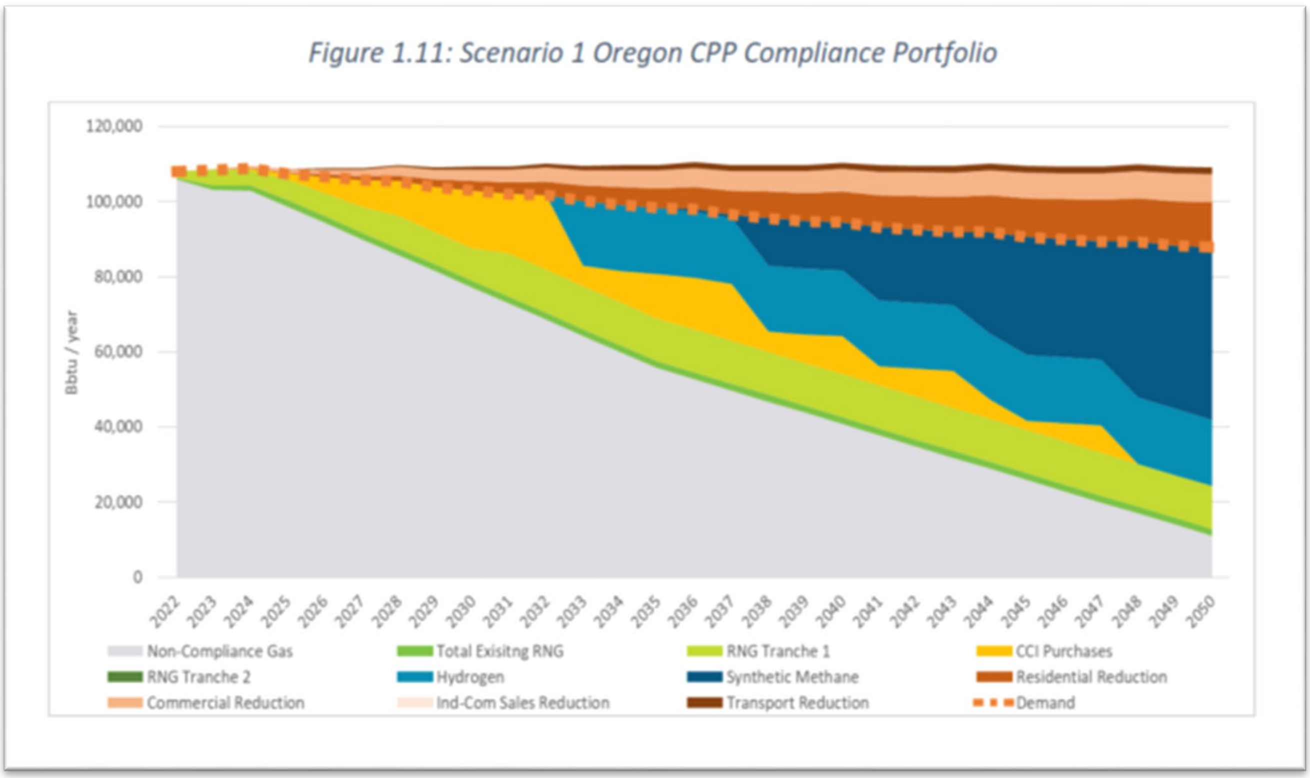
B. NWN's IRP includes few decarbonization measures in the next decade.

NWN's reliance on hydrogen and synthetic methane to reach 2050 emission targets has short-term impacts. The technology necessary to produce green hydrogen and synthetic methane is extremely unlikely to be commercially viable during the IRP's planning horizon and, since NWN heavily relies on these fuels, it proposes few

[85] Bloomberg New Energy Finance. (2020, March 30). "Hydrogen Economy Outlook." https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf.

actionable measures over the next decade. NWN expects to comply with the CPP in Oregon in the next decade primarily through tradable allowances, called Community Climate Investments (CCI), and investments in renewable natural gas (RNG).[86] In Washington, NWN expects to comply through purchased allowances, offsets, and RNG.[87]

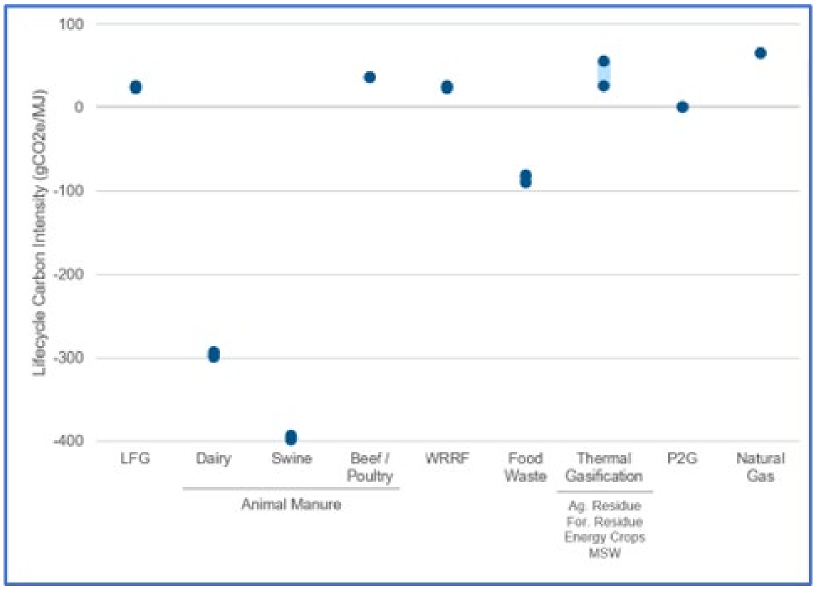
Figure 8: NWN IRP Compliance Plan for Oregon CPP



Like natural gas, RNG is primarily methane, a greenhouse gas approximately 86 times more potent than carbon dioxide over a 20-year period, and its usage produces the same emissions. It displaces the extraction of fossil fuels by recycling methane, making it generally eligible for credits. However, most sources of RNG have net positive lifecycle emissions. Additional emissions from leaks are likely undercounted. Ultimately, current emissions accounting overstates the true impact of RNG.

[86] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, page 26.
[87] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, page 27.

Figure 9: Lifecycle Emissions of RNG sources[88]



Additionally, the financial rewards for producing RNG disincentivize emissions reductions. For example, dairy farmers have an incentive to adopt unsustainable farming practices to increase methane production rather than reduce it. Research suggests that dry, as opposed to liquid-based, manure management systems result in fewer overall emissions.[89] Using liquid-based systems would result in greater revenue from the project but would also produce more emissions. Dairy farmers could also increase their herds to gain efficiencies, which would increase methane. Under this more accurate methodology, a farmer increasing a herd size for RNG production would *increase* GHG emissions. These unintended consequences of a combustion approach reduce the effectiveness of decarbonization targets. RNG thus overestimates the true emissions impact and any change in carbon accounting will increase acquisition costs. NWN fails to consider that current emissions accounting overstates the true impact of RNG, which could be addressed by policy changes.

Further, because RNG is NWN's predominant decarbonization measure over the next decade, its ability to acquire the fuel must be carefully vetted. NWN's source for the

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[88] Michigan Public Service. (June 7, 2022). Michigan Renewable Natural Gas Study. Draft Final Report v1. Submitted by ICF Resources, L.L.C. P. 113.
[89] Kotin, Adam, et al. *Diversified Strategies for Reducing Methane Emissions from Dairy Operations*. California Climate and Agricultural Network, Oct. 2015, https://calclimateag.org/wp-content/uploads/2015/11/Diversified-Strategies-for-Methane-in-Dairies-Oct.-2015.pdf.

available RNG inventory comes from a national 2021 ICF study, which revises assumptions made in a 2019 study and calculates the maximum RNG supply as "75% of our customer's population weighted share of the national RNG supply potential."[90] First, NWN uses the "High Resource Potential Scenario," which makes the following assumptions regarding supply availability:[91]

- Animal manure- 75 percent of technically available
- Food waste- 95 percent of eligible landfills
- Water Recovery Resource Facility- 95 percent of facilities with >3.5 MGD
- Agricultural Residue- 80 percent at $50/ton
- Energy crops- 60 percent at $50/ton
- Forestry and forest product residue- 80 percent at $50/ton
- Municipal solid waste- 80 percent at $50/ton

In its "High Resource Potential Scenario," the 2019 ICF study estimates a total Anaerobic Digestion (which the Plan calls "Tranche 1") of 14,777 billion Btu in Oregon and 1,425,300 billion Btu nationwide.[92] Relative to the 2019 study, the 2021 ICF study extends the analysis from 2040 to 2050 and raises its assumption that 75 percent of available resources are captured, up from 60 percent in the 2019 High Resource Scenario.[93] The Plan does not detail the total increase in Btu that NWN could capture according to the enhanced assumptions. Based on information shared in the Technical Working Group 3, tranche 1 appears to have increased 64 percent nationwide from around 1,400 annual trillion Btu in the 2019 report to 2,300 annual trillion Btu in the 2021 report.[94] To simplify assumptions, increasing total Oregon RNG tranche 1 supply by 64 percent yields 24,234 billion Btu. NWN expects current projects and those under

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[90] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, page 211.

[91] *Renewable Sources of Natural Gas*. American Gas Foundation, https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf?source=content_type%3Areact%7Cfirst_level_url%3Aarticle%7Csection%3Amain_content%7Cbutton%3Abody_link.

[92] *Renewable Sources of Natural Gas*. American Gas Foundation, https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf?source=content_type%3Areact%7Cfirst_level_url%3Aarticle%7Csection%3Amain_content%7Cbutton%3Abody_link.Appendix A

[93] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Technical Working Group, March 28, 2022.

[94] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Technical Working Group, March 28, 2022.

development to total 1,241 billion Btu by 2024, meaning that it will need to develop additional projects rapidly to achieve its "Balanced Decarbonization" targets of 11,396 billion Btu in Oregon by 2031 and 1,190 billion Btu in Washington by 2028.[95]

Figure 10: Estimated RNG Supply in Oregon

	Target date to source "High Resource" supply	Oregon RNG Supply
2019 ICF Study	2040	14,777 Bbtu
2021 ICF Update (estimate)	2050	24,234 Bbtu
NWN Balanced Decarbonization Scenario	2031	11,396 Bbtu
NWN RNG and H2 Policy Support Scenario	2027	14,606 Bbtu

NWN thus believes it can capture nearly half of the total achievable tranche 1 RNG potential statewide in less than a decade. In their RNG and H2 policy support scenario, the Plan assumes the acquisition of 60 percent of 2050 supply by 2027.[96] These assumptions are unreasonable based on their timelines. RNG is NWN's predominant decarbonization measure over the next decade and the inability to meet these bold timelines risks non-compliance.

Furthermore, NWN appears to assume that it can monopolize state RNG despite competition from other entities faced with the same decarbonization challenges. The incremental cost for each RNG site will escalate as the available supply dwindles, forcing NWN to source increasingly costly RNG to meet its decarbonization targets. The transportation sector is the predominant customer of RNG due to policies such as the California and Oregon Low Carbon Fuel Standards. The U.S. Department of Energy estimates that there are 500 landfills, 120 dairies, 70 wastewater treatment systems, and 10 other livestock RNG projects in the United States.[97] The transportation sector uses an estimated 75 percent of the RNG produced, suggesting that this sector will continue to

[95] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Workpapers, October 24, 2022, "Scenario Results," "Compliance Data" tab
[96] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Workpapers, October 24, 2022, "Scenario Results," "Compliance Data" tab
[97] *Advancing Technology For America's Transportation Future - Chapter Fourteen*. U.S. Department of Energy, https://www.energy.gov/sites/default/files/2022-10/Chapter_14-Natural_Gas.pdf.

compete aggressively for RNG supply, ultimately resulting in price increases.[98] The Plan's rapid adoption forecast and procurement challenges will increase customer costs. NWN must provide reasonable rates for customers and thus must bear the burden of proving that it can supply affordable RNG.

NWN's solution to these issues may be to purchase Renewable Thermal Credits (RTCs), which NWN believes "are recognized as compliant resources under Senate Bill 98 and the Oregon Climate Protection Program."[99] Purchasing RTCs from other parts of the country does not help NWN decarbonize *its* energy system, despite the RTCs counting for compliance. Additionally, NWN has not properly explored the possibility that these credits may not be an acceptable compliance mechanism under future Oregon laws. The Environmental Quality Commission or legislature could more properly conclude that RNG emissions should be calculated on a lifecycle basis, require RNG projects to reduce GHG emissions *in Oregon*, or cap the number of RTCs that might be used for compliance. If the Company cannot purchase an unlimited number of RTCs for compliance, it risks non-compliance. Ultimately, the more NWN relies on RTCs to meet compliance goals, the greater the risk that it will need to resort to uneconomical methods to meet compliance targets and pass those costs to ratepayers.

V. The Commission should require NWN to refile its IRP with an updated forecast of heat pump technology, a load forecast that reflects reality, and that reflects realistic fuel prices

A. Gas Heat Pump Assumptions

NWN relies heavily on natural gas heat pumps—a technology that is not currently commercially available in North America—to achieve its projected residential and commercial demand reductions. The plan models installation of gas heat pumps, dual fuel heat pumps, and furnaces.

[98] Paulos, Bentham. *Analysis: Why Utilities Aren't Doing More with Renewable Natural Gas. Energy News Network,* 14 Feb. 2019, https://energynews.us/2019/02/14/analysis-why-utilities-arent-doing-more-with-renewable-natural-gas/.
[99] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, page 185.

Figure 11: NWN's Project Residential Heating Installation by Type[100]

	Gas Heat Pump	Dual Source Heat Pump	Furnace
2022	0%	4%	96%
2030	8%	21%	71%
2040	28%	38%	34%
2050*	47%	48%	12%

*Average Percentages are greater than 100 percent after 2040 through 2050

The transition to more efficient modes of heating results in a total avoided demand of 168,485 billion Btu in the Balanced Decarbonation scenario.[101] NWN reaches the total by assuming that natural gas heat pumps consume 40 percent less fuel than furnaces.[102] While gas heat pumps may eventually become more efficient than furnaces, they are not currently commercially available to residents of North America.[103] NWN assumes that the technology becomes cost-competitive in the next two years and implicitly presumes that contractors can rapidly scale installations.[104] Again, NWN's compliance scenarios continue to rely on unrealized technologies.

If over the last 30 years the gas industry had devoted its vast resources to develop gas heat pump technology instead of fighting energy efficiency standards and disputing climate science, gas heat pumps might be available today for space and water heating.[105] As it stands, all the major heating appliance manufacturers have applied their R&D efforts to improving electric heat pumps and there is no major manufacturer or supplier of residential gas heat pumps in this country today.

Successfully transforming the market to this new, unproven gas heat pump technology would require significant heating industry support, consumer demand for a

[100] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Workpapers, October 24, 2022, "Emerging technology."
[101] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Workpapers, October 24, 2022, "Scenario Results," "Compliance Data" tab.
[102] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, page 168.
[103] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, page 169.
[104] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Workpapers, October 24, 2022, "Emerging technology."
[105] Biden's Proposed Phaseout of Inefficient Furnaces Would Cut Costs & Emissions. ACEEE, 13 June 2022, https://www.aceee.org/press-release/2022/06/bidens-proposed-phaseout-inefficient-furnaces-would-cut-costs-and-emissions.

new heating solution and a robust installation workforce trained to handle new toxic ammonia refrigerants and unfamiliar equipment. At this time, there is no evidence that any of these conditions are being met or will be met. NWN's assumptions about the potential for gas heat pump adoption contrast with its unwillingness to recognize the significant strides toward electric heat pump adoption that have already been made and that are likely to continue.

1. Industry Support

While market adoption of new technologies may start with relatively few disruptive players in any given market, complete transformation requires the industry as a whole to accept the new technology. There is no sign of even the beginnings of such a transformation to gas heat pump technology in the HVAC industry.

Meanwhile, electric heat pump sales have overtaken gas furnace sales nationally,[106] and federal programs like the Inflation Reduction Act and the Defense Production Act are specifically enlisting the efforts of the major HVAC suppliers to improve electric heat pump performance, encourage US manufacturing and increase consumer adoption of these critical carbon reducing electric technologies. The major manufacturers[107] including Carrier, Trane, Daikin, Mitsubishi, Lennox, Rheem, LG and Bosch and others are partnering with the US Department of Energy on the Cold Climate Heat Pump Challenge to make electric heat pumps more effective, cheaper, more widely adopted and grid interactive.[108] These investments have yielded significant developments: tests on new models indicate that heat pumps are capable of performing in as low as negative 23 degrees Fahrenheit, effectively meeting the needs of NWN's customer base.[109] As discussed in Section II.B, the Inflation Reduction Act includes incentives for electric heat

[106] *Residential Storage Water Heaters*. AHRI, https://www.ahrinet.org/sites/default/files/2022-12/October2022StatisticalRelease.pdf.
[107] "Partners." Energy.gov, Office of Energy Efficiency & Renewable Energy, https://www.energy.gov/eere/buildings/partners.
[108] "Residential Cold Climate Heat Pump Challenge." Energy.gov, Office of Energy Efficiency & Renewable Energy, https://www.energy.gov/eere/buildings/residential-cold-climate-heat-pump-challenge.
[109] "Trane Technologies Surpasses U.S. Department of Energy Requirements for High-Efficiency, Cold Climate Heat Pump." *Business Wire*, 3 Nov. 2022, https://www.businesswire.com/news/home/20221103005955/en/Trane-Technologies-Surpasses-U.S.-Department-of-Energy-Requirements-for-High-Efficiency-Cold-Climate-Heat-Pump.

pumps and electrification, which will further strengthen market signals to manufacturers to increase R&D in electric heat pumps.

Furthermore, NEEA has invested heavily in market transformation efforts aligned with the major manufacturers of electric heat pumps for space heating and water heating in the Pacific Northwest. For example, its annual budget supporting electric heat pump water heater market transformation in 2022 was $3.5 million and is projected to be nearly $2.5 million in 2023.[110] In contrast, the NEEA program supporting gas heat pump water heaters is funded for $0.4 million[111] in 2022 and $0.4 million in 2023 and is behind schedule according to its published Q3 2022 Market Progress Report.[112] NEEA identifies 3 risks regarding the Gas Heat Pump Water Heater (GHPWH) program.[113]

1. That GHPWH technology fails to mature or be successfully demonstrated
2. That the North America GHP Collaborative membership does not choose to pursue development of a shared investment platform.
3. That policy changes include more limitations on residential use of natural gas, diminishing the business case to commercialize GHPWH.

Given that this technology has not been commercialized in any product to date, there are no major water heater manufacturers developing this technology, there is very little NEEA investment in the market development program supporting it, and reports from NEEA that this program is behind schedule and burdened with the risk that development could be abandoned by the current industry partners, this market adoption projection lacks all credibility. For reference, electric heat pump water heaters rely on a technology that has been commercially available for over 100 years and there have been multiple major manufacturers supplying them to the Pacific Northwest for 12 years. NEEA has been aggressively supporting the technology for 10 years. ETO has been providing incentives to lower the installation costs by as much as 50%. With this concerted and prolonged effort, electric heat pump water heaters achieved 28% of the electric water

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[110] 2023 Operations Plan. Northwest Energy Efficiency Alliance, Nov. 2022, https://neea.org/img/documents/NEEA-2023-Operations-Plan.pdf.
[111] 2023 Operations Plan. Northwest Energy Efficiency Alliance, Nov. 2022, https://neea.org/img/documents/NEEA-2023-Operations-Plan.pdf.
[112] 2022 Q3 Quarterly Market Report. Northwest Energy Efficiency Alliance, https://neea.org/img/documents/NEEA-Q3-2022-Market-Progress-Report_2022-11-16-231306_zcjv.pdf.
[113] 2023 Operations Plan. Northwest Energy Efficiency Alliance, Nov. 2022, https://neea.org/img/documents/NEEA-2023-Operations-Plan.pdf. Page 95, The North America GHP Collaborative is a group of gas utilities and does not include any heat pump technology manufacturers.

heater sales in the Pacific Northwest in 2020 – 10 years after their initial introduction.[114] Given all the challenges regarding gas heat pump water heaters listed above, and the fact that they are not commercially available today, it is not credible to project the high levels of market adoption contained in the IRP.

While NWN projects rapid adoption of residential gas heat pumps for space heating, there is no NEEA Market Transformation program supporting the development of this technology and no funding projected for this work in 2023. NEEA has devoted $0.4 million of projected investment in emerging technology work for all natural gas technologies which would include heat pumps and dual fuel systems. In total, NEEA is spending nearly 8 times more resources on development of high efficiency electric technologies than it spends on emerging gas technologies.[115]

2. Consumer Demand

Gas heat pump technology does not provide an obvious benefit to the consumer that they could not get with existing products. First, gas fired heat pumps do not dramatically lower operating costs compared with electric heat pumps, and as gas prices increase this difference diminishes. Second, customers committed to heating with gas but wanting more efficiency will install a dual fuel system, which is an existing option widely available today. Third, consumers focused on upfront cost might choose a low-cost gas furnace, but with policy support for electrification they are increasingly more likely to prefer the superior comfort and efficiency of an existing electric heat pump. All of these existing factors will inhibit market adoption of this unfamiliar technology.

3. Installation Workforce

The success of gas fired heat pumps will depend on a robust installation workforce motivated to learn new skills and embrace an unproven technology. There is no evidence to support the argument that these installers would make the necessary time and resource investments to learn and incorporate gas heat pump technology when they already have

[114] NEEA Heat Pump Water Heater Benefit/Cost Model Review, Sept 1, 2022. https://neea.org/resources/heat-pump-water-heater-benefit-cost-model-review
[115] *2023 Operations Plan*. Northwest Energy Efficiency Alliance, Nov. 2022, https://neea.org/img/documents/NEEA-2023-Operations-Plan.pdf.

the solutions required to meet the needs of their customers and the building codes and regulations that increasingly favor low carbon heating technology like electric heat pumps. Adopting gas heat pump products will also require training on how to handle, maintain and dispose of the ammonia refrigerant which is a highly toxic substance.

Most HVAC installers are already trained to install and maintain gas furnaces and electric heat pumps. These technologies provide a range of options using proven technologies with millions of previous installations and satisfied customers and well-developed product lines from multiple manufacturers with a robust supply chain. On the contrary, gas fired residential heat pumps are not even commercially available today. Moreover, the proliferation of electrification policies makes investments in training on new gas technologies highly risky for HVAC installers.

Projections of even modest market adoption of unproven gas heat pump technology should be considered highly speculative. At this time, when dramatic carbon reductions are required today and solutions to achieve those reductions are commonly available, planning on unavailable technologies to reduce gas consumption at some time in the future should not be accepted in IRP planning.

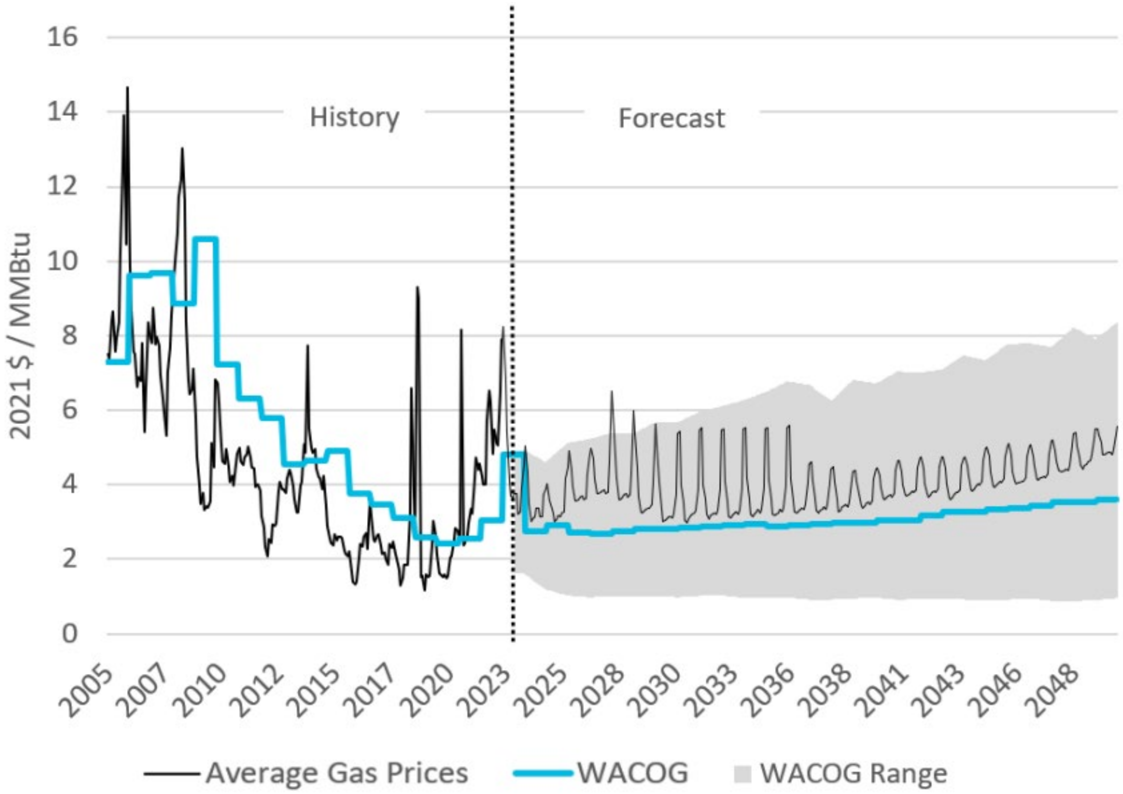
B. The IRP presumes unrealistic natural gas prices and load forecasts

1. Natural gas prices

NWN's projected natural gas prices are unrealistically optimistic, which makes gas projects look artificially favorable relative to alternatives, like DSM and electrification. NWN attributes the relatively high price of natural gas to Russia's invasion of Ukraine and concludes that "prices of conventional gas are expected to return to levels consistent with prices in recent years over the medium- and long-term."[116] Figure 6 below is NWN's forecasted weighted average cost of gas throughout the planning horizon.

[116] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, page 13.

Figure 12: NWN Natural Gas Price Forecast[117]



NWN forecasted natural gas prices through a Monte Carlo simulation that combined historical data with long-term prices supplied by a third-party consultant. The IRP provides forecasted prices for four major trading hubs: AECO, Opal, Sumas, and Westcoast Station 2. In each, prices remain relatively level though 2050, other than seasonal peaks.

NWN's conclusion that prices will return to a period of historically low prices is suspect as it seems to ignore that there has been a fundamental shift in energy that occurred over the last decade. First, domestic and international gas markets have continued to evolve. Countries across the globe have been transitioning away from coal and looking to other sources of energy, including natural gas and renewable energy. The United States is not immune to this global dynamic—the U.S. has much more international exposure to global prices now due to its LNG expansion.[118] Concurrently,

[117] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, page 45.
[118] U.S. Energy Information Administration. "U.S. liquified natural gas exports grew to record highs in the first half
of 2021." July 27, 2021. https://www.eia.gov/todayinenergy/detail.php?id=48876.

with the abundant and relatively low-cost price of gas since 2010, the electricity sector shifted an extraordinary amount of its supply from coal to other forms of generation, including gas.[119] It is also notoriously difficult to build new natural gas pipelines, which means that there is a finite capacity to transport natural gas to load.[120] This is particularly noteworthy during peak periods, like the February 2021 Winter Storm Uri Event, when the cold snap disrupted supply from Texas/Oklahoma, demand approached design day conditions, and pipeline operators issued warnings about supply cuts. The impact of the event was felt across the middle of the country, where prices reached nearly $200/MMBtu as far away as Minnesota.[121] Because the vast majority of commodity costs are borne by the customer, these types of price spikes can have a tremendous impact on customers' rates.[122] Finally, the cost of financing new fossil fuel projects, such as gas wells and the distribution system for carrying the gas, is increasingly expensive relative to alternative opportunities, such as renewable generation. In addition, after a decade of relatively low growth of returns, fossil fuel company shareholders are demanding higher returns, which means they will want to constrict supply to maintain relatively high commodity prices.

Our concern is validated, in part, by comparing the Company's forecast against other reputable forecasts. NWN's forecast differs greatly from a 2019 report compiled by the Northwest Power and Conservation Council (NPCC) and provides values for the AECO, Sumas, and Opal trading stations. The report, which was published before the recent price increases, forecasts gas prices increasing across all three trading hubs through 2045, with Sumas and Opal increasing roughly 67 percent from $2.7/MMBtu to $4.5/MMBtu and AECO increasing roughly 63 percent from $1.9/MMBtu to $3.1/MMBtu.[123] This aligns with the data from S&P Capital, which models natural gas prices based on futures. At

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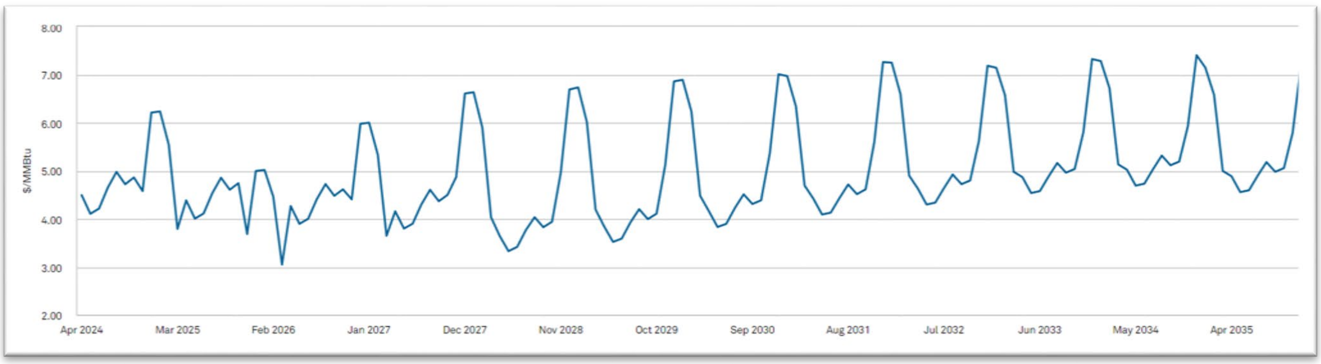
[119] U.S. Energy Information Administration, "Electric power sector CO_2 emissions drop as generation mix shifts from coal to natural gas," June 9, 2021. https://www.eia.gov/todayinenergy/detail.php?id=48296
[120] Forbes, "Oil and Gas Pipelines Increasingly Losing Legal Challenges," July 6, 2020., https://www.forbes.com/sites/scottcarpenter/2020/07/06/oil-and-gas-pipelines-increasingly-losing-legalchallenges/?sh=145797a91e88
[121] See Direct Testimony of Bradley Cebulko on behalf of the Citizens Utility Board of Minnesota before the Minnesota Public Utilities Commission, Exhibit_(BC-D), p. 12, December 22, 2021, in OAH Docket No. 71-2500-37763, MPUC Docket Nos. G008/M-21-138, G004/M-21235, G002/CI-21-610, G011/CI-21-611
[122] This is due to the structure of the purchase gas adjustment mechanism, whereby utilities pass onto customers all, or nearly, all of the commodity costs from fuel.
[123] Simmons, Steven. *Natural Gas Price Forecast for the 2021 Power Plan*. Northwest Power and Conservation Council, 12 Nov. 2019, https://www.nwcouncil.org/sites/default/files/2019_1112_2.pdf.

NW Sumas, the MI Forward model forecasts prices increasing to $4.11/MMBtu in May 2024 and to $4.56/MMBtu in May 2035 (May is the annual low in both years).[124] Although NWN's fuel price forecast is confidential, we can discern from Figure 12 above that the Company's expect weighted average cost of gas (WACOG) is expected to be ~$3/MMBtu through 2040 and less than $4/MMBtu through 2048.

Figure 13: S&P Global MI Forward Model for NW Sumas[125]



Similarly, the EIA projects the price of gas at the Henry Hub trading station to be $4.11/MMBTU in 2021, to dip in prices until 2025, then to increase consistently to $6.91/MMBtu in 2050, using nominal dollars.[126] This represents a 68 percent increase in natural gas prices during this period.[127] While regional prices differ from Henry Hub, it is unlikely that the prices in the Pacific Northwest will remain relatively constant through 2050, as NWN predicts, while Henry Hub prices increase significantly.

2. Load Forecast

The IRP reference case's load forecast is not realistic. NWN's customer count trends do not take into account 1) residential building code updates in Washington, 2) line

[124] Retrieved from S&P Capital on November 21, 2022. https://www.capitaliq.spglobal.com/web/client?auth=inherit#markets/gasFutures?key=982fafdb-b14f-4c18-b151-75be96d6c2c5

[125] Retrieved from S&P Capital on November 21, 2022. https://www.capitaliq.spglobal.com/web/client?auth=inherit#markets/gasFutures?key=982fafdb-b14f-4c18-b151-75be96d6c2c5

[126] *Annual Energy Outlook 2022*. U.S. Energy Information Administration, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=1-AEO2022®ion=0-0&cases=ref2022&start=2020&end=2050&f=A&linechart=~~~ref2022-d011222a.54-1-AEO2022&ctype=linechart&sourcekey=0.

[127] Henry Hub, which is located in Louisiana, is not one of the hubs that NWN modelled, but it is the most frequently cited pricing hub in the United States. The industry uses Henry Hub as a benchmark to quantify differences compared to the regional prices.

extensions allowance updates in Oregon, and 3) Inflation Reduction Act incentives to accelerate building electrification. Climate Advocates are also concerned that NWN is not accounting for the possibility of reduced load associated with local policies supportive of beneficial electrification. Each of these policy changes occurred after NWN developed and finalized the IRP. However, these policy changes, particularly Washington's building code updates and Oregon's line extension allowance reduction, will likely have near-term impacts as discussed below.

NWN uses the reference case customer count in six out of the nine scenarios. The customer count forecast, based on historic trends, is an overestimation considering the factors that will significantly reduce demand in the short and long term.

NWN identified the climate policies enacted in Washington and Oregon, including Senate Bill 98 and the CPP in Oregon, and House Bill 1257, the Climate Commitment Act, and commercial building codes updates in Washington, as the largest drivers of change to the load forecast in this IRP. This includes updates to Washington's commercial energy code approved by the State Building Code Council (SBCC). The update will require new commercial buildings and multifamily residential buildings to install electric heat pumps.[3] However, NWN's forecast did not include more recent SBCC updates that will limit natural gas use in residential buildings, which goes into effect in 2023.

Next, NWN does not include the Commission's recent rate case Order that requires NWN to reduce its line extension allowances.[128] The Commission ordered that NWN set its line extension allowances to $2,300 starting November 1, 2022, and decrease it each year after November 1, 2024. The Commission expressed concern with the higher LEA citing the unrecovered rate base investment from new plant even after 30 years.[129] Additionally, the Commission noted the impact of the CPP and local policy changes in the Order stating, "These changes point to a reasonable possibility that the company will encounter a trend of decreasing gas usage, potentially driven by economic signals toward

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[128] UG 435, Order, First Partial Stipulation Adopted Subject to Modification; Second and Third Partial Stipulations Adopted; Application for General Rate Revision Approved as Revised. October 24, 2022.
[129] UG 435, Order, First Partial Stipulation Adopted Subject to Modification; Second and Third Partial Stipulations Adopted; Application for General Rate Revision Approved as Revised. October 24, 2022, at 49.

fuel switching."[130] While the Commission does not stipulate how line extension allowances should decrease, it expects gas customer exits and a risk that gas line investments will be stranded.

Despite these policies driving down customer growth, in six out of the nine scenarios plus the reference case, the Company projects an increase in residential customer counts.[131] The reference case assumes an average compounded growth rate of 1.2 percent, increasing customer counts from around 600,000 to 1 million.[132] Because the reference case is based solely on historical trends, which do not incorporate the impacts of recent policy developments and market trends, the customer count the Company used in its selected scenario is likely an overestimation. Consequently, the Company's load forecast is built on inflated customer counts.

The Company's commercial customer count is also based on the reference case customer count. Consequently, the Company's load forecast under the scenario identified as least-cost and least-risk show a very slow decline in load for commercial customers. In Oregon, commercial demand is forecasted to fall by 6 percent by 2030 and 9 percent by 2050 under scenario 1.[133] In Washington, commercial demand is forecasted to fall by 7 percent by 2030 and remain relatively stagnant after that.[134] However, we are not confident that a slow decline followed by stagnant demand is aligned with rising natural gas prices, electrification trends, and climate policy that directs reductions in carbon emissions on the local, state, and federal level. Considering that policies such as the IRA heavily incentivize electrification, and Washington and Oregon have both introduced legislation that severely limits new customer growth, it seems more likely that there will be a continual decline in demand as existing customers transition to electric alternatives. For all of these reasons, the IRP's load forecast is unrealistic.

[130] UG 435, Order, First Partial Stipulation Adopted Subject to Modification; Second and Third Partial Stipulations Adopted; Application for General Rate Revision Approved as Revised. October 24, 2022, at 50.
[131] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, page 104.
[132] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Plan, September 23, 2022, page 104.
[133] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Workpapers, October 24, 2022, "Scenario Results," "Compliance Data" tab
[134] Docket No. LC 79, NW Natural 2022 Integrated Resource Plan, Workpapers, October 24, 2022, "Scenario Results," "Compliance Data" tab

VI. Conclusion

It is the Commission's duty to ensure that utilities comply with state policies and support the public interest. The transformative climate policies in Oregon and Washington require a significant shift in the Commission's regulatory approach to achieve equitable decarbonization. The Commission must implement regulatory practices that catalyze electrification and minimize the obligations of gas distribution customers.

Given the magnitude of decarbonization challenges and risks to ratepayers of an unmanaged transition, the Commission cannot afford to wait to take action. The Commission must direct integrated system planning to ensure that NWN evaluates the least cost, least risk approaches by relying on a comprehensive electrification model. Without electric utility involvement and a clear action plan in the IRP, NWN does not present a justifiable compliance strategy. The Commission must also explore the full set of available and proven performance based regulatory tools such as MYRP, fuel cost sharing, PIMs, and other measures to limit stranded assets. The Commission should direct NWN to provide publicly-accessible, overlayed maps to anticipate maintenance and capacity needs, and ultimately evaluate approaches to system pruning, a task firmly within NWN's expertise.

The Forest Grove Feeder uprate provides the Commission with an opportunity to exercise new regulatory procedures. NWN does not present a reasonable analysis to justify the uprate or detail how the expansion of the gas distribution network achieves state climate goals. The Commission must not acknowledge the Forest Grove Feeder; it should require a higher standard of proof that gas network expansions will be "used and useful."

Instead of providing robust analysis to support various decarbonization approaches, NWN provides strategies that are heavily skewed towards pipeline solutions. The Plan's underlying assumptions are highly risky and unlikely to be cost-effective compared to electrification. Six of NWN's nine compliance scenarios rely on significant supplies of hydrogen and synthetic methane, technologies that are not commercially viable, and model significant cost reductions for both energy sources for their use to be cost competitive. Relying on an array of future developments is highly risky and could burden customers with excessive costs. Due to these unrealistic assumptions, the Climate

Advocates urge the Commission to decline acknowledgement of the use of alternative fuels in NWN's IRP.

Finally, NWN uses flawed forecasts to develop compliance strategies that artificially skew in favor of pipeline solutions. NWN relies on unrealistic advancements to project a market for gas heat pumps despite the existence and comparative benefits of cost-competitive electric heat pumps. Despite electrification policies gaining traction, NWN projects a growth of roughly 400,000 customers by 2050. NWN also forecasts gas prices to remain relatively stable, as opposed to data provided by the EIA, which models rising gas prices across hubs in the Pacific Northwest and Henry Hub. The Commission cannot evaluate a least cost, least risk compliance scenario when provided untenable forecasts. Thus, the Commission must require NWN to refile its IRP with updated forecasts.

Dated: December 30, 2022

Respectfully Submitted,

/s/ Carra Sahler
Green Energy Institute at Lewis & Clark Law School

/s/ Greer Ryan
Climate Solutions

/s/ Lauren Goldberg
Columbia Riverkeeper

/s/ Alma Pinto
Community Energy Project

/s/ Brian Stewart
Electrify Now

/s/ Pat DeLaquil
MCAT

/s/ Angus Duncan
NRDC

/s/ Jim Dennison
Sierra Club

ATTACHMENT A

Rates & Regulatory Affairs
LC 79
Integrated Resource Planning
Data Request Response

Request No.: LC 79 Advocate DR 2

2. Please reference the Forest Grove Feeder Update as described in section 8.5.
   a. Did the Company examine alternative solutions (pipeline or non-pipeline) that could alleviate, reduce, or eliminate concerns with the Forest Grove Feeder? Please identify the project and its expected costs. Please also discuss why any alternative solutions considered were not chosen.
   b. When did the Company first recognize that it may need to make improvements to the Forest Grove feeder? Please provide relevant documentation.

Response:

a. The Company examined alternative solutions for insufficient pressure in the last segment of the Forest Grove Feeder during a peak cold event and presented those alternatives and their estimated costs in Chapter 8, Section 8.5.6 of the 2022 IRP. All the alternatives to the selected Forest Grove Feeder uprate project were more expensive and, in some cases, such as potential load savings from targeted interruptible schedule agreements, insufficient to prevent a greater than 40 percent pressure drop during peak conditions.

b. The Company first recognized that it might need to make improvements to the Forest Grove Feeder in 2019 and included the project in its 2019 System Reinforcement 10 Year Plan. In November of 2020, the Company installed an electronic portable pressure recorder (EPPR) and began collection of pressure and temperature data for use in validation of Synergi system modeling (See Figure 8.17 for EPPR readings compared to Synergi modeling).

   In 2021, enhancements provided by the Customer Management Module (CMM), described in Chapter 8, Sections 8.5.2 and 8.5.3, incorporated customer growth in the area that was not captured in the legacy models used in 2019. CMM's connection to the CIS system allows NW Natural to identify all active customers attached to the gas distribution network. New modeling included a higher number of customers compared with legacy models. The higher number of customers increased the peak hourly demand forecast on the Forest Grove Feeder, causing the system pressures to be lower than were shown in the earlier 2019 model estimates. As a result, the Forest Grove Feeder uprate project was included in the 2022 IRP Action Plan.

ATTACHMENT B

Confidential Attachment 1 to NWN Response to Climate Advocates' Data Request 7

Climate Advocates' Attachment B is Confidential and has been served upon the Commission and each party on the service list designated to receive confidential information Pursuant to Order 22-374.

ATTACHMENT C

Confidential Attachment 2 to NWN Response to Climate Advocates' Data Request 7

Climate Advocates' Attachment C is Confidential and has been served upon the Commission and each party on the service list designated to receive confidential information Pursuant to Order 22-374.

ATTACHMENT D

Confidential Attachment 3 to NWN Response to Climate Advocates’ Data Request 7

Climate Advocates' Attachment D is Confidential and has been served upon the Commission and each party on the service list designated to receive confidential information Pursuant to Order 22-374.

ATTACHMENT E

NW Natural

Rates & Regulatory Affairs

LC 79

Integrated Resource Planning

Data Request Response

Request No.: LC 79 Advocate DR 14

14. Please see workpaper "210094-NWN-IRP-WP-MC_Supply-Price-Synthetic-Methane."

a. Please confirm that the average synthetic methane cost in 2040 is roughly 66% less than the average 2022 cost and the 2050 synthetic methane cost is modeled at roughly 82.6% less than the average 2022 cost.

b. Please provide all underlying assumptions for these values.

c. Please explain if these values represent the separate production of hydrogen and methanation or only the methanation process.

Response:

a. The file referenced includes 510 different price paths for the price of synthetic methane corresponding with the reference case (band 1), the 9 scenarios modeled (Bands 2-10) and the 500 stochastic Monte Carlo draws. This DR does not reference a specific draw, so the value for the average across the Monte Carlo draws will be used. In 2022, the average price for bundled synthetic methane across the 500 draws is $33.12/Dth in 2022, $13.14/Dth in 2040 and $9.14/Dth in 2050. This is a reduction of 60% in 2040 relative to 2022 and 72% in 2050 relative to 2022. Some draws will have slower or steeper declines, and may have declines as high as those cited in the question.

b. The mean across draws is tied to the price estimates provided in the Attachments to the response to LC 79 Advocate DR 7. The code that generated the values in the workbook for synthetic methane cited in this DR are also included in LC 79 Advocate DR 13 Attachment 1.

c. These prices represent the unbundled price of synthetic methane, which includes the price of hydrogen *plus* the price to methanate that hydrogen via methanation. Per the response to LC 79 Advocate DR 13, the prices that are input into PLEXOS (the file referenced in this DR is a PLEXOS input file) back out the avoided costs of conventional gas to achieve the unbundled price of emissions reduction that input into the PLEXOS model.

LC 79-CERTIFICATE OF SERVICE

I hereby certify that, on this 30th day of December, 2022, I served the Confidential Opening Comments of the Climate Advocates in docket LC 79 upon the Commission and each party on the service list designated to receive confidential information pursuant to Order 22-374 through a secure, encrypted attachment to an e-mail.

ROSE ANDERSON
PUBLIC UTILITY COMMISSION OF OREGON
PO BOX 1088
SALEM OR 97308

BETSY BRIDGE
OREGON DEPARTMENT OF JUSTICE
1162 COURT STREET
SALEM OR 97301-4520

BRADLEY CEBULKO
STRATEGEN CONSULTING
PO BOX 47250
OLYMPIA WA 98504

PAT DELAQUIL
DECISIONWARE GROUP

WILLIAM GEHRKE
OREGON CITIZENS' UTILITY BOARD
610 SW BROADWAY STE 400
PORTLAND OR 97206

JENNIFER HILL-HART
OREGON CITIZENS' UTILITY BOARD
610 SW BROADWAY STE 400
PORTLAND OR 97205

BRADLEY MULLINS
MOUNTAIN WEST ANALYTICS
VIHILUOTO 15
KEPELE FI-90440

ERIC NELSEN
NORTHWEST NATURAL
250 SW TAYLOR ST
PORTLAND OR 97204

CHAD M STOKES
CABLE HUSTON LLP
1455 SW BROADWAY STE 1500
PORTLAND OR 97201

REBECCA TRUJILLO
NORTHWEST NATURAL
250 SW TAYLOR ST
PORTLAND OR 97204

Respectfully submitted,

Carra Sahler, OSB # 024455
Green Energy Institute at Lewis & Clark Law School
10101 S. Terwilliger Blvd.
Portland, OR 97219
T. 503-768-6634; C. 971-213-9480
E. sahler@lclark.edu