Natural Gas Fact Finding <u>Draft</u> Report

Oregon Public Utility Commission staff is pleased to present the **UM 2178 - Natural Gas Fact Finding Draft Report** (NGFF Draft Report). The NGFF Draft Report is informed by the docket's extensive stakeholder dialogue, expert consulting, and Integrated Resource Plan-based modeling from the utilities. It includes discussion of the docket findings and suggested next steps. As part of the NGFF Draft Report, staff recommended 25 near-term actions.

Stakeholders are invited to provide written comments on the NGFF Draft Report by June 3, 2022. Comments can be emailed to staff or directly to PUC.PUBLICCOMMENTS@puc.oregon.gov. Comments will be posted in the UM 2178 docket. Staff is particularly interested in stakeholder feedback on the draft report's recommendations.

Following receipt of written comments, the Commission plans to hold a Special Public Meeting in early July 2022 to discuss the NGFF Draft Report and inform the development of the NGFF Final Report. The NGFF Final Report is expected to be posted on August 12, 2022. The Commission will then hold a Special Public Meeting at the end of August to accept the report conclusions and discuss next steps. An outline of the schedule is included below:

Activity	Date
NGFF Draft Report posted; Schedule for publication and consideration of NGFF Final Report posted	April 15, 2022
Stakeholder Comments due on the NGFF Draft Report	June 3, 2022
Special Public Meeting to discuss NGFF Draft Report	Early July
NGFF Final Report posted	August 12, 2022
SPM to accept report conclusions and discuss next steps	Late August

Any questions regarding the NGFF Draft Report and the schedule can be sent to Kim Herb – Kim.Herb@puc.oregon.gov.

DOCKET: UM 2178

PUBLIC UTILITY COMMISSION
OF
OREGON

NATURAL GAS FACT FINDING

Draft Report

April 15, 2022

Contents

1 NATURAL GAS FACT FINDING EXECUTIVE SUMMARY

Oregon has taken explicit steps to reshape the state's energy market by introducing Greenhouse Gas (GHG) emission reduction targets reflecting national trends to actively address climate change through state policy. Policies like the Oregon Department of Environmental Quality's (DEQ) Climate Protection Program (CPP) and HB 2021 set ambitious GHG emission reduction targets that will have a permanent impact on regulated utility investments and operations. In addition, trends related to climate change and climate adaptation are driving consideration of deep decarbonization pathways. These trends include the evolution of regional and national policies that cap or price GHG emissions, and the rapid development and deployment of solutions designed to reduce energy related GHG emissions.

For the natural gas utilities overseen by the Oregon Public Utility Commission (OPUC or PUC), the DEQ's Environmental Quality Commission's 2021 adoption of CPP rules represented a first step in reorienting these utilities' near-term planning and future operations. By complying with the CPP, Oregon's fossil fuel suppliers – including the regulated gas utilities – must collectively achieve emission reductions of 50 percent by 2035 and 90 percent by 2050. Such significant emission reductions position these companies well for future climate policy changes at the regional or national level.

To assess the impact of the CPP on gas utilities, their customers, and other potential decarbonization activities, the PUC staff engaged in a dynamic, six-month public process of fact finding (UM 2178). The purpose of this Natural Gas Fact Finding (Fact Finding or NGFF) was twofold. The first was to analyze the potential bill impacts from the limiting of natural gas utilities' GHG emissions under the DEQ's CPP. The second was to identify appropriate regulatory tools to mitigate potential customer impacts and accommodate utility action.

To achieve these purposes, stakeholders, utilities, expert consultants, and staff collaborated to identify CPP compliance pathways, associated costs, implementation issues, and potential regulatory tools capable of mitigating customer impacts, increasing intergenerational equity, and incentivizing actions to meet CPP targets.

Informed by the docket's extensive stakeholder dialogue, expert consulting, and Integrated Resource Plan-based modeling from the utilities, staff offers this report on the docket findings and suggested next steps.

Broadly, our findings are that:

- **Momentum** for both limiting gas expansion <u>and</u> for gas supply innovations is accelerating.
- CPP compliance **costs and risks** to gas customers from gas utilities' compliance actions range from manageable to rather substantial by 2029, depending on the customer and their existing level of energy burden.
- CPP **compliance and decarbonization issues** that PUC activities will need to address are much better understood.
- A host of **regulatory tools** – organized into the categories of Planning, Programs, and Rate Making – are available to shape and manage the policy risks of various compliance pathways for gas utility decarbonization, and the PUC most likely has sufficient authority to implement them.

- A number of potential regulatory tools identified in this Fact Finding would require an optimization across the energy system, rather than a focus on a single fuel (i.e. natural gas or electricity). Implementing such tools would require work across a variety of dockets and utilities over the next decade. For these reasons, these tools would require an unprecedented degree of internal and external **coordination and additional resources**.

With regards to these findings, the report also includes staff's consideration of the suite of regulatory tools. Based on staff analysis, stakeholder feedback, and workshop discussions, staff developed a set of regulatory tool recommendations that should be best suited to address the identified issues given various constraints. The table below functions as a high-level summary of the near-term regulatory tools staff recommends.

Table 1: Roadmap of Staff Regulatory Tools for Oregon (See Section 5.7 for more details)

Section 5 Analysis	**Recommendation**	**Issue from Section 3.3**	**Regulatory Tool**		
			Planning	Programs	Ratemaking
Protecting Customers	Estimated Bill impact	Protection	X		
	Direct ETO to target programs to LI and EJ	Protection		X	
	EE measures that allow for customer hook-ups	Protection		X	
	EE programs to include transport	Protection		X	
	Continue development of HB 2475	Protection			X
	Align near-term investments with CPP compliance	Protection			X
Full Cost	Develop marginal abatement cost curve	Full Cost of Reducing Demand	X		
	Transport customer cost of compliance in rate cases	Full Cost of Reducing Demand			X
Access and Info	Quarterly stakeholder updates in UM 2178	Access	X		
	Maps in next IRPs	Access	X		
	RFA docket outreach through DEI Director	Access			X
Decarb Planning & Cost-Recovery	Utilities articulate electrification assumption in IRPs	Systems Approach	X		
	Electrification info and data from DSP	Systems Approach	X		
	Independent 3rd party analysis of key tech and market assumptions used by all 3 utilities	Systems Approach	X		
	CPP as an acknowledgeable item in IRPs	Systems Approach	X		
	Exploring IRP guidance from UM 2178	Systems Approach	X		
	Line extension policy exploration	Systems Approach			X
Monitoring, Tracking, and Reporting	Annual PUC report based on DEQ compliance filings	Systems Approach	X		
	Annual utility report on CPP compliance costs	Access	X		
	Enhance tracking of alternative supply of actual costs and report to planning	Access			X
	Explore linking CPP amortization to CPP performance	Protection			X
Incentivize GHG reduction pathways	Encourage use of SB 844 for Pilots	Urgent Action	X		
	Compliance costs into EE AC	Urgent Action			X
	Joint pilot for Green Hydrogen by 2025	Urgent Action			X
	ETO Expand vendor training for <u>all</u> heat pump tech	Urgent Action			X

2 BACKGROUND

2.1 PUC'S NATURAL GAS FACT FINDING

In December 2020, the PUC finalized its GHG work plan after five months of development and stakeholder input. The overall goal of the proposed work plan was to, "establish new analyses and actions within existing dockets and investigations, and consistent with the PUC's authorities and duties, so as to place the regulated utilities on sustainable pathways toward achieving the Governor's 2035 GHG reduction goals."[1] Specifically for gas ratepayers, the work plan proposed a study of the impact of the proposed DEQ CPP rulemaking to, "understand the customer dimensions and impacts of different decarbonization scenarios and thus help inform future decision making."[2]

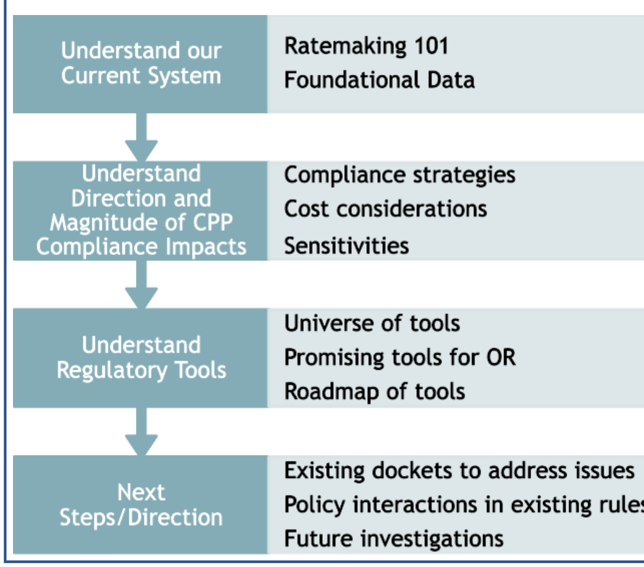
In June 2021, staff officially opened the Natural Gas Fact Finding under Docket No. UM 2178. The purpose of this Fact Finding was to analyze the potential natural gas utility bill impacts that may result from limiting GHG emissions of regulated natural gas utilities under the CPP and to identify appropriate regulatory tools to mitigate potential customer impacts. It was crafted to produce two primary outcomes: 1) An understanding of potential natural gas customer bill impacts associated with the CPP GHG emission target compliance; and 2) the identification of strategies and regulatory tools that equitably mitigate potential harm to natural gas customers while accommodating action that supports compliance.[3] The ultimate goal of the Fact Finding was to inform future policy decisions and other key analyses to be considered in 2022, once the CPP is in place.

The work plan (as outlined in Figure 1) was designed to:

- Help staff and stakeholders understand current natural gas and cost recovery systems;
- Understand the potential impacts of CPP compliance;
- Explore applicable regulatory tools; and
- Identify actions the Commission could take to protect customers.

Staff utilized a process that mixed facilitated workshops, public comments, and external analysis to develop an extensive set of documents.

Figure 1: Natural Gas Fact Finding Process



[1] Oregon Public Utility Commission EO 20-04 Work Plans. Page 2. https://www.oregon.gov/puc/utilities/Documents/EO-20-04-Work plans-Final.pdf.
[2] Oregon Public Utility Commission EO 20-04 Work Plans. Page 10. https://www.oregon.gov/puc/utilities/Documents/EO-20-04-Work plans-Final.pdf.
[3] *See* UM 2178, Staff's Initial Application, June 8, 2021. Page 16 of pdf. https://edocs.puc.state.or.us/efdocs/HAA/um2178haa11959.pdf.

Staff held five workshops, each of which was generally attended by over 90 people. In addition, the UM 2178 docket schedule offered multiple opportunities for public comment and access to utility compliance modeling workbooks. Staff also engaged the Regulatory Assistance Project (RAP) to assist staff and explore regulatory tools.

2.2 NATURAL GAS USE IN OREGON

Oregon is served by three natural gas Investor-Owned Utilities. All are standalone gas companies in Oregon with no electricity sales. Annual sales revenues for Oregon's three natural gas utilities were over $810 million in 2019.[4] In 2019, Oregon's natural gas customers consumed about 1.6 billion therms, or about 4.4 million therms per day.[5] NW Natural (NWN) is the largest of Oregon's three gas utilities, providing about 80 percent of total natural gas retail sales, with Avista representing 12 percent of retail sales, and Cascade representing 8 percent.

Oregon's customers are divided into four categories: residential, Firm commercial & industrial (Firm C&I), Interruptible C&I, and Transport. Firm C&I customers are generally small businesses, while Interruptible C&I customers are generally larger businesses. Transport customers are large, non-residential utility customers that have purchased their gas from another natural gas supplier (e.g., gas marketer) but who continue to use the regulated utility's distribution system to deliver their gas.

As can be seen in Figures 2 and 3,[6] while most natural gas utilities' revenues come from residential customers, much of gas delivered annually by these utilities is for transport customers. The revenues from transport customers to the regulated utilities is relatively small because these customers purchase their gas from gas marketers, not the utilities, and only use the utility's distribution system to deliver the gas to their location.

Figure 3: OR Natural Gas Utilities' 2019 Sales Revenue

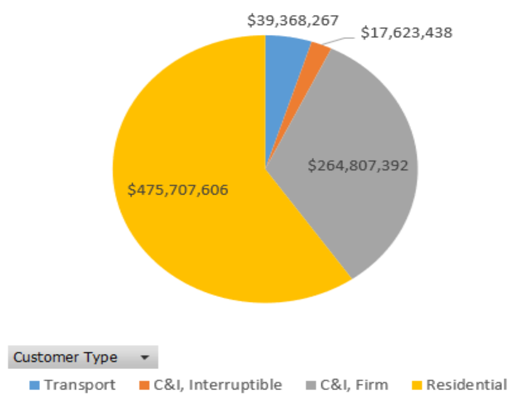
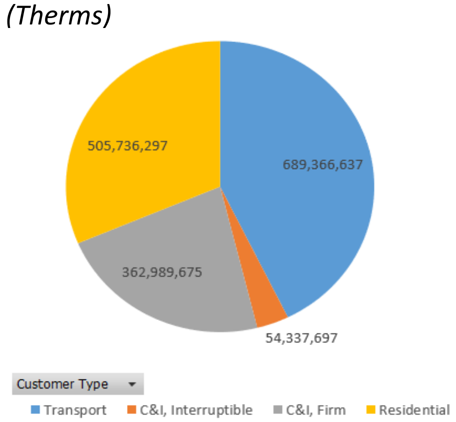


Figure 3: OR Natural Gas 2019 Delivery (Therms)



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[4] 2019 Oregon PUC Statistics Book. Page 42. https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2019-Oregon-Utility-Statistics-Book.pdf.

[5] Descriptive Statistics Excel Workbook, May 27, 2021. Available on Oregon PUC's Natural Gas Fact Finding webpage - https://www.oregon.gov/puc/utilities/Pages/EO-20-04-UP-FactFinding.aspx.

[6] *See* Descriptive Statistics Excel Workbook, May 27, 2021. Available on Oregon PUC's Natural Gas Fact Finding webpage - https://www.oregon.gov/puc/utilities/Pages/EO-20-04-UP-FactFinding.aspx.

2.3 THE CLIMATE PROTECTION PROGRAM

The CPP, effective in January 2022 (OAR 340-271), is designed to substantially reduce greenhouse gas emissions in Oregon over the next thirty years. The CPP establishes a declining limit, or cap, on greenhouse gas emissions from fossil fuels used throughout Oregon, including diesel, gasoline, natural gas, and propane. This includes emissions from fossil fuels used in transportation, residential, commercial, and industrial settings. It also uses a best available emissions reductions approach for other site-specific emissions at facilities, such as emissions from industrial processes.

Companies regulated under the declining cap, known as covered fuel suppliers, include the three natural gas utilities and other suppliers of liquid and gaseous fossil fuels. The aggregate emissions covered under the CPP represent about half of the state's greenhouse gas emissions, with natural gas utilities making up 26 percent of total CPP covered emissions (NW Natural 21 percent and Avista and Cascade 3 percent each).[7] The 2022 cap is based on average emissions from 2017 to 2019 for the covered fuel suppliers. The CPP requires greenhouse gas reductions of 50 percent by 2035 and 90 percent by 2050.[8]

Covered fuel suppliers must demonstrate compliance every three years along a steady trajectory towards the two milestones in 2035 and 2050. The first compliance period is 2022-2024, with covered fuel suppliers first demonstrating compliance in November 2025. Companies demonstrate compliance by submitting one compliance instrument or community climate investment (CCI) credit (discussed in more detail below) for each ton of covered emissions reported in their annual greenhouse gas emissions reports to DEQ during the compliance period. Under the CPP, each natural gas utility receives a free annual distribution of compliance instruments based on their share of the overall declining emissions cap.

While DEQ prescribes exactly the number of compliance instruments that will be supplied to each natural gas utility in years 2022-2050, there are additional flexibility mechanisms. Covered fossil fuel suppliers can trade unused compliance instruments or bank them for future use. These companies can also optionally contribute funds to DEQ-approved third parties in order to receive CCIs that work similarly to the compliance instruments DEQ distributes (e.g., each CCI credit allowing supply of fossil fuels that when combusted emit 1 metric ton CO2 equivalent).

Covered fuel suppliers can earn CCI credits by contributing funds to third-party entities to implement projects that reduce greenhouse gas emissions in Oregon. The contribution amount for a CCI credit is established by DEQ. The contribution amount starts at $107 (2021) per CCI credit and increases over time.[9] CCIs are designed to reduce emissions by at least one MT CO2e on average, prioritize benefits in or near environmental justice communities, and reduce co-pollutants. CCI credits can be banked for two compliance periods and cannot be traded. Covered fuel suppliers can only use a limited number of CCIs to meet compliance obligations. The limit begins at 10 percent of total compliance obligations for the first compliance period and eventually grows to 20 percent by the third compliance period.[10]

In short, DEQ's CPP lays out a regulatory framework that prohibits supply of natural gas by the three utilities above the amounts prescribed by the rules. From the outset in 2022, these amounts decline by

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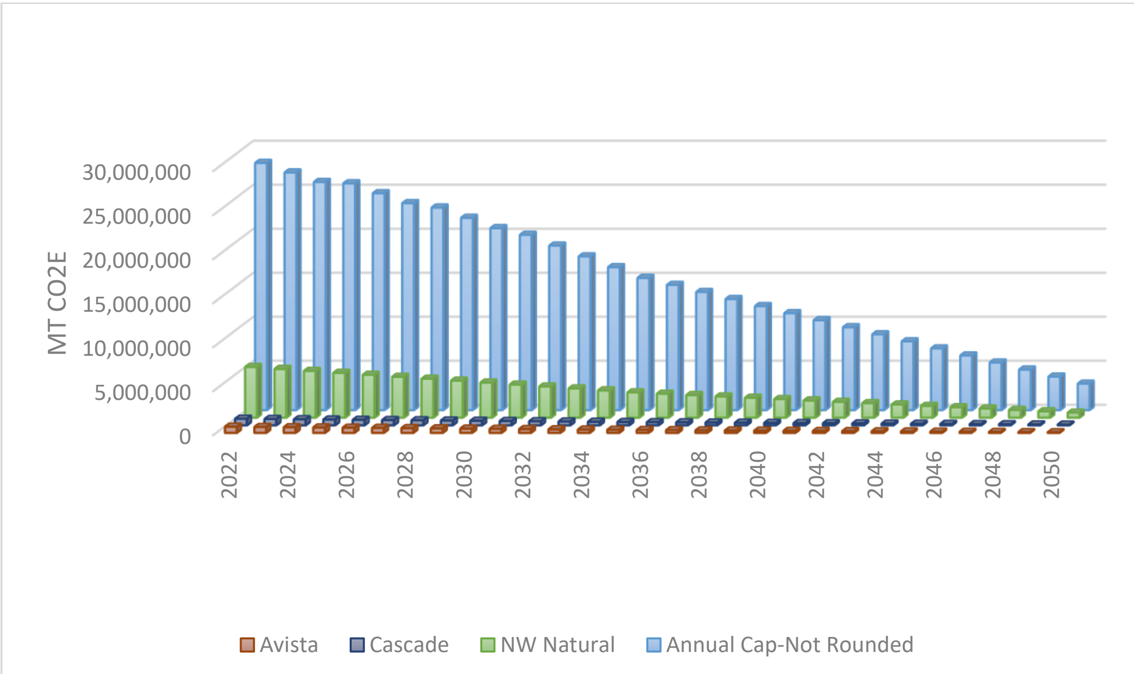
[7] *See* Supplemental Cap Information Excel Workbook. Available on Oregon DEQ's Climate Protection Program website = [https://www.oregon.gov/deq/ghgp/pages/climate-protection.aspx.](https://www.oregon.gov/deq/ghgp/pages/climate-protection.aspx)
[8] *See* OAR 340-271-9000, Table 4.
[9] *See* OAR 340-271-9000, Table 7.
[10] *See* OAR 340-271-9000, Table 6.

50 percent by 2035, and by 90 percent by 2050. While there are some flexibilities such as trading and CCIs, these requirements represent a significant, rapid, and mandatory requirement in the reduction of the utilities' supply of natural gas. Figure 4 provides a sense of the magnitude of the reductions required by the CPP.

Figure 4: Climate Protection Program Emission Caps[11]



3 KEY FINDINGS, ISSUES, AND STAFF ANALYSIS

The compliance modeling, stakeholder dialogue, and discussion around regulatory tools in the Fact Finding led to several findings:

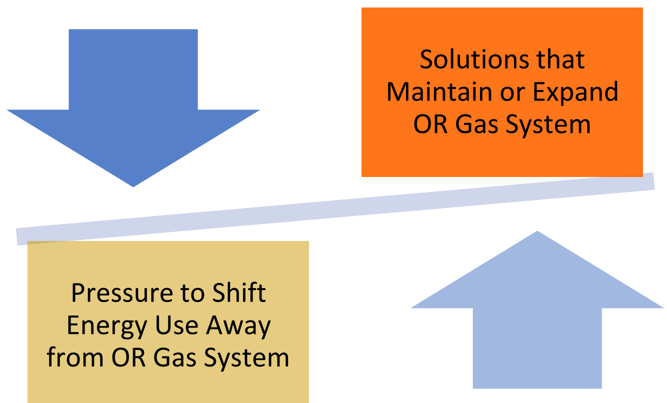
- **Momentum** for both limiting gas expansion and for gas supply innovations is accelerating.
- CPP compliance **costs and risks** to gas customers from gas utilities' compliance actions range from manageable to rather substantial by 2029, depending on the customer and their existing level of energy burden.
- CPP **compliance and decarbonization issues** that PUC activities will need to address are much better understood.
- A host of **regulatory tools** – organized into the categories of Planning, Programs, and Rate Making – are available to shape and manage the policy risks of various compliance pathways for gas utility decarbonization, and the PUC most likely has sufficient authority to implement them.
- A number of potential regulatory tools identified in this Fact Finding would require an optimization across the energy system, rather than a focus on a single fuel (i.e. natural gas or

[11] See OAR 340-271-9000, Tables 2 and 4.

electricity). Implementing such tools would require work across a variety of dockets and utilities over the next decade. For these reasons, these tools would require an unprecedented degree of internal and external **coordination and additional resources**.

3.1 MOMENTUM

The regulation of the gas industry appears to stand at a crossroad. Given the desire by most of the public to address global warming due to fossil fuel use, momentum exists for limiting gas expansion and reducing or shifting energy use away from the Oregon gas system, as well as for accelerating and deploying gas supply decarbonization innovations that maintain or expand the gas system.



The gas industry, and federal and state governments, have committed to exploring and investing in unprecedented levels of low-to-zero carbon natural gas technology solutions. These range from investments in supply solutions like Renewable Natural Gas (RNG), synthetic natural gas, and hydrogen to demand solutions like gas heat pump water heaters and furnaces.

In the opposite direction, dozens of local authorities across the U.S. – including California and Massachusetts – have adopted ordinances and building codes to advance building electrification and ban new hook-ups.[12] The purpose of these policy changes is to transition away from natural gas use so as to reduce GHG emissions and avoid costly investments in the near-term that may not be fully utilized in the future.

These two futures for the gas industry are often described as being in opposition to each other. Staff finds that it may also be the case that some combination of choices – between encouraging low-to-zero carbon gas technologic advances and regulatory actions that limit future gas customer and infrastructure growth – may best balance the various technology, cost, and regulatory risks associated with meeting the state's GHG emission targets.

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[12] *See* Appendix C - RMI Building Electrification Policy Pressures. *See also* California Public Utility Commission rulemaking R.20-01-007 (2020) and Massachusetts Department of Public Utilities Order 20-80.

3.2 MODELING COSTS & RISK

The structure of the NGFF allowed utilities and stakeholders to explore a wide range of possible compliance scenarios. As a result, participants were able to glean an understanding of the impact of various pathways, explore sensitivities, and begin the process of stress testing the reasonableness of underlying assumptions put forth by both utilities and various stakeholders.

As a foundation for all other analytic inquiries, staff asked the gas utilities to model how they would comply with DEQ's CPP. Each utility modeled three overall CPP compliance scenarios (base case, high innovation, and accelerated electrification) with multiple sensitivities. The purpose of the modeling was to understand more about the cost and timing of the strategies the companies were contemplating to meet CPP GHG emission targets. By broadly understanding how utilities might comply and the associated costs and timelines for different strategies, the Commission, staff, and stakeholders might better understand where, when, and which regulatory tools might be used to mitigate costs and risks.

There were two general points of agreement:

1. Gas utilities will need to take significant near-term action to decarbonize: "Business As Usual" growth and operations of the system result in emissions exceeding the 2035 compliance targets.
2. Any compliance pathway will very likely increase the costs of energy service for all categories of customers over the next decade.[13]

3.2.1 Scenarios as Compliance Pathways

The gas companies were asked first to model how they might envision complying with the CPP, and then to consider a set of sensitivities, which were intended to stress test the company's proposed pathway. These sensitivities tested decarbonized gas availability, decreases in the number of customers, a more aggressive policy environment, and a reduction in availability of alternative compliance mechanisms. The gas companies were further asked to model scenarios with high electrification and high levels of support for innovation as different scenarios. A summary of the sensitivities and scenarios are in Table2. Full descriptions can be found in Appendix A.

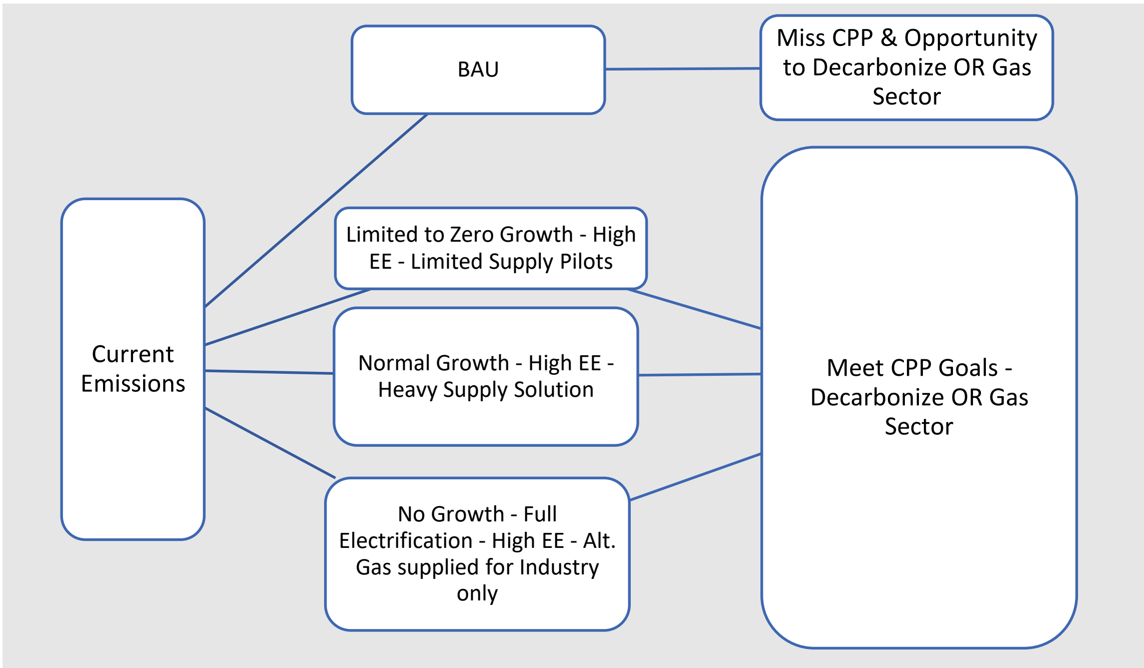
[13] As the only outlier, NW Natural's base case modeling actually projected slightly lower residential customer bills in 2050.

Table 2: Scenarios and Sensitivities

Scenarios	Base Case Scenario	Utilities model what they see as most optimal compliance pathways
	Alt. Scenario 1 – Innovation / Electrification / SCC	Modeled a PTC for green hydrogen and syngas before 2026, use of higher Social Cost of Carbon, and high electrification of buildings
	Alt. Scenario 2 – Delayed innovation / Accelerated Electrification	Lower energy efficiency (EE) technology adoption curves, limited availability of RNG, and very rapid electrification of existing customers
Sensitivities	Declining Customer Counts	Modeled sensitivities that consider zero and negative customer growth
	Aggressive Timeline	CPP targets are advanced to align more closely with HB 2021: CPP targets 45% below baseline by 2030, 80% below baseline by 2040
	No CCIs	Modeled impacts of removing CCI compliance options
	Restricted RNG	Applied constraints on assumptions about the availability of RNG to meet emission reduction goals

The scenarios represent factors that are outside utility control, such as market and policy assumption variations. Scenarios combined with sensitivities test how well compliance pathways respond when market and policy factors differ from what was thought to be most likely as represented in the base case. The various scenarios modeled produced different compliance pathways. The uncertainty in costs, performance risks, and availability of resource options for each pathway to decarbonize has raised many more questions to be addressed to ensure the planning and decision-making process supports the identification of the least-cost and least-risk approaches to future GHG emission compliance. While the gas companies, stakeholders, policy makers, and regulators must chart a pathway to meet the CPP requirements, technology costs and performance remain highly speculative. The analysis from the NGFF, while informative, made it clear that more robust modeling and rigorous vetting of resource assumptions within Integrated Resource Plans (IRPs) will be required to make informed assessments about least cost, least risk paths for compliance.

Figure 5: Compliance Pathways



3.2.2 Summary of Costs and Risks from Scenarios

All parties agreed that the rigor and analysis that comes with a full IRP[14] would be needed for more definitive modeling conclusions. While the compliance modeling often provided a wide range of results from which trends were difficult to detect, there were still many important learnings gleaned from the Fact Finding. Perhaps more than anything, this exercise helped all parties understand what information should be modeled more rigorously in IRPs and what new information should be brought into IRPs to help assess least-cost/least-risk compliance strategies.[15] In addition to a general trend of increased customer bills attributable to CPP compliance, this new information includes:

- Cost, feasibility, and ratepayer impacts of CPP specific compliance strategies.
- A need to understand the interdependency of the gas and electric systems in terms of costs and emissions that result from policies that shift load away from gas.
- The necessity to include transport customers in CPP compliance activities.
- Costs of non-compliance, while not modeled, drives understanding of risk in future planning.

(Suggested changes to the IRPs are more fully detailed in Appendix B.)

Base Case

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[14] The IRP presents a utility's current plan to meet the future energy and capacity needs of its customers through a "least-cost, least-risk" combination of energy generation and demand reduction. The plan includes estimates of those future energy needs, analysis of the resources available to meet those needs, and the activities required to secure those resources. *See* https://www.oregon.gov/puc/utilities/Pages/Energy-Planning.aspx.

[15] *See* Appendix B on Suggested changes to IRPs.

The Fact Finding's base case scenario was presented by each utility in September 2021 and represents the starting point for analysis.[16] The base cases reflect the gas utilities' preferred compliance strategies for residential, commercial, and industrial customers, given their most recent planning and what was understood about the CPP rules prior to adoption.

In the base case scenarios, annual bills increased in the near term and showed a range of outcomes. The estimated bill increases varied across companies and customer types. Additionally, the rate and direction of bill increase changed in later years of the model. CPP compliance costs to gas customers range from single digit percentages to rather substantial by 2025, depending on the customer and utility modeling. Figure 6 and Table 3 illustrate the estimated bill impacts over time.[17]

Figure 6: Annual Bill Impacts in Base Case

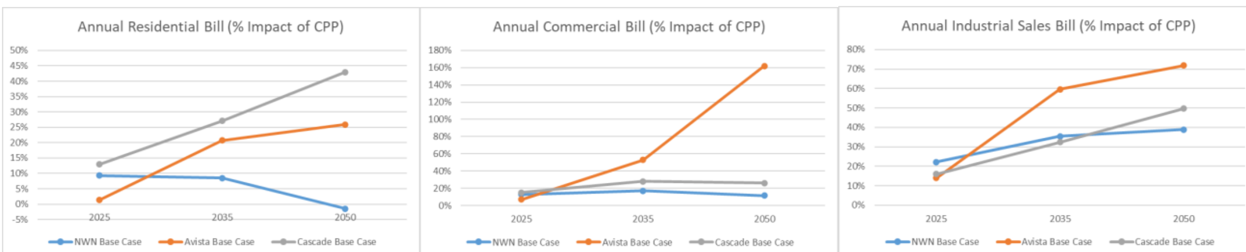


Table 3: Trends in Estimated Bill Impacts over Time

	2025			2035			2050*		
Util.	Res.	Com.	Ind.	Res.	Com.	Ind.	Res.	Com.	Ind.
AVA	1%	7%	14%	21%	53%	60%	26%	162%	72%
CNG	13%	15%	16%	27%	28%	32%	43%	26%	50%
NWN	9%	17%	22%	9%	17%	35%	-2%	12%	39%

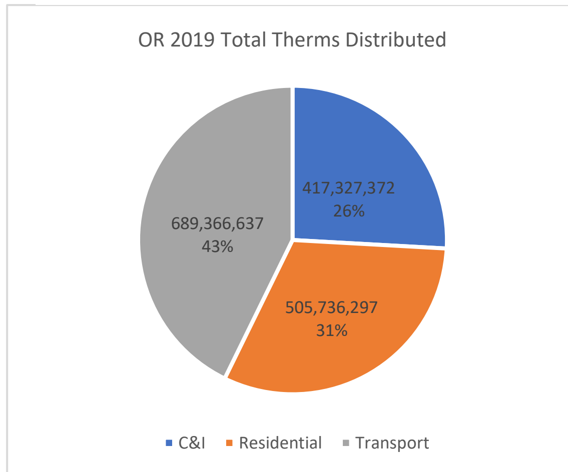
*AVA and CNG only go to 2040 so those values were used in place of 2050

[16] *See* NGFF Workshop 3 presentations and link to modeling materials available on Oregon PUC's Natural Gas Fact Finding website – https://www.oregon.gov/puc/utilities/Pages/EO-20-04-UP-FactFinding.aspx.
[17] *Ibid.*

Transport Customers

Transport customers are customers that pay Oregon's gas utilities to transport gas to their location, but that pay a gas marketer, not the gas utility, for the actual gas. However, it is the gas utility that is a regulated entity under CPP and is the entity through which transport gas emissions are regulated.

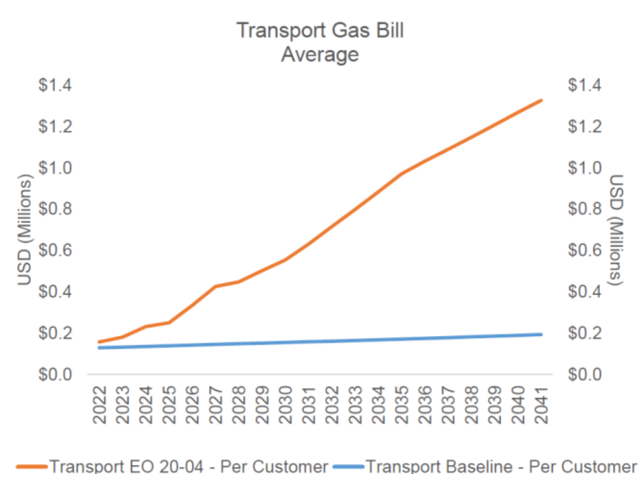
Figure 7: 2019 Total Therms Distributed



As can be seen in Figure 7, which simplifies customers into three categories, Transport customers accounted for over 40 percent of total therms distributed in 2019. With the adoption of CPP rules, the gas utility is now accountable for this large portion of emissions. This creates a situation in which the regulated gas utilities will need to consider developing more programs and activities aimed directly at reducing transport customers' GHG emissions and ways for those customers to pay for those programs.

The bills transport customers receive from a gas utility represent only a portion of their total gas costs.[18] The additional cost to transport customers from their regulated utility for CPP compliance, on a $/therm basis, appears large on a relative basis, as it is only compared to what transport customers pay now to the regulated gas utilities, which is the cost of moving their gas. It is important to note that rate spread determinations have not yet been established, and how compliance costs would be spread across all customers has not been determined.

Figure 8: Avista Base Case Transport Customer Bill Increases due to CPP



However, as an imperfect way to try to understand CPP compliance for transport customers, staff pulled from the utility modeling how an evenly spread $/therm could manifest. As an example, Avista modeled price impacts to transport customers in its base case as seen in Figure 8. Transport customers see an increase in the average bills they receive from the gas company, which reflects the increased cost of compliance per therm

[18] When representing the CPP compliance bill impacts to these customers as a percent of the bill impact, one only captures the increase to what transport customers pay to regulated gas utilities. It would not accurately represent the percent increase because it would not include the cost of the gas itself and the percent increase would appear very high, as compared to the total bill paid to the regulated gas utilities.

over the time horizon. Understanding how compliance costs could be spread is an open and unresolved issue that will need to be further explored in future cost recovery dockets. Additionally, Transport load, as well as associated emissions and compliance costs, have not previously been addressed in IRPs and will need to be captured in future gas IRPs.

Renewable Natural Gas

Assumptions about RNG (biogenic, hydrogen, and synthetic methane) costs and availability was also a topic of interest. Utilities modeled RNG use for compliance in all scenarios. Given the nascent market for RNG of various types, the use of RNG as a compliance strategy creates uncertainty and will require additional analysis of RNG costs and availability in future IRPs.[19] By 2025, the utility models projected RNG costs ranging from about $6/dekatherm to $12/dekatherm and these costs are assumed to decrease at different rates after 2025. For comparison purposes, natural gas is currently trading in a range of $3 to $5 per dekatherm.

Each of the three utilities came up with different assumptions about how much RNG they would be able to secure over time. These varying assumptions made it difficult to generalize about the costs and availability of RNG, as well as the impacts on future customer bills. However, the use of neutral third-party market information about the RNG market and other nascent compliance solutions and technologies should provide a way to reduce uncertainty around compliance costs and risks in future IRP analyses.

Declining Customer Counts

Finally, modeling scenarios with declining customer counts provided limited insights. This may be due to inconsistencies in how each company modeled assumptions about how to handle the relatively fixed costs of existing infrastructure given a shrinking customer base. For example, Cascade's modeling showed the bill impact from declining customer counts to be virtually unchanged when compared with its base case. Avista's model showed customer costs decreasing significantly in its declining customer count scenario when compared with its base case. Meanwhile, NWN's model showed a substantial increase in customer costs under its declining customer scenario. This reinforces the need to refine and standardize how such scenarios of declining customer counts should be modeled in future IRPs. The table below, summarizes the modeling results by scenario and sensitivity. More information on the modeling results can be found in Appendix A.

Table 4: Scenario Modeling Summary

Scenario	Results – high level summary
Base Case	Generally, compliance with GHG emission regulations resulted in a range of both increased and decreased customer bill impacts. The source of those bill changes varied by company and compliance strategy. There is a lot of variation in the models, which reinforces the need to look at these issues more closely in the context of a planning document such as an IRP.
Restricted RNG	Restricting RNG had mixed results – NWN modeled increased RNG prices with the restriction, resulting in higher compliance costs compared to base case. Avista and Cascade reduced how much RNG was used for compliance, which reduced their overall cost of compliance compared to their base case scenarios.

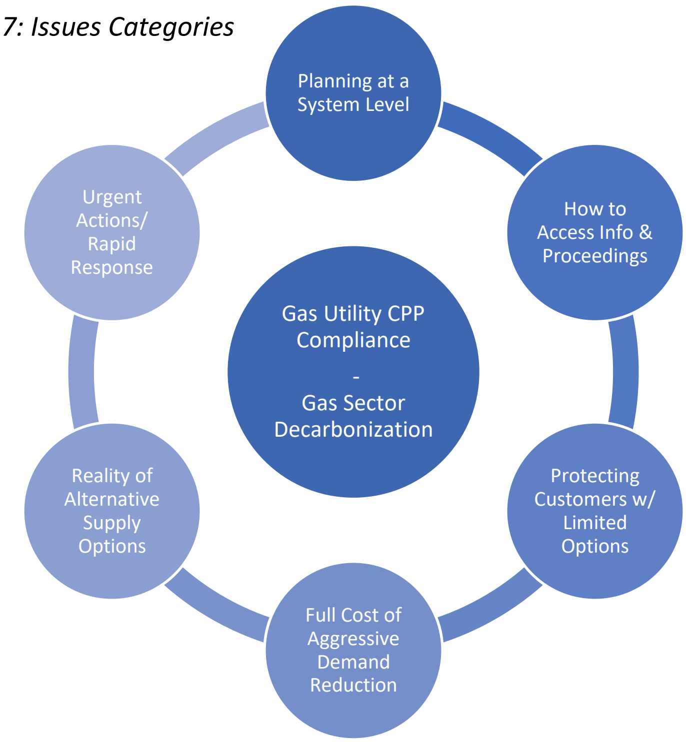
[19] *See* RNG modeling recommendations for IRP in Appendix B.

Declining Customer Counts	NWN modeling showed customer declines result in increased compliance costs above those of its base case as the years progressed. Avista compliance costs decreased with declining customers and Cascade saw costs remain almost identical to its base case.
Aggressive Timeline	NWN costs increased in the middle years of the model run but the difference between this scenario and the base case shrank as they approached 2050. Avista and Cascade's aggressive timeline model runs showed compliance costs consistently higher than in their base cases for all customer types.
No CCIs	All companies showed that the inability to use CCI's would result in higher compliance cost than in their base cases in the early years; But by 2050, the three utilities' modeling runs arrived at different conclusions, with NWN's annual compliance costs continuing to outpace compliance costs in its base case, while Avista's cost differential was shrinking, and Cascade's annual compliance costs were the same as in its base case.
Alt. Scenario 1 - Innovation	Cascade's model resulted in bill impacts that were lower than in their base case. Avista's modeling summary showed zero change in bill impacts, but the workbooks showed negative bill impacts for all customers except transport, and then compliance cost increases similar to those found in their base case. NWN's bill impacts for the scenario increased significantly due to high electrification-related customer declines, which resulted in costs not tied to energy use being spread over many fewer customers (a 318% increase in non-energy charges in 2050). There was no increase in hydrogen usage on NWN's or Avista's system because the high electrification rates reduced or eliminated the need for fuel 'innovation.' Hydrogen usage was significantly decreased as a solution for Cascade when compared to its base case. For Avista, this scenario saw its transport customers pay an increasing share of the utility's compliance costs as the utility's retail customer count declined.
Alt. Scenario 2 – Accelerated Electrification	Like Scenario 1, Cascade modeled bill impacts that were lower than their base case. Avista's summary showed zero bill impacts, but the workbooks showed negative impacts in 2025 and then similar increases to the base case by 2035. NWN modeled the most aggressive electrification assumptions, resulting in a scenario that showed a significant drop in customers on the system and a 405% increase in residential bills by 2050. NWN also showed a moderate amount of industrial EE around 2035 and the use of banked allowance credits collected before 2042 for CPP compliance in the 2040s.

3.3 Issues to Be Addressed by PUC CPP Compliance and Decarbonization Activities

The analysis of costs and risks led to the identification of several near- and long- term issues that the PUC will need to address as utilities undertake CPP compliance activities. Broadly, they can be broken into six overarching categories shown in the figure below.

Figure 7: Issues Categories



3.3.1 Gas and Electric Energy System Planning

Stakeholders identified the interconnected nature of Oregon's gas and electric systems. The attempts to model those interactions as part of this investigation proved to be beyond the limitations of the modeling and showed how difficult it would be to analyze the costs and benefits of strategies that contemplate shifting heating loads from gas to electric in Oregon as part of a single fuel utility's IRP. **To meet the state's GHG reduction targets and avoid unnecessary costs and reliability risks, the planning of both gas and electric utilities will require the sharing of key data in the near-term and the explicit recognition of planning interdependencies.**

3.3.2 How to Access Information and Proceedings

Stakeholders continually raised concerns about the complexity and resource commitment necessary to acquire key regulatory information and meaningfully engage in planning processes. Environmental justice and low-income advocates, as well as business and industry advocates, noted that to advance their perspective on gas utility decarbonization holistically and effectively, they would have to involve themselves over the next two years in many gas-related dockets. In short, **the volume of information that must be analyzed *and* the necessity to carry a consistent message across many different dockets presents a barrier to participation for many stakeholders.**

3.3.3 Protecting Customers with Limited Options

In terms of customer protection, stakeholders identified two types of customers especially at risk from higher costs because they lacked the ability to easily substitute away from the natural gas system. Those two groups were low-income residential customers and many types of businesses, large and small, reliant upon gas for specific end-use processes. For low-income customers, higher cost most likely translated to greater unavoidable energy burden.[20] For some Oregon businesses, there are limited-to-no-economic substitutes currently for certain gas end-uses. This includes emissions control technologies, outdoor heating for nurseries, and process heat to meet food safety standards. **Tools that provide targeted mitigation of certain customer bill increases, without hindering progress toward compliance, would be of high value to the process of gas system decarbonization.**

3.3.4 Full Cost of Aggressive Demand Reduction

Many stakeholders put forth ideas to rapidly reduce customer demand to meet CPP targets. Beneficial Electrification (BE) emerged as a key concept. The Regulatory Assistance Project offers this description of beneficial electrification:

> For electrification to be considered beneficial, it must meet one or more of the following conditions without adversely affecting the other two: 1.S. Saves consumers money over the long run; 2.E. Enables better grid management; and 3.R. Reduces negative environmental impacts.[21]

For residential customers, this may include replacing gas fired furnaces, stoves, and water-heaters with those powered by electric heat pump and induction technology. For commercial customers, this may include swapping an existing gas-fired boiler for an electric boiler. However, much is unknown about how to deploy BE in Oregon and what the resulting emissions and cost impacts might be to the electric system. Without careful analysis, planning, and execution, BE has the potential to shift greater energy demand, peak risk, distribution costs, and reliability concerns to electric ratepayers. Most stakeholders acknowledged that more must be learned to understand the costs and risks from BE. Conversely, with good planning, beneficial electrification could create system benefits. Other states are attempting BE pilots, and the electric utilities' IRPs and Distribution System Plans could be crafted to provide valuable insights into the tradeoffs around aggressive demand reduction actions for both gas and electric ratepayers. **Tools that facilitate a coordination between gas IRPs, electric IRPs, and Distribution System Plans may enable analysis of customer costs, grid management, and emission impacts of load reduction associated with load shifts.**

3.3.5 Alternative Supply Options and Availability

Each utilities' base case CPP compliance modeling relied on decarbonizing the fuel they provide through large amounts of RNG, green hydrogen, and/or synthetic gas. These supply-side alternatives to natural gas currently represent a significant part of each companies' compliance strategy. Notably, large-scale hydrogen availability at a reasonable price is necessary in less than 15 years.

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[20] *See* Oregon Department of Energy, Legislative Report 2021, pg. 18. Defines Energy Burden as "…the percentage of household income spent on energy and transportation costs." It's used as an indication of energy affordability, and anyone paying more than 6 percent of their household income on energy is considered energy burdened. According to the 2020 Biennial Energy Report's Energy 101: Equity and Energy Burden, about "25 percent of Oregon households are energy burdened – and that's based on numbers from before the COVID-19 pandemic."
[21] Farnsworth, D., Shipley, J., Lazar, J., and Seidman, N. (2018, June). Beneficial electrification: Ensuring electrification in the public interest. Montpelier, VT: Regulatory Assistance Project.

Table 5: Alternative Supply Projections

Utility	RNG Supply Penetration by 2025		RNG Supply Penetration by 2035	
	Volume (Dth/year)	% of Deliveries	Volume (Dth/year)	% of Deliveries
Avista	317,875	2%	2,932,134	40%
Cascade Natural Gas	1,544,229	10%	6,673,003	26%
NW Natural	4,842,842	4%	8,399,503 **(bio)** 13,551,224 **(H2)**	23%

Many stakeholders believed the quantities and the timeline of availability put forth by the companies were not realistic. Further, they made the case that relying on these natural gas alternatives placed a tremendous amount of compliance and financial risk on the companies, and thus ratepayers, in later years, as it allows for the continued expansion of the gas system with the promise of future low-to-zero GHG fuel supplies. Further work is needed to understand how speculative or certain such projections of alternative fuels might be, and who might carry the risks of relying on developing decarbonized gas to meet CPP goals. **To inform risk assessments, it will be important for the Commission and stakeholders to monitor, track, validate, and report market trends and forecasts for alternative gas availability and costs in planning dockets and rate cases.**

3.3.6 Need for Urgent Action/Rapid Response

Gas utilities face an immediate, urgent need to develop and deploy strategies to meet near-term CPP compliance obligations. We heard interest in exploring how the PUC could facilitate the deployment and cost recovery of nascent technologies to decarbonize fuels and improve energy efficiency, as well as exercising new policy direction to promote fuel switching to reduce natural gas use.

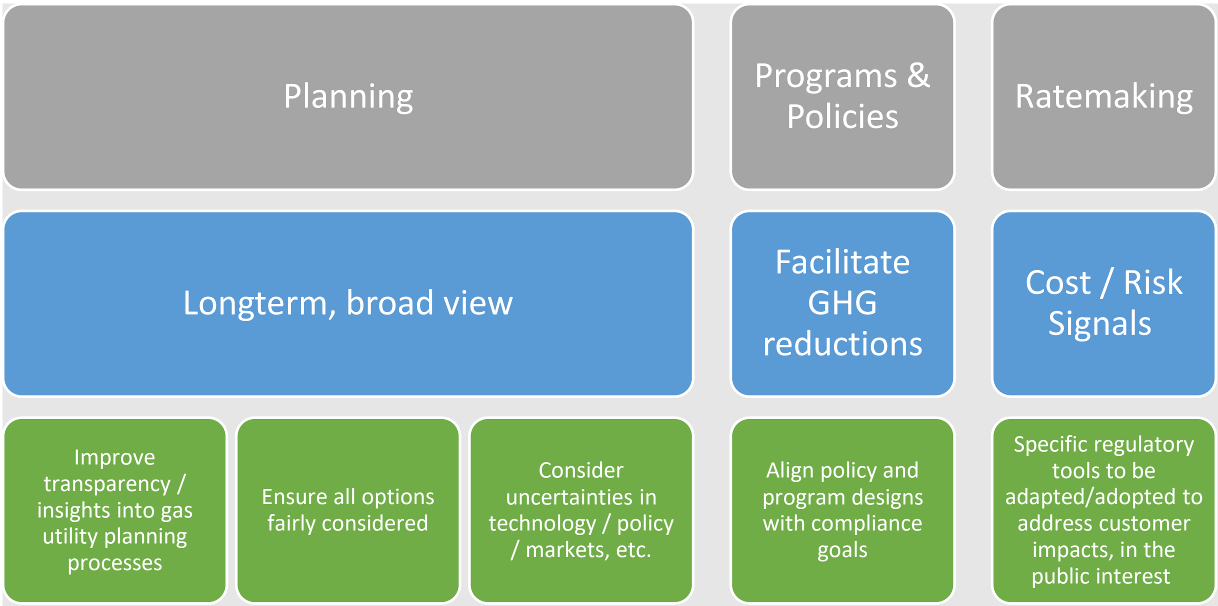
Because of the high levels of uncertainty inherent in developing new policy and installing new technologies, deploying regulatory tools that both open the doors for novel solutions and reduce customer risk exposure will be a challenge. While the Commission has some existing tools at its disposal, some will need to be used successfully for the first time (e.g., SB 844, which allows gas companies to receive financial incentives for GHG emission reductions activity costs that are outside their normal course of business) and others may need to be revisited to explore the boundaries of what is possible within them (e.g., ETO energy efficiency programs). **Regulatory tools that provide incentives for action while managing risk, and risk expectations, may help facilitate the rapid response needed to meet CPP targets while protecting customers.**

4 Regulatory Tools

In this proceeding, staff, stakeholders, and utilities, led by the Regulatory Assistance Project (RAP), explored regulatory tools that could be used to address the customer impacts while meeting CPP targets.

Staff relied on a framework provided by RAP (summarized in Figure 10) to organize categories of tools and explore the benefits and tradeoffs associated with the different tools. These categories include three types of tools: planning, programs, and ratemaking. They provide signals to customers about system costs and goals. This section gives a high-level overview of each of these categories (additional information is included in the workshop materials).

Figure 8: Categories and Goals of Regulatory Tools



4.1 Planning Tools

Oregon has robust Integrated Resource Planning (IRP) processes for both its gas and electric utilities.[22] Nevertheless, as the energy system is evolving in response to price signals and targets as set forth in the CPP and HB 2021, planning requirements can also evolve to ensure that they are responsive to changing circumstances. Several options for amending current planning requirements were discussed over the course of the investigation. This included both changes that could be made within current guidelines and ideas for adding new requirements. A promising example of a new planning tool that falls within current guidelines includes explicitly requesting gas and electric utility planning processes to analyze scenarios that cut across their service areas. This would include requiring the use of common assumptions to model the cost and emission impacts of high electrification scenarios.

4.2 Programs

Utility programs, like energy efficiency or green hydrogen pilots, offer opportunities to address challenges within an evolving system. The Fact Finding workshops provided an opportunity to consider ways in which the Commission could revisit current programs while ensuring alignment with customer and system needs to comply with CPP requirements. The importance of prioritizing solutions that addressed considerations of equity was emphasized by stakeholders, as was the possibility of exploring pilots to test key uncertainties around new technology (e.g., gas powered heat pumps; green hydrogen production; etc.).

[22] *See* Order No. 07-002 and Errata Order No. 07-047 for a list of the IRP guidelines that drive the IRP process.

4.3 RATEMAKING TOOLS

The final category of tools are reforms to gas ratemaking that can direct how investments are incentivized and socialized, limit cost-shifting across rate classes, or protect certain customers from increased energy burden. Several approaches were discussed, including:

- Updating when, where, and the extent to which customer contributions to line extensions are shared or targeted. Many stakeholders noted future uncertainty about the extent of network utilization and how much and what type of gaseous fuel will flow through that network.
- Aligning asset depreciation timelines with anticipated use over a decarbonization timeline. Depreciation expenses are normally spread over an asset's projected lifetime. Changes to depreciation timelines thus affect the revenue requirement and send a signal about the usefulness of specific assets over a longer timeframe. For example, accelerating depreciation expenses to front-load cost recovery leads to rate increases in the near-term, but avoids the future problem of recovering fixed costs from fewer and fewer customers if customers leave the system.
- Rate design that induces reductions at periods of peak demand, including peak season or peak day prices or inclining block structures, can encourage energy efficiency or align usage with GHG emission reduction targets.
- HB 2475 allows the Commission to consider rate structures for separate classes or sub-classes of customers based on energy burden in rate cases. Such rate structures could provide discounts to mitigate effects of higher bills due to the CPP. To this end, NW Natural's and Avista's general rate revision proposals, currently being reviewed by the PUC, include differential rate proposals.[23]
- Changing the utility's business model motivations can also help align utility behavior with transition targets. For example, future rate adjustments could shift from being deferrals related to the cost of CPP compliance to being associated with achieving CPP targets.
- Performance-based regulation, in addition to currently utilized decoupling, could allow the Commission to consider desired goals and outcomes and then to design metrics to meet those goals.

Staff finds current PUC authority likely sufficient to apply all of the regulatory tools found in the categories of planning, programs, and ratemaking to support and shape any number of CPP compliance pathways. However, some of the tools require new resources and a coordinated, strategic focus to both develop and implement across dockets and utilities, as they call for optimization across Oregon's entire energy system, not just a single fuel.

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[23] *See* Docket No. UG 433 (Avista) and Docket No. UG 435 (NW Natural).

5 Staff Analysis and Recommendations

The compliance modeling, workshops, and stakeholder input gave staff an excellent set of raw materials from which to analyze costs, risks, and implementation options. The analysis and considerations below are meant to serve as an initial guide into the application of the identified regulatory tools.

5.1 Reality of Rate Pressure Risk

Staff believes compliance with the CPP will very likely increase costs to all customers in the near-term, and the modeling suggests it may have differing impacts. The extent of rate impacts depends upon the type of customer, compliance strategies deployed, and gas company characteristics.

While utility modeling showed a range of customer impacts from CPP compliance, in the absence of some form of intervention, the greatest burden from any increased bills will likely fall to those already experiencing high energy burdens. All stakeholders involved in the workshops expressed concern about the potential impacts that will result from further burdening low-income and other at-risk customers. Further, the risk is not limited to gas customers. Initial analysis and research point to electrification costs, for either new or existing gas customers, spilling over into ratepayer impacts on electricity customers as well.[24]

The rate pressure risk grows beyond just the cost of compliance. Two other risks stand out in staff's analysis. The first is the rate pressure risk from penalties due to non-compliance (discussed below). The second is the risk of customer migration to the electric system. If customers leave the gas system, the cost of gas infrastructure must be spread over a smaller customer base. The potential for a feedback loop emerges, where increasing cost due to a shrinking customer count potentially accelerates more motivated and affluent customers to leave the gas system.

To this end, staff conducted its own investigation of residential customers' propensity to connect or disconnect from the natural gas grid.[25] Our research into the elasticity of residential demand confirmed two things: 1) Decisions to depart the system happen only after sustained price increases and generally lag those increases by two to three years, and 2) Cost increases will be felt more acutely by energy burdened customers because their options to respond to price signals are limited. Communications about the permanency of CPP compliance costs and Oregon's commitment to decarbonization may have an impact on the lag in gas consumer decisions.

Finally, regarding declining customer counts, staff would note that Oregon's current regulatory structure, and recent experience in the telecom industry, creates some level of institutional bias toward recommendations that maintain customer counts. This is due to how rate spread and rate design is conducted. Staff analysis shows that activities that decrease customer counts force fixed costs to be spread across fewer customers, exacerbating energy burden for those customers that cannot transition. Oregon's telecom experience over the past 25 years may serve as an example of regulatory problems when a subset of customers cannot transition away from a monopoly experiencing negative growth.

[24] Gridworks Central California Pilot of CPUC. https://gridworks.org/2021/09/lessons-learned-so-far-in-targeted-building-electrification/.

[25] See Appendix D – Elasticity.

Utility modeling suggested that there could be significant cost impacts to commercial, industrial, and transport customers, not just residential customers. For some commercial and industrial gas customers, slight increases in fuel prices are difficult to pass along to their customers without significantly risking their place in the market and as such, need to be absorbed by the company. Potential increases in costs to industrial and commercial customers could have negative externalities for which policy interventions may be justified.

CPP compliance creates rate pressure risks that could exacerbate energy burden issues – for many types of customers. It will largely fall to the PUC, all utilities, and well-informed stakeholders to strike the proper balance of investments to achieve CPP compliance and decarbonize the Oregon gas sector.

In light of this analysis, staff recommends regulatory tools that mitigate near-term price increases, limit long-term risks, and fairly manage any transition to new technologies. Potential solutions are discussed below.

5.1.1 Protecting Customers With Limited Options

Staff identified the following near-term actions that could help protect customers from bill increases.

<u>Planning</u>

- Include estimated customer bill impact analysis in IRPs to ensure transparency of trends and implications of compliance pathways as represented in portfolios.

<u>Programs</u>

- Direct Energy Trust of Oregon (ETO or Energy Trust) and Community Action agencies to work with utilities to expand and target energy efficiency programs to low income and environmental justice communities to reduce energy burden and minimize anticipated bill impacts. This would include conducting outreach with targeted customers to receive input on program designs to maximize effectiveness.
- Prioritization of incremental energy efficiency for CPP compliance that lowers natural gas usage but allows for customer count growth to continue at some level so as to avoid near-term outcomes that place upward rate pressures on those customers unable to exit the gas system and would therefore be forced to cover an increasing proportion of fixed costs.
- Ensure the gas utilities either fold transport gas customer into existing efficiency programs or into new programs, paying their fair share relative to what other ratepayers pay for energy efficiency programs.

<u>Rates</u>

- Develop and adopt a HB 2475 bill discount and implementation regime that will mitigate rate increases for energy burdened customers.
- Align near-term investment levels with annual progress in CPP compliance in order to limit uncertainty around accumulation of long-term capital assets.

5.1.2 Full Cost of Aggressive Demand Reduction

Staff believes the following tools could be used to facilitate coordination between gas and electric utilities to enable analysis of customer costs, grid management, and emission impacts of load reduction associated with aggressive gas demand reduction.

Planning

- Develop marginal abatement cost curves for IRPs that identify all resources potentially used by utilities in CPP compliance.

Rate making

- Explore rate spread and rate design issues for transport customers in general rate cases.

5.2 Coordinated Communication and Stakeholder Access

Much like the outcome of the PUC's 2018 SB 978 report,[26] community-based and business organizations interested in impacting PUC and utility CPP decisions noted the difficulty in achieving procedural inclusion across the spectrum of gas dockets. Staff agrees that these participants have a point. The nature of Oregon's utilities (single fuel utilities) and existing planning processes (single company Integrated Resource Plans) make it difficult to evaluate risk, outcomes, and impacts of compliance strategies, and make it challenging for some impacted stakeholders to engage in the process.

For example, to effectively drive their policy perspective and engage with each gas utility, these groups would have to dedicate additional resources to participate in some mix of the following over the next three years alone:

Three IRP dockets	Three IRP updates	Three depreciation dockets	Three purchased gas adjustment dockets
Every filed gas rate case	Deferrals for RNG, hydrogen, and synthetic gas projects or pilots	Deferrals for design and implementation of low-income gas differential rates	Energy Trust's annual budget and goal setting process.

As noted in Section 3.3.2, the sheer volume of information moving through so many dockets simultaneously creates a barrier to effective participation by stakeholders.

In light of this analysis, staff recommends solutions be evaluated by their ability to involve, communicate with, and enable the particpation of new or resource-limited stakeholders.

5.2.1 Access Info and Proceedings

The following activities will improve stakeholder's access and awareness of gas utility's information and proceedings.

Planning

- Staff should post quarterly updates and any annual CPP compliance reports in UM 2178 and on the PUC website for stakeholders that track gas docket activities and note how and when stakeholders could get involved.

[26] Oregon PUC. SB 978 – Actively Adapting to the Changing Electricity Sector. September 2018.

- Require the gas utilities to develop in their next IRPs, publicly available maps of their system overlaying depreciation data and including lists of infrastructure and associated depreciation schedules.

Ratemaking

- Ensure full stakeholder engagement in dockets considering rate basing of RNG, Automatic Adjustment Clauses, and Affiliate Interest applications through outreach led by the DEI Director.

5.3 Decarbonization Policies as Key Determinants to Planning and Cost-Recovery

The GHG emission reduction targets with the passage of HB 2021 and the adoption of the CPP rules reshaped Oregon's energy policy landscape, especially for utility resource planning. Three immediate impacts emerged in staff's analysis.

First, for resource plans to be consistent with the long-run public interest and Oregon energy policy, a "least-cost, least-risk" IRP must now also demonstrate how a utility will achieve state-set, utility-specific emission reduction targets and at what cost. From staff's perspecitve, utility GHG emissions and the risk of non-compliance with the CPP, will be critical performance metrics in determining the efficacy of utility investments and the prudency of operational decisions.

Second, resource planning will increasingly require systems thinking.[27] Oregon's carbon reduction goals cement the interrelatedness of gas and electric utility operations decisions more than ever before. Increasingly, utilities, stakeholders, and the PUC will need to consider the energy system and ratepayers on the whole. Key policy decisions can easily have consequential, systemwide feedback loops that span beyond an individual gas or electric utility's IRP or operations. For example, a policy to electrify existing gas customers could have knock-on effects to electric utility winter reliability, HB 2021 compliance, and electric ratepayer costs. However, understanding cost and emission impacts across utilities proves challenging in Oregon's resource planning environment as interplaying impacts are not readily apparent or captured by the current planning processes.

To meet the state's GHG reduction targets and avoid unnecessary costs and reliability risks, the integrated resource planning of both gas and electric utilities will require the sharing of key data and the explicit recognition of planning interdependencies. To address this issue, staff identified the following applicable near-term actions.

Planning

- Request gas and electric utilities to develop and articulate individual electrification assumptions in future gas and electric IRPs that others can reference.
- Given that electrification, as a potential compliance pathway, involves costs at the distribution level of the electric system, staff will work with electric utilities to include in either their August 2022 Phase 2 DSP filings or other future DSP filings, the cost elements, costing methodology, and estimated average distribution cost to electrify existing gas customers.
- The PUC should contract with an independent third party (e.g., consulting firm or regional non-profit like NEEA) to evaluate market trends around alternative fuel and low-carbon technology

[27] Systems thinking is defined as a way of making sense of the complexity of a situation by looking at it in terms of wholes and relationships rather than by splitting it down into its parts.

cost and availability and to analyze Pacific Northwest market adoption of decarbonization technologies that are central to any utilities' CPP compliance pathway on a regular basis to inform utility planning.
- Staff to treat CPP compliance as an acknowledgeable element of any future gas IRP or IRP update.
- Staff recommends exploring in the future the use of the IRP guidance found in Appendix B. Staff will seek a waiver to adopt this new guidance where it conflicts with existing IRP guidance in Order Nos. 07-002 and 07-047 or existing GHG planning guidance in Order No. 08-339.

Rates

- PUC Rates, Finance, and Audit (RFA) staff and Oregon Department of Justice are to explore with gas and electric utilities an interim, easily implemented approach to line extension allowance policy in future upcoming gas and electric rate case dockets that reflects the benefits, costs, and risks associated with system growth or improvements relative to the state's policies on decarbonization.

5.4 Risk and Uncertainty Warrant Robust Monitoring, Tracking, and Reporting of Utility Compliance and Broader Market Trends

As noted in Section 3.1, there is considerable pressure for natural gas utilities to initiate robust decarbonization plans while there remains numerous uncertainties around the form, cost, and pace of change that is needed. Amidst this backdrop of uncertainty is a constant: the near-term risk of non-compliance with the CPP.

This is not an abstract concern. The compliance regime for the CPP has already begun. In just over three years, the DEQ will close the first compliance period and assess fuel supplier performance, including the gas utilities, over the preceding three-year period. During this first compliance window, there is a 10 percent limit on the use of the alternative compliance mechanisms (a.k.a., CCIs), no weather-adjustment, and no roll-over of unmet reductions to the next three-year compliance period.

Further, the CPP rules grant the DEQ broad discretion to impose penalties.[28] While the DEQ has not yet announced how it will apply penalties, the PUC staff's operating assumption is that the floor of any non-compliance penalty should be at least the cost of a CCI on a per metric ton basis. For the current three-year compliance period, the average cost of a CCI as an alternative compliance mechanism will be approximately $108/metric ton, unadjusted for inflation.[29]

Imposing a penalty at the CCI price on a per metric ton basis poses a potentially sizeable, near-term, financial risk to the gas utilities. The table below attempts to characterize this financial impact.

[28] OAR 340-271-0010.
[29] See OAR 340-271-9000. Table 7.

Table 6: Potential Impact of Missed Compliance

Utility	3-Year, CPP Emissions Allowance[30] (Metric Tons)	1.5% CPP Exceedance (Metric Tons)	1.5% Exceedance in Gas Sales (Therms)	Potential 2025 Fine @ Avg. CCI $/Metric Ton		Comparator: *2020 Operating Expenses*
AVA	2,028,960	30,434	5,636,000	$3,286,915		$96,658,000
CNG	2,145,309	32,180	5,959,192	$3,475,401		$48,930,000
NWN	16,615,303	249,230	46,153,619	$26,916,791		$402,484,000

Table 6 shows the emission allowances for each utility in the first three-year compliance window and what a seemingly small amount of non-allowed emissions might cost. If gas companies emitted 1.5 percent more emissions than they were allowed, and the penalty for each metric ton of emission overage was set at the average price of using a CCI for compliance, gas companies could be looking at a fine at the end of the first compliance period that is between three and seven percent of their operating expenses in a given year.

The resulting uncertainty and possible financial risk highlight the need for robust monitoring, tracking, and reporting of both the efficacy of compliance strategies and market developments informing the selected compliance strategy. For reference purposes, each gas utility put forth their preferred strategy to achieve compliance by 2025 in this docket. The table below summarizes each utility's preferred 2022 through 2024 compliance strategy by element.

Table 7: Total Aggregate Reduction for 2022 through 2024 Period by Strategy

Utility	Aggregate 3-Year, CPP Emissions Reduction Goal		Additional EE/DR			RNG			CCI		Other			Total
	(Tons Reduced From Baseline)		%	Dth	Tons	%	Dth	Tons	%	Tons*	%	Dth	Tons	Tons*1
AVA	188,282		7%	251,710	13,985	12%	-	23,095	81%	153,521	2%	75,148	3,973	190,601
CNG	249,567		14%	655,882	34,801	9%	403,350	21,402	77%	193,364				249,567
NWN	759,354		14%	2,007,951	106,542	51%	3,657,331	386,279	35%	264,718				757,539
	Totals			2,915,542			4,060,681			611,603		75,148		

** - ton equivalent for CCIs*

**1 - Modeled totals may not equal the Aggregate 3-Year CPP Emission Reduction Goal.*

The emissions levels set for the first compliance window (2022 through 2024) require that the gas utilities accomplish what appear to be achievable emission reductions with all three companies making use of allowed CCIs to aid overall company compliance. Perhaps the two biggest near-term challenges will be their reliance on RNG and building the compliance-related infrastructure for the 2025-2027 time period. To this end, NWN is actively pursuing RNG projects, and both Cascade and Avista have indicated in their most recent IRPs that RNG is a resource they have begun pursuing and that the Commission should expect to see it in their forthcoming IRPs.

By comparison, the GHG emission reducing resources required by the end of the second compliance window (2025 through 2027) are substantially larger than the first compliance window. As shown in Table 8, collectively, Oregon's gas utilities will have had to have discovered and captured:

- 61.6 million Dekatherms of additional avoided demand with energy efficiency and demand reduction,

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[30] Calculated using the numbers in OAR 340-271-9000. Table 4.

- 30 million Dekatherms of biogenic RNG,
- 1.7 million CCI credits,
- 920,000 Dekatherms of hydrogen, and
- 300,000 Dekatherms of avoided demand with other programs.

Table 8: Total Aggregate Reduction for 2022 through 2027 by Strategy

Utility	Aggregate 6-Year, CPP Emissions Reduction Goal	Additional EE/DR			RNG			Hydrogen			CCI		Other			Total
	(Tons Reduced From Baseline)	%	Dth	Tons	%	Dth	Tons	%	Dth	Tons	%	Tons*	%	Dth	Tons	Tons
AVA	630,153	7%	835,252	44,156	19%	2,780,979	119,785	8%	919,771	48,624	64%	410,229	3%	377,496	19,956	642,751
CNG	812,939	12%	1,816,124	96,364	43%	6,600,449	350,220	0%	-	-	45%	366,356	0%			812,939
NWN	3,537,123	20%	79,987,893	701,017	38%	25,264,527	1,340,536	0%	-	-	42%	1,483,624	0%			3,525,177
	Totals		82,639,268			34,645,955			919,771			2,260,210		302,348		
	Additional from first compliance window		61,639,346			30,148,407			919,771			1,648,606				

With under six years before such solutions need to be in place, and recognizing the effort involved in deploying new solutions, the gas utilities will need to move at an unprecedented scale and speed to meet these emission reduction goals. To manage and mitigate ratepayer risk, the Commission will need to regularly assess and validate performance of the utilities' preferred compliance strategies so course corrections can be made quickly, if necessary.

While each utility is unique and must be afforded the space to choose how they meet CPP compliance, they all function within the same set of market and regulatory constraints. Staff found the divergent forecasts of technology progress and the market availability of alternatives in the utilities' compliance strategies somewhat perplexing and unhelpful overall given the market they share. This highlights the uncertainty that remains around utility compliance strategies and the associated risks of entirely independent planning processes. Given the time constraints of the CPP goals, staff believes the IRP process of each utility individually assessing technology progress and forecasting alternative fuel availability may be inefficient and lead to counterproductive outcomes in planning to meet compliance needs.

To inform risk assessments, staff believes the following tools would help the Commission and stakeholders monitor, track, and incorporate market trends and forecasts for alternative gas availability and costs.

<u>Planning</u>

- Develop an annual PUC report to Commissioners, linked to the DEQ's annual GHG reporting used for CPP compliance, that monitors, tracks, and reports on gas utility CPP performance comparing forecasted versus actual emission reductions and CPP costs.

<u>Rates</u>

- Utilities submit annual report on full CPP compliance costs, including alternative supply options such as RNG for all customers, including transport customers, as part of purchased gas adjustment or some other annual filing for tracking and planning activities.
- Explore linking the amortization of CPP compliance costs from deferrals to actual CPP performance.

5.5 Actively Incentivize or Facilitate GHG Emission Reduction Pathways

The base case long-term compliance strategies of the utilities all rely on growing amounts of RNG, green hydrogen, synthetic biofuels, and new energy efficient gas equipment technologies. By doing so, these strategies mitigate the need for electrification and placing limits on new customer hook-ups. However, stakeholders noted that aggressive electrification strategies and placing limits on new customer hook-ups should be considered as actions to reduce gas system emissions as an alternative to putting effort into reducing the carbon content of gas service. In either approach, the potential variance around the future cost, availability, and market adoption of new technology makes the efficacy of these compliance strategies highly uncertain. Further, nearly every pathway – from renewable hydrogen to aggressive electrification – will require thoughtful but rapid piloting and implementation. And in many cases, pilot projects may require significant coordination across gas and electric utilities.

Staff feels it is important for the Commission to place a near-term premium on flexibility in exploring a range of strategies, regardless of the implementing party. Feedback from these projects – and from DEQ annual compliance reporting – will help inform planning and prudency determinations.

In short, current levels of uncertainty do not preclude exploration, but rather rapid experimentation and evaluation paired with market research.

Staff believes the following tools can help provide incentives for action while managing risk and risk expectations to facilitate the rapid response needed to meet CPP GHG emission reduction requirements while protecting customers.

Planning

- Encourage and support the use of SB 844 to encourage actions to reduce GHGs that may not currently be cost-effective, but that advance the piloting and deployment of new technologies.

Programs

- Adopt a compliance cost of carbon into gas energy efficiency avoided costs that reflects CPP-related risks in order to accurately value and support energy efficiency opportunities and investments.
- Request the gas and electric utilities explore studying the development of a joint pilot for Green Hydrogen production and present their findings to the Commission before January 2025.
- Direct Energy Trust:
    - To expand training vendors on electric and gas heat pump technology through education and pilots and increase the marketing of heat pump technology on its website. This includes dual-fuel and gas-powered heat pump technology.

5.6 Match PUC Commitments to Available and Dedicated Resources

Analysis:

Many of the proposed regulatory solutions to key issues require a commitment of resources. Currently, the PUC lacks staffing to implement such regulatory tools as: joint-utility planning, or initiating substantial new investigations, or studies for such important things as beneficial electrification, fuel switching, or a more comprehensive and holistic approach to infrastructure investments (e.g., line extension allowances) in an era of rapid decarbonization.

Competing priorities from the implementation of new work under HB 2021, HB 2165, HB 2475, and HB 3141 make it difficult to pursue any large-scale, cross-cutting regulatory tool development or new gas decarbonization dockets at current PUC staffing levels. The near-term application of many of the far-reaching regulatory tools identified here can only be accomplished within existing dockets at this time. The PUC must match its commitments to available and dedicated resources in order to ensure its chosen investigations and regulatory decisions deliver productive, timely results.

5.7 Roadmap Summarizing Staff's Near-Term Recommendations

Staff's recommended next steps are informed by a combination of many things and represent near-term activities to undertake in 2022 and 2023 to address the issues identified earlier in this report. The regulatory actions were identified through our Fact Finding effort.

Table 9: Roadmap of Near-Term Actions to Address Issues

Section 5 Analysis	**Recommendation**	**Issue from Section 3.3**	**Regulatory Tool**		
			Planning	Programs	Ratemaking
Protecting Customers	Estimated Bill impact	Protection	X		
	Direct ETO to target programs to LI and EJ	Protection		X	
	EE measures that allow for customer hook-ups	Protection		X	
	EE programs to include transport	Protection		X	
	Continue development of HB 2475	Protection			X
	Align near-term investments with CPP compliance	Protection			X
Full Cost	Develop marginal abatement cost curve	Full Cost of Reducing Demand	X		
	Transport customer cost of compliance in rate cases	Full Cost of Reducing Demand			X
Access and Info	Quarterly stakeholder updates in UM 2178	Access	X		
	Maps in next IRPs	Access	X		
	RFA docket outreach through DEI Director	Access			X
Decarb Planning & Cost-Recovery	Utilities articulate electrification assumption in IRPs	Systems Approach	X		
	Electrification info and data from DSP	Systems Approach	X		
	Independent 3rd party analysis of key tech and market assumptions used by all 3 utilities	Systems Approach	X		
	CPP as an acknowledgeable item in IRPs	Systems Approach	X		
	Exploring IRP guidance from UM 2178	Systems Approach	X		
	Line extension policy exploration	Systems Approach			X
Monitoring, Tracking, and Reporting	Annual PUC report based on DEQ compliance filings	Systems Approach	X		
	Annual utility report on CPP compliance costs	Access	X		
	Enhance tracking of alternative supply of actual costs and report to planning	Access			X
	Explore linking CPP amortization to CPP performance	Protection			X
Incentivize GHG reduction pathways	Encourage use of SB 844 for Pilots	Urgent Action	X		
	Compliance costs into EE AC	Urgent Action			X
	Joint pilot for Green Hydrogen by 2025	Urgent Action			X
	ETO Expand vendor training for <u>all</u> heat pump tech	Urgent Action			X

6 CONCLUSION

This investigation focused on establishing an initial understanding of the impact of the CPP on the gas utilities and their customers and which mix of regulatory tools should be considered to achieve compliance while mitigating certain cost impacts. The timely modeling completed by each gas utility and the constructive engagement by dozens of stakeholders resulted in an initial analytic foundation from which to guide and assess compliance strategies and initial long-term plans.

Meeting the emissions targets in the CPP is an imperative and will ultimately bring benefits from a climate perspective. It may also bring benefits at the individual level that have not yet been closely analyzed by the PUC but may be analyzed in future investigations. However, modeling done by the gas utilities provided understanding both about the nature of the impacts of compliance with the CPP and existing barriers to assessing and mitigating energy decarbonization risk in planning more broadly. It is highly likely that most if not all CPP compliance strategies will come with increased costs and risks that must be monitored and tracked, and when appropriate, mitigated. If correctly done, the transition to a decarbonized gas sector can create benefits and long-term cost savings for customers and the Oregon economy.

The issues identified by stakeholders and staff and the suggested next steps are driven by the urgent need for action. Collectively, Oregon's three gas utilities must find and secure approximately 1.2 million metric tons of GHG emission reductions by 2025. Further, the pressure for near-term emissions reductions increases greatly after 2025. By 2028, in less than six years, an additional 3.8 million metric tons of new GHG emission reductions must be secured. Solutions – be they supply oriented or demand reducing – must scale quickly in the near-term. Despite uncertainty around the efficacy and long-term cost trends of compliance tools, the pace of necessary emission reductions will likely require utilities and customers to assume increased levels of risk over the next ten years.

Feedback from both the utilities and other stakeholders throughout the process made it clear that this urgency is understood. Stakeholders agreed that regulatory tools should facilitate strategies that result in real reductions in GHG emissions and that they should do so in ways that seek to minimize costs and risks. All stakeholders supported compliance strategies and associated regulatory tools that reduced gas use per customer. Staff believes that customers, especially low-income customers, are best protected with compliance strategies and regulatory tools that reduce compliance uncertainty at relatively low-cost in the near-term and maintain compliance flexibility.

Further strategy-specific regulatory tools that attempt to address uncertainty, costs, and risks associated with compliance also bring their own risks. As the utilities, stakeholders, and the PUC gain experience from implementation of tools and strategies for compliance in individual utility dockets over the next few years, it will also be important for staff and/or the Commission to identify a future docket where a comprehensive dialogue can occur among all stakeholders around the collective efficacy of CPP compliance as a group. A notable juncture to bring all stakeholders and utilities together for such a group conversation – like what has happened in UM 2178 – would be in late 2024, which will be toward the end of the CPP's first, three-year compliance period.

Finally, staff believes the state's new emission reduction targets for fossil fuel suppliers via DEQ's CPP, and for electric utilities via HB 2021, are of paramount importance to the state while being indicative of future climate policies regionally and federally. Within the bounds of the PUC's current resources and utility regulatory structure, staff recommends regulatory tools that build on lessons learned and seek to address many of the issues identified through this Fact Finding. These recommendations include actions that mitigate ratepayer impacts by looking holistically at energy system planning in Oregon; are effective, efficient, and equitable; and that generally strike a balance between managing risk and encouraging action.

Appendices

7 Appendix A: Scenario Descriptions

7.1 Modeling Direction: Deliverables, Sensitivities, and Alternative Scenarios

A key component of the PUC's Natural Gas Fact Finding (NGFF, Fact Finding, or UM 2178) was the development of Compliance Models to establish a range of potential costs associated with achieving the goals of DEQ's Climate Protection Program (CPP). The development of this data served as the foundation for identifying and assessing which regulatory tools may be needed in the future by the utilities and the PUC to support the CPP and natural gas utility decarbonization.

The launch and completion of the utility Fact Finding modeling occurred before two key events: each utility's Integrated Resource Plan (IRP) and the finalization of DEQ's CPP in rules. Because of this, the utilities lacked the latest IRP information, the time and resources to run full IRP models, and complete certainty of important operational details. Thus, staff informed all Fact Finding participants that while the accuracy of any modeling cost estimates would be limited, the information would be valuable going into 2022. In that year, CPP compliance would begin, and each utility would begin development – and for NW Natural, completion – of their next IRPs. The information from the Fact Finding would serve to foreshadow utility compliance strategy and the direction and magnitude of compliance potential costs, in addition to starting an important dialogue among all stakeholders about the application and efficacy of regulatory tools needed to achieve the state's GHG reduction goals.

Prior to any utility modeling, staff created a summary of key utility data that could help stakeholders with their analysis of utility compliance modeling. Titled "Foundational Data," these documents comprise two Excel workbooks using data from multiple public sources and can be found online at this link.

The utilities were asked to deliver two large sets of deliverables in a very short time. The first was a presentation and underlying data to their initial NGFF model runs with selected sensitivities. The second was a presentation using alternative scenarios, which were shaped by participant input in the form of written and verbal comments. The table below captures the major milestones in the NGFF compliance modeling activities, with links to key documents.

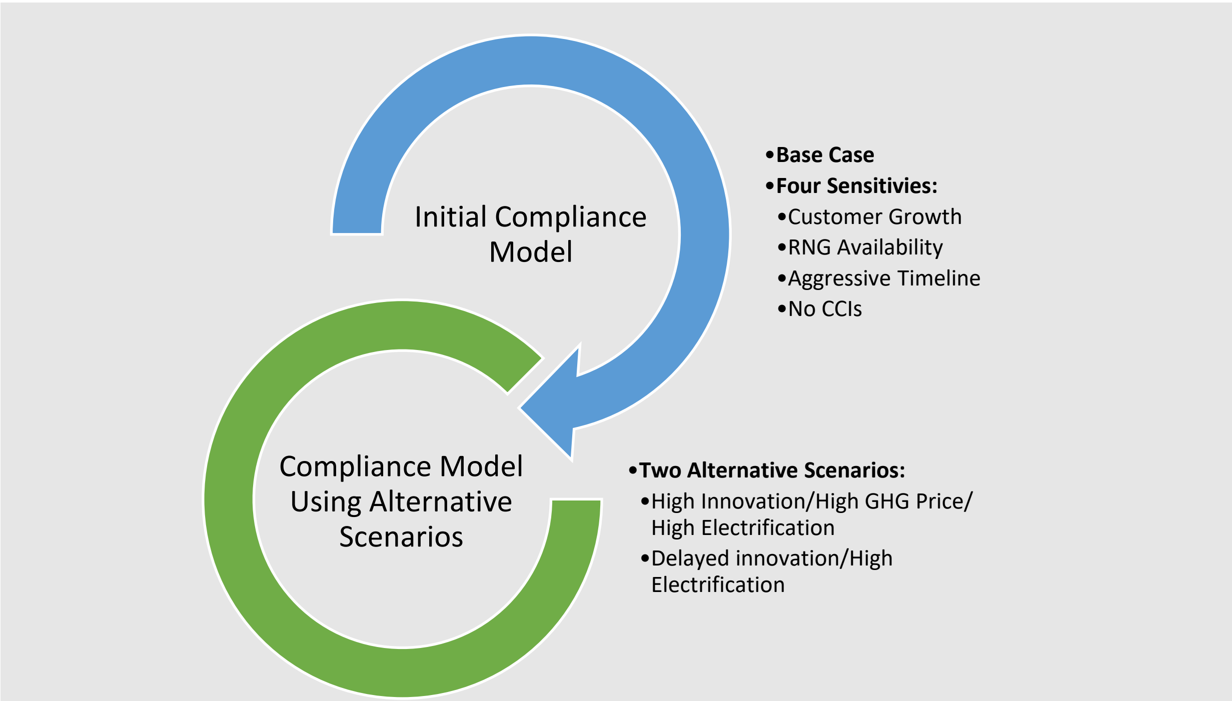
Table A1: Major Milestones in NGFF Modeling Activities

Date	Deliverable/Item	Additional information
July 8, 2021	Staff's initial compliance modeling proposal	Initial expectations for data to be used (inputs) by utilities in their analysis, the key deliverables to be shared (outputs). Modeling sensitivity selection occurs after input from stakeholders.
July 26 -30, 2021	Stakeholder comments on modeling proposal and suggestions for potential sensitivities	*See docket for more information.*
Aug. 4, 2021	Modeling sensitivities to inform initial model	Four sensitives selected by staff after stakeholder input.

Date	Deliverable/Item	Additional information
Sept. 7-24, 2021	Utilities' initial modeling results	Initial modeling results provided on Sept. 7 with some supplemental and revised filings through Sept. 24. *See docket for more information.*
Sept. 24-27, 2021	Stakeholder comments on utility modeling results	Alliance of Western Energy Consumers Sierra Club Joint Parties, including Climate Solutions Citizens' Utility Board NW Natural Wendy Woods RNG Coalition Metro Climate Action #1 & #2
Oct. 1, 2021	Staff's alternative modeling scenarios	Alternative scenarios differ from sensitivities in that the scenarios alter the underlying assumptions, and in some cases, the data used by the initial model. Two alternate scenarios were selected based on participant feedback in NGFF workshops and from comments.
Nov. 17, 2021	Utilities' alternative modeling scenario runs	Avista's presentation of results CNG's presentation of results NW Natural's presentation of results

Given the timing and short turnaround time for the initial model runs, the natural gas companies were asked to use past IRP data, the most current version of CPP rules, and to model a base case of CPP compliance strategies they envisioned worked best for their company. They were also asked to consider a set of sensitivities, which were intended to stress test the company's proposed pathway. The selected alternative modeling scenarios attempted to show the impact of CPP compliance in two possible futures, combining multiple sensitivities within the initial model: one in which there was aggressive electrification of gas loads, and one in which efforts were directed to accelerate innovation in decarbonizing gas. Figure A1 provides a graphic representation of the scenarios and sensitivities the utilities modeled.

Figure A1: Scenarios and Sensitivities for NGFF Utility Modeling



7.1.1 Key Deliverables from Initial Modeling

Each utility delivered a presentation and underlying data as part of the model runs. Specified outputs to be shared included the following:

1. Forecast of emissions (weather adjusted)
    a. Graphic of million metric tons CO2e per year
        i. Stacked Area chart
        ii. Estimates of avoided emissions by compliance strategy and technology
    b. Supporting table capturing underlying data used in graphic by year
    c. Annual emissions reduction by compliance strategy, technology, and portfolio of technologies
    d. Annual emissions reduction in metric tons by technology by year
    e. Annual emissions above or below annual DEQ CPP threshold

2. Data supporting the development of emissions forecasts, including but not limited to:
    a. Load forecast and growth assumptions
    b. Use per customer estimates
    c. Compliance strategy assumptions
        i. Demand, supply, and capture assumptions
        ii. Sector/customer class reduction assumptions
        iii. Technology assumptions
            1. Cost trajectory curves over time for each technology
            2. Tons of emissions avoided per therm for each technology
            3. Variable costs per therm for each technology

d. Any major distribution or transmission system upgrades or changes
e. In addition to the above data, all model inputs, outputs, and workpapers provided in electronic format with all references and formulae intact.

3. Description of approach and/or assumptions, including but not limited to:
    a. Values and terms selected for DEQ key assumptions
    b. Model methodology
    c. Description of weather pattern forecasts impacting load forecast
    d. Avoided costs assumptions, such as peak day usage and savings ratios

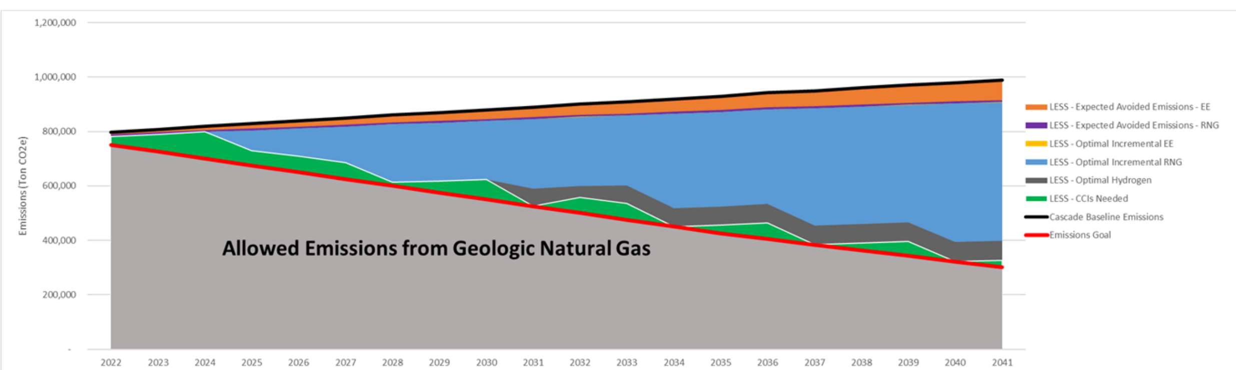
4. Estimated Net Present Revenue Requirement of Compliance Model and Comparison Across Selected Sensitivities
    a. Twenty year time horizon minimum
    b. Annual and total Revenue Requirement difference between Compliance Model and most recent IRP's preferred portfolio
    c. Annual and total Revenue Requirement difference between Compliance Model and selected sensitivities.

7.1.2 Results of Base Case Compliance Strategies

The base case strategies for CPP compliance varied across utilities. Figures A2-A4 below summarize the compliance strategies each utility presented in UM 2178 workshops.

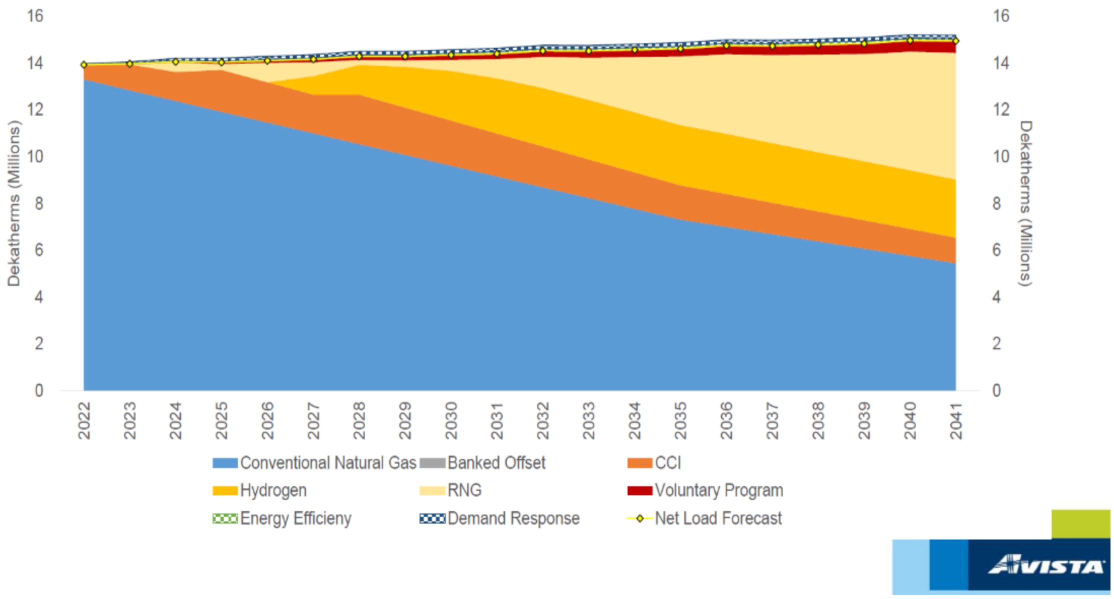
Cascade relied on CCIs in the near term and then heavily on incremental RNG (blue sliver in Figure A2) beyond what it planned for with SB 98 RNG (purple sliver in Figure A2).

Figure A2: Cascade CPP Base Case Compliance Strategies



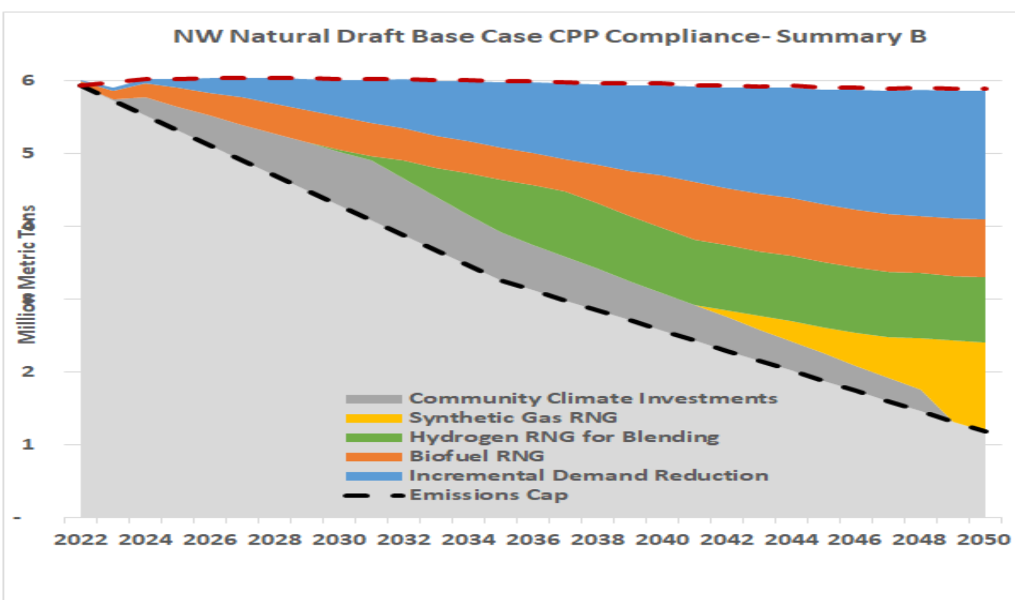
Avista also relied on CCIs in the near term and biofuel RNG throughout, but brings in hydrogen in 2026.

Figure A3: Avista Base Case CPP Compliance Strategies



NW Natural increasingly relies on demand reduction/EE over the course of the compliance timeframe. Its use of biofuel RNG and CCIs start in the near term and play a moderate role throughout, with CCI's decreasing and RNG increasing. By 2031 it introduces hydrogen and by about 2040, begins to envision the inclusion of synthetic gas RNG.

Figure A4: NW Natural Base Case CPP Compliance Strategies



7.1.3 Sensitivities

Below is a description of each of the four sensitivities to accompany the initial model run's base case. Each sensitivity was run in isolation from the other. A comparison of the results for each sensitivity are included in Figures A5-A8.

7.1.3.1 Customer Decline

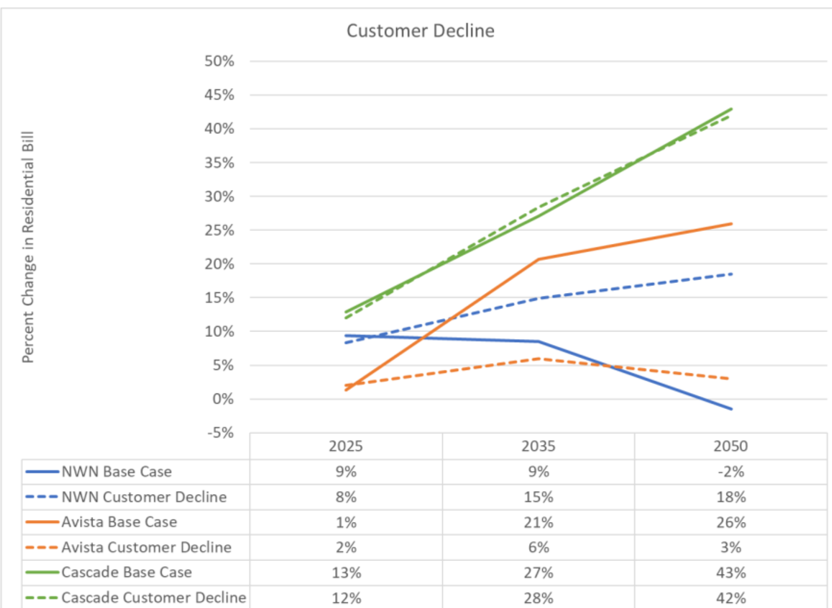
Issue: How might policies limiting customer growth and associated GHG emissions inform regulatory tools to consider.

Approach: Model sensitivities that consider zero and negative customer growth.

Sensitivity: Current IRP forecasted load growth through 2025; no new customers beginning from 2025 through 2030; -0.75 percent customer growth beginning in 2031 through the end of model's time horizon.

Results: NWN modeling showed customer declines result in increased compliance costs above those of its base case as the years progressed. Avista compliance costs decreased with declining customers and Cascade saw costs remain almost identical to its base case.

Figure A5: Customer Decline Sensitivity Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN Customer Decline	8%	15%	18%
Avista Base Case	1%	21%	26%
Avista Customer Decline	2%	6%	3%
Cascade Base Case	13%	27%	43%
Cascade Customer Decline	12%	28%	42%

7.1.3.2 RNG Availability

Issue: Uncertainty about availability of RNG.

Approach: Apply constraints on assumptions about the availability of RNG to meet emission reduction goals.

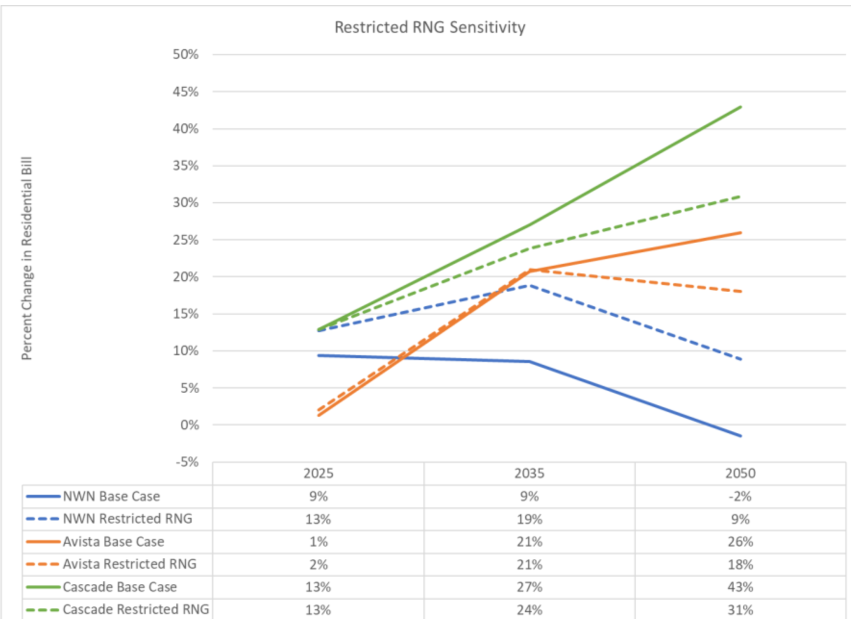
Sensitivity: Limit RNG availability to the annual percentages set by SB 98 and found in ORS 757.396(1).

(a) In each of the calendar years 2020 through 2024, five percent may be renewable natural gas;

(b) In each of the calendar years 2025 through 2029, 10 percent may be renewable natural gas;
(c) In each of the calendar years 2030 through 2034, 15 percent may be renewable natural gas;
(d) In each of the calendar years 2035 through 2039, 20 percent may be renewable natural gas;
(e) In each of the calendar years 2040 through 2044, 25 percent may be renewable natural gas; and
(f) In each of the calendar years 2045 through 2050, 30 percent may be renewable natural gas.

Results: Restricting RNG had mixed results – NWN modeled increased RNG prices with the restriction, resulting in higher costs compared to base case. Avista and Cascade reduced how much RNG was used for compliance, which reduced the overall cost of compliance compared to their base case scenarios. This generally increased cost of compliance for NWN, but Cascade and Avista saw decreased compliance costs in the later years of the model run when compared to their base cases.

Figure A6: Restricted RNG Sensitivity Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN Restricted RNG	13%	19%	9%
Avista Base Case	1%	21%	26%
Avista Restricted RNG	2%	21%	18%
Cascade Base Case	13%	27%	43%
Cascade Restricted RNG	13%	24%	31%

7.1.3.3 More Aggressive Timeline on Climate Policy

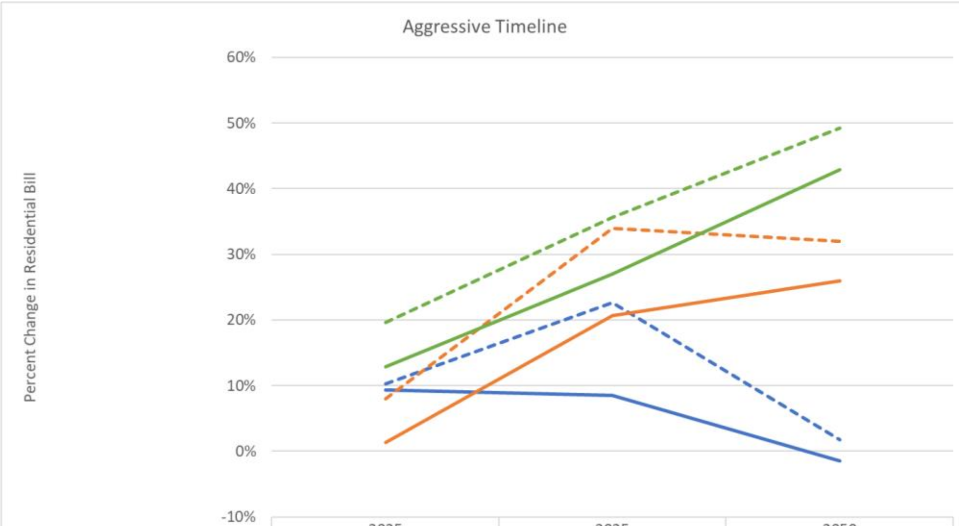
Issue: The Governor's Executive Order set state emission reduction targets of at least 45 percent below 1990 levels by 2035 and at least 80 percent below 1990 levels by 2050. The DEQ Climate Protection Program is poised to make progress towards these state emission reduction targets. However, there is the potential for future policy to have more aggressive targets.

Approach: Using the same target reduction emissions currently contemplated by DEQ for 2035 and 2050, advance the dates to align with the date bookends (2030 and 2040) of the recently passed OR legislation for electric utilities (HB 2021).

Sensitivity: CPP targets of 45 percent below baseline by 2030, 80 percent below baseline by 2040.

Results: NWN costs increased in the middle years of the model run but the difference between this sensitivity and the base case shrank as they approached 2050. Avista and Cascade's aggressive timeline model runs showed compliance costs consistently higher than in their base cases for all customer types.

Figure A7: Aggressive Timeline Sensitivity Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN Aggressive Timeline	10%	23%	2%
Avista Base Case	1%	21%	26%
Avista Aggressive Timeline	8%	34%	32%
Cascade Base Case	13%	27%	43%
Cascade Aggressive Timeline	20%	36%	49%

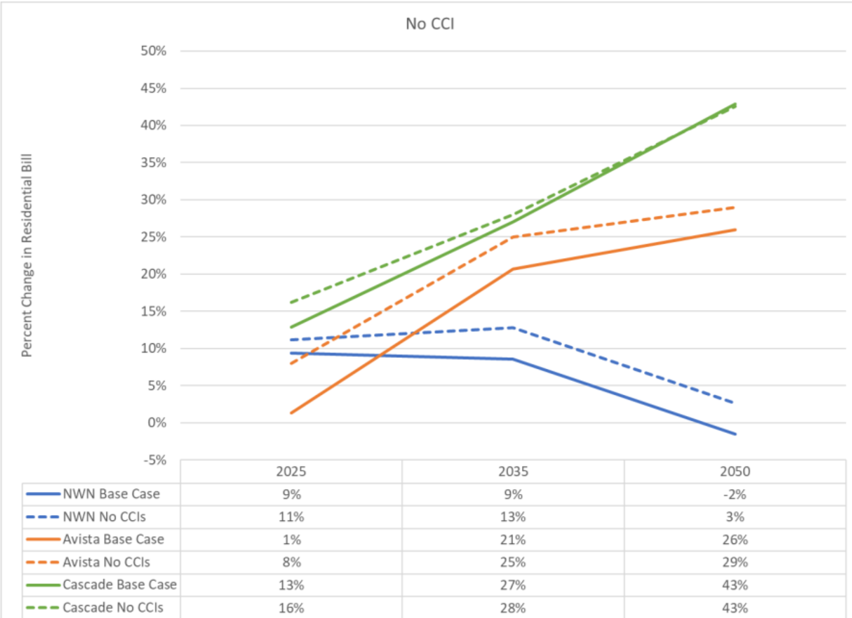
7.1.3.4 No CCI

Issue: Community Climate Investments (CCI) are a CPP compliance instrument. However, it is not currently clear to PUC how the emissions associated with these projects will be quantified and verified. PUC staff would like to understand the role CCIs play in accomplishing compliance with emission reductions and what emission reduction options become more viable if they are not part of a solution set.

Approach: Remove the availability of CCIs.

Results: All companies showed that the inability to use CCI's would result in higher compliance cost than in their base cases in the early years; But by 2050, the three utilities' modeling runs arrived at different conclusions with NWN's annual compliance costs continuing to outpace compliance costs in its base case, while Avista's cost differential was shrinking, and Cascade's annual compliance costs were the same as in its base case.

Figure A8: No CCI Sensitivity Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN No CCIs	11%	13%	3%
Avista Base Case	1%	21%	26%
Avista No CCIs	8%	25%	29%
Cascade Base Case	13%	27%	43%
Cascade No CCIs	16%	28%	43%

7.1.4 Alternative Scenarios

The alternative scenarios were run after the initial compliance models were completed and shared. They were greatly shaped by participant feedback. They combined multiple sensitivities from the previous model run, in some cases with new data. These two scenarios were designed to characterize possible futures that explored potential impacts, suggesting different policy and planning approaches.

7.1.4.1 Alt. Scenario 1: Accelerated Innovation / Electrification / High Social Cost of Greenhouse Gas

Approach:

- **Accelerated Innovation:** Assume a 30 percent six-year production tax credit for the production of green hydrogen and syngas for which construction begins before 2026.[31] It is anticipated that projects may be outside the ordinary course of business and would result in near-term and aggressive emission reductions.
- **Higher Cost of GHG:** Assume updates to the social cost of carbon. Beginning in 2026, adjust the CCI price to align with the Social Cost of Carbon's 95^{th} percentile with a three percent discount.[32] For example, starting in 2026 use the starting value of $173.

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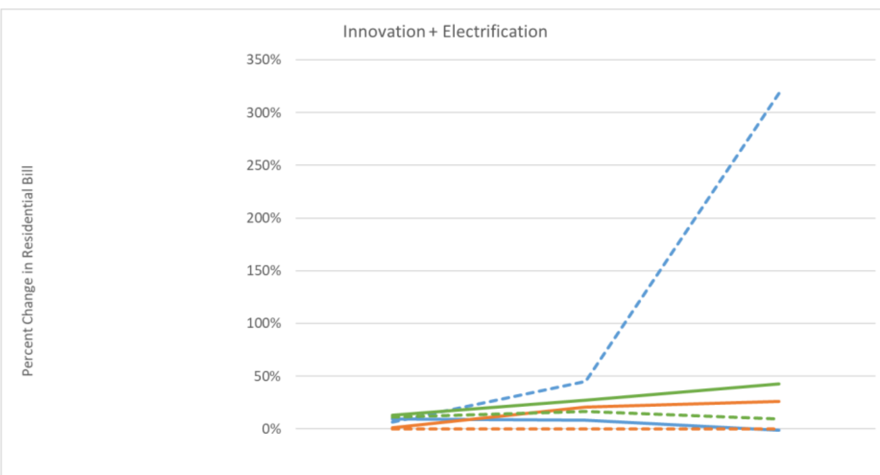
[31] *See* page 49 of the Department of the Treasury, General Explanations of the Administration's Fiscal Year 2022 Revenue Proposals https://home.treasury.gov/system/files/131/General-Explanations-FY2022.pdf.
[32] *See* Social Cost of Carbon table A-1 in Appendix – Annual SC-CO2, SC-CH4, and SC-N2O Values, in 2020-2050. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide – Interim Estimates under Executive Order 13990. Interagency Working Group on Social Cost of Greenhouse Gases, United States Government. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

- **Electrification:**
  - Fraction of new buildings (residential and commercial) using gas goes from its present share to zero in 2030 and stays zero thereafter.
  - Existing buildings converting to electricity goes from its present share to 90 percent in 2050.
  - Light industry converts to 90 percent electricity by 2050.

Results: Cascade's model resulted in bill impacts that were lower than in their base case. Avista's modeling summary showed zero change in bill impacts, but the workbooks showed negative bill impacts for all customers except transport, and then compliance cost increases similar to those found in their base case. NWN's bill impacts for the scenario increased significantly due to high electrification-related customer declines, which resulted in costs not tied to energy use being spread over many fewer customers (a 318 percent increase in non-energy charges in 2050). There was no increase in hydrogen usage on NWN's or Avista's system because the high electrification rates reduced or eliminated the need for fuel 'innovation.' Hydrogen usage was significantly decreased as a solution for Cascade when compared to its base case. For Avista, this scenario saw its transport customers pay an increasing share of the utility's compliance costs as the utility's retail customer count declined.

Figure A9: High Innovation + Electrification + High SCC Scenario Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN Alt. Scenario 1 - Innovation	6%	45%	318%
Avista Base Case	1%	21%	26%
Avista Alt. Scenario 1 - Innovation	0%	0%	0%
Cascade Base Case	13%	27%	43%
Cascade Alt. Scenario 1 - Innovation	11%	17%	9%

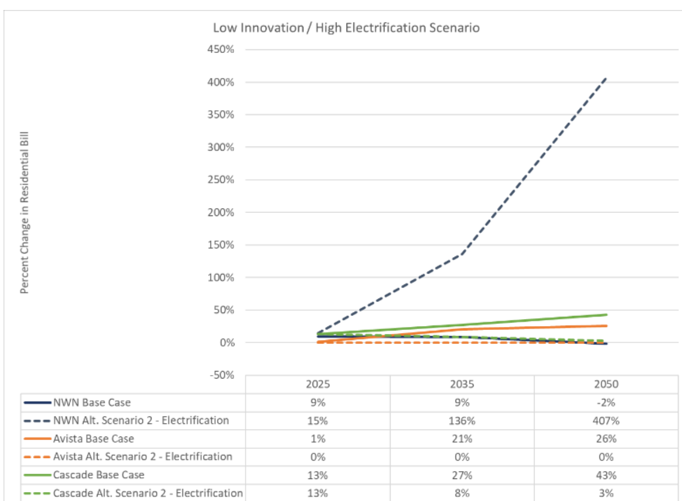
7.1.4.2 Alt. Scenario 2: Delayed Innovation / Accelerated Electrification

Approach:

- **Delayed Innovation:** Use a slower energy efficiency technology adoption curve. Gas heat pump water heaters come to market, but there are no gas heat pumps until after 2030 and they assume a traditional s-curve adoption pattern.[33]
- **Supply Competition:** RNG availability is limited to the percentage of the national RNG resource equal to the company's throughput share of total gas use in the U.S., including power sector use. National RNG resource is ICF's Low Resource Potential for RNG in 2040, namely 1,660 trillion Btu (tBtu) of RNG produced annually for pipeline injection by 2040.[34]
- **Very Rapid Electrification:**
  - The fraction of new buildings (residential and commercial) using gas goes from its present share to zero in 2025 and stays zero thereafter.
  - Fraction of existing buildings converting to electricity goes from its present share to 90 percent by 2040.

Results: Like the Accelerated Innovation and Electrification w/High SCC Scenario, Cascade modeled bill impacts that were lower than their base case. Avista's summary showed zero bill impacts, but the workbooks showed negative impacts in 2025 and then similar increases to the base case by 2035. NWN modeled the most aggressive electrification assumptions, resulting in a scenario that showed a significant drop in customers on the system and a 405 percent increase in residential bills by 2050. NWN also showed a moderate amount of industrial EE around 2035 and the use of banked allowance credits collected before 2042 for CPP compliance in the 2040s.

Figure A10: Delayed Innovation/High Electrification Scenario Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN Alt. Scenario 2 - Electrification	15%	136%	407%
Avista Base Case	1%	21%	26%
Avista Alt. Scenario 2 - Electrification	0%	0%	0%
Cascade Base Case	13%	27%	43%
Cascade Alt. Scenario 2 - Electrification	13%	8%	3%

[33] *See* Comments of the Oregon Citizens' Utility Board on Modeling and Alternative Scenarios. Filed September 24, 2021. https://edocs.puc.state.or.us/efdocs/HAH/um2178hah163235.pdf.

[34] *See* American Gas Foundation Study Prepared by ICF. Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment. December 2019. https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.

7.1.4.3 Modeling Parameters for Alternative Scenarios

Companies were instructed to use existing models and data to create the alterative scenarios with the following deliverables:

- Updated graphics and tables comparable in format to those submitted for the base case and associated sensitivities.
- To the extent possible and applicable, staff asked that Avista and Cascade replicate the Scenario Comparison table created and shared by NW Natural, and that all companies use this format to include the alternative scenarios described above.
- **Data for Electrification:**
    - Where a load currently served by gas is not eliminated, but rather served by another resource, total annual MMBtu transferred to the alternative source must be identified for each year.
    - Staff will calculate estimated costs of the transferred load and associated emissions, taking into consideration the electrification cost elements proposed by stakeholders in comments.
- **Low and Moderate Income Customers**: Indicate the assumed or known percentage of low and moderate income residential customers.
- **Bill Impacts:** Report bill impacts in terms of $/therm

TABLE A2. SUMMARY OF COMPLIANCE BASE CASE, SENSITIVITIES, AND SCENARIOS IMPACTS

	Sensitivities/ Scenarios	Renewable Supply Penetration (% of Deliveries)			Biofuel RNG Penetration (% of Current Deliveries)			Renewable Supply Portfolio Cost (2020$/Dth)			Total Incremental Cost of CPP Program (Million 2020$/Year)[35]			Community Climate Investments (% of Emissions)			Annual Residential Bill Impact (% Impact of CPP)			Annual Industrial Sales Bill Impact (% Impact of CPP)		
		2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050
Northwest Natural	Base Case	*4%*	*23%*	*72%*	*4%*	*8%*	*14%*	*$12.25*	*$11.85*	*$11.77*	*$142*	*$256*	*$242*	*6%*	*20%*	*0%*	*9%*	*9%*	*-2%*	*22%*	*35%*	*39%*
	Restricted RNG	4%	23%	72%	4%	9%	11%	$18.75	$18.26	$16.90	$142	$317	$324	6%	20%	0%	13%	19%	9%	30%	59%	68%
	Customer Decline	4%	17%	65%	4%	9%	15%	$12.25	$11.93	$11.59	$118	$181	$186	6%	20%	0%	8%	15%	18%	18%	27%	37%
	Aggressive Timeline	4%	47%	65%	4%	16%	20%	$12.25	$13.15	$11.74	$168	$493	$360	13%	20%	20%	10%	23%	2%	27%	73%	58%
	No CCIs	10%	36%	72%	10%	15%	18%	$12.25	$12.64	$12.89	$167	$313	$296	0%	0%	0%	11%	13%	3%	26%	45%	51%
	Fed RNG Support	4%	23%	72%	4%	8%	14%	$8.58	$8.76	$8.80	$142	$239	$160	6%	20%	0%	7%	4%	-9%	18%	26%	17%
	Vol Comm Support	4%	16%	48%	4%	8%	9%	$12.25	$11.85	$11.25	$124	$214	$160	2%	20%	20%	8%	6%	-6%	19%	30%	25%
	Alt. Scn. #1	4%	12%	23%	4%	6%	6%	$12.25	$12.13	$12.13	$0	$0	$0	0%	0%	0%	6%	45%	318%		Unknown	
	Alt. Scn. #2	4%	9%	14%	4%	5%	5%	$12.25	$12.25	$12.25	$0	$6	$13	0%	0%	0%	15%	136%	407%			
Avista	*Base Case*	*2%*	*40%*	*54%*	*2%*	*20%*	*34%*	*$12.23*	*$9.71*	*$8.95*	*$2*	*$19*	*$26*	*13%*	*17%*	*17%*	*1%*	*21%*	*26%*	*14%*	*60%*	*72%*
	Restricted RNG	2%	40%	49%	2%	20%	27%	$12.23	$9.69	$8.54	$2	$19	$24	13%	17%	17%	2%	21%	18%	16%	62%	54%
	Customer Decline	2%	35%	47%	2%	15%	27%	$12.23	$9.31	$8.64	$2	$13	$15	13%	17%	17%	2%	6%	3%	16%	52%	59%
	Aggressive Timeline	9%	59%	76%	9%	39%	54%	$12.23	$10.55	$9.40	$6	$38	$46	13%	17%	17%	8%	34%	32%	33%	99%	93%
	No CCIs	15%	50%	61%	15%	30%	41%	$12.23	$10.23	$9.22	$7	$28	$35	0%	0%	0%	8%	25%	29%	34%	72%	80%
	Alt. Scn. #1	0%	26%	32%	0%	0%	0%	$0.00	$7.08	$5.44	$0	$0	$0	7%	0%	0%	0%	0%	0%	0%	0%	0%
	Alt. Scn. #2	0%	28%	49%	0%	0%	0%	$0.00	$7.08	$5.44	$0	$0	$0	5%	0%	0%	0%	0%	0%	0%	0%	0%
Cascade	*Base Case*	*10%*	*26%*	*65%*	*10%*	*26%*	*57%*	*$5.86*	*$4.94*	*$3.01*	*$12*	*$25*	*$33*	*6%*	*8%*	*0%*	*13%*	*27%*	*43%*	*16%*	*32%*	*50%*
	Restricted RNG	10%	25%	54%	10%	25%	46%	$5.86	$4.91	$2.75	$12	$21	$20	6%	6%	0%	13%	24%	31%	16%	29%	37%
	Customer Decline	6%	17%	28%	6%	15%	27%	$5.86	$4.91	$3.05	$11	$27	$32	10%	9%	10%	12%	28%	42%	15%	34%	49%
	Aggressive Timeline	17%	43%	83%	17%	37%	75%	$5.86	$4.78	$2.97	$20	$37	$43	6%	6%	0%	20%	36%	49%	24%	42%	56%
	No CCIs	16%	35%	65%	16%	27%	57%	$5.86	$4.59	$2.91	$16	$26	$33	0%	0%	0%	16%	28%	43%	20%	33%	49%
	Alt. Scn. #1	11%	33%	45%	11%	33%	44%	$5.86	$4.81	$2.39	$13	$24	$12	6%	0%	0%	11%	17%	9%	14%	21%	12%
	Alt. Scn. #2	6%	8%	13%	2%	3%	5%	$11.76	$4.66	$1.70	$16	$9	$2	9%	9%	3%	13%	8%	3%	16%	11%	4%

[35] Red figures indicate that the cost of compliance to NW Natural is offset by assumed electrification, where the cost of this electrification needs to be assessed on the electric rather than gas grid.

8 APPENDIX B: IRP GUIDANCE

Throughout the Fact Finding workshops and comments, staff heard feedback from stakeholders about ways to leverage and improve upon the existing gas utility integrated resource planning process. Staff, with support from the Regulatory Assistance Project, attempted to capture and categorize this feedback in Table B1 to help inform future IRPs. This table serves as a reference and compendium for ideas received as part of UM 2178 and to be considered potentially in the future when the Commission embarks on revising IRP guidance.

TABLE B1: IRP-RELATED FEEDBACK

Category	Addition to IRP
Expand Public Access & Equity	Expand communications about IRP - basics, process and outcomes/implications, start to expand customer understanding of impacts of new policies (CPP)
	Utilities should record and post workshops on website
	Capture additional customer information, create a baseline of customer statistics (energy burden, participation in programs - e.g., EE and LI) by location (e.g., zip code)
Load Forecast – Improvements	Consider and reflect potential impacts of local policies to limit gas in new construction.
	Provide data on customer trend gas and electric usage assumed for space and water heating, (gas furnaces/electric heat pumps/gas domestic hot water heaters/heat pump water heaters) across service territory population, by county or zip code, # customers and share of electric utility overlap (*recent history and current state*)
	Provide transparent assumptions and data about customer technology adoption and behavior, including end use fuel splits between electric and gas over time and justification for technology adoption assumptions (e.g., relying on technology adoption modeling? Does modeling approach assess/compare all customer options?) (*forward looking*)
	Identify transportation load - industry types/end uses and explore H2 potential for these customers. Characterize how this load is currently served to understand new liability for compliance – include seasonality and daily nature of emissions
	Conduct sensitivities to load forecast around customer adoption of emerging EE technologies
RNG	Quantify the near- and long-term geographic availability of RNG potential, updated regularly. Provide detailed discussion/description with supporting workpapers for assumptions used to model RNG resources and market. Develop Base/Low/High cases of resource costs. Base/accelerated/delayed cases for availability and base/low/high volumes. Essentially creating a resource potential assessment for RNG. Be explicit about total RNG resource potential and justify assumptions about what will be available to Oregon gas utilities.
	Provide Bundled vs unbundled RNG assumptions
	Discussion of RNG affiliate plans

H2	Provide detailed discussion/description with supporting workpapers for assumptions used to model H2 resources. Develop Base/Low/High cases of resource costs. Base/accelerated/delayed cases for availability and base/low/high volumes. Essentially creating a resource potential assessment for H2 designed around end uses that can feasibly use H2. Be explicit about total H2 resource potential and justify assumptions about what will be available to Oregon gas utilities. Assumptions should include whether sited with energy user or if transport from production to end user required and costs/risks of new pipeline delivery infrastructure or storage needed.
EE and Beneficial Electrification	Review cost effective EE potential
	Develop Beneficial Electrification assumptions in coordination with electric utility
System Mapping / Infrastructure	Include planned infrastructure costs identified as new customer vs. maintenance of existing system. Identify high priority projects and 5 year planned investments with non-pipeline alternatives considered.
	Identify areas of new development / system expansion- with as much granularity as possible
	Scenarios of load decline should include assessment of stranded asset risk
	Include current rate base depreciation assumptions, list of assets and amortization schedules
Scenarios	H2 and RNG delayed growth vs. base case assumptions
	CPP compliance requirements more stringent than current (as modeled in UM 2178 scenario)
	Decline in load starting in 2030, after 2025-2030 no growth (as modeled in UM 2178)
Transparency and Clarity	Provide input data and results in a clear and transparent manner. Including such things as units, methodologies, assumptions, sources, and application.
Emissions	All portfolios should be designed to meet CPP, include discussion around risk of noncompliance costs
Cost and Risks	Account for biogenic CO_2 from RNG

9 APPENDIX C: RMI BUILDING ELECTRIFICATION POLICY PRESSURES

This table is an excerpt from materials provided by the Rocky Mountain Institute to PUC staff via email on November 2, 2022.

- It is an informal landscape scan of the future of gas proceedings across the country.

- While RMI intends to keep it updated, it is a work in progress and not intended to be comprehensive or up-to-the-minute. Some states may have more details than others.

- For the most accurate information, refer to the state PUC dockets, many of which are linked in the "proceedings" tab.

- If you have questions, corrections, or additions, please contact Sherri Billimoria (sbillimoria@rmi.org) or Abby Alter (aalter@rmi.org).

State	Docket #	Title/link	Key filings to date	State-wide energy strategies, plans, or studies	Any state commitments / indications around electrification?
California	R1807006	Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service	Fourth Amended Scoping Memo and Ruling from 9.15.21		SB 1477 (2018) funded and required CPUC to develop BUILD and TECH programs to reduce GHG from buildings AB 3232 (2018) required CEC to release an assessment of "the feasibility of reducing [GHG] emissions of California's buildings 40 percent below 1990 levels by 2030" link
	R1901011	Order Instituting Rulemaking Regarding Building Decarbonization			
	R2001007	Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning	10/14/21 Amended scoping memo outlines tracks 2a, 2b, and 2c scope and timeline. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M415/K275/415275138.PDF		
	R1202008	Order Instituting Rulemaking To Adopt Biomethane Standards And Requirements, Pipeline Open Access Rules, And Related Enforcement Provisions.	Staff published proposal.		
	CEC 21-IEPR-05	Natural Gas Outlook and Assessments -- IEPR (Integrated Energy Policy Report)			

Colorado	21M-0395G	Commission Review of the Regulation of Gas Utilities	Opening order C21-0516 (lists of questions for comment periods, plus procedural/leg background)	Colorado Greenhouse Gas Pollution Reduction Roadmap (Jan. 2021)	Roadmap shows significant electrification is needed AQCC says building reductions will be 100%
	21R-0449G	Proposed Amendments to the Commission's Rules Regulating Gas Utilities, 4 Code of Colorado Regulations 723-4, Relating to Gas Utility Planning and Implementing SB 21-264 Regarding Clean Heat Plans and HB 21-1238 Regarding Demand Side Management	NOPR filed 10/1/2021		
	20M-0439G	Investigation Into Retail Natural Gas for GHG Emissions			
Massachusetts	20-80	Investigation by the DPU on its own Motion into the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals		Massachusetts 2050 Decarbonization Roadmap (Dec 2020) 2030 Clean Energy and Climate Plan (Dec 2020)	2050 Roadmap ID's high-electrification as the least-cost pathway 2030 CECP states that Mass Save will work to phase out incentives for fossil fuel appliances by 2025

Minnesota	21-566	In the Matter of Establishing Frameworks to Compare Lifecycle Greenhouse Gas Emissions Intensities of Various Resources, and to Measure Cost-Effectiveness of Individual Resources and of Overall Innovative Plans	Notice of comment issued 9/3/21	Decarbonizing Minnesota's Natural Gas End Uses: Stakeholder Process Summary and Consensus Recommendations (July 2021)	
	21-565	In The Matter Of A Commission Evaluation Of Changes To Natural Gas Utility Regulatory And Policy Structures To Meet State Greenhouse Gas Reduction Goals	7/28: Centerpoint, CEE, Fresh Energy made a procedural proposal (which was filed in both 566 and 565) suggesting to suspend the 21-324 (where Centerpoint was applying for approval of RNG tariffs) proceeding in order to address the carbon accounting (for NGIA technologies) through public process		
Nevada	21-05002	Investigation Regarding Long-Term Planning For Natural Gas Utility Service In Nevada.	Procedural order filed 9/24/21	Pathways and Policies to Achieve Nevada's Climate Goals: An Emissions, Equity, and Economic Analysis (Oct 2020)	

New Jersey	GO20010033	In the Matter of New Jersey Natural Gas Commodity and Delivery Capacities in the State of New Jersey - Investigation of the Current and Mid-Term Future Supply and Demand	Opening order/notice of hearing filed April 20, 2021		
New York	20-G-0131	Proceeding on Motion of the Commission in Regard to Gas Planning Procedures	3.19.20 Opening order 8.10.20 Preliminary comments of Renewable Heat Now 2.12.21 Staff proposals on gas system planning and moratorium management 5.4.21 RHN Gas Planning Comments		No sector-specific ghg target; significant heat pump targets within efficiency programs
Philadelphia		PGW Diversification Study			
Washington	UG-210729	Consideration of whether to continue to use the Perpetual Net Present Value Methodology to calculate natural gas line extension allowances	Notice of item to be considered... filed 9/21/21	2021 State Energy Strategy	

Washington, D.C.	U-210553	Examination of energy decarbonization impacts and pathways for electric and gas utilities to meet state emissions targets		2021 State Energy Strategy	
	FC1167	In the Matter of the Implementation of the Climate Business Plan	WGL's compliance filing 9.1.21 (comments due within 60 days) Pepco's electrification study 8.27.21 (comments due within 60 days) Commission order No. 20754 lays out next steps		Carbon Free DC has identified the need to eliminate fossil fuel use in buildings, primarily via electrification (link)
Wisconsin	5-FE-104	Focus on Energy Quadrennial Planning Process IV	EE Potential Study filed 9.10.21		

10 Appendix D: Elasticity

The Fact Finding modeling suggests that under most scenarios all customers (residential, commercial, and industrial) will see cost increases in the near term. NWN modeling suggests that by 2040, under some scenarios, some customers would see a cost ***decline***. However, given how far out in the future those cost declines are projected and the disagreement between NWN and the other gas utilities' models, staff believes it is appropriate to plan for cost increases to customers under all scenarios proposed by utilities.

Part of what initiated the Fact Finding was the concern that as the energy system decarbonizes, low income customers would not only experience increases in fuel costs, but also be saddled with increasing costs associated infrastructure costs being spread over a smaller customer base. This, it was assumed, could be the result of decarbonization efforts that motivated more affluent customers to leave the gas system entirely and to switch to all electric homes. Staff conducted its own analysis of customer bill impacts of natural gas decarbonization to better understand the extent to which this might warrant the use of policy intervention. That analysis follows.

10.1 Staff's Elasticity Analysis

Staff notes that if a natural gas utility raises its rates, natural gas customers are likely to change their behavior accordingly. These behavior changes can come in two possible forms:

- Changes in natural gas consumption, or
- Deciding whether to remain on the natural gas grid or seek alternative energy sources.

The elasticity of natural gas consumption has been well studied in academic literature, particularly in the last few years. Using data from over 300 million household natural gas bills in California and rigorous econometrics, Auffhammer and Rubin 2018 estimate that the residential natural gas consumption elasticity is between -0.17 and -0.23. Staff created its own econometric model using data aggregated to the state-year level and found an elasticity that is also near this range.

Aufhammer and Rubin break down the elasticity by season and by income and notes that low income households exhibit higher elasticity than high income households, and households in the winter exhibit higher elasticity than in the summer. These elasticity estimates vary from -.05 for high-income households in summer to -.52 for low-income households in the winter. This implies that should natural gas prices rise in response to decarbonization, low-income households in the winter are most likely to change their consumption patterns.

Staff conducted preliminary empirical modeling to investigate residential customers' propensity to connect or disconnect from the natural gas grid. Staff created an econometric model using annual data on state-level natural gas connections, residential natural prices, population and economic activity and various sets of controls. The econometric model assumes that residential consumers would not immediately change their equipment in response to a change in natural gas price, but instead do so after observing sustained price changes for multiple years. While Staff's results are preliminary and not corroborated by any known literature, they are suggestive of the following things:

- At an aggregate level, residential customers' natural gas connection decisions only react to a price change after at least 2-3 years. Absent outside pressures to connect or disconnect, it is unclear whether this reaction comes through existing customers switching natural gas connections to electric connections or new residential structures selecting non-gas heat sources.

- Regardless of the time lag, residential natural gas connection or disconnection appears to be highly price inelastic. Staff's preliminary model suggests that the price elasticity is approximately -.10 . However, staff reiterates that this value is preliminary and does not account for endogeneity of variables that likely biases the estimate in an indeterminant manner.

Due to data limitations, staff's estimates do not account for any changes in technology or financial incentives that may reduce the costs to switch from natural gas to electricity. However, staff's estimated negative elasticity implies that there will be some, albeit small, natural attrition from the natural gas system or slowdown in new connections if the push to decarbonize results in higher prices even without added incentives.

There is unfortunately also a gap in the academic literature regarding the elasticity of natural gas connections and disconnections, which makes it difficult to precisely determine the rate at which customers defect from the natural gas system. However, there has been recent research investigating the effects of the switch away from natural gas. Lucas and Hausman 2021 investigates who bears the cost of a declining utility and notes that a ten percent decrease in residential utility customers leads to only a five percent decrease in revenues, implying that the remaining utility residential customers bear a higher burden in costs. This is to say that should there be a large defection from natural gas utilities due to decarbonization, the remaining infrastructure costs will not scale down and will be paid by those remaining on the system.

What this suggests is that any cost increase is felt more acutely by customers that are already facing energy burden. Energy burdened customers' ability to respond to price signals appears to be limited to reduction in use, which in the case of gas used for heating, may result in a decrease in home comfort felt more by these customers than those who can maintain home heating expectations by either absorbing the cost increase, or ultimately changing heating sources.