BEFORE THE WASHINGTON

UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. AVISTA CORPORATION DBA AVISTA UTILITIES Respondent.	DOCKET NOS. UE-240006 and U6-240007 *(Consolidated)*

TESTIMONY OF

WILLIAM GEHRKE

ON BEHALF OF

NW ENERGY COALITION

July 3, 2024

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Gehrke, and I am a Senior Technical Analyst at the NW Energy Coalition ("NWEC" or the "Coalition"). My business address is 811 1st Ave., Suite 305, Seattle, WA 98104.

Q. Please provide your background and expertise.

A. I have a bachelor's degree and master's degree in Economics from Florida State University. In past roles, I have worked for the Florida Public Service Commission and Oregon Citizens Utility Board, the statewide residential customer advocate for Oregon. I have previously provided testimony and comments before the Federal Energy Regulatory Commission (FERC) and Oregon Public Utility Commission (OPUC). In my past roles, I have worked on ratemaking, resource planning and policy dockets. My CV is provided in WG-2.

Q. On whose behalf are you testifying?

A. NWEC.

Q. What is the purpose of this response testimony?

A. My testimony will address three main issues. First, I discuss Avista's proposal to earn a return on Purchase Power Agreements, concluding that such a request is not in the public interest because it would raise the cost of compliance with the Clean Energy Transformation Act (CETA). Second, I note that the current equal percent of revenue allocator for the Colstrip Tracker Schedule 99 is inconsistent with cost allocations for other trackers and does not adequately apportion Colstrip costs. Instead, the Commission should require Avista to use the generation allocator for

Schedule 99 costs. Third, I recommend that Avista discontinue line extension allowances for large volume customers in 2025. Lastly, I recommend that Avista no longer offer service connections under Schedule 145.

II. RETURN ON POWER PURCHASE AGREEEMENTS

Q. Please summarize Avista's proposal regarding a return on Purchase Power Agreements.

A. In its initial filing and testimony, Avista has included interest earnings for certain power purchase agreements ("PPA") at the Company's proposed authorized rate of return of 7.61%.[1] Avista cites RCW 80.28.410(2)(b) as its rationale for including the additional earnings, appearing to make the argument that the Washington statute requires the Company to recover earnings on renewable PPAs entered into as part of CETA compliance.[2]

Q. Do you support Avista's proposal to include a return for PPAs?

A. No. The NW Energy Coalition recommends the Commission reject Avista's proposal to provide an incentive for purchased power agreements. Aside from the code, Avista does not provide additional rationale for the inclusion of the incentive, one that will cost customers several million dollars over the rate plan.[3]

Q. For which PPAs does Avista seek a return?

A. In this case, Avista proposes a return on three PPAs: Chelan, Clearwater III and Columbia Basin Hydro.[4] The Chelan purchase power agreement is a hydroelectric

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[1] SJK-1T at 49:13-15.

[2] *Id.*

[3] *Id.* at 49:16-19.

[4] *Id.* at 49:14.

resource 88 MW contract that came into effect on January 1st, 2024.[5] Chelan PUD is a public power agency headquartered in Wenatchee, Washington. Avista currently has three contracted PPAs associated with Chelan PUD.

The Clearwater III purchase power agreement is a contract with NextEra for 100 MW of wind capacity for a project located in Montana.[6] Clearwater III was selected out of Avista's 2022 All Source RFP.

The Columbia Basin Hydro purchase power agreement is for a hydroelectric resource contract for 146.3 MW.[7] The power from this contract comes from several hydroelectric projects operated by Columbia Basin Hydropower and owned by several Washington irrigation districts.

Q. Do you agree that RCW 80.28.410 requires the Commission to approve a return on PPAs?

A. I am not an attorney, but in my lay interpretation, I do not believe the statute requires the Commission to provide such a return. RCW 80.28.410(2) states the utility "may…defer for later consideration by the Commission," costs included in subsections (a) and (b) – the latter including a rate of return for PPAs. "Later consideration by the Commission" indicates to me – as a non-attorney – that the Commission retains its broad discretion to approve or reject a proposal to receive a return on PPAs.

Q. Have utilities argued for this type of incentive in other states?

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[5] SJK-1T at 27:7.

[6] *Id.* at 36:18-19.

[7] *Id.* at 37:12.

A. Yes. The Oregon Public Utilities Commission (OPUC) grappled with the issue of utility self-build/self-own bias for several years in a standalone docket.[8] The docket analyzed the premise that an inherent bias exists in utility resource procurement, one that favors utility ownership of generation assets over PPAs due in part to an inability to earn a return on PPAs.[9] Following workshops, proposals and counterproposals from utilities and stakeholders, and written comments in response to those proposals, the OPUC concluded:

> We too accept the premise that a bias exists in the utility resource procurement process that favors utility-owned resources over PPAs…..Although we accept this premise, we share the concern raised by NWEC, CUB, ICNU, and others that, even after this lengthy proceeding, we know little about the scope and impact of this bias. We have identified its existence, but are not able to quantify its significance. We do not know whether the current regulatory process has, in fact, failed to prevent the utilities from acquiring higher cost, utility-owned resources. Due to this uncertainty, <u>we are unable to determine whether any of the proposals in this docket would mitigate the bias without improperly rewarding the utilities and unfairly harming customers. Both proposals address the self-build bias by providing utilities monetary incentives to enter into PPAs. Because we have not quantified the impact of the bias on rates, however, the cost of the proposed incentives</u>

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[8] *See,* In the Matter of the Public Utility Commission of Oregon, *An investigation regarding performance-based ratemaking mechanisms to address potential build-v.-buy bias*, Public Utility Commission of Oregon, Docket UM 1276.

[9] *See id*.

might greatly exceed whatever harm might otherwise be inflicted on customers.[10]

(emphasis added)

In this case, Avista makes no showing that a bias exists, nor does the Company make any attempt to quantify that bias. It is possible then – if not, likely – that rewarding Avista with a full rate of return for CETA-compliant PPAs would overcompensate the utility at the expense of customers.

Q. What would be the cost impact of providing an incentive on purchase power agreements?

A. In the initial filing, Avista notes that its incentive proposal would result in the Company earning $659 thousand in 2024, $1.499 million in 2025 and $2.335 million in 2026.[11] These figures would increase along with any additional CETA-compliant PPA acquisition in the future.

Q. Does Avista's proposal follow traditional cost-based rate-making?

A. No. Avista does not use utility financing – debt or equity - to fund purchased power agreements. Instead, it contracts with a third-party power plant owner and pays for the resource over the contract's duration. These costs are paid for by customers through the power cost rates. As a result, under Avista's proposal customers would be charged for two financing costs, which is not appropriate for cost-based pricing. New projects built for purchased power agreements require capital to construct the power generation and interconnection facilities. The non-utility owner of the facility either uses its balance sheet to finance the project or

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[10] *See id.,* Order 11-001, p. 5.

[11] KJS-2 Tab E-3.23,5.12 PF PPA.

obtains financing backed by the purchased power agreement. Regardless of the method used to acquire capital for a purchased power agreement project, the contracted price is structured to cover the capital costs associated with the agreement, including a return on investment.

If an additional incentive for Avista was added to purchased power agreements, customers would pay for two revenue streams associated with financing the project - first through the contract price and secondly through Avista's proposed incentive. Avista provides no justification as to why paying for two sets of financing costs is beneficial for customers.

Q. Is there an alternative to allowing Avista to receive its full rate of return for PPAs?

A. Yes. As I mentioned earlier, I don't believe the Commission is required to provide any financial incentive for the Company to procure clean energy through PPAs. If the Commission comes to the conclusion that it is so compelled, or is otherwise inclined, RCW 80.28.410(2)(b) allows for "a rate of return of no less than the authorized cost of debt and no greater than the authorized rate of return for the electrical company." In order to protect customers and keep CETA compliance costs low, the Commission, in the case that it feels obligated, should allow for a return for PPAs equal to the cost of debt.

Q. Would Avista's proposal change their incentive to build a CETA-qualified generating asset versus contract for a CETA-qualified generating asset?

A. That is unlikely. In the coming years, Avista will be acquiring resources during a period of resource acquisition for most electric utilities in the Northwest. In response to state and federal policies, load growth, electrification, and decarbonization efforts, utilities in the region are seeking to build non-emitting resources to meet electricity demand.[12] Renewable energy developers are stepping up to meet that demand. Furthermore, regardless of the incentive on PPAs, Avista must acquire resources available to meet customers' energy and capacity needs while following Washington state policy. As a regulated utility, Avista must also demonstrate that it acted prudently in order to recover costs associated with the lowest reasonable-cost resource. It is counterintuitive, then, that adding additional costs to a contracted resource via a newly established return would result in a greater acquisition of contracted resources. At the end of the day, Avista must choose the lowest-cost resource that fits the resource need, this is true with or without a return added for PPAs.

Q. What is your final recommendation regarding Avista's proposal to add a return on PPAs?

A. I recommend the Commission reject Avista's proposal to include a rate of return for PPAs. In the alternative, should the Commission feel compelled to provide an incentive, it should set the rate of return for PPAs at the cost of debt for the Company.

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[12] *See* Puget Sound Energy Clean Implementation Plan, Seattle City Light 2022 Integrated Resource Plan, Portland General Electric's 2023 Clean Energy Plan, Idaho Power 2023 Integrated Resource Plan.

III. COLSTRIP SCHEDULE 99 – RATE SPREAD

Q. Please describe Schedule 99 and the circumstances that led to its creation.

A. The Colstrip Generating Station is a coal generation power plant located in Colstrip Montana, of which Avista owns 15% each of Units 3 and 4, totaling 222 MW. Under WAC-480-100-619, Avista is required to remove the costs associated from coal-fired generating resources - including Colstrip - from rates by December 31st, 2025. In UE-220053, Avista's 2022 General rate case, parties to the rate case agreed in settlement to a tracking mechanism for Colstrip related costs.[13] The settlement was approved on December 12, 2022 in Final Order 10/04. Schedule 99 thus includes all Colstrip-related costs, except costs associated with transmission investment or expenses included in the Energy Recovery Mechanism ("ERM"). On December 31st, 2025, Avista will transfer ownership of its share of Colstrip to Northwestern Energy. Schedule 99 will account for the revenue requirement associated with Colstrip in 2025 and will continue to exist in order to account for future decommissioning and remediation costs related to Colstrip.

NWEC continues to support the tracking of revenue and expenses in Schedule 99.

Q. What is the current rate spread used to allocate Colstrip costs associated with Schedule 99?

A. The Settlement included a provision stating that Schedule 99 costs are to be spread based on an equal percent of revenue basis.[14]

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[13] *See WUTC v. Avista,* Dockets UE-220053, UG-220054 and UE-210854 (*consolidated),* Order 10/04, Appendix A (Dec. 12, 2022).

[14] *Id.* at ¶ 14(c).

Q. Do you agree with the equal percent of revenue rate spread as approved in settlement?

A. I do not.

Q. What is your concern with the equal percent of revenue rate spread?

A. The current methodology for allocating Schedule 99 utilizes the total revenue from 2019 to distribute generation costs. It uses the percentage of revenue spread, incorporating all revenue classes (transmission, generation, distribution, and billing) from 2019 to allocate future generation costs. Non-generation revenues are not linked to Colstrip. Therefore, a more accurate approach is required to distribute the costs of the Colstrip tracker. The tracker will collect Avista's Washington-allocated 2025 Colstrip revenue requirement and prudent decommissioning and remediation expenses for the future. Given that Schedule 99 collects costs from customers in the future, an equal percentage of the revenue rate spread from 2019 will not have significance as customer revenues change.

Accurately allocating costs for a single-issue tracker, such as the Colstrip tracker, is crucial. For instance, Avista's Energy Recovery mechanism effectively distributes variances between baseline and actual power costs using a generation allocator (E02 Allocator).

Q. Is there an alternate method to allocating costs in Schedule 99?

A. Yes. The proper way to allocate Schedule 99 costs would be using the generation allocator S01. Prior to Colstrip's expenses being taken out of base rates and placed into the Schedule 99 tracker, Colstrip's costs were allocated on the basis of the generation allocator S01.

Q. Have you provided an example of how this rate allocation would work for Schedule 99?

A. Yes. Exhibit WG-3 provides the spread of costs using NWEC's proposed allocator.

Q. What is your recommendation regarding the rate spread for Schedule 99?

A. The Coalition recommends changing the cost allocator for Colstrip Schedule 99 to the generation allocator S01. This cost-based allocation better matches the cost-of-service principals for Schedule 99 allocation for Avista's electricity generation customers.

IV. LINE EXTENSION ALLOWANCES FOR NON-RESIDENTIAL CUSTOMERS

Q. Please summarize your testimony on this topic.

A. The Coalition recommends that the Commission discontinue offering line extension allowances (LEA) for Schedule 131, 132, and 146 on January 1st, 2025. The Coalition also recommends that the Commission require Avista to no longer offer service under the Company's Rural Gas Service Connection (Schedule 154).

Q. What was the outcome of Avista's last general rate case on line extension allowances for the natural gas system?

A. In the last general rate case, the Commission accepted a stipulation that agreed to phase out natural gas line extension allowances in the last general rate case by 2025.[15]

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[15] *See WUTC v. Avista,* Dockets UE-220053, UG-220054 and UE-210854 (*consolidated),* Order 10/04 at ¶¶ 86-88 (Dec. 12, 2022).

Q. Did the settlement detail how Avista would phase outline extension allowances?

A. Yes. The agreement outlined Avista's plan to gradually phase out natural gas line extension allowances over three years. For 2023, LEAs would be determined using a net present value method based on a two-year timeframe. In 2024, the calculation would be based on a one-year timeframe. Finally, in 2025, the Company would not offer any allowance for natural gas line extensions.[16]

Q. Does NWEC support the settlement provision phasing out LEAs?

A. Yes. The Coalition continues to support the agreement from the previous rate case.

Q. Did Avista implement the agreed upon changes to Avista's Washington 151 Natural Gas Extension tariff?

A. Partially. On December 14, 2022, the Company requested a revision of Schedule 151.[17] In this tariff revision, the Company has implemented the proposed reduction of the Line Extension allowances for tariff Schedules 101, 102, 111, 112, and 116. For Schedule 131, 132, and 146, the tariff reads that line extension allowances will be calculated on a case-by-case basis for Avista. These tariff schedules are intended for large commercial or industrial customers who consume more than 250,000 therms of gas annually.

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[16] *Id.*

[17] *See* Schedule 151 tariff sheet, Exhibit WG-4.

Q. Why are LEAs for gas usage inappropriate?

A. Historically, gas LEAs provided a framework for incenting the expansion of the gas system using ratepayer dollars. In recent years, Washington energy policy has challenged the LEA framework. While new natural gas load may have short term economic benefits, LEAs grow the natural gas system's fixed costs adding risk to future customers of the gas system if natural gas demand declines. Additionally, natural gas utilities in Washington are subject to carbon regulation, and will need to reduce all new emissions associated with new natural gas throughput. Expansion of the natural gas system will make it more difficult to meet state decarbonization goals.

Q. What is NWEC's position on Schedule 131, 132, and 146 line extension allowances?

A. NWEC suggests making revisions to Schedule 151 by discontinuing line extension allowances for Schedules 131, 132, and 146, effective January 1st, 2025. This change is in line with the gradual reduction of line extension allowances outlined in the settlement from Avista's previous general rate case. Based on answers to discovery requests to NWEC, Avista does not appear to oppose discontinuing the LEAs for those schedules.[18] However, the Commission should still make clear that Avista should discontinue the LEAs in order to ensure the Company is not encouraging the proliferation of industrial gas use.

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[18] *See* Exhibit WG-5

Q. What is Schedule 154?

A. Schedule 154 is a rate schedule that applies to rural gas service connections for residential and farm customers in rural areas.[19] Under this rate schedule, Avista covers the service connection cost, and the applicant is responsible for the customer service line cost. Service is only provided under this tariff if the expected annual revenue from the new customer connection is at least one-third of the service connection cost.

Q. What is NWEC's proposal on Schedule 154?

A. This natural gas rate schedule is a modified form of a line extension allowance, allowing a prospective applicant to receive a no-cost service connection.[20] Similar to other LEAs, NWEC recommends that the Company no longer offer service under this tariff because provides a venue for customers to connect to the natural gas system using ratepayer funds. If a new customer connects to the natural gas system via Schedule 154, that customer is entitled to a ratepayer funded service connection. With LEAs no longer being offered in 2025, Schedule 154 could be used as way to bypass the LEA reduction. Removing Schedule 154, on the other hand, will not harm customers because this service is infrequently used, and has not received as service request since at least 2019.[21] Based on answers to discovery, Avista does not appear to oppose discontinuing Schedule 154.[22]

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[19] *See* Exhibit WG-6.

[20] *Id.*

[21] *See* Exhibit WG-7.

[22] *Id.*

V. CONCLUSION

Q. Please summarize your recommendations.

A. First, I recommend the Commission reject Avista's proposal to earn a rate of return for purchase power agreements. In the alternative, the return should be set at the Company's cost of debt. Second, I recommend that Commission adjust the rate spread for Schedule 99 by using the generation allocator S01. Third, I recommend the Commission require Avista discontinue line extension allowances for Schedules 131, 132, and 146 by Jan. 1, 2025 and eliminate Schedule 154.

Q. Does this conclude your testimony?

A. Yes.