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March 8, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
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Re: LC 79 – NW Natural's 2022 Integrated Resource Plan: Supplemental Comments

Northwest Natural Gas Company, dba NW Natural (NW Natural or Company), files herewith supplemental comments to questions in Administrative Law Judge Spruce's memorandum dated February 13, 2023.

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Sincerely,

/s/ Rebecca Trujillo

Rebecca Trujillo
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Attachment

OPUC LC 79 NW Natural Supplemental Questions Responses
March 8, 2023

NW Natural appreciates the opportunity to respond to the questions raised in Administrative Law Judge Spruce's February 13, 2023 memorandum in docket LC 79. At the outset, NW Natural believes it is important to point out that the questions raise broader policy implications and will impact all utilities that file IRPs in Oregon. As such, NW Natural recommends these questions be posed in a generic docket related to the IRP Guidelines to better ensure all Oregon utilities and interested stakeholders have the chance to weigh in on these important issues related to analysis of electrification in Oregon IRPs. This would also avoid a situation where policy decisions impacting all utilities are made in utility-specific dockets like LC 79 without participation of all potentially interested parties.

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?

NW Natural believes that the primary objective of an IRP is to analyze what resources are needed by a utility to serve that utility's customers' energy needs and develop an action plan that represents the best combination of cost and risk to serve those needs based upon that analysis. This is supported by the Commission's IRP Guidelines and a long history of IRPs in Oregon. While the analytical tools and complexity of the analysis have evolved through time, the potential for electrification of natural gas utility load does not require a change to this primary objective for utility-specific IRPs.

In its 2022 IRP, NW Natural modeled a wide range of electrification, including the most aggressive electrification that is conceivable, to understand what resource decisions would need to be made to serve the resulting loads to NW Natural. NW Natural also modeled what different levels of electrification might mean for planning resources for its customers in prior IRPs. This is appropriate and aligned with how an IRP analysis has been completed by utilities for many years: evaluate the load that needs to be served, identify the options available to serve it, and select the resources that represent the best combination of cost and risk to serve those needs. All Oregon natural gas utilities, or local distribution companies (LDCs) are modeling and intend to model what different levels of electrification would mean in terms of impact on their load and the resources required to serve it in their IRPs.

Completing this work and including customer bill impacts in IRPs to understand the full impact of potential electrification, in terms of what gas utility customers pay their gas utility for service, should be the primary objective of modeling electrification in LDC IRPs.

Beyond the primary objective, NW Natural also realizes that the benefits, costs, and challenges of different forms of decarbonization at the societal level are needed to make sound decisions on utility regulation. As such it makes sense to coordinate analysis across gas and electric IRPs in the state to better understand the impacts of the actions contemplated by each utility in their IRPs. This coordination would allow insight into whether proposed actions of specific utilities are meeting broader climate policy goals in a least cost-least risk manner. Specific to electrification, understanding the emissions and cost impact to Oregon utility customers (most of whom are both gas and electric utility customers) of varying levels of electrification in comparison to the corresponding levels of gas utility decarbonization in terms of the bills they would pay to both the electric and gas utility is relevant in evaluating what is being proposed in a specific utility's action plan.

Given the need for this analysis, a secondary objective in terms of modeling electrification in gas utility IRPs should be developing the data needed by electric utilities to model the load and resource need impacts of varying levels of building electrification to feed their own customer bill impact estimates. NW Natural can work with the other LDCs, OPUC Staff, stakeholders, and electric utilities to provide the energy (Btus) that would be electrified, both over a year and during peak winter conditions, for different levels and types of electrification to aid in this evaluation. This would allow for a customer bill impact for both electric and gas utility service under different levels of electrification to be compiled from the results of gas and electric IRPs.

NW Natural can also provide the emissions intensity of natural gas utility service under different levels of electrification in the context of the Climate Protection Program (CPP) and other environmental policies so that the emissions impact of electrification at the customer and societal level can be made alongside cost comparisons.

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

NW Natural presumes that this question refers to the following found on page 10 of Staff's Opening Comments in this docket (LC 79):

While the full cost of electrification is not known at this time, this should not deter Staff, stakeholders, or the utilities from directional analysis in this IRP that attempts to estimate the costs and benefits to customers and the electric system from different gas planning scenarios for informational purposes.

Staff proposes a study by Synapse, supported by OPUC Staff, that would add proxy electrification and capital investment costs to NW Natural's NPVRR in each scenario. The intent of the study would be to provide information for a conversation about the costs of electrification scenarios as compared to other decarbonization pathways. This could be a step toward the type *of analysis considered in Docket No. UM 2178 that looks at coordinating assumptions between gas and electric IRPs. While such a study could potentially be made available before the acknowledgement decision in this IRP, it would likely be used as a starting point for a longer conversation about how to consider costs of electrification versus gas decarbonization, and not leaned upon heavily by Staff in acknowledgement discussions.*

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?

While it is not entirely clear, NW Natural presumes that the proxy electrification cost at issue in this question is an estimate of the costs of electrification of would-be direct use gas utility load *to the electric sector to serve incremental electric load*. Presuming this is what is meant by "proxy electrification cost" NW Natural is concerned by the approach and believes that a single proxy electrification cost is not desirable or feasible given that the Oregon electric utilities that also serve the LDCs' customers have disparate load and emissions profiles and resource needs. Furthermore, the costs of electrification at different levels, or for electrification of different end uses, is likely to result in far different costs *per unit of electrification* on the electric grid. While NW Natural is not opposed to an appropriately detailed estimate of the costs of electrification that is not set at a single figure for all electric utilities in Oregon, all end uses, and all levels of electrification, a single proxy electrification cost is likely to oversimplify a complex issue and could be more misleading than helpful.

Rather than use a proxy cost, a more reliable way to assess the costs of electrification on the electric sector and to understand the impact to Oregon utility customers would be to align energy use assumptions and share electrification related load and cost data across the electric and gas utilities regulated by the OPUC. While numerous electric utilities serve the current and potential future gas utility customers in Oregon, more than 80% of Oregon gas utility customers are also served by investor-owned electric utilities (IOUs) that are regulated by the OPUC and hence file IRPs with the Commission. IRPs, both electric and gas, already contain detailed analysis of the resources (and their associated costs) that are needed to serve different levels and various profiles of load. Aligning assumptions across gas and electric IRPs to understand the cost and customer bill impacts to Oregonians for their utility service would provide a far better estimate of the costs of differing levels and types of electrification that could be compared against the corresponding levels and options for gas decarbonization in the context of HB 2021, the CPP, and other environmental policies. NW Natural is willing to work with Oregon IOUs so that the needed information can be found across gas and electric IRPs. While differences in the timing of IRP filings mean this path forward is imperfect, it is a much-preferred approach to a single proxy electrification cost that cannot be replicated outside of the analysis in IRPs.

While IRP analysis is a preferred approach for customers whose gas and electric utilities are regulated by the OPUC, a proxy electrification cost could be a reasonable path forward to evaluate different pathways for decarbonization for the minority of Oregon gas utility customers that are not served by electric utilities regulated by the Commission.

That said, if the Commission decides that the development of a "proxy electrification cost" is the appropriate path forward, it is important that this cost (or these costs) is (are) developed by Staff or an unbiased independent third party that is chosen with stakeholder input. NW Natural is concerned that this decision may be rushed,[1] and that consensus amongst stakeholders about the approach to the modeling and selection of consultant should be prioritized.

Lastly, given that emissions reduction is provided as the primary reason for electrification being socially desirable, cost alone is insufficient to understand the impact of electrification. Electrification does not equate to decarbonization, and for many Oregon gas utility customers, electrification would result in a societal *increase* in emissions – at least in the near term. It is critical to understand not only the cost impact of electrification in detail for Oregonians, but also the impact to emissions, both now and into the future while recognizing both electric and gas utilities' compliance with Oregon climate policy. A proxy electrification cost could not help in providing information relative to the impact to societal emissions from electrification.

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

Any estimate of the cost of building electrification that does not (1) use Oregon-specific household and business level estimates of annual and peak usage from actual usage data; and (2) account for the cost of generation, transmission, and distribution investments required at a utility specific level to serve this electrified load; and (3) recognize that different levels and types of electrification will result in differing per unit costs on the electric system should not be considered sufficient information to evaluate action items in an IRP.

[1] Staff's Opening Comments (at page 10) state the proxy electrification cost study "could potentially be made available before the acknowledgement decision in this IRP" which is currently scheduled to go to a Public Meeting for an acknowledgement decision in June 2023 with final stakeholder comments due in early May 2023.

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

Per the above discussion, estimates of the costs of electrification as part of electric utility IRPs are the preferred way to develop detailed and reliable electric system costs of would-be natural gas utility energy services. NW Natural's 2022 IRP includes estimates of customer bill impacts for a wide range of electrification and estimates of the amount of energy electrified could be provided at an hourly level for evaluation in electric IRPs as part of a coordination effort.

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

See the responses to a and b above.

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?

It is again important to point out that Oregon LDCs have been modeling and will continue to model the load impacts of differing levels of electrification and what that electrification means for the resources the LDCs need to serve that load in their IRPs. This is an appropriate analysis to be completed by a gas utility in its IRP to support the development of an action plan. However, it is not appropriate for LDCs to model the cost of the load being electrified *to the electric sector* or to model gas customer funded electrification initiatives in a gas utility IRP.

The cost of serving the load on the electric sector, as discussed above, is best estimated by the electric utilities that would be serving the load. They are better equipped to assess what generation, transmission, and distribution resources would be needed to meet the incremental load on their systems.

Additionally, gas customer funded electrification is not a viable resource option for consideration by a natural gas utility to meet the needs of its customers' natural gas use. Modeling gas utility customer funded electrification would be modeling a third-party's ability to provide would-be gas energy services without an assessment of the costs of those services from its provider.

While it is reasonable for a gas utility to model voluntary or policy-directed customer defection to electric service as NW Natural has done extensively in its 2022 IRP, modeling of this nature keeps intact the fundamental nature of an IRP: an exercise to determine how a utility can best provide its customers with the product they have chosen to purchase from the utility.

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?

It is important to first point out that the Commission directs Oregon utilities and the Energy Trust of Oregon to utilize the total resource cost (TRC) test to evaluate energy efficiency. The TRC test incorporates household/customer costs. As such, Oregon LDCs' modeling in IRPs already incorporates household costs in evaluating energy efficiency, with much of this evaluation being completed by the Energy Trust of Oregon. This assessment of customer/household costs that are not collected from utilities is not included in the resource planning optimization completed by the LDCs as it would not be feasible and would not result in an apples-to-apples comparison of different resource options.

Furthermore, NW Natural, in general, does not believe it's a good idea to include non-utility costs in the cost optimization models that are the primary tool for analysis in IRPs for both gas and electric utilities. These resource optimization models naturally evaluate resources from a utility cost perspective. This is partially because it is not possible to evaluate societal costs across fuel sources without developing a cross-sectoral model, like those used in deep decarbonization studies. This is to say that it is not possible to input a single "proxy electrification cost" into a gas utility resource planning model to properly evaluate customer decisions, as the underlying optimization is not a customer choice model, but a utility cost minimization model.

Additionally, it would not be appropriate to include household electrification costs without including other relevant household costs (like gas equipment costs). Given that there are many types of customers (e.g., low income residential, high income residential, small commercial, etc.), moving to this type of modeling would be overly complex and unwieldy.

While it makes sense to compare utility customer costs more broadly across electric and gas utility service and include end use equipment and conversion costs, it would be better to compile this information from the results of the analysis- proposed above- across electric and gas IRPs. Such customer bill impact estimates, from both the electric and gas utility, would provide rigorously developed information to understand customer choice dynamics. This process would be much preferred versus directing gas utilities to consider electric service costs in gas IRPs or electric utilities to consider gas utility service costs in electric IRPs.[2]

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[2] Noting again that emissions of these options should also be considered given that decarbonization is the primary rationale cited for electrification.

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

According to the final Staff report in UM 2178, the Commission "will conduct a technical study to inform future gas and electric IRPs with guidance on information requirements to facilitate joint utility decision making for least-cost, least-risk GHG emission reduction strategies." This study, if done in a transparent process and with the addition of a consultant that has a strong background in gas utility resource planning, is an appropriate next step to better understand what should be done in future IRPs.

Furthermore, the as noted above, NW Natural contends that broader issues that will impact all Oregon LDCs or all utilities in Oregon are not best addressed in utility specific IRP dockets. This set of comments is a good example. These questions are IRP policy questions that would be best addressed in a generic docket discussing IRP policy and guidelines that is separate from the analysis of a given utility in an IRP. Deliberation of these questions would surely impact all Oregon LDCs and is likely to impact Oregon electric utilities regulated by the Commission as well. Indeed, many of the questions asked about uncertainty and risk apply to all the regulated energy utilities that perform IRPs. Keeping these discussions in a single forum would allow participation by all stakeholders and make it easier to keep track of the arguments being made as well as direction from the Commission to utilities and stakeholders in preparing and reviewing IRPs.

Additionally, NW Natural recommends the Commission direct Oregon LDCs and IOUs to complete the "Proposed HVAC System Heating Peak Load Study" included in Appendix D of NW Natural's reply comment in LC 79 that starts on page 117. This would provide Oregon specific estimates of annual and peak usage of different heating types, most critically homes heated by electric heat pumps, in real world conditions in Oregon to be used to estimate the load impacts of electrification so that the resulting estimates of generation, transmission, and distribution needs are realistic and robust.

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?

NW Natural described in detail in our IRP why making decisions about future conditions in long-term assumptions is unnecessary to evaluate the Action Plan in NW Natural's 2022 IRP.[3] The Company detailed how the Action Plan is a prudent path forward as it allows needed near-term action without doubling-down on any long-term future condition. The actions items contained

[3] See NW Natural's reply comments in LC 79 at https://edocs.puc.state.or.us/efdocs/HAC/lc79hac155918.pdf

in the Action Plan are relatively low regret actions that are needed to maintain delivery of safe and reliable and comply with environmental policy in the near-term without delay. As such, the current guidance for least cost/least risk guidance is sufficient to evaluate the Action Plan in NW Natural's 2022 IRP.

More specifically, it is important to understand that costs and risks are often fundamentally opposing outcomes that are balanced against each other through resource planning. The definition of cost is straight forward and defined by IRP guideline 1 as the present value revenue requirement using a discount rate equal to the weighted-average cost of capital. The definition of risk is much broader and less well defined by the guidelines. Guideline 1 says that at a minimum the IRP should address sources of risk and uncertainty for:

> *demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.*

Guideline 1 then contains a catch all clause:

> *Utilities should identify in their plans any additional sources of risk and uncertainty.*

These additional sources of risk and uncertainty may incorporate, but are not limited to, reliability risk, safety risk, other sources of cost risk (e.g., cost overrun), stranded asset risk, policy risk, or customer equity risk. In all cases of risk and uncertainty, the utility can increase costs to reduce the chances of bad outcomes for customers (i.e., reduced risk) or gain additional insight via pilots, surveys, expert testimony (i.e., reduce uncertainty). In short, there is no single portfolio of resources that is both the least cost portfolio and the portfolio with the least risk. The least cost/least risk planning standard that has been the standard for IRPs is truthfully a shorthand description for the least cost portfolio given an acceptable level of risk and uncertainty.

Staff's opening comments for OPUC LC 79 (at page 25) provides a good contextual description of risk versus uncertainty:

> *In his seminal book, Frank Knight draws a distinction between these two core ideas discussing the unknown. [footnote omitted] As Knight defines it, something is "risky" if the outcome is unknown, but the probability distribution of the outcome is known. This framework works well for well-understood, longstanding processes backed with data such as weather, price fluctuations, or population modeling. Conversely, something is "uncertain" if neither the outcome nor the probability distribution is known. This is more appropriate for future events that do not have much precedent or data, such as the effects of novel policy changes or adoption of new, disruptive*

technologies. Fitting a probability distribution to uncertain outcomes treats uncertain events improperly as risky events, muddying this subtle but important distinction.

NW Natural appreciates this framework that Staff raises about the distinction between risk and uncertainty. This conceptual framework provides a basis to discuss the uncertainty of future conditions and how the IRP guidelines translate risk and uncertainty into actionable steps for the utility to take that reflect the appropriate risk thresholds.

While the NW Natural agrees with the distinction between risk and uncertainty, variables that we model in the IRP as uncertain, per Guideline 1, should not be bucketed into one category or the other as alluded to in Staff's comments. In practice, we can never truly know the underlying distribution for most of the stochastic variables that we model. Unlike a coin toss where the probability distribution is known (binomial distribution with equal chance of two outcomes), the true probability distribution of shocks to gas prices is unknowable. For variables with *longstanding processes backed with data*, such as weather and gas prices, we use history as a guide to create a distribution to pull from, but we can never be certain that history represents the true underlying distribution for the future. For variables that have less historical data (e.g., synthetic methane prices and availability), it is incorrect to describe them as being completely uncertain. We have data gathered frequently from independent third-party providers thus far to inform the average value and to develop a likely range of values. While the shape of the underlying distribution of nascent markets may be more uncertain than other variables with a long history of data, we do have information from data thus far to make a reasonable range to potential values.

While it is easy to make a theoretical distinction between risk and uncertainty, in practice the *probability distribution* of any cost or quantity input will never be 100% known. Staff's comments provide a great framework for understanding the distinction between risk and uncertainty, but the comments lack a discussion of how this distinction helps in the deployment of an IRP. Resources must meet a minimum threshold of certainty to be included in the IRP. Resources that do not meet this threshold are "left on the cutting room floor" and are not evaluated through the IRP model, for example importing RNG (compressed or liquified) via tankers from foreign countries. This threshold may not always be crystal clear, but renewable natural gas, hydrogen, and synthetic methane are broadly being discussed as low carbon fuel throughout the industry with a lot of supporting cost and availability of data. The IRP would be remiss to exclude them from the analysis.

Staff's question asks:

> *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?*

NW Natural has analyzed an extremely wide range of different future conditions and developed an action plan that takes near-term action that is robust to all potential futures. The Monte Carlo results from the IRP modeling provides this insight. NW Natural believes that the Monte Carlo process and results are exactly "how" uncertainty of many future conditions are *addressed* in the development of the action plan. Using the results of the Monte Carlo is "how" we *weigh* the risk of potentially bad outcomes for customers and develop an action plan that is a least- cost portfolio of resources for an acceptable level of risk and uncertainty. This seems like the best approach in the interest of customers.