March 8, 2023

Via Electronic Filing

Oregon Public Utility Commission
201 High St. SE, Suite 100
Salem, OR 97301-3398

Re: OPUC Docket LC 79 - Response to Questions regarding NW Natural's 2022 IRP

The Climate Advocates (Green Energy Institute at Lewis & Clark Law School, Climate Solutions, Columbia Riverkeeper, Community Energy Project, Electrify Now, MCAT, NRDC, and Sierra Club) appreciate the opportunity to offer comments in response to the six questions posed by the Commission on February 13, 2023.

1. What should be the objective, or what should be the multiple distinct objectives, for modeling electrification of end uses in NW Natural's future IRPs?

The main objective for modeling electrification of end uses in NW Natural's future IRPs (and the other gas utility IRPs) is to help identify the least cost, least risk pathway to decarbonizing our energy system in line with state targets and policy.

Some additional objectives related to this main objective include:

- Accounting for and projecting reduced gas demand resulting from electrification that occurs over the course of the next twenty years.

- Assessing the sensitivity of the company's resource plans to accelerated rates of electrification, including targeted electrification, to determine stranded asset risk (including specific planned investments) and to identify potential avenues for avoiding gas system investments and reducing costs/stranded assets through weatherization, electrification, and decommissioning gas assets.

- Evaluating electrification of end uses as a non-pipeline alternative and as a potentially least cost, least risk strategy for compliance with the CPP targets.

We note that any resulting modeling should generally reflect and align with load forecast assumptions and models relied on by electric utilities in territory overlapping with NW Natural's.

2. Regarding Staff's proposal to develop a proxy cost for electrification:

a. How might the use of a proxy electrification cost in this IRP improve the ability to evaluate NW Natural's current or future IRPs?

We think a proxy electrification cost would improve the Commission's ability to determine whether investments proposed by NW Natural are in the public interest. Presently, there is a dearth of reputable electrification cost estimates across the country, much less cost estimates focused on Oregon. Each utility service territory has a unique mix of climate and building stocks, each of which has a large influence on the cost of electrification. For example, buildings in colder climates need larger, more powerful heat pumps than buildings in warmer climates. Newer buildings are less likely to need panel and wiring upgrades to accommodate additional electric appliances. Developing proxy Oregon-specific electrification costs by building type will provide better information for comparing the costs and benefits of electrification.

Second, developing proxy electrification costs will remove the awkward instruction to a gas utility to estimate accurately the costs and benefits of a resource that could reduce its sales and require significant changes to its business model.

Finally, NW Natural currently predetermines the gas utility customer count projections for every IRP model scenario. These projected customer counts can vary between scenarios to allow for fast or slow electrification assumptions, but within each model run there is no possibility for cost-effective electrification to impact that customer count. If a set of proxy electrification costs were introduced into the gas utility's model, then the customer count could become a dynamic variable subject to the model's cost optimization process. In this way, the level of cost-effective electrification can be examined.

b. How accurate should a proxy electrification cost be to provide actionable or useful information in an IRP?

To be useful, these proxy electrification costs need to be developed at the sector (residential, commercial and industry) level for specific end-use applications (primarily space and water heating, cooking and industrial process heat). Furthermore, the proxy costs need to include the annual, seasonal and peak period needs of the electricity system, which will vary according to the types and rates of electrification assumed in the electric system model. Additionally, the cost of heat pumps for heating water and space are rapidly declining as the technology rapidly improves. Much like wind, solar, and storage cost estimates for the past 15 years, electrification cost assumptions developed today will likely be outdated by the development of the next IRP. Furthermore, like electric generation resource cost assumptions, the actual cost of a specific resource will be different from the generic costs used in the IRP. It would be reasonable for the Commission to hold electrification assumptions to the same standard it has applied to electric generation resource cost assumptions in the electric IRPs and instruct the gas utilities to use cost sensitivity analysis to determine if the optimal resource portfolio would change based on the assumed cost of electrification.

c. How might electrification cost estimates be made more accurate and informative now and in future IRPs?

As noted above, there is a lack of reliable, state-level data on buildings and their likely electrification costs. Any proxy electrification cost will be improved by better data on existing building stocks in the various microclimates across our state.

Electrification costs are expected to become lower over time, due to technological improvements, economies of scale, overcoming market barriers, and additional incentives and policy support. Electrification costs assumed in future IRPs should account for these developments by incorporating the latest-available average unit and installation costs, model specifications (using high-performance models, since these will become increasingly available over time), and available incentives.

The Commission should also look to reputable studies to guide reasonable assumptions for estimating costs over the planning horizon. For example, a 2017 National Renewable Energy Laboratory (NREL) report modeled residential heat pump efficiencies and cost. The report forecasted significant efficiency gains in both warm and cold climates and produced three different scenarios that modeled performance improvements through 2050. The "Moderate Advancement" scenario estimated a roughly 1 percent annual efficiency gain and cost reductions.[1]

The Commission should also look at the pace of development to contextualize estimates included in reports. The volume of investments domestically and globally, resulting in breakthroughs such as Trane's prototype that performs at temperatures as low as -23 degrees Fahrenheit, already suggests that technological gains may exceed expectations.[2] Assuming technological progress,

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[1] Jadun, Paige, et al., *Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050*, National Renewable Energy Laboratory (2017), https://www.nrel.gov/docs/fy18osti/70485.pdf

[2] "Trane passes heat pump challenge," Cooling Post (November 4, 2022), https://www.coolingpost.com/world-news/trane-passes-heat-pump-challenge/

sourced from predictive studies, is necessary to accurately evaluate electrification potential and is consistent with best practice for electric generation cost assumptions in electric IRPs.

d. What specific elements of the cost of electrification need to be considered and assumed in such a proxy cost assessment?

- Any marginal cost increases or cost savings to ratepayers from replacement of gas appliances with electric appliances at the end of their natural service lifetimes, including available incentives.

- Cost of replacing gas appliances with electric appliances in a planned or accelerated replacement program for a targeted geographical area to avoid a costly gas system investment.

- Social cost of carbon applied to the carbon emissions reductions from electrification (including both avoided CO_2 from combustion in gas end uses and avoided methane leaks from extraction to consumption) which offset the electrification costs. The social cost of carbon should be based on the latest federal or state estimates, such as the U.S. Environmental Protection Agency's 2022 estimate,[3] and should apply a discount rate no greater than 2.5%. Alternatively, the CPP's CCI credit cost could provide a useful price per ton of avoided emissions.

- Monetized public health benefits from avoided combustion emissions associated with gas end uses (particularly emissions of nitrogen oxides). These benefits may be estimated using tools like EPA's Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA). Wherever possible, benefits related to avoided indoor air pollution from electrification should also be evaluated and monetized.

- Installation and other building upgrade costs such as wiring and electric panels.

- Electricity price estimates for the entire planning horizon.

There are variables other than cost that the Commission will need to consider as well. For example, the proxy estimates will have to make end-use-specific assumptions about the following: end-use ramp rate (i.e., adoption rate), technical capabilities of classifications of end-

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[3] Envt'l Protection Agency, Supplementary Materials for the Regulatory Impact Analysis for the Supplemental Proposed Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances (Sept. 2022), https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf.

use equipment (e.g., the coefficient of performance for cold climate heat pumps and regular air-source heat pumps), and the crossover temperature when customers will use backup heating sources.

In sum, typical least cost optimization models used in utility IRP modeling rely on a combination of investment costs, operating costs, performance, and lifetime to calculate life-cycle costs for various technology options, and the models can calculate the marginal cost of an additional unit of electrification for a specific end use in a particular sector. The electric system marginal costs for specific electrification options would provide the gas utilities with the cost data needed to include an electrification option into the equipment replacement decision upon retirement of a gas appliance (or sooner if incentives are applied to decrease the cost of the electrification option). These costs should be evaluated on the assumption that electric utilities are taking advantage of opportunities to mitigate peak impacts.

3. Regarding electrification, what is NW Natural's responsibility to model electrification, as well as the company's capability to model electrification in future IRPs?

The company cannot pretend electrification is not happening and that its business will not be fundamentally affected by the trend toward, and incentives offered for, electric solutions to home and water heating. The Company is also obligated to comply with the CPP. It cannot do so using fossil gas and, based on the known technical and economic potential of commercially available alternative fuels, such as RNG and hydrogen, the Company cannot rely on alternative fuels to comply with the CPP. Electrification is a cost-effective, abundant, available resource for compliance. Further, not only does NW Natural have a responsibility to ensure the investments, programs, and activities it proposes to the Commission are prudent and in the public interest, it is obligated to identify sources of risk and uncertainty.

We do not believe a gas-only utility has the information or expertise to properly model the impact of electrification. As a result, two options present themselves:

- Option One: NW Natural can secure reliable models/projections from the electric utilities whose territories overlap with NW Natural's; or

- Option Two: a third party could develop and model the rates and costs of electrification.

With respect to the first option, we assume this approach can offer sector-level costs for specific end-use applications (primarily space and water heating, cooking, and industrial process heat), allowing better examination of the impact to annual need and peak needs of the gas system. For this approach to be correct for annual, seasonal, and peak demand periods, the electrification proxy costs (preferably by sector and end-use application) must include these same peak demand impacts on the electric system. A matrix of scenarios could then explore how near-term rates of cost-effective electrification are impacted by critical parameters, such as cost of RNG versus the cost of electric heat pump installation, or the cost of electric peaking power.

Alternatively, a third party assessment of electrification rates and costs could be useful to compare long-term outcomes between scenarios and identify near-term actions common to most scenarios, which could be useful to the electric utilities as well. Depending on how ambitious the assessment, it might require cooperation and data from all the electric and gas utilities in the state, along with involvement from community-based, environmental, and environmental justice organizations.

Either way, the aim is to understand the cost of NW Natural's gas systems-only solutions to meet demand and comply with the CPP, in comparison with alternative electrification options.

4. Should NW Natural's models be limited solely to its costs as a utility or should they incorporate household costs of electrification to some extent?

For a fair comparison among resources, some accounting for customer costs of electrification should be included. Having said that, costs should incorporate all incentives and rebates available, including IRA incentives, and assess the possibility that energy efficiency programs in the state may increase electrification incentives over time.

5. What actions by the Commission, if any, are necessary or helpful to enable appropriate modeling to be done now and in future IRPs?

The Commission will need to make a decision about how to best move forward with this important initiative. The Commission might consider making a decision in this docket as it applies to NW Natural's IRP, but announce to the larger UM 2178 docket a request for feedback on the question of how to proceed, as well as any scope of work and qualifications of any third-party should that be the selected option.

Aside from the question of how to best model electrification, the Commission should require natural gas utilities to provide a retrospective of its forecasts from prior IRPs to allow for a comparison with actual trends.

6. How should the significant uncertainty about many future conditions, such as load estimates or zero carbon fuel cost and supply availability estimates, be addressed or weighed in the development of the near-term action plan? Is the current guidance for least cost/least risk planning sufficient?

Although the least cost, least risk framework for evaluating pathways to meet demand while achieving state decarbonization targets is the right one to apply (see response to Question #1 above), the current guidance for applying this framework may be insufficient to protect ratepayers and ensure appropriate gas utility planning for the future. For example, current guidance does not address the cost lock-in and stranded asset risk if NW Natural's vision of the future does not become reality. It also does not account for the risks and lost opportunities for savings if NW Natural refuses to examine right-sizing the gas system and enabling or, at the very least, accounting for electrification.

Having said that, the current framework could be sufficient if the Commission appropriately values risk. For example, relying on synthetic methane to become both commercial and cost-effective to meet the utility's future demand is extremely risky and should be assessed as such. It is imperative that the Commission articulate when it determines a plan is too risky for customers. Additionally, the utility must be challenged to properly quantify risks, the cost to customers for meeting system needs, and how to comply with the CPP. Relying on the utility to properly evaluate its options in a non-biased way may be difficult, prone to spurious assumptions by the utility, and pose risks to ratepayers and meeting climate goals if non-commercial products do not materialize during the planning horizon.

Accordingly, we offer a few thoughts.

- We recommend that potential solutions that *may* become commercial and cost-effective in the future be removed from consideration until the company can demonstrate viability. All decisions in the near term should be based on currently available solutions that enable NW Natural to meet load while complying with the CPP. As new potential solutions become commercially available, those can be added to the analysis. At the very least, the Commission should instruct gas utilities to file IRPs that include only currently available technologies as a reference point to evaluate the risks posed by gas utility plans for compliance.

- The Commission should require inclusion of near term investments that demonstrably reduce greenhouse gas emissions. NW Natural should not be proposing gas investments that meet projected near term demand issues, while delaying decarbonization investments. These gas investments risk creating stranded assets or path dependence that commit the company to relying on riskier decarbonization strategies that may have higher long-term costs.

- NW Natural should institute a Demand Response program in lieu of investments in fossil fuel infrastructure. NW Natural could use demand response and voluntary demand reductions to manage peak loads. Customers have no idea a peak load event is happening and will choose to use their gas devices whether they are critical or not (e.g. outside heating appliances, gas fire-pits, decorative gas fireplaces). Customers could be financially motivated to reduce demand in the same way PGE does with its peak time rebates. This is a potentially more cost effective use of ratepayer dollars than investing in infrastructure builds that will not be fully utilized in the long term when demand declines.

Finally, the traditional ways of understanding the role of uncertainty are scenario and probabilistic analyses. The current use of scenario analysis is very limited and not particularly insightful. A significant improvement would be to require parametric scenario runs, where the change in a critical result metric (such as the customer cost or GHG reduction cost) are examined for a range of customer counts, load forecasts, technology cost and low-carbon fuel costs. While NW Natural's IRP provided results from 500 Monte Carlo scenarios using probability distributions for many of the model input parameters, it did not provide a sufficient analysis of the results.

Thank you for this opportunity to assist you with these important topics.

Respectfully Submitted,

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