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Public Utility Commission Oregon
Attention: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-1088

Re: Docket No. LC 81 – Avista Utilities 2023 Natural Gas Integrated Resource Plan Reply Comments

Avista Corporation, dba Avista Utilities (Avista or the Company), provides the following reply comments in response to the comments filed by the Oregon Public Utilities Commission (Commission) Staff (Staff), the Alliance of Western Energy Consumers (AWEC), the Oregon Citizens' Utility Board (CUB), and Rogue Climate regarding the Company's 2023 Natural Gas Integrated Resource Plan (IRP). Avista appreciates the participation from the various stakeholders in seeking the most reasonable natural gas resource plan for Avista's customers in Oregon.

First, Avista objects to the recommendations of non-acknowledgment of the 2023 IRP. Future technologies, policies, and fuel costs are unknown and will continue to be unknown, yet this fact does not warrant Avista's IRP from being acknowledged. A non-acknowledgement outcome differs from previous IRPs, where the same process was followed and input from interested parties was encouraged and considered. Avista conducted a fair and transparent economic evaluation of resource alternatives to serve Oregon natural gas customers. Acknowledgement of the IRP should not be based on disagreements with the results but rather or not the Company met the planning requirements to serve its customers under the IRP requirements. The 2023 IRP process included a Preferred Resource Strategy (PRS) optimizing for least cost compliance while including fuel price and load risk. Avista further studied the PRS through a Monte Carlo or Stochastic analysis of the assumptions and conducted a thorough scenario analysis to measure portfolio impacts to the unknown futures. These scenarios included electrification of customers and limits on fuel type options. Scenarios are intended to alter a future by more than one expected piece of data to help understand future risks of outcomes not expected in the base case assumptions. Sensitivity analysis is helpful when measuring the impact of a single data piece such as prices. Avista provides this clarity to help understand the difference in modeling based on comments received, particularly those of Staff. These scenarios are broken out by expected futures as found in the PRS scenarios, the low future expectations as found in the electrification scenarios, and the high future expectation where customer growth continues despite policy. These scenarios clearly create a range of future expectations as directed by IRP guidelines.

Many innovative technologies will be needed to solve not only the challenges on the natural gas system, but also on the electric grid to meet state decarbonization mandates. Renewable Natural Gas (RNG) has proven to be a valid method to reduce emissions, and per Climate Protection Program (CPP) rules, should be considered a viable option for CPP compliance, rather relying on procuring the maximum amount of Community Climate Investments (CCI) credits. When considering least cost and least risk, CCI credits are not a long-term solution, so compliance risk remains and drives the need to acquire RNG or other alternative clean fuels. The process to contract for alternative fuels such as RNG will have longer lead times when compared to purchasing a CCI credit. Also, preconceived pathways should not be assumed in IRP planning, rather modeling future scenarios is the bedrock of why IRPs are completed. Avista has shared all costs and inputs on its external website and has walked through these costs with TAC members. Agreement on prices will always be a complicated process, which is why Avista uses industry data or third-party studies for prices or inputs whenever available. It is worth noting that no comments were provided to Avista that disagreed with the assumptions or results of the IRP during the TAC process. In the future, if a new supply asset is acquired, a separate process and analysis is done to evaluate costs and risks compared to the available options at that time. This process will compare the actual cost of a project and impacts on cost and risk to Avista's Oregon customers.

Avista acknowledged electrification as a resource consideration in this IRP. Understanding how cost impacts from the electric grid and conversion costs for the homeowners remains a risk prone calculation. The number of high-level assumptions used in these figures creates a final product that is based on the overall customer base using broad but reasonable assumptions. Conversion costs can vary drastically by service territory, end use, building envelope, incentives, and end use efficiencies. The only way to pinpoint the specific costs would be to conduct a customer-by-customer study using local HVAC and plumbing contractors. Another critical factor in this electrification option surrounds Avista's ability to force a customer to leave its natural gas system. Some customers will convert to electric with incentives, tax credits, and price response, yet others, for a variety of reasons may not, due to resiliency, comfort, avoiding inconveniences, and upfront costs. While energy costs, equity, and environmental components will drive future IRP selections, these costs and implications of compliance may put LDCs at a crossroad of non-compliance to the CPP if they cannot procure or own fuels to reduce emissions.

The work facilitated in the 2023 IRP demonstrate multiple avenues to comply with the CPP while continuing to serve customer demand. In the event alternative fuels such as clean hydrogen and synthetic methane do not progress as expected, electrification or technological innovation of the end use may be a least cost and least risk choice. At this time and based on the analysis done within this IRP process, electrification does not appear to be least cost either through price elasticity or gradual decrease in customers on the distribution system. This, among other risks, will be continually measured and researched, and included in each consecutive IRP process.

Finally, Avista acknowledges policy in Oregon may fundamentally change growth expectations. Avista welcomes a separate, unified, and state-wide effort among all involved energy providers to address system-wide planning. However, Avista's rigorous, multi-year IRP process, which input from interested parties was encouraged and considered, and sound mathematical modeling techniques were applied, resulted in a set of well-vetted, risk-tested solutions across a wide variety of potential futures for Avista's Oregon customers. Through this transparent process, Avista, assisted by the aid of public scrutiny, established for its customers clear, viable, and lowest-cost pathways to compliance with all climate policies in Oregon across all scenarios.

For all of these reasons, Avista requests the Commission **<u>acknowledge</u>** its 2023 IRP.

The following comments are in response to Staff's requests for what they asked Avista to address in reply comments.

Staff's Requests for Reply Comments

Request No. 1: Avista should present a revised Action Plan with Action Items proposed over a consistent timeframe.

Response: Please see Attachment A for a revised Action Plan.

Request No. 2: Avista should detail what steps the Company will take in working with the Technical Advisory Committee (TAC) to correct the Company's approach to climate modeling so future IRPs use a credible forecast for modeling, long-term investments, and decisions.

Response: Avista will continue to transparently run its TAC process including a full month for input from TAC members prior to submitting its IRP. Climate modeling will evolve, like all IRPs data and considerations, and Avista will use the best knowledge and information including the new information learnings from this IRP process in its 2025 IRP. While it is helpful for Staff to recommend to Avista the best ways to model climate change, timeliness of information and guidance will always be an issue in IRPs. Staff's criticism of Avista's use of global climate models (GCMs) indicates these models can only forecast trends and show significant deviations from historical records indicating flaws in the model or assumptions. Unfortunately, Staff nor any other party provided disagreement with Avista's approach during the TAC process. Avista would propose that this topic be approached again during the 2025 IRP development. Further, the GCMs have significant variability in future predictions and since claimed to be not accurate by Staff, Avista will consider the use of alternative methods and/or studies for climate forecasts in its 2025 IRP.

Request No. 3: In future IRPs, provide a comparison between the current CPA and the last CPA, including a narrative explanation of major changes in the potential.

Response: Avista would like to provide clarification as to why the cumulative 20-year savings efficiency potential drops from 18 million therms in the 2021 IRP to 15.3 million therms in this IRP, as provided by the Energy Trust of Oregon (ETO). In Chapter 3, Table 6 illustrates more savings than the previous IRP across every savings category. While 18 million therms is the cost-effective achievable potential from the previous IRP, the corresponding value is 21.6 million therms in this IRP, not 15.3 million therms which is the deployed potential.

Table 6 - 20-Year Cumulative Savings Potential by IRP vintage (Millions of Therms)

	2023 IRP	2020 IRP	Difference
Technical	27.6	24.9	2.7
Achievable	22.3	22.2	0.1
Cost-Effective	21.6	18.0	3.6
Deployed	15.3	14.8	0.5

Also in Chapter 3, Table 7 accounts for the difference between the cost-effective achievable potential between IRPs. The largest driver of increased potential is the load and stock forecast, followed by new emerging technology measures and measure updates. Adding up these differences results in the 3.6 million therm difference between 2023 and the previous IRP.

Table 7 – Difference Between 2023 and 2020 Cost-Effective Achievable Potential (Millions of Therms)

	Difference	Share of Difference
Load and Stock Forecast	+ 1.29	36%
Emerging Technology	+ 0.84	23%
Measure Updates	+ 0.68	19%
Avoided Costs	+ 0.48	13%
Discount Rate	+ 0.34	9%
CE Override	- 0.01	0%
Total	**+ 3.63**	

Request No. 4: Avista should provide an update on the development of all new program offerings, including: timelines for implementation, the Company's thoughts on achieving the saving projected for 2023, and the building of programmatic infrastructure to ramp up to the greater savings forecasted for 2024.

Response: In the spring of 2023, an energy efficiency program was launched for the Company's Interruptible Schedule 440 customers, and in the fall of 2023 a program for Transport Schedule 456 is being implemented. Additionally, Avista is working with the ETO to offer additional programs for its low-income customers and studying the viability of a targeted energy efficiency program offering in two service areas in the Company's service territory to launch in 2024. The ETO's savings goal in 2023 is 427,000 therms and they anticipate exceeding that by achieving an estimated 493,868 therms. During the ETO's 2024 Budget and Action planning process, the Company has reiterated the need to achieve all cost-effective savings and is fully committed to funding energy efficiency as it relates to its least cost planning process. Engagement will be ramped up to Interruptible, Transport, and low-income customers to further support participation and savings. Finally, a low-income hybrid heating pilot is launching in October 2023.

Request No. 5: Avista should discuss whether it intended to apply gas-to-gas costs as electrification conversion values, and if so, why that approach is reasonable.

Response: Avista modelled electrification as a gas equivalent cost, allowing the PLEXOS model to choose electrification or other fuel options to serve customers' heating demands. Avista considered three ways to model electrification: 1) reduce load through the load forecast if electrification is cost-effective for the customer; 2) build a new combined electric and natural gas model that allows the model to select how to serve customer requirements; and, 3) model electrification as natural gas equivalent cost considering customer conversion costs and the new electric demand. Avista chose option 3 to ensure the model can select the most cost-effective method to serve BTU heating demand through either electrification or clean fuels.

The costs included in the IRP were appropriately applied as an estimate of electrification costs. These costs were utilized to make sure overestimates of electrification conversion were not directly applied to the final calculations in amounts that may skew the results away from its selection. Within the IRP, these values range by area and conversion type and are estimated in cities outside of Avista's service territory. Conversion costs will differ by area, building shell age, and efficiency, among other items. In initial comments, concerns with the cost of conversion are discussed, which was low in comparison to most studies, while also pondering why more electrification is not chosen. This is the crux of the problem for Avista, and the low estimates show it is not cost-effective, due to the combination of conversion cost and new electric load. Additionally, supply chain issues, conversion uptake, and the ability to convert fuel types remain larger issues to electrification to determine if it is even possible. For example, how many electricians and plumbers are available to provide these services outside of natural conversion? Will more technicians migrate to jobs if the demand for these services is there? Lastly, will customers agree to a time consuming and high-cost conversion at the time their equipment fails.

Working through how CCIs and other rules and regulations affect the cost of electrification are the primary areas Avista would like to investigate going forward. Additionally, to remain transparent in the process, these costs were discussed in TAC Meeting #4 with all interested parties, who voiced no concerns. Consideration of changes in the 2025 IRP will continue to be explored within the TAC process for all members to provide input and feedback.

Request No. 6: Avista should respond to Staff's concerns about its use of gas-to-gas conversion costs in its modeling, and detail initial steps the Company will take in working with the TAC and Staff to further explore the modeling of electrification as a proactive resource strategy, and the differences between electrify existing and new construction.

Response: Please see response to Request No. 5. Avista will continue to transparently run a TAC process including a full month for input from TAC members before submitting an IRP. Electrification modeling will evolve, like all IRPs, and Avista will use the best knowledge and information including the latest information learnings from the 2023 IRP in its 2025 IRP.

Opportunities to hone and revise assumptions remain a major goal of each IRP. The analysis in future IRPs will be thoroughly reviewed with the TAC for feedback and considerations, as was done throughout the 2023 IRP process. Further, the Company would like to understand expectations of a proactive resource strategy and how this consideration should fall under an LDC responsibility. If alternative fuels prove to be a least cost resource, should the electric providers add this fuel switching cost to resource options in their IRP too?

Additional elements such as estimates from electric providers should be provided to LDCs if this is the intended direction within an IRP. Avista cannot estimate costs for each provider based on their resource needs, so would look to the Commission to accurately estimate these costs. Consideration should also be given to the current mix of generation or delivered electricity emissions and implications to convert to a potentially more carbon intensive energy source, even in the near term. Risks of electricity providers meeting climate goals and cost implications from new transmission and distribution should be considered in this price.

Request No. 7: Avista should comment on including the latest information on distribution projects in future IRP Updates.

Response: Avista strives to consider the latest information available at the time of the IRP development and will continue to include the latest information available in the IRP and through regularly scheduled quarterly meetings with the OPUC. An updated list of Oregon projects from the 2023 IRP is provided below (Chapter 8 of the 2023 IRP). Note there are no high-pressure capital projects currently planned for the next four years, unless a large customer drives the need for upgrades.

Table 8.2: City Gate Station Upgrades

Location	Gate Station	Project to Remediate	Cost	Year	Updates
Medford, OR	Medford #2431	TBD	-	TBD	Continue to monitor need.
Sutherlin, OR	Sutherlin #2626	TBD	-	TBD	May be required to accommodate new customer in 2024.

Request No. 8: Avista should discuss how Order No. 23-281 may impact Avista's current distribution system planning practices. For example, by including analysis of evaluation elements in future IRPs or IRP Updates for Oregon city gate projects, how current targeted conservation resource practices may change, and how demand response offerings fit into its consideration of targeted conservation resources in the future.

Response: Avista is currently engaged with the ETO to identify areas where targeted energy efficiency can help to offset a future system enhancement or upgrade. Currently, Avista does not expect a need for distribution upgrades until 2026 at the earliest, however, this is dependent on customer growth and opportunities to offset these capital projects through energy efficiency, demand response, or other non-pipe alternatives. Understanding where growth will occur is challenging, and Avista will do its best to direct resources and opportunities to avoid these costs where possible. Additionally, Avista has added 3 programs (low-income residential, interruptible, transport) of note to its energy efficiency offerings to help obtain all cost-effective savings and across all customer classes. These programs will help acquire all cost-effective energy efficiency and help to mitigate additional demand.

Request No. 9: Avista should discuss how and if the change to line extension allowances agreed to in the UG 461 Stipulation may impact the Company's revenue requirements, and scenario analysis in future IRPs.

Response: Avista will consider the change to line extension allowances as agreed to in UG 461 in future customer expectations and revenue requirements. This was not analyzed during the 2023 IRP as the settlement stipulation from UG 461 has not yet been approved by the Commission. Careful review and thought will be necessary to fully understand the impacts to Avista's revenue requirements but will be considered in future IRPs.

Request No. 10: Avista should describe how the Black & Veach, Lazard's, and Bloomberg studies inform its green hydrogen price and availability assumptions and how it modeled future price and availability uncertainty.

Response: These studies provide third-party pricing forecasts for non-traditional energy supply. Avista does not procure any significant supply of green hydrogen at this time and has limited budget for research and development. Using publicly available third-party studies provides a reasonable method to determine potential future prices without creating added expenses to Avista's customers for planning consideration. Avista utilized the Black & Veach study to estimate a beginning cost for hydrogen and decreased the annual cost to reflect the studies anticipation on the price of green hydrogen. As with synthetic methane, Avista assumed a supply availability based on the demand for the fuel. The United States Department of Energy also has a program to spur the cost of clean hydrogen to $1 per 1 kilogram in 1 decade. This program is named "The Hydrogen Shot" and is expected to reduce hydrogen costs significantly by the early 2030's. These programs, in combination with federal programs like the Inflation Reduction Act (IRA), are expected to drastically reduce the costs of hydrogen while increasing the supply availability.

Request No. 11: Avista should include information regarding the Company's ability to procure the synthetic methane at the levels necessary for the Oregon PRS. This should include a description of supporting documentation it relied on regarding synthetic gas market development in the United States; price and availability ranges used in Monte Carlo analysis; and any NPVRR analysis it conducted to measure the severity of bad outcomes associated with missing synthetic methane targets or a future in which the synthetic methane procured cannot be used for CPP compliance.

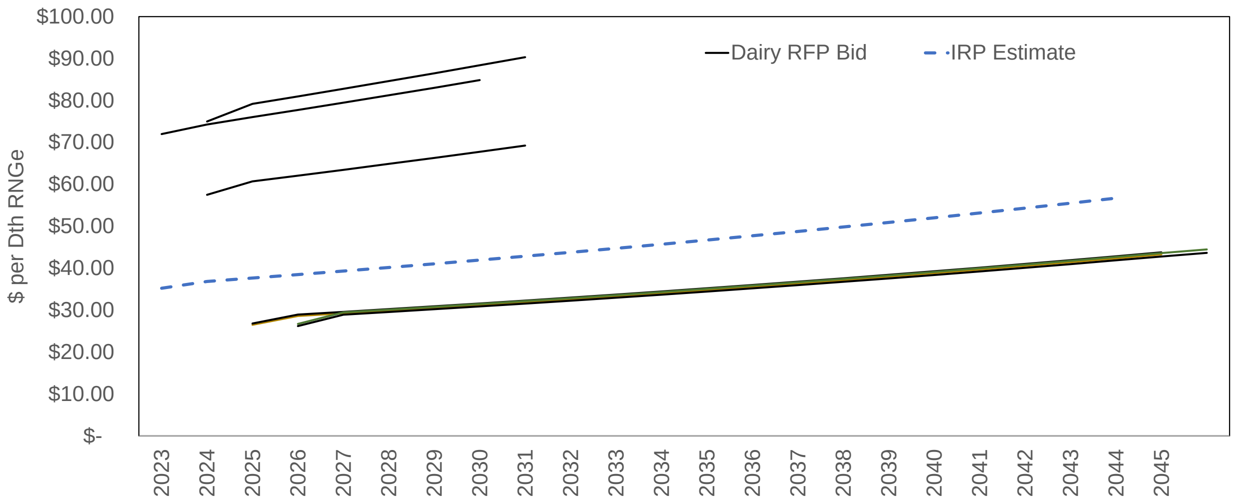
Response: Avista agrees future natural gas alternative technologies are a risk to meet the climate goals of the state and Avista's PRS. But there are also technology risks for electrification in serving new winter loads previously not electrified. These technology risks include long duration energy storage, green hydrogen-based peaking fuels, carbon capture for the electric businesses, and the significant uncertainty in heat pumps to provide enough BTUs during cold weather events. Studies in response to Request No. 10 illustrate the expected hydrogen market over the study horizon. For example, the IRA offers incentives for carbon reducing fuels and technologies and are expected to drastically reduce the carbon content found in the nation's energy grid.

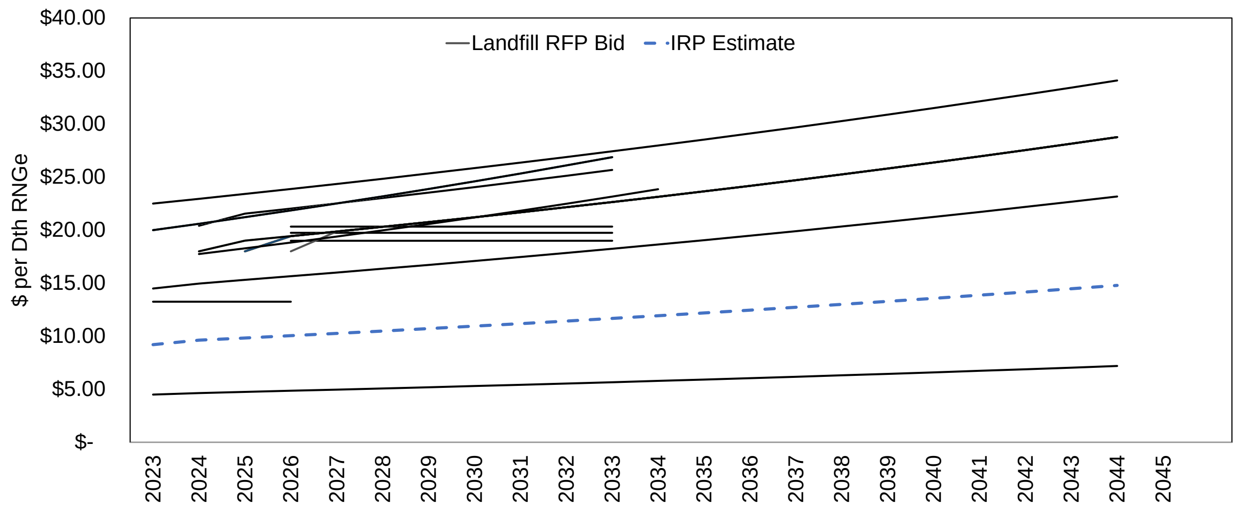
Further, Avista conducted a 500-draw price forecast for each alternative supply-side resource to account for pricing risks of these new technologies. The methodology generated random monthly prices following a lognormal distribution type around resource-specific expected annual price curves, constrained by minimum and maximum values, and varied by an error standard deviation curve and autocorrelation factor. The resultant set of price forecasts for each resource represents the range used in Monte Carlo analysis. Availability ranges were not applied in Monte Carlo analysis. Synthetic methane was constrained based on demand of the resource and is a common method used by consultants in fundamental forecasts of natural gas among other commodities. The assumption is if there is demand for a given item or commodity, supply will grow based on this demand and cost implications.

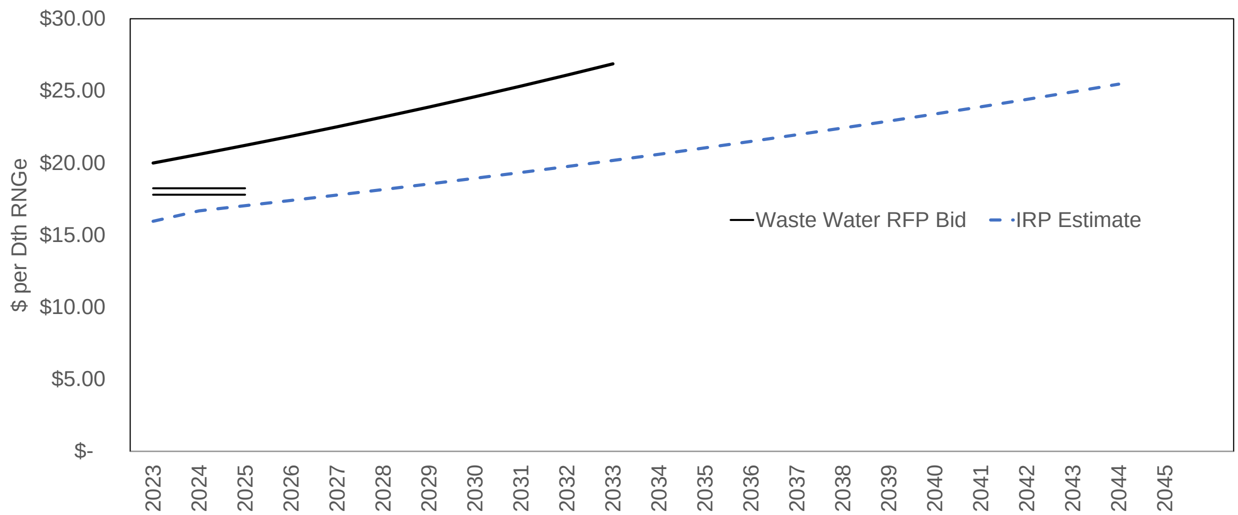
Assuming the price forecasts of synthetic menthane prove to be correct, Avista, if it chooses to, can ensure supply. Synthetic methane is a derivative of green hydrogen which is a derivative of clean electricity. If Avista does pursue synthetic methane, it will be acquired either through ownership or long-term contracts for the clean electricity by building generating facilities and the associated hydrolysis and air capture facilities to produce the gas. Further, Avista has storage rights at Jackson Prairie to deal with fluctuations in production vs. demand. Avista is less concerned with the volume of the production but rather at what price can any volume be developed assuming air capture and electrolysis (or alternative) technology can scale.

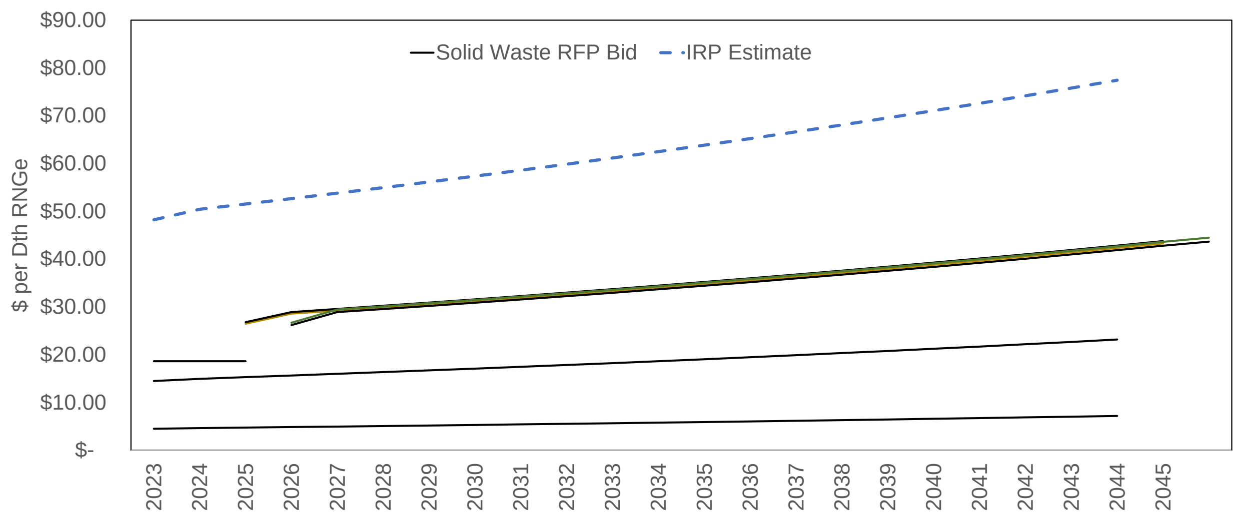
Request No. 12: Avista should provide a brief explanation of how RNG cost assumptions have changed since the 2018 report was published, and if so, further explain how the Black & Veatch study remains applicable.

Response: The Black & Veatch report was provided to Avista through a consulting contract. These prices estimate production costs of RNG by source. While costs vary depending on location, market factors, and capital structure, the costs align with those Avista has seen in the initial Request for Proposal (RFP) process. The difference being the RFP considers market factors, such as the Low Carbon Fuel Standard (LCFS) and Renewable Identification Number (RIN) program, in their bid price offer. The graphs below show bid prices per MMBtu as compared to IRP estimates (dashed line) by source. These costs align with the market and in some cases, such as solid waste, are on the high side of prices.









Request No. 13: Avista should explain its strategy to acquire the millions of therms of RNG indicated in the Company's Action Plan and its reasoning behind its decision not to select any of the RFP response offerings.

Response: Avista is planning to acquire RNG volumes to meet carbon reduction requirements in both Oregon and Washington. Since these requirements increase over time, Avista's strategy is to acquire RNG through the RFP process in the near term, with a focus on long-term purchase contracts that have volumetric flexibility at least cost. An annual RFP cycle will continue to provide market indicators for pricing and volumetric availability.

In the case of the 2022 RNG RFP, Avista did not select any of the RFP response offerings because the pricing was higher than the Pine Creek RNG projects, which came to Avista as off-cycle (prior to and after the RFP cycle) proposals and has since been contracted for by Avista.

Request No. 14: As discussed in Section 7.1.1, Avista should explain how the Company intends to measure cost effectiveness within a changing resource portfolio in line with the CPP.

Response: As actual resources are presented to Avista, cost-effectiveness will be determined using the PLEXOS model and assumptions for a supply selection within the model. The model will contain updated costs, where available, and assumptions where needed. Other methods and models may be used in addition to PLEXOS to create a robust process for resource evaluation and will be discussed during the TAC process.

Request No. 15: Avista should discuss the extent to which the Company has been able to successfully mitigate costs from unused capacity resources in the past, Avista's release market forecast, and Avista's long term mitigation strategy.

Response: Avista's contracted pipeline capacity on Gas Transmission Northwest (GTN) consists of two pieces of King-Malin transport that are only October through March, so customers are not paying for transportation through the summer months, rather only when they do need it. The capacity in the summer is only 13,500 dekatherms for Oregon customers vs. the winter of 35,120 dekatherms, saving customers about $0.25 per MMBtu per day.

Avista's subscription on Northwest Pipeline includes a long-standing segmentation done for a receipt point of natural gas, where gas is produced, in the Rockies with a delivery to Grants Pass, Oregon. The Company releases the Rockies to South Idaho path to IGI Resources, Inc. and maintains a path from Stanfield to Grants Pass, Oregon for customers. This means customers do not pay for a 10,000 MMBtu piece of pipeline because of the release.

A release market forecast is based on the IRP from a peak resource need and market conditions on a monthly and daily basis. Avista's long term strategy is to maintain deliverability of the necessary volumes of natural gas as dictated by the IRP. Depending on where alternative fuels reside, these resources may be necessary for delivery well into the future.

Request No. 16: Avista should provide the NPVRR for each scenario / portfolio / future. Provide all results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results. If levelized costs are in fact fungible with NPVRR, Avista should explain why the Company chose not to include NPVRR in the IRP.

Response: Rank ordering scenario results as suggested would be an incorrect methodology in the IRP. Comparing similar scenarios would be appropriate and is provided within the IRP as levelized costs consider NPVRR, including capital cost, making it a present value, yearly indicator. While the study horizon may change and alter the NPVRR, using a levelized price makes result comparisons easier. For example, when comparing the electrification scenarios to the PRS, they appear closer than with levelized costs. This is due to the first two years of the study only relying on natural gas, mostly, with some CCIs and alternative fuels as electrification begins in the year 2025. The results of NPVRR from 2023-2042 can be found below and is represented by scenario:

Scenario	20 year NPVRR (Billions $)
PRS - Allowance Price Ceiling	$ 4.65
PRS - High Prices	$ 5.08
PRS	$ 3.93
PRS - Low Prices	$ 3.51
High Customer Case	$ 4.05
Average Case	$ 3.84
Electrification - High Conversion Costs	$ 5.77
Electrification - Expected Conversion Costs	$ 4.45
Electrification - Low Conversion Costs	$ 3.75
Hybrid Total Costs	$ 4.75
Limited RNG Availability	$ 4.31
Carbon Intensity	$ 4.02
Social Cost of Carbon	$ 7.01
Interrupted Supply	$ 3.95

NPVRR will be done on a portfolio level in future IRPs as unintended confusion seems to have occurred based on levelized costs.

Request No. 17: Avista should conduct a sensitivity analysis to determine the NPVRR improvement by acquiring CCIs up to DEQ limits, as needed, in each year that they are less expensive than other compliance options.

Response: In its 2023 IRP, Avista ran 14 separate scenarios to understand the risk and cost of various futures. In its acquisition of RNG to date, Avista expects RNG to be a cheaper option to CCIs, so running additional sensitivities will not provide additional understanding of least cost as has been continually described throughout chapters 6 and 7. Regardless, in response to the request, the NPVRR of a Max CCI sensitivity from the PRS base assumptions is $4.576 billion.

Request No. 18: Avista should clarify why the PLEXOS selected RNG over CCIs from 2023 to 2026 if indeed CCIs are the cheaper resource.

Response: Need is the simple answer. The CPP creates a need for carbon reducing resources or demand reduction. RNG is selected as an offset as CCIs are limited in availability, while reducing each year moving forward. PLEXOS looks at the entire horizon and determines the least cost option. If purchasing RNG can be done at a cheaper price and satisfies model constraints for energy and environmental areas, the resource is selected. The environmental cap is based directly on the CPP and is broken out by each LDC. As mentioned previously, CCIs run out in the near term so other avenues to meet energy and emissions constraints are analyzed. Also, CCIs must be paired with the fuel, meaning it's an additional cost to provide both energy and procure the CCI for compliance. Natural gas price is high in the near term so the full cost of compliance to meet energy demands and emissions constraints are considered when selecting RNG. As prices of RNG or natural gas change, strategy must change to account for least cost and risk. This will be an ongoing analysis to determine the least cost and least risk answer when comparing resources.

Request No. 19: Avista should clarify how PLEXOS accounts for the emissions from transport and interruptible customers, as well as how the Company intends to attribute CCP compliance costs to transport and interruptible customers.

Response: Avista accounts for emissions from all customers, including transport and interruptible customers, the same way. The Company assumes transport and interruptible customers only use natural gas, so emissions are related to their estimated demand. With these customers, Avista supplies the environmental offset to meet CPP cap constraints as a system, where all customers comply with the CPP cap. The model allows for both transport and interruptible customers to select alternative resources as with other classes in the model. CPP compliance costs are expected to be included as a volumetric charge for all customer classes.

Request No. 20: Referencing the discussion in Section 8.3, Avista should provide PRS information that includes planned infrastructure costs, identified as new customer vs. maintenance of existing system. Include both transportation and storage assets as well as distribution assets (including line extension allowances).

Response: Jackson Prairie costs do not change based on the addition of new customers, as the facility requires capital to keep its rated capacity operationally available in addition to running the facility. Planned infrastructure costs have been included in response to Request No. 7. Avista does not track costs of new verses existing in this context for distribution, as all customers benefit from the resource. Expected maintenance of the existing system was not included in the PRS.

Year	JP (OR) ($,000's)	OR Transportation ($,000's)
2023	$ 625	$ 18,217
2024	$ 642	$ 18,581
2025	$ 652	$ 18,953
2026	$ 664	$ 19,332
2027	$ 678	$ 19,718
2028	$ 690	$ 20,113
2029	$ 704	$ 20,515
2030	$ 718	$ 20,925
2031	$ 732	$ 21,344
2032	$ 747	$ 21,770
2033	$ 762	$ 22,206
2034	$ 778	$ 22,650
2035	$ 794	$ 23,103
2036	$ 811	$ 23,565
2037	$ 828	$ 24,036
2038	$ 845	$ 24,517
2039	$ 863	$ 25,007
2040	$ 882	$ 25,508
2041	$ 901	$ 26,018
2042	$ 920	$ 26,538
2043	$ 941	$ 27,069
2044	$ 961	$ 27,610
2045	$ 983	$ 28,162

Further, Avista is not expecting many new natural gas customers in the future. For new customers only, as agreed to and if approved by the Commission in Avista's 2023 general rate case, line extension allowances for connecting new customers will be reduced to the following amounts: $2,500 in 2024, $1,250 in 2025, $750 in 2026 and $0 for all future years beginning in 2027.

Request No. 21: Referencing the discussion in Section 9.2.1, Avista should provide the avoided costs of selecting electrification. If the PLEXOS model does not have information on

the avoided costs of electrification, Avista should explain whether the PLEXOS model has any output that could be used to help inform the avoided cost and provide a detailed example.

Response: Section 9.2.1 is not known to Avista or its documents. Appendix 6.4 contains the avoided costs from these scenarios where electrification was selected and is provided below.

APPENDIX 6.4: ELECTRIFICATION – LOW CONVERSION COST CASE AVOIDED COST ($/DEKATHERM)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	6.93	5.68	4.46	3.95	3.73	3.66	3.47	4.15	4.40	4.62	5.02	5.19
ID_Ind	6.31	5.13	4.07	3.61	3.42	3.38	3.29	3.99	4.25	4.48	4.84	5.02
ID_Res	7.09	5.83	4.57	4.04	3.82	3.74	3.52	4.20	4.45	4.68	5.08	5.25
Klamath Falls_Com	6.17	4.81	4.84	5.37	5.49	6.12	6.95	8.20	9.37	11.34	11.75	12.05
Klamath Falls_Ind	5.67	4.66	4.68	5.28	5.42	6.06	6.88	8.13	9.32	11.27	11.68	11.97
Klamath Falls_Res	6.26	4.85	4.88	5.39	5.52	6.14	6.97	8.22	9.39	11.36	11.78	12.07
LaGrande_Com	7.06	5.98	5.62	6.12	6.19	6.76	7.30	8.50	9.62	11.54	12.01	12.30
LaGrande_Ind	5.47	4.73	4.73	5.37	5.51	6.12	6.90	8.15	9.33	11.24	11.65	11.96
LaGrande_Res	7.05	5.98	5.62	6.12	6.19	6.76	7.31	8.51	9.63	11.54	12.02	12.31
Medford_Com	6.11	4.79	4.81	5.35	5.48	6.11	6.94	8.18	9.35	11.32	11.73	12.03
Medford_Ind	5.64	4.59	4.63	5.23	5.37	6.02	6.84	8.09	9.27	11.21	11.63	11.92
Medford_Res	6.26	4.85	4.87	5.39	5.51	6.14	6.97	8.21	9.38	11.35	11.77	12.06
OR_Tport	5.48	4.17	9.56	9.35	2.81	9.60	9.93	10.22	10.56	10.88	11.30	11.60
Roseburg_Com	6.16	4.80	4.82	5.35	5.48	6.11	6.94	8.19	9.36	11.32	11.74	12.03
Roseburg_Ind	5.65	4.58	4.63	5.22	5.37	6.01	6.84	8.09	9.26	11.21	11.62	11.92
Roseburg_Res	6.25	4.85	4.87	5.39	5.51	6.14	6.97	8.21	9.39	11.35	11.77	12.06
WA_Com	9.21	8.11	6.98	6.62	6.59	6.73	6.77	6.61	6.63	6.80	7.24	7.44
WA_Ind	8.58	7.56	6.59	6.28	6.28	6.45	6.59	6.44	6.47	6.65	7.05	7.26
WA_Res	9.29	8.18	7.03	6.66	6.63	6.77	6.80	6.63	6.65	6.83	7.27	7.46
WA_Tport	5.53	6.51	5.85	5.58	5.62	5.81	6.18	6.04	6.08	6.26	6.62	6.86

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	5.44	5.70	5.97	6.23	6.56	6.97	7.31	7.61	8.01	8.34	8.71
ID_Ind	5.29	5.54	5.81	6.08	6.41	6.82	7.16	7.44	7.85	8.16	8.55
ID_Res	5.50	5.75	6.03	6.29	6.61	7.03	7.37	7.67	8.08	8.42	8.78
Klamath Falls_Com	12.40	12.78	21.11	21.22	21.13	18.93	18.55	18.03	17.61	15.86	13.79
Klamath Falls_Ind	12.34	12.71	21.02	21.14	20.93	18.70	18.30	17.69	17.14	15.35	13.16
Klamath Falls_Res	12.42	12.81	21.13	21.25	21.19	19.01	18.63	18.15	17.77	16.04	14.00
LaGrande_Com	12.63	12.83	21.15	21.27	21.18	19.00	18.62	18.12	17.71	15.95	13.93
LaGrande_Ind	12.33	12.65	20.93	21.07	20.69	18.41	18.00	17.19	16.37	14.51	12.10
LaGrande_Res	12.64	12.84	21.15	21.28	21.21	19.02	18.64	18.16	17.77	16.02	14.01
Medford_Com	12.38	12.76	21.08	21.20	21.08	18.88	18.49	17.95	17.42	15.62	12.50
Medford_Ind	12.29	12.65	20.97	21.09	20.87	18.62	18.22	17.58	16.96	15.12	12.36
Medford_Res	12.41	12.79	21.12	21.23	21.16	18.96	18.58	18.06	17.57	15.70	12.35
OR_Tport	12.17	12.53	20.74	20.89	20.91	18.46	18.08	17.60	17.32	15.82	14.21
Roseburg_Com	12.39	12.76	21.09	21.21	21.10	18.90	18.51	17.98	17.45	15.66	12.54
Roseburg_Ind	12.29	12.65	20.96	21.09	20.88	18.64	18.24	17.60	17.00	15.18	12.47
Roseburg_Res	12.41	12.80	21.12	21.24	21.16	18.97	18.58	18.09	17.58	15.80	12.53
WA_Com	6.86	6.96	7.22	7.48	7.44	7.74	8.12	8.48	8.94	9.34	9.77
WA_Ind	6.70	6.79	7.05	7.32	7.28	7.57	7.96	8.30	8.76	9.13	9.59
WA_Res	6.89	6.99	7.24	7.51	7.47	7.76	8.15	8.52	8.98	9.38	9.81
WA_Tport	6.30	6.40	6.66	6.94	6.92	7.20	7.60	7.93	8.39	8.76	9.23

Appendix 6.4: Limited RNG Availability Case Avoided Cost ($/Dekatherm)

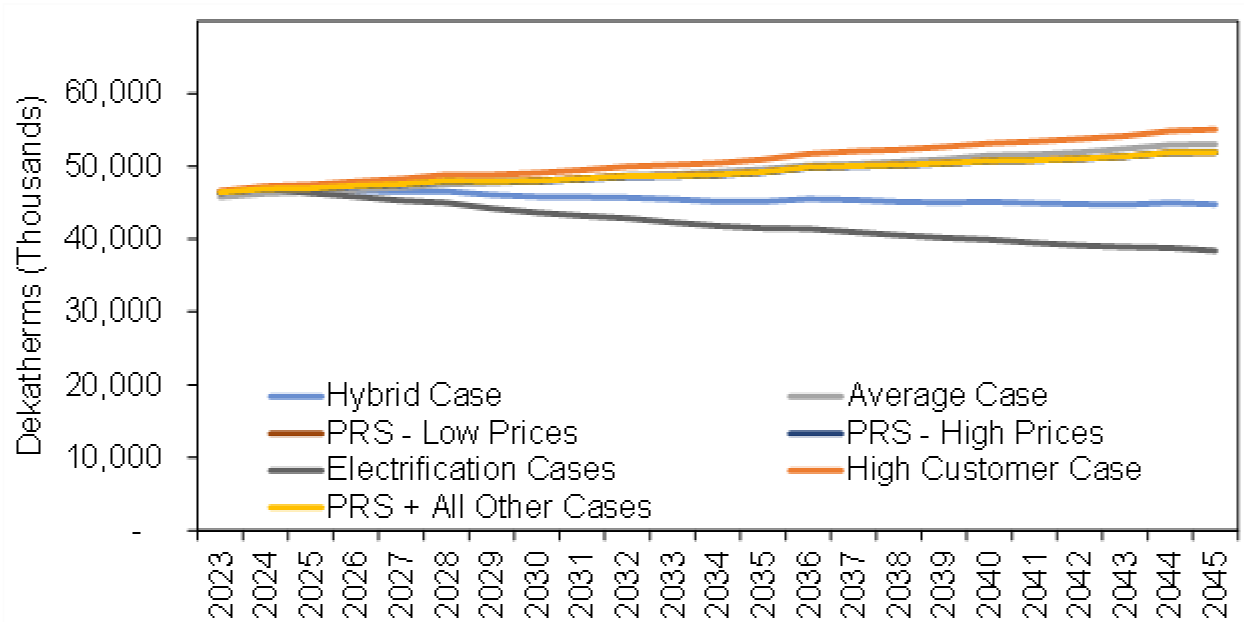
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ID_Com	6.94	5.70	4.49	3.99	3.79	4.03	3.91	4.56	4.78	5.09	5.23	5.43
ID_Ind	6.32	5.14	4.09	3.64	3.47	3.62	3.61	4.29	4.53	4.81	4.83	5.04
ID_Res	7.11	5.86	4.60	4.09	3.89	4.14	4.00	4.65	4.86	5.19	5.39	5.59
Klamath Falls_Com	5.71	8.79	9.18	9.70	9.84	10.48	31.76	32.05	29.32	25.85	32.73	31.44
Klamath Falls_Ind	5.67	8.64	9.02	9.60	9.76	10.41	31.66	31.96	29.26	25.77	32.48	31.19
Klamath Falls_Res	5.75	8.83	9.22	9.72	9.87	10.50	31.79	32.07	29.34	25.87	32.82	31.53
LaGrande_Com	5.31	8.78	8.94	9.40	9.55	10.34	29.16	29.52	27.03	24.07	30.62	29.51
LaGrande_Ind	5.49	8.70	9.06	9.67	9.83	10.52	31.58	31.88	29.18	25.72	32.06	30.77
LaGrande_Res	5.93	9.60	9.65	10.18	10.33	11.29	31.90	32.11	29.34	25.89	32.74	31.45
Medford_Com	5.64	8.75	9.14	9.67	9.82	10.46	31.73	32.03	29.31	25.83	32.63	31.34
Medford_Ind	5.64	8.56	8.97	9.56	9.71	10.35	31.60	31.92	29.23	25.74	32.28	31.01
Medford_Res	5.20	8.11	8.53	9.16	9.56	10.43	31.78	32.07	29.33	25.86	32.74	31.45
OR_Tport	5.48	10.13	9.56	9.35	9.40	10.02	31.18	31.49	28.83	25.43	32.35	31.10
Roseburg_Com	5.66	8.77	9.16	9.68	9.82	10.46	31.74	32.04	29.31	25.83	32.63	31.35
Roseburg_Ind	5.65	8.54	8.97	9.55	9.70	10.34	31.59	31.92	29.22	25.74	32.26	30.99
Roseburg_Res	5.74	8.82	9.21	9.72	9.86	10.50	31.78	32.07	29.33	25.86	32.76	31.47
WA_Com	8.31	8.40	7.29	6.96	6.96	7.51	7.57	7.35	7.31	7.63	7.91	8.14
WA_Ind	8.59	7.58	6.62	6.31	6.33	6.72	6.93	6.76	6.77	7.00	7.08	7.32
WA_Res	8.35	8.43	7.32	6.98	6.98	7.53	7.59	7.37	7.33	7.65	7.95	8.17
WA_Tport	5.53	6.51	5.85	5.58	5.62	5.81	6.18	6.04	6.08	6.26	6.25	6.49

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ID_Com	5.69	6.10	6.24	6.61	6.92	7.34	7.66	7.93	8.30	8.55	8.85
ID_Ind	5.32	5.68	5.89	6.25	6.59	7.01	7.36	7.65	8.06	8.32	8.66
ID_Res	5.84	6.27	6.38	6.75	7.05	7.48	7.78	8.05	8.41	8.65	8.94
Klamath Falls_Com	30.11	28.67	27.27	25.81	24.35	22.82	21.35	19.74	18.16	16.46	14.73
Klamath Falls_Ind	29.88	28.44	27.06	25.61	24.17	22.65	21.21	19.61	18.06	16.36	14.64
Klamath Falls_Res	30.19	28.75	27.35	25.88	24.41	22.87	21.40	19.79	18.20	16.50	14.77
LaGrande_Com	28.46	27.28	26.07	24.75	23.49	22.05	20.64	19.08	17.54	15.90	14.22
LaGrande_Ind	29.48	28.04	26.66	25.22	23.81	22.31	20.94	19.34	17.85	16.15	14.45
LaGrande_Res	30.11	28.67	27.27	25.81	24.34	22.82	21.36	19.74	18.16	16.46	14.73
Medford_Com	30.01	28.57	27.18	25.72	24.27	22.75	21.30	19.69	18.12	16.42	14.69
Medford_Ind	29.71	28.26	26.89	25.45	24.03	22.52	21.12	19.51	17.99	16.29	14.56
Medford_Res	30.12	28.68	27.28	25.82	24.35	22.82	21.36	19.74	18.16	16.46	14.73
OR_Tport	29.76	28.30	26.91	25.46	24.01	22.46	21.16	19.55	18.07	16.36	14.65
Roseburg_Com	30.02	28.58	27.19	25.74	24.28	22.76	21.31	19.70	18.13	16.42	14.69
Roseburg_Ind	29.69	28.25	26.89	25.45	24.03	22.52	21.12	19.52	18.00	16.29	14.57
Roseburg_Res	30.13	28.69	27.30	25.83	24.37	22.84	21.37	19.76	18.17	16.47	14.74
WA_Com	7.55	7.87	7.91	8.31	8.24	8.54	8.89	9.18	9.57	14.08	14.37
WA_Ind	6.77	6.99	7.15	7.52	7.49	7.79	8.18	8.53	8.99	13.54	13.91
WA_Res	7.59	7.91	7.94	8.33	8.27	8.58	8.92	9.21	9.60	14.10	14.39
WA_Tport	5.95	6.08	6.37	6.68	6.69	7.00	7.42	7.82	8.35	12.97	13.41

Request No. 22: Staff would like the Company to discuss how the Company modeled the Hybrid option of the electrification scenario, including cost and demand implications and the likelihood of hybrid heat pump adoption.

Response: Avista did not include new customers in the electrification scenario. The hybrid scenario considers space heating only for any new residential or commercial customer beginning in 2025. The space heat demand begins at temperatures less than or equal to 40 degrees Fahrenheit or 25 heating degree days. Cost implications on a NPVRR basis can be found in response to Request No. 16. Additionally, demand implications when compared to other scenarios can be found in the IRP in Table 7.1 and below. Note the declining demand expectations from this scenario places it between the PRS and electrification.

Figure 7.1: Demand by Scenario



Request No. 23: Referencing the discussion in Section 9.2.1, Avista should provide the percentage of gas customers leaving the system in the two instances where PLEXOS selects Building Electrification as a resource.

Response: Section 9.2.1 is not known to Avista or its documents. The table below shows the decrease in demand from overall demand in the electrification low conversion costs scenario and the limited RNG availability scenario as compared to the PRS. The electrification scenario has a forced removal of gas customers to the power grid, so the amount of electrification chosen in 2023 thru 2045 is combined with these conversion customers, making the delta higher in comparison to the limited RNG availability scenario. In the limited RNG scenario, electrification is chosen in 2023, also for the entire study period through 2045, but when compared to growth expectations, is much less as a percentage considering new customers on the LDC system.

Scenario	PRS Demand (1,000 Dth)	Electrification - Low Conversion Cost Demand (1,000 Dth)	Limited RNG Availability Demand (1,000 Dth)	PRS (Customers)	Electrification - Low Conversion Costs (Delta vs. PRS)	Limited RNG Availability (Delta vs. PRS)
2023	46,394	45,483	44,867	379,669	-2%	-3%
2024	46,884	46,024	45,344	384,908	-2%	-3%
2025	46,990	45,335	45,445	390,101	-4%	-3%
2026	47,315	44,882	45,762	395,177	-5%	-3%
2027	47,553	44,357	45,995	399,998	-7%	-3%
2028	48,000	44,040	46,436	404,756	-8%	-3%
2029	47,895	43,242	46,335	409,488	-10%	-3%
2030	48,008	42,663	46,448	414,184	-11%	-3%
2031	48,295	42,232	46,735	418,880	-13%	-3%
2032	48,628	41,870	47,063	423,575	-14%	-3%
2033	48,713	41,309	47,152	428,251	-15%	-3%
2034	48,854	40,819	47,293	432,919	-16%	-3%
2035	49,203	40,513	47,642	437,564	-18%	-3%
2036	49,860	40,434	48,295	442,201	-19%	-3%
2037	50,051	40,021	48,490	446,823	-20%	-3%
2038	50,167	39,577	48,606	451,426	-21%	-3%
2039	50,424	39,235	48,863	456,019	-22%	-3%
2040	50,758	38,948	49,193	460,587	-23%	-3%
2041	50,855	38,518	49,293	465,148	-24%	-3%
2042	51,062	38,172	49,501	469,703	-25%	-3%
2043	51,348	37,944	49,787	474,269	-26%	-3%
2044	51,879	37,834	50,313	478,838	-27%	-3%
2045	51,948	37,437	50,387	483,488	-28%	-3%

Request No. 24: Referencing the discussion in Section 9.2.1, Avista should discuss how selection of the electrification scenarios may assist in reducing the CPP compliance costs.

Response: Section 9.2.1 is not known to Avista or its documents. When electrification is selected, it may help reduce Avista's CPP costs as electrified load is no longer an obligation under Avista's cap trajectory. However, alternative fuels remain a cheaper option as compared to electrification. Avista analysis has shown in its electrification scenarios that although it may be a resource option, the selection as a least cost for CPP compliance is not supported as Staff and other comments suggest. Please see the response to Request No. 16 for NPVRR for cost implication results for selecting electrification vs alternative fuels and market offsets.

Staff Requests for Future IRPs

Request for Next IRP 1: Avista's scenario analyses should reflect the potential for Oregon policies mandating electrified space and water heating, reductions in line extension allowances, and other such policies that might reduce customer count expectations.

Response: Avista will include this request in the 2025 IRP.

Request for Next IRP 2: Avista should describe its strategy for synthetic methane procurement through the lens of on-system ownership of green hydrogen and/or carbon capture facilities and off-system contracts.

Response: Avista is open to dialogue regarding this question in the 2025 IRP process and not as a specific action item.

Request for Next IRP 3: The next IRP should include an update of Avista's approach to hydrogen acquisition as it relates to build versus buy to ensure Avista's proposed levels of synthetic methane usage.

Response: Avista is open to dialogue regarding this question in the 2025 IRP process and not as a specific action item.

Request for Next IRP 4: In its next IRP, Avista should continue to include and update its build versus buy decision-making approach and engage with stakeholders on this topic in a TAC meeting.

Response: Avista is open to dialogue regarding this question in the 2025 IRP process and not as a specific action item.

Conclusion

In the path of a transparent process and meeting stakeholder expectations, Avista works with the TAC as a sounding board and major contributor to its IRP. Avista appreciates stakeholders' participation in the Company's IRP TAC and looks forward to continued collaboration in the Company's resource planning efforts. As requested above, Avista asks that the Commission acknowledge its 2023 IRP as the Company has met all IRP requirements.

Please contact Tom Pardee with any questions regarding these comments at 509-495-2159 or tom.pardee@avistacorp.com.

Sincerely,

/s/ Shawn Bonfield

Shawn Bonfield
Sr. Manager Regulatory Policy & Strategy
509-495-2782
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Attachment A

The 2023-2024 Action Plan below provides a detailed list of actions the Company anticipates over the 2025 Natural Gas IRP planning horizon.

2023-2024 Action Plan

1. Purchase Community Climate Investment credits for compliance with the CPP for years 2022 through 2026.
2. ETO identified 546,000 therms in the 2023 IRP verses 427,000 therms of planned savings in the 2023 ETO Budget and Action Plan. Avista will work with the ETO to meet the IRP gross savings target of 568,000 therms in 2024, 590,000 therms in 2025 and 614,000 therms in 2026.
3. A new program offered by ETO for interruptible customers in 2023 to save 15,000 therms. (This action item is included in the summary values in Action item 4.)
4. Engage Oregon stakeholders to explore additional new offerings for interruptible, transport, and low-income customers to work towards identified savings of 375,000 therms in 2024, 381,000 therms in 2025 and 371,000 therms in 2026.
5. In Oregon, acquire 8.64 million therms of RNG in 2023, 21.80 million therms of RNG in 2024, 23.52 million therms in 2025, and 26.03 million therms in 2026.
6. In Washington, purchase allowances or offsets for compliance to the Climate Commitment Act for years 2023 through 2026 to comply with emissions reduction targets.
7. Begin to offer a Washington transport customer energy efficiency program by 2024 with the goal of saving 627,237 therms.
8. Explore methods for using Non-Energy Impact (NEI) values in future IRP analysis to account for social costs in Oregon and Washington to ensure equitable outcomes.
9. Explore using end use modeling techniques for forecasting customer demand.
10. Consider contracting with an outside entity to help value supply side resource options such as synthetic methane, renewable natural gas, carbon capture, and green hydrogen.
11. Regarding high pressure distribution or city gate station capital work, Avista does not expect any supply side or distribution resource additions to be needed in our Oregon territory for the next four years, based on current projections. However, should conditions warrant that capital work is needed on a high-pressure distribution line or city gate station in order to deliver safe and reliable services to our customers, the Company is not precluded from doing such work. Examples of these necessary capital investments include the following:
    - Natural gas infrastructure investment not included as discrete projects in IRP

- Consistent with the preceding update, these could include system investment to respond to mandates, safety needs, and/or maintenance of system associated with reliability

- Including, but not limited to Aldyl A replacement, capacity reinforcements, cathodic protection, isolated steel replacement, etc.

    - Anticipated PHMSA guidance or rules related to 49 CFR Part §192 that will require additional capital to comply

- Officials from both PHMSA and the AGA have indicated it is not prudent for operators to wait for the federal rules to become final before improving their systems to address these expected rules.

    - Other special contract projects not known at the time the IRP was published

- Other non-IRP investments common to all jurisdictions that are ongoing, for example:

    - Enterprise technology projects & programs

    - Corporate facilities capital maintenance and improvements