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January 16, 2024

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 on Staff's Final Comments & Recommendations**

Avista Corporation, dba Avista Utilities (Avista or the Company), provides the following comments on Oregon Public Utilities Commission (Commission) Staff's (Staff) final comments and recommendations pertaining to the Company's 2023 Natural Gas Integrated Resource Plan (IRP).

First, Avista objects to Staff's recommendations of non-acknowledgment of the 2023 IRP. As mentioned in its previous reply comments, Avista conducted a fair and transparent economic evaluation of resource alternatives to serve Oregon natural gas customers while following the same process as past IRPs, which all have been acknowledged. Much of Staff's comments pertaining to their recommendation of non-acknowledgment relate to the Climate Protection Program (CPP), which on December 20, 2023, the Oregon Court of Appeals has ruled the CPP rules as invalid. Regardless of the CPP being ruled invalid, Avista conducted a least cost solution to serve customer demand given the environmental and economic constraints known at the time of the IRP. This court decision now complicates this IRP process and renders much of the discussion contained within Staff's comments as moot. As such, all Staff recommendations, expectations, and requests relating to the CPP should not be adopted by the Commission. Further, the court decision will alter the Company's Preferred Resource Strategy (PRS) that contained a least cost compliance path to meet CPP requirements.

Second, if the Commission chooses not to acknowledge Avista's IRP, it then begs the question of what the purpose of acknowledgment really means. Importantly, an IRP is a planning document that is not approved, is updated every two years, and does not include any form of a prudency determination on the content within the plan. Rather, the prudency of resource acquisitions or investments will be determined through the general rate case process. As such, a review of the time, effort, and resources to process an IRP is warranted. A general rate case has a 10-month procedural schedule while it will be nearly 11 months since the time of filing to a Commission decision on Avista's 2023 IRP. If acknowledgment does not have true impact, is the time, analysis, and extended review process worth the effort?

Third, the overall number of recommendations, expectations, and requests proposed by Staff is overly burdensome and not warranted. Avista must fulfill requirements and directives from each Commission it serves within the IRP. Combining Staff's list with that in the other states Avista serves will be difficult, if not impossible, to complete in Avista's 2025 IRP. Another general concern Avista has with Staff's recommendations, expectations, and requests is that many of the items require or request discussion and involvement from Avista's Technical Advisory Committee (TAC). For this IRP, Staff devoted a significant amount of time to reviewing the IRP after it was completed and filed with the Commission but did not significantly contribute during the TAC process when the IRP was in development, and where Staff had the opportunity to provide feedback in time for changes to be made before the IRP was finalized. Had Staff been more involved in the TAC process, some or many of their comments and concerns likely could have been alleviated. For Avista's next IRP, it is unreasonable to expect Avista to complete Staff's requests if Staff may not fully participate or contribute in the TAC discussions on the items requiring completion during the public process. Further, certain items requested by Staff, described later in these comments, should be led by Staff, especially when it comes to presenting Staff's own ideas or concepts.

Turning attention to other issues, the availability, and volumes of RNG was a shared concern by Staff and other parties. With the CPP no longer in effect, these concerns are no longer valid, however, the notion there are not enough quantities of RNG available as modeled in Avista's 2023 IRP to meet either near term or long-term requirements as selected in the PRS is incorrect. As indicated by both the 2022 and 2023 Alternative Fuel Request for Proposal (RFPs), volumes bid exceeded assumptions of the PRS. This is also supported by the United States Energy Information Administration that has stated there was an equivalent of 212 billion cubic feet of landfill gas alone collected in 2022.[1] Finally, additional capacity is based on climate programs including the CPP and incentives from the Inflation Reduction Action (IRA).[2] Concerns regarding price and availability appear to be related to projects within the Northwest, whereas the CPP did not constrain project locations allowing for greater availability.

Avista included electrification as an option to serve demand and price elasticity to switch from natural gas was measured in all scenarios in the 2023 IRP. For its methodology, Avista did the following: (1) chose to reduce the costs of electrification to the homeowner and included a lower-than-expected cost of equipment and installation to be overly conservative and not bias the assumptions toward retaining natural gas; (2) included a 50% reduction in upfront cost from incentives to drive down the overall cost to the homeowners from programs like the IRA; (3) spread the upfront costs over three years as a form of annuity to pay for the costs, meaning it was not a lump sum payment and should be more affordable to the homeowner; and (4) utilized estimated electric rates from local providers on a cents per kWh basis. Importantly, Avista reviewed this methodology with the TAC, as well as posted all models and assumptions to its website.

In general, the electrification methodology drastically undercuts the likely cost to electrify a residential or commercial customer. Despite these efforts and transparency, respondents have shown little interest in furthering the conversation around why it was not selected, instead just

[1] Biogas-Renewable natural gas - U.S. Energy Information Administration (EIA)
[2] Text - H.R.5376 - 117th Congress (2021-2022): Inflation Reduction Act of 2022 | Congress.gov | Library of Congress

choosing to not believe the model results. It should be noted that two scenarios did choose electrification as a resource. These scenarios included "Limited RNG Availability" and "Electrification – Low Conversion Costs" meaning the model does select these resources when cost-effective. Other factors may influence electrification selection such as homeowner choice, program incentives, cost, and policy directives such as building codes. Avista accounted for these with all known policies, incentives, and estimated costs, which again were lower than indicated by market studies. The actual number of conversions is, and will remain, unknown, therefore scenario analysis is required to measure possible future outcomes, as was done in the 2023 IRP and will be done in future IRPs. No feedback was provided to Avista through the TAC process on electrification, including on the IRP draft. With the repeal of the CPP, electrification is further uneconomic for Avista customers.

In final comments, Staff requests future IRPs to include a database containing information about feeders, in service dates of pipes, and lowest recent observed pressures. Avista would like to better understand this request during the 2025 IRP process and hear feedback and considerations from TAC participants before dedicating time and effort to this request. Confidentiality issues of the release of this data in public forums would also need to be addressed prior to any release. Currently, Avista does not have electronic pressure monitoring of every pipe on its distribution system. If required, Avista could provide pressure data at the end of the heating system, but it would not include all systems. Also, actual pressures are irrelevant as the modeled design day is the critical data to understand actual system constraints.

The following comments are in response to specific Staff's Recommendations, Expectations, and Requests.

## Recommendations

**Recommendation 1: Do not acknowledge 8.64 million therms of RNG in 2023**.

**Response**: Avista disagrees with Staff's recommendation regarding the procurement of RNG in 2023 to meet its PRS. Staff notes that it has historically not "recommended acknowledgement of procurement that may be too substantially complete";[3] however, this statement appears to imply that acknowledgement of resources identified in the PRS equates to a prudency determination of an actual acquisition. As noted above, an acknowledgement of an IRP is not a pre-approval of prudency for any action taken by a utility pursuant to its plan. Absent the repeal of the CPP, the Commission should not adopt this recommendation. Because the CPP is now repealed, this recommendation is moot. Note Avista has acquired RNG for purposes of CPP compliance that it now must figure out how it will use and how it will seek recovery of the costs, if need be. Avista may repurpose this RNG, which may include possibly using the RNG under Senate Bill 98.

**Recommendation 2: For the IRP Update the Company should update the load forecast with a downscaling methodology using Multivariate Adaptive Constructed Analogs as employed by Oregon State University's Institute of Natural Resources.**

**Response**: Avista will utilize a "to be determined" RCP as guided by the TAC process for the 2025 IRP. These futures may include RCP 4.5, 6.0, or 8.5. Methodologies to incorporate weather futures for all service territories will be discussed with the TAC and incorporated with the final set of analysis for the 2025 IRP, with input from Staff and other interested parties. This methodology of using the TAC for input is important as all interested parties, including TAC members, can provide valuable input and expanded knowledge to IRP considerations. Other studies may also be considered depending on availability, prior to a final selection used for the 2025 IRP. This will include the Multivariate Adaptive Constructed Analog methodology pending further review and understanding on impacts and applications to the entire service territory.

**Recommendation 3: Regardless of the analytical approach taken to create the PRS, future IRPs should include alternative resource portfolios that represent different utility decisions.**

**Response**: Avista disagrees with Staffs conclusions surrounding the use of portfolios being new to the next IRP. Regardless, Avista will develop alternative resource portfolios as was done in the 2023 IRP. Chapter 4 summarizes this risk by resource option including four types of RNG (dairy,

[3] LC 81, Staff final comments at p. 11.

landfill, wastewater, solid waste), synthetic methane, and hydrogen. This will include stochastic analysis to measure risk for each set of resource options for all alternative resource portfolios.

**Recommendation 4: Future IRPs should include stress testing of the PRS and alternative resource portfolios and provide metrics comparing the severity and variability of risk in alternative portfolios.**

**Response**: Avista will stress test each set of resources and portfolios of resources in the 2025 IRP and show cost on a total cost and average rate methodology.

**Recommendation 5: In the next IRP should include modeling of all relevant distribution system costs and capacity costs, including additional projects that would be needed in high load scenarios as well as costs that would not be incurred in lower load scenarios.**

**Response**: In the 4-year action plan, Avista did not have any expected distribution projects to estimate system and capacity costs. In the 2025 IRP, Avista will work with Staff and the TAC to determine the horizon for these costs. Avista has recently concluded that approximately 4,000-8,000 feet of distribution pipeline will have to be installed along with an enhancement at the Sutherlin city gate station to serve a new large industrial customer located in Sutherlin, OR. Distribution and city gate station designs and cost estimates are currently in progress. An analysis for the Sutherlin gate station was completed by the ETO, found in Attachment B, to understand whether targeted energy efficiency could be fruitful in avoiding this enhancement. A summary of this analysis concludes that it would not be possible for energy efficiency to reduce these capacity enhancements.

**Recommendation 6: Avista work with the TAC to develop additional scenarios and sensitivities for the next IRP, including for example: greater price variation for low carbon resources, high cost for low carbon resources, omission of any highly uncertain resource, or utilization of only existing resources.**

**Response**: Avista clearly articulated a set of stochastic price variations, found in Chapter 4, for each resource considered in the 2023 IRP. Additionally, it was requested in TAC 2, 3, and 4 for input on scenarios and model runs to consider. No input was provided to Avista by any parties, including Staff. Avista will consider costs and risks of resources through stochastics and different sets of portfolio assumptions in the 2025 IRP.

**Recommendation 7: To start to understand baseline electrification occurring naturally, Staff recommends Avista use advanced metering infrastructure data and Form 10Q data to capture customer behavior as discussed in Section 6.3. At the IRP update, Avista should present that information in the attached worksheet templates (Attachment B).**

**Response**: Avista has contracted with an outside consultant for the development of an end use model. This model should help provide analysis of stock rollover for possible conversions to electric end uses, price elasticity, and other factors necessary to better estimate electrification from policy or otherwise. This model will be used in the 2025 IRP. Historic customer counts and trends take into consideration market elements such as conversions or lost customers and are used as a baseline input to begin forecasting future customer growth.

**Recommendation 8: In the IRP update, Avista should clarify whether it has precedent agreements or other contracts for the GTN (Gas Transmission Northwest) Xpress. If so, Avista should explain its capacity on this new expansion.**

**Response**: Avista bid into the GTN Xpress expansion to firm up capacity to electric generation plants but did not receive new capacity from this expansion. No capacity bids were placed for the natural gas business for this project.

## Expectations

**Expectation 1: At a TAC meeting for the next IRP, Avista should provide an estimate of the capacity in MW of electrolyzers, renewable generation, and methanation equipment needed in each year to include synthetic methane in the Oregon PRS. The Company should also**

**provide the cost and quantity of CO2 needed in each year in key portfolios to support synthetic methane production. Lastly, the Company should seek alignment from participants regarding price and availability forecasts and approaches for modeling risk.**

**Response**: Avista will provide the requested information in the 2025 IRP. This material and price forecasts will be reviewed with the TAC.

**Expectation 2: Avista should provide an RNG procurement update in its next IRP Update including a comparison of projected and actual procurement; RNG prices secured; a description of how the Company has leveraged other carbon markets to reduce RNG costs; and how the Company is applying the environmental attributes of the RNG procured to CPP compliance. Further, where actuals volumes of RNG used for CPP compliance are less than those projected, the Company should describe its plan to address those compliance deficiencies.**

**Response**: Avista will provide this information in the next IRP TAC meeting and include any supply contract information in the 2025 IRP.

**Expectation 3: The next IRP should show a load forecast that reflects GCM trends by downscaling the model appropriately onto the Company's Oregon service territory.**

**Response**: Avista will use techniques and further learnings to apply GCM trends to the Oregon territory in its 2025 IRP. These techniques may include those recommended by Staff, pending analysis and a full understanding of how they should be applied, the resulting analysis will be presented to the TAC for feedback.

**Expectation 4: For the next IRP, engage the TAC regarding the GCM model downscaling methodology proposed for the next IRP.**

**Response**: Avista will apply a methodology to appropriately downscale the model in the 2025

IRP, with input and considerations through the TAC process.

**Expectation 5: For the next IRP, include a scenario of future weather informed by the RCP 6.0 model.**

**Response**: The RCP 6.0 is not available from either the MACA study as requested by Staff, nor the weather futures obtained from the BPA as used in the 2023 IRP. A study to include 6.0 would potentially require procurement of the data from a source with the capability to run such data. Further, high level results from the weather futures used in the 2023 IRP, between RCP 4.5 and 6.0, show little deviation through 2050. This time horizon would not change for the 2025 IRP. As an alternative scenario the average of the RCP 4.5 and 8.5 could be used as a midpoint estimate.

**Expectation 6: For the next IRP, include a scenario of no future customer growth beyond 2027.**

**Response**: A set of no growth scenarios was provided in the 2023 IRP through the Low, Expected, and High Electrification scenarios and the Hybrid scenario. A no growth scenario will be provided beyond 2027 for the 2025 IRP.

**Expectation 7: Continue to work with TAC members on how to model customer growth impacts from HB 3409 and the potential for further Oregon electrification policies reflecting those in place in Washington.**

**Response**: Avista will provide this information in the 2025 IRP. All known policies, rules, and codes are included in the IRP at the time of development. Potential impacts of unknown policies can be measured through a scenario.

**Expectation 8: For the next IRP, update its customer growth modeling to reflect the line extension allowance decision flowing from Docket No. UG 461.**

**Response**: Avista will provide this information in the 2025 IRP.

**Expectation 9: For the next IRP, update its application of IRA credits to all applicable resources, including electrification resources.**

**Response**: Avista applied IRA credits to all resources, based on IRA interpretation, in the 2023 IRP, and will provide this information in the 2025 IRP. This includes the conversion costs for electrification by area and class (residential and commercial).

**Expectation 10: Scenarios and sensitivities developed for the next IRP should include complex possible futures that capture plausible sources of risk due to uncertainty; Avista should explore its resource portfolios against these scenarios. Avista should run stochastic analysis for price and demand assumptions consistent within scenarios and report risk severity metrics for each scenario.**

**Response**: Avista will provide this information in the 2025 IRP.

**Expectation 11: Avista should engage stakeholders and the TAC to seek input on any additional modeling methodologies or techniques to better capture risk.**

**Response**: Avista will provide this information in the 2025 IRP.

**Expectation 12: Avista should work with Staff and the TAC to investigate PLEXOS' ability to integrate risk aversion.**

**Response**: Avista will work with Staff and provide this information in the 2025 IRP.

**Expectation 13: In its next IRP, Avista include a qualitative risk matrix in the next IRP that consolidates risk assessment for each resource in one chart and provides a narrative risk assessment about each resource option's potential for negative outcomes due to uncertainty.**

**Response**: Avista will provide this information in the 2025 IRP and work with Staff for further understanding on risk assessment illustrations, tables, or graphs in the form of an example to meet this expectation.

**Expectation 14: The Company should conduct a review, comparing projections from this IRP to actuals of their resource assumptions, quantitative least-cost/least risk predictions, and forecasts.**

**Response**: Avista will provide this information in the 2025 IRP. An additional understanding of the goals of this expectation will be necessary to fully evaluate the information requested.

**Expectation 15: Avista should work with the TAC to develop electrification modeling that reflects refined customer attrition assumptions.**

**Response**: Avista will provide this information in the 2025 IRP with the added capability of an end use model. This will include expected attrition and will remove customers and load prior to forecast along with electrification as a resource selection to further reduce load if economic.

**Expectation 16: The next IRP include electrification modeling assumptions that decrease capacity costs, distribution system costs, and other appropriate expenses corresponding with reduced demand from electrification**.

**Response:** Staff notes in its final comments that costs may not be "meaningfully reduced in electrification scenarios, despite a 33 percent decline in customer count. Examples of these expenses include DSM programs, Jackson Prairie Storage costs, and gas pipeline system costs."[4] The cost to run and operate the Jackson Prairie Storage facility is tied to an ownership agreement in which Avista is a 1/3rd owner. While demand may be reduced, this does not infer the storage facility is used or needed less. Paired with safety and capital needs to keep the facility and Avista's

[4] LC 81 Staff Final Comments at p. 31.

customers investment in the facility operational, assuming cost reduction is not reasonable. Incremental costs of DSM may be reduced, but with the low costs of DSM and their selection in a CPA, they would still be likely lower than an avoided cost when compared to other supply side resources. In any case Avista sees these investments in DSM as important in the resource selection process to provide the least cost to customers.

Additionally, the gas pipeline system costs may not decrease if customers electrify and leave the system due to the system still needing to be maintained. Any reduction in system costs would be locational and dependent on the customers on each segment of the local distribution network. Avista did not model a full revenue requirement in the 2023 IRP, so these distribution system costs have already been excluded. If the Commission finds this expectation to be reasonable in future IRPs, assumptions of system costs reductions will need to be supported by data.

As a reminder, the IRP has not historically been tasked with distribution system investment at this level, so a large amount of work would be needed to provide these inputs. Reasonability of assumptions should come from input from all TAC members as guided by the TAC process, as has been done historically. A case for why and how costs would go down in these cases, as suggested by Staff, would need to be fully vetted, which could be done through a specific Scenario in the 2025 IRP. However, Avista does not expect these costs to decline, unless disallowance or guidance is given to avoid capital programs to deliver and manage a safe and reliable distribution system. There may be market opportunities to release Oregon’s share of storage capacity at Jackson Prairie, but it is a valuable resource relied upon during peak day and high price events in the region. If Jackson Prairie were to be removed from Oregon’s resource options, additional risk may be present if not replaced by an on-demand resource to supply peak resource needs. Avista is open to dialogue regarding this expectation in the 2025 IRP process.

**Expectation 17: Future IRPs should include a scenario with significantly increased residential heat pump adoption and the corresponding shift in winter load from the gas system to the electric system.**

**Response**: Avista will provide this information in the 2025 IRP, as was done in the 2023 IRP. It would be helpful for Staff to describe what different information is expected.

**Expectation 18: Avista should work with the TAC to more fully explore and model the potential of dual fuel heat pumps in the next IRP, for example by ensuring that the use of some dual fuel heat pumps is represented in Monte Carlo risk analysis.**

**Response**: Avista will provide this information in the 2025 IRP but provides caution that use of dual fuel heat pumps will be dependent of the individual home/business design.

**Expectation 19: Before the next IRP, Staff expects Avista to work with the TAC to consider Staff's revised Electrification Incentive Strategy (see Attachment A).**

**Response**: Avista will add this expectation to a TAC meeting for discussion but expects Staff to take the lead to explaining the strategy to the TAC, including cost justification.

**Expectation 20: Staff expects Avista to work with the TAC to identify a PacifiCorp IRP scenario reflecting electrification that Avista might use to generate a load forecast for its next IRP. Before the next IRP, Avista should work with PacifiCorp to collect the load forecasts used in planning that most closely reflects a building electrification scenario for the overlapping territories. With these load forecast results, Avista should discuss with PacifiCorp supporting commentary regarding supply-side and demand-side resource impacts, rate impacts, and associated GHG (greenhouse gas) emissions with each scenario/portfolio. Avista should discuss with the TAC the extent to which the Company might be able to model the equivalent in its next IRP.**

**Response**: Avista is planning on using an end use model with estimated rates and revenue requirements for all jurisdictions. In the event information is available that would help Avista to further develop assumptions in its 2025 IRP, consideration will be given to include and adjust inputs to the model prior to the final portfolio results. Without a statewide process, results from

PacifiCorp would only give Avista a portion of the inputs needed to develop inputs fully and properly. Other inputs would be needed for Avista's Oregon service territory, such as Oregon Trail Electric, Medford Electric Utility, and the City of Ashland Electric Department. In addition, information would need to be developed for the Company's Idaho and Washington service territories to properly estimate system impacts, as the model solves for a system least cost. Avista would find it helpful for this information to be provided from a coordinated statewide process to ensure data collection and vetting of units and assumptions are correct for use prior to an effort of this magnitude. Lastly, without Commission direction to PacifiCorp, they may not be willing to release all available information.

**Expectation 21: Before the next IRP, Staff expects Avista to host electrification workshops, addressing the issues listed in Section 6.4 to support a discussion on a proactive resource strategy.**

**Response**: Avista will add this expectation to a TAC meeting for discussion but expects Staff to take the lead on presenting and explaining the strategy to the TAC where needed.

**Expectation 22: Avista should update its distribution system planning practices and its future IRP processes as outlined in Attachment C.**

**Response**: Avista would like to investigate the feasibility of the expectations outlined in Attachment C and will attempt to include them when addressing future distribution planning. Avista is open to dialogue regarding these expectations in the 2025 IRP process. Items referring to NEIs (Attachment C.2.b) may not be available to include in such analysis until they are fully analyzed and vetted by a selected consultant, Avista, and the TAC. Until such metrics are available, it is unreasonable to consider inclusion of the methodology in Attachment C as directed. As noted by Staff in final comments, "Staff cautions that such an endeavor should include extensive engagement with, and involvement of, Oregon communities." The purpose of this NEI study consideration in the 2025 IRP is to further evaluate impacts not historically considered as a part of the natural gas IRP process. The study Scope of Work (SOW) is included in Attachment A. At this time Avista is not considering community outreach as coordinating such an endeavor would require internal resources and FTEs to facilitate such a process, which are not available. Also, pending a filing date of April 1, 2025 for the 2025 IRP, the timeframe for a consultant to perform such a study would not be feasible, as results would be needed prior to September 1, 2024 for incorporation into the model. This work would be required to begin prior to a final acknowledgement of the Avista 2023 IRP. Also, depending on the direction of the NEI study, this information may not be available in the 2025 IRP. Avista currently has a firm bid on the cost of the NEI study, however, the cost is material and a decision to proceed has not yet been made.

**Expectation 23: Avista should apply distribution system planning practices as outlined in Attachment C to the Sutherlin project and should continue to explore targeted electrification to offset demand at the Sutherlin gate station.**

**Response**: Avista would like to investigate the feasibility of the expectations outlined in Attachment C, and will attempt to include them when addressing the constraints of the Sutherlin distribution and gate station. Refer to Expectation 22 response for further dialogue. Avista is open to dialogue regarding these expectations in the 2025 IRP process. Please refer to the ETO analysis done for Sutherlin in Attachment B.

**Expectation 24: For future IRPs, the Company should discuss in a TAC meeting how Avista envisions avoided costs determinations aligning with resource portfolios made up of higher priced fuels and declining natural gas, and how that will be reflected in its next IRP.**

**Response**: Avista will discuss this topic in the 2025 IRP process.

**Expectation 25: In the next IRP, Avista should include a workpaper of the fixed fees paid on each unit of capacity under contract and provide an update on potential or existing plans to retire firm capacity contracts.**

**Response**: Avista will provide this information in the 2025 IRP. Pending new policies and rules, these avoided costs will be illustrated in a table by Scenario if not included in the PRS scenario. All known policies and expectations will be included in the PRS at the time of the final analysis.

**Expectation 26**: In future IRPs, Avista should include a discussion of cold weather reliability standards including foreseeable cold weather risks to its supply-side resources including transportation and storage capacity resources.

**Response**: Avista will provide this information in the 2025 IRP.

## Requests

Avista will consider Staff's requests in the 2025 IRP as time allows. Due to the number of recommendations and expectations that may be adopted by the Oregon Commission, paired with the requirements in the Company's other jurisdictions, it is unlikely all of Staff's requests will be accomplished as these requests have the lowest priority for Staff.

## 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, and disregard any of Staff's recommendations and expectations that pertain to the CPP due to it now being invalid.

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
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Avista is seeking consulting assistance to identify societal non energy impacts (NEI) for resource decisions in the natural gas distribution business. Avista and other regional utilities will be seeking alternative natural gas fuel supplies over the coming decades to comply with state clean energy policies. Avista seeks to understand costs and benefits to resource decisions going beyond reduction in greenhouse gas emissions.

Avista seeks to understand NEI's for the following resource alternatives:

- Renewable Natural Gas
- Hydrogen & Synthetic Methane
- Natural Gas

For each fuel type discussed below a cost estimate in a US $ per dekatherm equivalent for each NEI is required, if the NEI impact is related to construction, these benefits may be levelized over the life of the project when calculating the $ per dekatherm equivalent. For processes requiring electricity for production, NEI's for the electric demand is not required, but the electric consumption shall be provided (i.e. kWh per mmBTU).

The areas of potential study are shown in Table 1, the Consultant may propose additional areas.

**Table 1: Societal Non-Energy Impact Areas**

| **Area of Study** | **Generalized Approach** |
|---|---|
| **Public Health** | Air emissions contributed due to consumption of hydrocarbons consumed during the <u>production</u> of the fuel. Such as PM2.5, $SO_2$, $NO_X$, and GHG. Also include difference in methane or other GHG as compared to traditional natural gas. |
| **Safety** | Fatalities and injuries resulting from operations of production |
| **Land Use** | Consider the footprint of facilities that are above and beyond the standard calculations considered as part of alternative facility construction for the required energy. Displacement of land that was beyond the facility's footprint may also be considered. |
| **Water Use** | Identify water usage and impact of usage on process with return of a product back to a clean product (i.e. fracking water not always useful after usage) |
| **Economic** | Induced economic impact to the facilities construction and operation, including job growth. |
| **Community Odor Pollution** | Aromatic quality of the air in the community including mercaptan and organic decomposition. This should also consider the air quality of processes to create fuels. |
| **Process Bi-products** | Value in the creation of biproducts such as carbon black, biochar, fertilizers, carbon fiber, or graphite. |

| | |
|---|---|
| **Local Distribution Pipeline** | Impacts related increase or decrease in requirement to the Local Distribution Company (LDC) pipeline network, includes qualify of gas and volume impacts |

**Renewable Natural Gas**

The primary sources of renewable natural gas (RNG) are landfill gas, digesters at water resource recovery facilities (wastewater treatment plants), livestock farms, food production facilities, and organic waste management operations; all of which convert biogas containing methane to a methane concentration comparable to that of pipeline quality natural gas. All RNG alternative production technologies might possibly be considered to minimize the reliance on fossil natural gas and reduce the carbon intensity of the gas delivered to customers, or they could provide possibilities for network extension to boost overall capacity.

Avista priority sources of RNG include the following sources:

- Landfill
- Wastewater Treatment
- Dairy
- Industrial Food Processing

**Hydrogen**

Avista may develop small amounts of green hydrogen to inject in the pipeline to offset traditional natural gas. Alternatively, Avista may use hydrogen combined with a methane source to create synthetic methane. Likely sources of green hydrogen include electrolysis but may also include other sources with lower greenhouse gas emissions, than seen in traditional natural gas. For this fuel source the Consultant will identify NEI values for hydrogen and hydrogen used to create synthetic methane.

Avista priority sources of hydrogen-based fuels include the following sources:

- Electrolyzer based hydrogen (identify any differences between PEM and Alkaline methods if applicable)
- Steam Reforming Hydrogen with carbon sequestration
- Pyrolytic Methane
- Synthetic methane combining hydrogen with Direct Air Capture

**Natural Gas**

Avista sources natural gas from Alberta, British Columbia, and Rocky Mountain States. Avista request NEI values for the production of natural gas for upstream.

**Project Requirements**

1. Bi-weekly meeting to discuss methodology and progress once the project gets momentum (i.e. June), monthly meetings or ad hoc requests for can be done prior to that time.
2. Provide a excel summary table for each resource value type in $/Dth equivalent in 2024 dollars. Sources and any documentation can be provided in this document
3. A slide deck will be the report, no written report is require to keep costs low
    a. identify each resource and the NEI impacting the resource,
    b. Draft slides will be prepared for review by Avista TAC and a final slides will follow after consideration of any comments.
    c. For any comments or items discovered outside of budgetary or time constraints shall be identified along with the time and roadblocks to complete such analysis.
4. Provide a presentation to Avista Technical Advisory Committee on the content of the draft report, July 30, 2024.
5. Finalize slide deck September 1, 2024

**Timeline and Payment Structure**

Project Kickoff: Q1 2024

Project Complete Q3 2024

Milestone Payment Structure to be discussed.

# Memo

**To:** Lisa McGarity, Terrence Brown, Tom Pardee, Avista

**From:** Alex Novie, Spencer Moersfelder, Andrew Shepard, Kyle Morrill, Janelle St. Pierre

**cc:** Tracy Scott, Fred Gordon, Elaine Prause

**Date:** December 15, 2023

**Re:** Targeted Load Management (TLM) Potential Analysis: Sutherlin and Medford (Updated)

## Background

This memo summarizes the TLM analysis for Sutherlin and Medford, conducted by Energy Trust of Oregon (Energy Trust) in 2023 in collaboration with Avista following the TLM process phases described in this memo. The analysis results indicated that accelerated energy efficiency can only meet a portion of the load reduction needs that Avista identified for Medford and Sutherlin in the specified timeframe. Other resources, such as demand response, would need to be implemented in parallel with energy efficiency to potentially meet the load reductions specified by Avista to defer a system upgrade in these areas. Additional analysis would be required to assess feasibility of other demand-side resources; Energy Trust believes that analysis of other demand-side solutions that go beyond efficiency, such as demand response, is currently the purview of Avista. Based on available information, Energy Trust is not currently anticipating that we will pursue TLM implementation in either Sutherlin or Medford in 2024; this is reflected in Energy Trust's most recent budget at the time of this memo for 2024-2025.

## Targeted Load Management (TLM) Overview

Targeted Load Management (TLM) is a suite of energy efficiency[1] program, planning, and customer services that Energy Trust can offer utilities as a demand-side management solution (e.g., energy efficiency and distributed generation) in specific geographic areas where utilities have a system constraint. In 2018, Energy Trust began exploring TLM pilots with PacifiCorp and NW Natural. In more recent Integrated Resource Planning (IRP) proceedings, Oregon Public Utility Commission (OPUC) staff have directed Oregon's investor-owned utilities to collaborate with Energy Trust to explore demand-side options like TLM before making investments in transmission and distribution. Starting in 2023, Energy Trust's collaborations with utilities to explore possible areas for future TLM

[1] For electric utilities, renewable energy generation can also be used to offset loads in a targeted area.

implementation are part of joint utility-specific action plans (USAPs). To explore possible areas for TLM implementation, Energy Trust collaborates with utility partners to understand the peak load reduction needs of a local area to inform which energy efficiency measures can bring a reduction in usage and demand through targeted program delivery. The objective of collaboration between Energy Trust and a utility partner is to determine where targeted energy efficiency can meet local system needs and deliver these benefits to the utility and local communities in a specific timeframe.

For gas utilities, TLM efforts can reduce peak gas demand in constrained areas through targeted and accelerated energy efficiency to offset investments in transmission and distribution (e.g., new pipes). For gas utilities, the peak load reduction is often expressed in "peak therms" – either "peak day therms" or "peak hour therms" – for a specific area, season (e.g., winter) and/or time of day (e.g., early morning heating in commercial facilities).

**Targeted Load Management Process Phases**

Based on learnings from previous TLM pilots, Energy Trust has developed a process to collaborate with utility partners to explore areas for possible TLM implementation. These process phases are designed to guide how Energy Trust and partner utilities collaborate and appropriately use resources to determine the viability of specific areas for TLM implementation. Figure 1 summarizes the primary TLM process phases for Energy Trust and each utility partner to analyze potential areas and arrive at a "go" or "no-go" decision on TLM to include funding for program implementation and delivery in Energy Trust's next budget. This process is subject to continuous improvement and may change as refinements are incorporated.

*Figure 1: Targeted Load Management Process*


A summary of roles for Energy Trust and utility partners at each stage of the process is as follows:

1. *Identify constrained areas and utility needs*
    a. Energy Trust: Collaborates with utility partner to understand various utility management needs (e.g., peak demand, flexible load, carbon)
    b. Utility partner: Analyzes grid needs and grid constraints, typically through IRP (historical) and new processes like DSP, CEP, and CPP
2. *Analyze resource potential (one or many sites)*
    a. Energy Trust: Use Resource Assessment (RA) Model to estimate potential in local areas

    b. Utility partner: Provides data on specific feeder(s) and any market verticals; Provides localized avoided costs estimates
3. *Develop TLM program planning and strategies*
    a. Energy Trust: Use existing suite of measures and offers mapped to determine energy efficiency potential in each TLM area; Consider local community needs for design and delivery
    b. Utility partner: Quantify combined load reduction impact of Energy Trust energy efficiency and utility demand side options to manage utility loads.
4. *Go/No-Go decision with Energy Trust and utility partner*
    a. Joint decision between Energy Trust and utility partner to determine whether energy efficiency can play a suitable role in conjunction with other demand side resources to reduce utility loads in a specified area
5. *Build out budget and strategies for annual Energy Trust's annual budget*
    a. Energy Trust: Owns the program delivery strategy and implementation plan for energy efficiency TLM
    b. Utility partner: Agrees to fund Energy Trust TLM through the Energy Trust's budget process and any additional funding
6. *TLM Implementation*
    a. Energy Trust: Lead all aspects of implementation for EE
    b. Utility partner: Collaborate in key areas, including regional account management/ outreach, marketing, community engagement (e.g., CBIAG), and any joint delivery of offers

**Analyze Resource Potential**

Over the course of four months, Energy Trust worked with Avista to scope the resource potential analysis for the two sites identified as constrained areas in Avista's most recent IRP. In this iterative process, Avista provided Energy Trust with data on premises (or sites) and load reduction needs in Medford and Sutherlin. Avista identified the following load reduction targets for deferral.

- Medford: 691 peak hour therms
- Sutherlin: 121 peak hour therms

Energy Trust leveraged the efficiency potential modeling from Avista's most recent IRP to assess the contribution that energy efficiency can make to help achieve peak load reduction targets in Medford and Sutherlin. This resource assessment is based on a forecast of expected load and building stock and provides an estimate of energy efficiency resource potential at a range of costs that is achievable over a defined number of years.

Avista provided a list of Premise ID's associated with each proposed TLM site which were used to scale the resource assessment model's input assumptions by customer type. Table 1 below is the load forecast composition of each proposed TLM location used in the resource assessment.

*Table 1: Load Forecast Composition*

| *Customer Segment* | **Medford** | **Sutherlin** |
|---|---|---|
| **Residential** | 62% | 64% |

| | | |
|---|---|---|
| **Commercial** | 37% | 25% |
| **Industrial** | 1% | 10% |

Table 2 below details results from the resource assessment modeling compared to Avista's target goals and business-as-usual activity in each location. Model results show that the utility load reduction target for Medford is 144% of total cost-effective achievable resource, meaning there is insufficient efficiency potential to effectively defer Avista's investment in system expansion in this location. For Sutherlin, the utility load reduction target is 77% of total cost-effective achievable resource, meaning that nearly all efficiency potential in the market would need to be acquired to effectively defer investment in system expansion. For reference, the maximum annual efficiency acquisition that Energy Trust forecasts in Avista's IRP builds to 4% of statewide potential in 2035. Avista's Sutherlin goal would require roughly 600% the rate of maximum Energy Trust efficiency program activity in each year of a three-year TLM project.

*Table 2: Resource Assessment Model Results Compared to Historical Acquisition*

| *Area* | **Utility Target Goal** | **Total Efficiency Resource** | **Historic Annual Average** |
|---|---|---|---|
| **Medford** | 691 | 479 | 11 |
| **Sutherlin** | 121 | 158 | 2 |
| *All units are peak hour therms.<br>Total efficiency resource is cost-effective achievable potential and includes three years of replace on burnout and new construction measures.* | | | |

The historical annual average peak day therm savings provide additional context for the needed peak reductions; utility target goals are roughly 60 times greater than an average historical year of Energy Trust program activity in both Medford and Sutherlin.

In addition to the resource assessment view provided above, Energy Trust compared Avista's peak reduction targets to results from the Northwest Natural TLM pilot. The NWN pilot proceeded in three phases, the latter two of which involved enhanced incentives, targeted marketing and additional delivery infrastructure. Results from these latter two phases were generalized to a three-year timeline and proportionally applied to: 1) Avista's total efficiency resource for Medford and Sutherlin as "Pilot Total Resource Results" and 2) relative increases to business-as-usual activity in Medford and Sutherlin as "Pilot Historical Results".

Table 3 below shows the contribution that TLM could make to help Avista achieve peak reduction targets based on NWN TLM pilot results. This contribution is estimated to be around 10% of the target peak savings goals. A 29-year TLM project timeline would be needed to achieve all peak savings assuming that the NWN TLM pilot results hold for Medford and Sutherlin.

*Table 3: Comparison of Targets to Historical TLM Pilot Results*

| *Area* | Utility Target Goal | Pilot Total Resource Results | Pilot Historical Results |
|---|---|---|---|
| **Medford** | 691 | 66 | 63 |
| **Sutherlin** | 121 | 18 | 12 |
| *All units are in peak hour therms.*<br>*Pilot results assume a three-year TLM implementation timeline.*<br>*We would need 29 years of focused TLM delivery to achieve utility target goals.* | | | |

**Summary of TLM Program Designs and Strategies**

A suite of program designs and strategies can be deployed for TLM to accelerate energy efficiency in a targeted area. Previous Energy Trust TLM program designs and strategy have included the following components:

- **Increased incentives**: maximum incentives based on statewide cost effectiveness, and max allowed based on potential for higher localized avoided costs to cover up to full project cost for key measures reducing peak.
- **Increased Trade Ally (TA) engagement**: training, participation agreements, single point of contact support, incentive form assistance.
- **Increased Trade Ally Business Development Funds**: to subsidize and support TA sponsored marketing efforts.
- **Increased Marketing**: local newspapers, social media, tabling at local events, TLM landing page.
- **Increased Customer outreach and engagement**: proactive contact with large commercial and industrial customers.

**Energy Trust Resources for TLM Planning and Implementation**

Prior to execution, Program implementation teams develop budgets and energy savings targets for target areas.  Budgets are based on resource assessment models, previous program activity in targeted areas, and additional assessments of target demographic and trade ally resources. The potential for industrial and large commercial projects is assessed by their respective programs. The success of any TLM effort can be heavily influenced by participation from these large customers; a few large projects can significantly impact load reductions in a specified target area. A market assessment of these large-user customer types is crucial to developing accurate budgets and savings targets.

After a decision is made to pursue TLM implementation, Energy Trust would develop a comprehensive budget and program deployment plan. This effort may take between three and six months depending on the complexity of the strategies and any work that might need to be set up (e.g., contractor RFP/RFQ for targeted delivery). Deployment strategies are developed and scoped specifically to targeted regions and specific to the promoted measures. Local resources are assessed, and if potential for partnerships exists, the Programs will work with community-based organizations to explore promotional and deployment strategies. Local program representation is extremely important to the success of these efforts. Local program representatives will be hired if the target area does not have adequate coverage via preexisting program delivery structures.

During TLM deployment, ongoing support for trade allies and incentive application processing may require a full FTE per program. Engaging the market through comprehensive marketing strategies is crucial for success. A marketing plan and strategies would be developed for targeted regions. Program marketing staff are on point to execute the plan. TLM specific marketing support is also provided throughout the duration of the TLM effort.

**Energy Trust Recommendation for TLM Implementation in 2024**

In 2023, Energy Trust and Avista exchanged information over several months, to identify constrained areas and utility needs, analyze resource potential and possible program strategies to develop a recommendation for 2024 implementation that would be reflected in Energy Trust's 2024-2025 budget. The analysis results indicate that even accelerated energy efficiency would be insufficient on its own to meet load reduction needs identified for identified for Medford and Sutherlin. Thus, Energy Trust is not anticipating that we will pursue TLM implementation in either Medford or Sutherlin in 2024; this is reflected in Energy Trust's budget at the time of this memo for 2024-2025.

While Energy Trust does not recommend TLM as the only option to reduce loads in Medford and Sutherlin, accelerated deployment of energy efficiency measures through TLM implementation could contribute to a broader set of demand-side options Avista could pursue to support energy needs in these areas.[2]

**Next Steps**

During this process, Energy Trust staff noted the productive lessons learned in conducting analysis of potential sites for TLM implementation, including:

1. Develop process and rules of thumb to iterate on EE potential at future potential TLM sites relative to local load reduction needs
2. Understand data needs for site analysis
3. Understand time horizons for utility system planning for local load reduction needs
4. Seek efficiencies in communication and coordination with utility, noting the need for early collaboration

These lessons learned provide opportunities for both Energy Trust and Avista to explore how we might collaborate on future TLM opportunities. This ongoing collaboration is highlighted in the Energy Trust's 2024-2025 USAP with Avista. In addition, Energy Trust sees possible opportunities to apply some of the TLM program delivery strategies to further gas savings in specific areas outside of a TLM implementation effort.

Energy Trust will continue to explore additional TLM program delivery strategies that leverage market intelligence and delivery networks across Avista's Oregon service territory and seek to better understand how TLM investments can bring benefits in communities through both procedural and distributional equity.

[2] Energy Trust is also accelerating energy efficiency deployment across the service territory to drive more savings. Some of the program strategies and tactics are similar, but with a territory-wide focus.