BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-240006

DOCKET UG-240007

DIRECT TESTIMONY OF

JOEL C. ANDERSON

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, business address and present position with Avista Corporation?

A. My name is Joel C. Anderson. My business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Regulatory Analyst in the Regulatory Affairs Department.

Q. Would you briefly describe your educational background and professional experience?

A. I am a 2005 graduate of Eastern Washington University with a bachelor's degree in Business Administration, majoring in Finance. In 2012, I became a Certified Public Accountant in the State of Washington. I joined the Company in January 2013, after spending seven years working in various accounting positions in the banking industry. I started with Avista as an Internal Auditor. In January 2016, I joined the Regulatory Affairs Department as a Regulatory Analyst. In my current role, I am responsible for the Company's natural gas cost of service studies in all jurisdictions, among other things.

Q. What is the scope of your testimony in this proceeding?

A. My testimony presents the natural gas cost of service study and revenue normalization adjustment prepared for this filing. The results of this study were provided to Company witness Mr. Miller and were used to inform the spread of the proposed increase by service schedule. Company witness Mr. Garbarino will testify regarding the electric cost of service study and the electric revenue normalization adjustment. My testimony will also present the findings of the Decoupling Evaluation performed by Gil Peach and Associates and will request that the Commission authorize an extension of the current Decoupling Mechanism through December 31, 2026. A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits that accompany your testimony?

A. Yes. I am sponsoring Exh. JCA-2 related to the natural gas cost of service study. This exhibit was prepared by me and consists of summaries of information derived from the Cost of Service Study. I am also sponsoring Exh. JCA-3 which is the third-party Decoupling Evaluation Report prepared by H. Gil Peach & Associates LLC, Exh. JCA-4 which is the weather normalization model, and Exh. JCA-5 which is the revenue normalization model.

II. RESULTS OF NATURAL GAS COST OF SERVICE STUDY

Q. Please briefly summarize your testimony related to the natural gas cost of service study.

A. I believe the Base Case cost of service study presented in this case is a fair representation of the costs to serve each customer group. The cost of service study indicates that General Service Schedules 101 (serving mostly residential customers) and Transportation Schedule 146 are under parity as the classes provide less than the overall rate of return under present rates. The other classes, Large General and Interruptible Schedules (111/112/116, 131/132), are over parity as they provide more than the overall rate of return at present rates. Table No. 1 shows the rate of return and the relationship of the customer class return to the overall return (relative return ratio) at present rates for each rate schedule as well as the revenue-to-cost parity ratio at present rates for each rate schedule:

Table No. 1 – Relative Rates of Return at Present Rates, Return Ratio and Parity Ratio

Rate Schedule	Rate of Return	Return Ratio	Parity Ratio
General Service Schedule 101	4.77%	0.89	0.97
Large General Service Schedules 111/112	8.50%	1.58	1.17
Interruptible Sales Service Schedule 132	10.25%	1.90	1.29
Transportation Service Schedule 146	2.21%	0.41	0.77
Total Washington Natural Gas System	5.39%	1.00	1.00

III. NATURAL GAS REVENUE NORMALIZATION

Q. Would you please describe the natural gas revenue normalization adjustment included in Company witness Ms. Schultz's Natural Gas Pro Forma Study?

A. Similar to the electric revenue normalization adjustment, sponsored by Mr. Garbarino, there are three separate adjustments that normalize revenue as part of the natural gas revenue normalization adjustment:

1. Weather Normalization and Gas Cost Adjustment: Column 2.10 of Ms. Schultz's exhibit Exh. KJS-3, page 7 is a Commission Basis weather normalization restating adjustment. Revenues for this adjustment are based on rates that were in effect during the July 2022 through June 2023 test period, and therm sales and revenues have been adjusted to reflect normal weather conditions. The weather-related revenues associated with the Company's natural gas Decoupling Mechanism are removed in this adjustment, as therm sales and revenues have been normalized to reflect normal weather conditions.

2. Eliminate Adder Schedules: In addition to the weather normalization adjustment, Ms. Schultz study also includes an Eliminate Adder Schedules restating adjustment in column 2.11 of Exh. KJS-3, page 7, which removes the impact of adder schedule revenues and related expenses during the July 2022 through June 2023 test period.

3. Pro Forma Revenue Normalization: The Pro Forma Revenue Normalization Adjustment in column 3.01 of Exh. KJS-3, page 9, adjusts July 2022 through June 2023 test period customers and usage for any known and measurable (pro forma) changes. In addition, the adjustment re-prices billed, unbilled, and weather adjusted usage at the base tariff rates approved for the test period, as if the December 21, 2023, base tariff rates were effective for the full 12 months of the year.

<u>Weather Normalization:</u>

Q. Beginning with the <u>first</u> revenue normalizing adjustment, what is the Commission Basis weather normalization adjustment?

A. Weather normalization is a required element of Commission Basis reporting pursuant to WAC 480-90-257. The intent of this adjustment is for Commission Basis adjusted revenues and natural gas costs to reflect operations under normal temperature conditions during the reporting period.

Q. Would you please briefly discuss natural gas weather normalization?

A. Yes. As in past cases, the natural gas weather normalization adjustment is developed from a regression analysis of 10 years of billed usage-per-customer and billing period heating degree-day data. The resulting monthly weather sensitivity factors (use-per-customer-per-heating-degree day) are multiplied by the monthly test period number of customers, which is then multiplied by the difference between normal and actual heating degree-days. This calculation produces the change in therm usage required to adjust existing loads to the amount expected if weather had been normal.

Q. In the discussion of electric weather normalization sponsored by Mr. Garbarino, he indicated that the adjustment utilized sensitivity factors from the 10-year period January 2013 through December 2022. Is this true for natural gas as well?

A. Yes, the natural gas weather adjustment utilized updated weather sensitivity factors for the same 10-year period.

Q. Is the Company proposing any changes to its weather normalization methodology?

A. The Company is proposing two changes to the weather normalization methodology. First, the Company proposes to change the definition of "normal" from a 30-year to a 20-year rolling average. Second, the Company proposes to adjust its non-degree day seasonal regression factors from seasonal factors to monthly factors. These two changes are discussed in detail in Company witness Dr. Forsyth's testimony (Exh GDF-1T).

Q. Is this proposed weather adjustment methodology consistent with the methodology utilized in the Company's last general rate case in Idaho?

A. Yes, with the inclusion of the two changes noted above this methodology was included in the Company's most recent general rate case filing. Both changes were agreed to by the Parties as part of a broad Settlement Stipulation that was approved by the Idaho Commission.

Q. What data did you use to determine "normal" heating degree days?

A. Normal heating degree-days are based on a rolling 20-year average of heating degree-days reported for each month by the National Weather Service for the Spokane International Airport weather station. Each year the normal values are adjusted to capture the most recent year with the oldest year dropping off, thereby reflecting the most recent information available at the end of each calendar year. The calculation includes the 20-year period from 2003 through 2022.

Q. What was the impact of natural gas weather normalization on the 12-months ended June 2023 test year?

A. Weather was warmer than normal during the July 2022 through June 2023 period. The adjustment to normal required an increase of 134 heating degree-days for the test year. The adjustment to sales volumes was an increase of 163,374 therms.

Q. What was the impact of this adjustment on Commission Basis results of operations?

A. The Commission Basis weather normalization adjustment increased total natural gas revenue by $28,000, which after the offsetting decrease to purchased gas expense of $127,000, resulted in a decrease to distribution margin of $99,000. The combined effect of netting the decrease to distribution margin against the decoupling revenue offset of $57,000, resulted in a net margin weather adjustment of $(43,000).[1] After an increase for Federal Income Tax, the weather normalization adjustment produced an operating income of $(34,000), as shown below:

<u>Table No. 2: - Weather Normalization Adjustment Summary</u>

General Business Revenue (Sales)	$	28,000
Other Revenue (Decoupling Deferred)	$	(127,000)
Total Revenue (Net Adjustment)	$	(99,000)
Less: Purchased Gas Expense	$	57,000
Distribution Margin Weather Adjustment	$	(43,000)
Less: Revenue Related Expenses	$	0
Less: Federal Income Tax	$	9,000
Net Operating Income	$	(34,000)

<u>Eliminate Adder Schedules:</u>

Q. Moving on to the <u>second</u> revenue normalizing adjustment, what is the purpose of the Eliminate Adder Schedule adjustment?

A. The Eliminate Adder Schedule adjustment removes both the revenues and expenses associated with all adder schedule rates, except current natural gas costs (Purchased

[1] The Decoupling Mechanism went into effect January 1, 2015.

Gas Cost Adjustment Schedule 150), since these items are recovered/rebated by separate tariffs and, therefore, are not part of base rates. The items eliminated include: Schedule 195 (Optional Renewable Natural Gas), Schedule 175 (Decoupling Mechanism Rate Adjustment), Schedule 189 (Fixed-Income Senior & Disabled Residential Service Discount Rate Adjustment), Schedule 191 (Demand Side Management Rate Adjustment), Schedule 192 (Low Income Rate Assistance Program Rate Adjustment), Schedule 176 (Tax Customer Credit AFUDC), Schedule 178 (Tax Customer Credit), and Schedule 155 (Gas Rate Adjustment). This adjustment also identifies and consolidates all the purchased gas cost related accounts into the "City Gate Purchases" line item in order to simplify the Pro Forma Revenue Normalization adjustment described below.

Q. What was the impact of the Eliminate Adder Schedule adjustment on Commission Basis results of operations?

A. The Commission Basis Eliminate Adder Schedule adjustment results in a nearly equal and offsetting reduction to both revenue and expense and the resulting adjustment was an increase to net income of $8,000.

<u>Pro Forma Revenue Normalization:</u>

Q. Please describe the <u>third</u> revenue normalizing adjustment, the Pro Forma Revenue Normalization adjustment.

A. The purpose of the "Pro Forma Revenue Normalization" adjustment is to restate distribution revenue on a forward-looking basis and to remove natural gas costs. This is accomplished by re-pricing test period normalized billing determinants (including unbilled and weather adjustments, as well as any known and measurable changes to the test year loads and customers) to reflect revenues for the July 2022 through June 2023 test period.

Q. Does the Pro Forma Revenue Normalization Adjustment contain a component reflecting normalized natural gas costs?

A. No, natural gas commodity costs previously shown as an equal and offsetting amount in both revenue and expense, have been removed from the Company's filing.

Q. What is the impact of the Pro Forma Revenue Normalization adjustment?

A. The Pro Forma Revenue Normalization adjustment increases total natural gas revenue by $89,786,000. After taking into account the offsetting effect of the decrease to revenue from rates with the elimination of both the restated decoupling deferred revenue $2,714,000 and transportation revenue of ($333,000), this resulted in a total pro forma revenue adjustment increase of ($1,797,000). After an offset for revenue-related expenses and taxes, Washington net operating income increased $1,922,000 as shown below.

<u>Table No. 3 – Summarize Revenue Normalization Adjustment</u>

General Business Revenue	$	(89,786,000)
Other Revenue (Eliminate Decoupling Deferred)	$	(2,714,000)
Other Revenue (Transportation)	$	333,000
Total Revenue (Net Adjustment)	$	(92,176,000)
Eliminate Purchased Gas Expense	$	90,370,000
Distribution Margin Adjustment	$	(1,797,000)
Revenue Related Expenses	$	4,230,000
Federal Income Tax	$	(511,000)
Net Operating Income	$	1,922,000

IV. NATURAL GAS COST OF SERVICE

Q. Please describe the natural gas cost of service study and its purpose.

A. A natural gas cost of service study is an engineering-economic study which separates the revenue, expenses, and rate base associated with providing natural gas service to designated groups of customers. The groups are made up of customers with similar usage characteristics and facility requirements. Costs are assigned in relation to each group's test period load and facilities requirements, resulting in an evaluation of the cost of service provided to each group. The rate of return by customer group indicates whether the revenue provided by the customers in each group recovers the cost to serve those customers. The study results are used as a guide in determining appropriate rate spread among the groups of customers.

Q. What is the basis for the natural gas cost of service study provided in this case?

A. The cost of service study provided by the Company as Exh. JCA-2 is based on the 12-months ended June 2023 test year pro forma results of operations for Rate Year 1 presented by Ms. Schultz in Exh. KJS-3.

Q. Please explain the basic concepts involved in performing a natural gas cost of service study.

A. There are three basic steps involved in a cost of service study: functionalization, classification, and allocation. First, the expenses and rate base associated with the natural gas system under study are assigned to functional categories. The FERC uniform system of accounts provides the basic segregation into production, underground storage, and distribution. Traditionally, customer accounting, customer information, and sales expenses are included in the distribution function and administrative and general expenses and general plant rate base are allocated to all functions. In this study I have created a separate functional category for common costs. Administrative and general costs that cannot be directly assigned to the other functions have been placed in this category.

Second, the expenses and rate base items are classified into three primary cost components: demand, commodity, and customer-related. Demand-related (capacity) costs are allocated to rate schedules based on design day peak demand. Commodity-related (energy) costs are allocated based on each rate schedule's share of commodity consumption. Customer-related items are allocated to rate schedules based on the number of customers within each schedule. The number of customers may be weighted by appropriate factors such as relative cost of metering equipment. In addition to these three cost components, any revenue-related expenses are allocated based on the proportion of revenues by rate schedule. The final step is allocation of the costs to the various rate schedules utilizing the allocation factors selected for each specific cost item. These factors are derived from usage and customer information associated with the test period results of operation.

Q. Are Cost of Service studies a required component of general rate case filings?

A. Yes. WAC 480-07-510(6), which discusses cost studies in general rate proceeding filings, was amended by General Order R-599 on July 7, 2020, to state that a company's initial general rate case filing must include a cost of service study that complies with the new chapter WAC 480-85.

Q. Has the Company complied with all requirements of WAC 480-85?

A. Yes, the Company believes the natural gas cost of service study presented in this filing meets all the requirements set forth in WAC 480-85.

Q. Please identify cost of service studies conducted in the last five years for the company?

A. The natural gas cost of service studies provided in the last five years can be found in Dockets UG-190335, UG-200901, and UG-220054.

Methodology

Q. Does the Natural Gas Base Case cost of service study utilize the same methodology from the Company's last natural gas case in Washington?

A. Yes, the Base Case cost of service study was prepared using the same methodology used in our previous rate case and complies with WAC 480-85-060 resulting from the new cost of service rules approved in July 2020.

Q. Please explain the cost of service study presented in Exh. JCA-2.

A. Exh. JCA-2 presents the results of the cost of service study in the form of the natural gas cost of service template available from the Commission in compliance with WAC 480-85-040(1). Electronically the template consists of six workbook tabs that are presented as separate sections in this exhibit. Section A is the Revenue Requirement cross-reference which shows Ms. Schultz revenue requirement development (Exh. KJS-3) expressed at the FERC Account level to facilitate assignment of costs to customer rate classes in the study. Section B presents the FERC Account level cost of service results for all customer rate classes. Section C shows the allocation factors used to assign each type of cost to the customer rate classes. Section D is a summary of the revenue requirement adjustments shown in Section A. Section E is a high-level summary of the cost of service results showing the Parity ratio at present rates and the Revenue-to-Cost ratio at proposed rates. Finally, Section F shows meter, services, meter-reading, and billing costs by schedule at the proposed rate-of-return.

The Excel model used to calculate the base case cost of service and supporting schedules have been included in its entirety electronically and a hard copy is in the workpapers accompanying this case. While there are "macros" to facilitate printing certain workpapers, no macros are integral to the cost of service model calculations.

Q. What are the key elements that define the cost of service methodology?

A. Consistent with the allocation methodologies defined within WAC 480-85-060 underground storage costs classified as balancing are allocated to all customers based on winter sales. All remaining costs are allocated to sales customers based on average winter sales that exceed average summer sales. Natural gas main investment is allocated based on peak demand and annual throughput, respectively. Other system facilities that serve all customers are classified by the peak and average ratio that reflects the system load factor, then allocated by peak demand and throughput, respectively. Meter installation and services investment is allocated by number of customers weighted by the relative installed cost of those items. General plant not specifically defined within rule is allocated based on the Company's blended four-part factor allocator (four-factor), discussed below. Administrative & general expenses are segregated into labor-related, plant-related, revenue-related, and "other." The costs are then allocated by factors associated with labor, plant in service, or revenue, respectively. The "other" A&G amounts are allocated based on the Company's four-factor.

Q. Please describe how investment in distribution mains is classified and allocated under the Company's proposed main allocation.

A. The investment in distribution main is classified as a demand-related cost, however, it is not allocated solely on peak demand. In accordance with WAC 480-85-060, the Company uses the system load factor for allocating this portion of its demand-related costs. This method allocates demand-related costs based on a combination of peak demand and average demand. Average demand is essentially another term for average throughput.

The Company used the system load factor to determine how much of the demand-related costs would be allocated based on annual throughput and how much would be allocated based on design day peak demand[2]. A system load factor was calculated based on throughput and peak demand. The load factor is the ratio of average load to peak load, and when multiplied by the plant investment, provides an estimate of the costs that can be attributed to average use rather than peak use.

The resulting load factor was used to divide the demand-related costs into peak demand and average demand for purposes of allocating the costs to the rate schedules, with the demand-related costs being allocated 38.35 percent on average demand and 61.65 percent on peak demand. The load factor provides a reasonable basis for determining what portion of the costs should be allocated based on average demand.

Q. Please describe how Customer Relations Distribution Costs are Classified.

A. Customer service, customer information and sales expenses are the core of the customer relations functional unit which is included with the distribution cost category. For the most part, these costs are classified as customer-related. The only exception is uncollectible accounts expense, which is considered separately as a revenue conversion item.

Q. How has the Company allocated the general plant costs, intangible plant costs, and other A&G expenses (common costs)?

A. Property insurance and taxes are functionalized and allocated based on plant in service. Pensions and employee insurance expenses are allocated based on salary and wages. FERC fees are identified and allocated based on energy consumption. Revenue-based fees, uncollectible accounts expenses, and excise taxes are allocated by relative share of total revenue. The remainder of general plant, intangible plant and other A&G expenses are considered common costs and are allocated based on the Company's four-factor. This allocation

[2] Peak demand is defined as the actual five-day peak demand from the test year.

factor is the cost of service equivalent of the four-factor allocator used in the Company's results of operations reporting. The four-factor has historically been utilized by the Company to allocate common operating costs and plant between states (Washington, Idaho, and Oregon) and among services (electric and natural gas) for purposes of the Company's Commission Basis results of operations.

Q. Please describe the components of the four-factor.

A. The four-factor is comprised of the following four equally weighted components:

- Direct O&M excluding resource costs and labor
- Direct O&M labor
- Number of customers
- Net direct plant

Q. Please describe the benefits of the four-factor allocator.

A. There are two primary benefits of the four-factor. First, it reflects a variety of relationships that are consistent with the specific costs and plant items which are recognized as serving multiple functions. Second, it provides consistency and balance between the way common costs are allocated for purposes of Commission Basis results of operations and the cost of service study used in general rate cases.

Q. Did the Company prepare an analysis of Intangible Plant balances while preparing this Cost of Service Study?

A. Yes. Account 303.120 software costs are associated with the meter data management system (MDM) and advanced metering infrastructure (AMI) project. An analysis of Account 303.100 computer software by project is included in the Company workpapers. No additional functionalization resulted from the project level analysis. Common intangible plant costs have been allocated based on tangible plant. This treatment of intangible plant costs is consistent with the Company's past natural gas cost of service studies.

Results

Q. What are the results of the Company's natural gas cost of service study?

A. The cost of service study indicates that General Service Schedule 101 (serving mostly residential customers) and Transportation Schedule 146 are providing less than the overall rate of return (unity), and Large General and Interruptible Schedules (111/112/116, 131/132) are providing more than unity. The following table shows the rate of return, the relative return ratio, and the parity ratio at present rates for each rate schedule.

Table No. 4 - Base Case Results

Rate Schedule	Rate of Return	Return Ratio	Parity Ratio
General Service Schedule 101	4.77%	0.89	0.97
Large General Service Schedules 111/112	8.50%	1.58	1.17
Interruptible Sales Service Schedule 132	10.25%	1.90	1.29
Transportation Service Schedule 146	2.21%	0.41	0.77
Total Washington Natural Gas System	5.39%	1.00	1.00

The summary results of the study were used for consideration in the development of the proposed rates.

V. DECOUPLING MECHANISM EXTENTION

Introduction

Q. Is the Company proposing to extend its electric and natural gas decoupling mechanisms in this case?

A. Yes, the Company is proposing to extend the mechanisms through this Two-

Year Rate Plan (through calendar year 2026). Based on proven benefits to both the customer and the Company that the Decoupling Mechanisms have shown to date, as validated in the second Independent Final Report (Exh JCA-3), and the lack of adverse impacts associated with these mechanisms, the Company requests the Commission approve the continuation of the Decoupling Mechanisms. By extending the mechanisms and providing some certainty to the Company that it can recover a significant portion of its fixed costs of providing service, the Company is able to maintain its central focus of being a trusted energy advisor to its customers without adverse or uncertain financial impacts from evolving customer choice in the future. The Company believes, consistent with the Commission's conclusion when they approved the mechanisms in 2014 and reauthorized the mechanisms in 2019, that the Decoupling Mechanisms continue to be in the public interest, promote the policy goals of increased conservation, and result in fair, just, reasonable, and sufficient rates.

Background

Q. Would you please provide the background of the Company's Decoupling Mechanisms?

A. Yes. On November 25, 2014, the Commission issued Order 05 in Dockets UE-140188 and UG-140189, approving the settling parties' request to implement electric and natural gas Decoupling Mechanisms for five years. Later, on March 25 2020, the Commission ordered the continuation of the mechanism through March 31, 2025 in Order No. 09 in Dockets UE-190334 and UG-190335. In its extension of the Decoupling Mechanisms, the Commission stated, "continuing Avista's decoupling mechanisms until March 31, 2025, is in the public interest and will result in rates that are fair, just, reasonable and sufficient."

The purpose of the Decoupling Mechanisms is to decouple the Company's Commission-authorized revenues from energy sales, such that the Company's revenues will be recognized based on the number of customers served under the applicable service schedules. The Decoupling Mechanisms allows the Company to: 1) defer the difference between actual decoupling-related revenue approved for recovery in the Company's last general rate case; and 2) file a tariff to surcharge or rebate, by rate group, the total deferred amount accumulated in the deferred revenue accounts for the prior January through December time period.

Q. Did the Company contract with an independent, third-party to evaluate its Decoupling Mechanisms?

A. Yes. As part of the decoupling mechanisms approval, the Commission required a third-party evaluation, paid for by Avista shareholders, to be completed three years after it was ordered to be continued in Dockets UE-190334 and UG-190335. The Commission required the Company to consult with its Energy Efficiency Advisory Group ("Advisory Group") in the development of the Request for Proposals (RFP) and the selection of the consultant to perform the evaluation. After incorporating input from the Advisory Group, Avista was required to file its draft RFP, including the scope of the evaluation query, with the Commission for approval. At a minimum, the evaluation was to address:

- The mechanisms' impact on conservation achievement
- The mechanisms' impact on Company revenues
- The extent to which fixed costs are recovered in fixed charges for the customer classes.
- Excluding new customers from the decoupling mechanisms
- Using a moving average of weather data shorter than 30 years based on the data gathered by Avista regarding a 30-, 20-, 15-, and 10-year moving average
- The 3 percent cap on annual adjustments compared with (1) a 5 percent cap, had it been implemented as we have approved for other utilities in Washington, and (2) no cap on annual adjustments

In compliance with Order 09, the Company filed its draft RFP on November 21, 2022. In preparation of completing the draft RFP, the Company engaged with the Advisory Group in the development of the RFP and included all requested edits, modifications, and suggestions into the RFP document.

The Company issued the filed RFP to a group of consultants that were shared with the Advisory Group. H. Gil Peach & Associates was ultimately selected as the consultant for this project. In addition to meeting the requirements set forth in the Statement of Work contained within the RFP, H. Gil Peach & Associates has completed the first review of the Company's decoupling mechanisms (see Exh. PDE-2, Dockets UE-190334 et. al.), and completed a similar review for Puget Sound Energy, which in the Company's view, added to their qualifications. H. Gil Peach & Associates issued a final report to Avista on December 19, 2023. The final report, labeled "Avista Decoupling Evaluation (Independent Final Report)," is included as Exh. JCA-3.

<u>Purpose and Benefits of Decoupling</u>

Q. What is the purpose and benefits of Decoupling?

A. As described in the Commission's *Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, To Encourage Utilities To Meet Or Exceed Their Conservation Targets* in Docket U-100522, ("Decoupling Policy Statement"), decoupling is "a means to separate a utility's recovery of costs and return from the amount of energy it sells."[3] Said another way, decoupling is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. As noted in the Commission order approving Avista's

[3] Docket U-100522, Para. 7

Decoupling Mechanisms, decoupling removes the so-called throughput incentive and is intended to promote more aggressive pursuit of cost-effective conservation. As shown in Table Nos. 5 and 6 below for both electric and natural gas residential customers, Avista has continued to see a decline in use-per-customer for the past several years which is illustrative of the need, and importance of the Decoupling Mechanisms:

Table No. 5: Electric Residential Use-Per-Customer

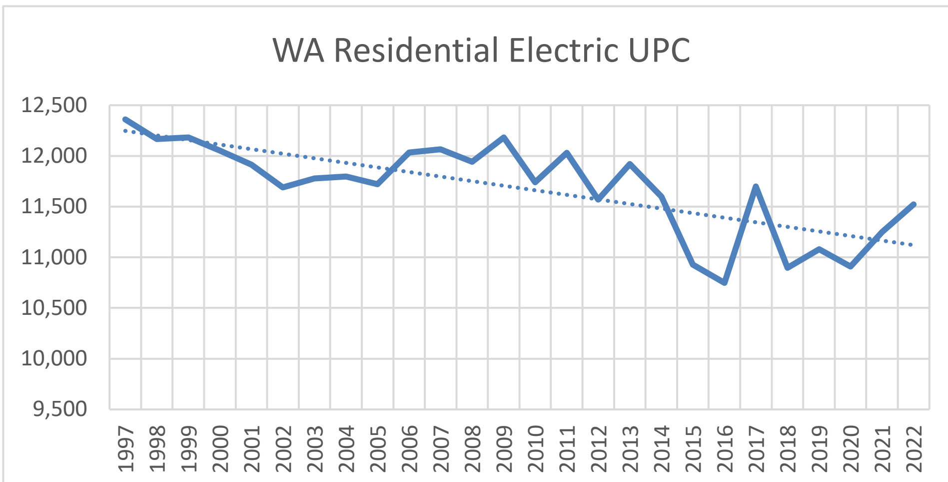
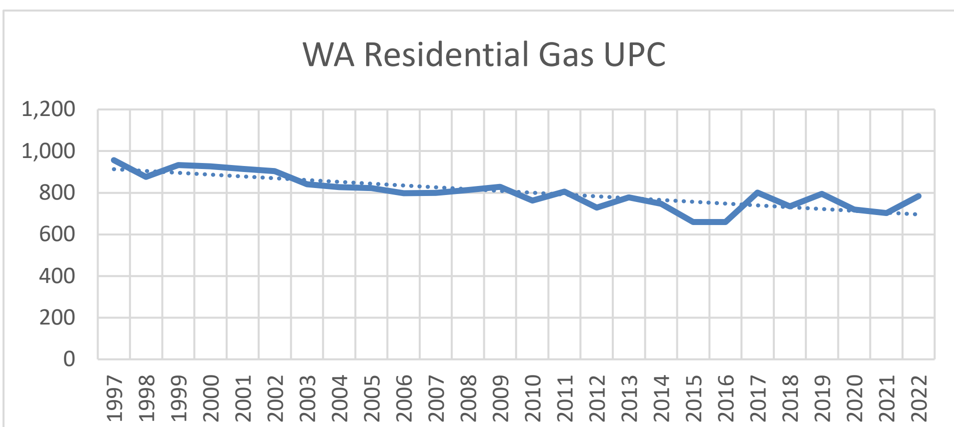


Table No. 6: Natural Gas Residential Use-Per-Customer



Absent the Decoupling Mechanisms, in periods of declining use-per-customer similar to what the Company has experienced, Avista would under-recover its fixed costs of providing service to its customers in the periods in between general rate case filing (given that a majority of the Company's fixed costs are recovered in variable energy rates). To the extent use-per-customer declines from programmatic and non-programmatic DSM, or distributed generation resources between general rates cases, the Decoupling Mechanisms provide the Company recovery of its fixed costs for providing service to its customers. These are the same fixed costs, on a revenue-per-customer basis, that the Commission approves for recovery in a general rate case. In addition, the mechanisms ensure that to the extent there is customer growth in the rate year and beyond, the revenues are available to offset the growth in utility costs following the test year. By allowing the Company to recover a significant portion of its fixed costs of providing service, the Company can maintain its central focus of being a trusted energy advisor to its customers without uncertainty as to the financial impact customer choice may have on the Company.

Q. Would you say that the Decoupling Mechanisms have provided benefits to the Company and its customers?

A. Yes. As further detailed in the analysis provided in the Independent Final Report, the Decoupling Mechanisms have proven to be a vital and meaningful program for both the Company and its customers. Not only has the program accomplished its original objectives of removing the disincentive for the Company to promote the efficient end-use of energy through conservation, but it has also been beneficial to customers in times of a colder than normal winter, or a hotter than normal summer, when the Company has returned those additional revenues back to customers. The Decoupling Mechanisms also stabilizes revenue for the Company and rates for Customers.[4]

[4] The independent third-party final report states "Avista's decoupling mechanism has had a stabilizing effect on revenue, reducing variability in half for electric and by one-fifth for natural gas of variability without decoupling" (Page 2-22 Exh. JCA-3)

Decoupling Mechanism Performance

Q. How have the Decoupling Mechanisms performed?

A. The Decoupling Mechanisms have proven to work for both the customers' and the Company's benefit, as intended. Table No. 7 below, reproduced from the Independent Final Report (Exh. JCA-3, Table 2-3), shows the deferral balances for the Residential Customer Groups for electric were in the surcharge direction for 2018 and 2019 deferral period, and in the rebate direction for the 2020, 2021 and 2022 deferral period.

Table No. 7: Summary of Electric Deferral Balances

Electric						
Residential Group						
	Notes	2018	2019	2020	2021	2022
Summary of Deferred Revenue (1,000$)						
Deferred Revenue		8,620	1,182	(811)	(5,124)	(16,126)
Requested Recovery	A	9,571	5,904	(1,112)	(5,801)	(18,646)
Customer surcharge (rebate) revenue		6,627	5,904	(1,112)	(5,801)	(18,646)
Carryover deferred revenue		2,943	-	-	-	-
Summary of Decoupling Rate Adjustment						
Earnings Test Results (Over/Under)	B	Under	Under	Under	Under	Under
Decoupling rate (Schedule 75) (cents/kWh)	C	$ 0.279	$ 0.244	$ (0.045)	$ (0.234)	$ (0.725)
Incremental revenue (percent)		4.3%	-0.4%	-3.0%	-2.0%	-4.7%
Limited by 3% cap?	D	Yes	No	No	No	No
Notes						
A: Requested recovery is equal to deferred revenue after adjusting for shared excess earnings (if applicable), deferral balance carryover from prior year (if any), interest, and revenue related expenses.						
B: Indicates whether or not earnings were over or under Avista's allowed return. When earnings exceed Avista's allowed return, half of excess earnings are shared with customers through the decoupling rate adjustment.						
C: Decoupling rates Schedule 75 (electric) and Schedule 175 (natural gas) take effect on November 1st, 2019, for 2018 results and August 1st of the following year for 2019-2022 results.						
D: As a response to the COVID 19 pandemic, Avista proposed replacing the 3% cap with a 0% cap on the decoupling rate adjustment effective August 1st, 2020, shown in the 2019 column of this table. This change only applied to 2019 results and only impacted the electric non-residential rate group as this group was the only one that would have resulted in an increase in rates.						

Table No. 8 below, reproduced from the Independent Final Report (Exh. JCA-3, Table 2-4), shows the deferral balances for the Residential Customer Groups for natural gas were in the surcharge direction for 2018, 2020 and 2021 deferral period, and in the rebate direction for the 2019 and 2022 deferral period.

Table No. 8: Summary of Natural Gas Deferral Balances

Natural Gas						
Residential Group						
	Notes	**2018**	**2019**	**2020**	**2021**	**2022**
Summary of Deferred Revenue (1,000$)						
Deferred Revenue		741	(1,054)	1,174	6,559	(1,069)
Requested Recovery	A	556	(896)	1,256	7,021	802
Customer surcharge (rebate) revenue		556	(896)	1,256	5,379	802
Carryover deferred revenue		-	-	-	1,643	-
Summary of Decoupling Rate Adjustment						
Earnings Test Results (Over/Under)	B	Over	Under	Under	Under	Under
Decoupling rate (Schedule 75) (cents/kWh)	C	$ 0.420	$ (0.685)	$ 0.925	$ 3.899	$ 0.587
Incremental revenue (percent)		4.2%	-1.2%	1.8%	3.0%	-2.5%
Limited by 3% cap?	D	No	No	No	Yes	No
Notes						
A: Requested recovery is equal to deferred revenue after adjusting for shared excess earnings (if applicable), deferral balance carryover from prior year (if any), interest, and revenue related expenses.						
B: Indicates whether or not earnings were over or under Avista's allowed return. When earnings exceed Avista's allowed return, half of excess earnings are shared with customers through the decoupling rate adjustment.						
C: Decoupling rates Schedule 75 (electric) and Schedule 175 (natural gas) take effect on November 1st, 2019, for 2018 results and August 1st of the following year for 2019-2022 results.						
D: As a response to the COVID 19 pandemic, Avista proposed replacing the 3% cap with a 0% cap on the decoupling rate adjustment effective August 1st, 2020, shown in the 2019 column of this table. This change only applied to 2019 results and only impacted the electric non-residential rate group as this group was the only one that would have resulted in an increase in rates.						

Table Nos. 7 and 8 above also provide a summary of the billing rate effects from each of the Company’s Decoupling Mechanism Rate Adjustments from 2018 through 2022. The primary drivers of the changes in the deferral balances were deviations in use-per-customer primarily driven by actual weather being different from normal weather in any given year, and continued energy efficiency savings that were acquired beyond what was built into the Company’s test year.

Independent Report Findings and Recommendation

Q. What were the findings and recommendations from H. Gil Peach’s

Independent Report, included as Exh. JCA-3?

A. The Independent Final Report issued by H. Gil Peach and Associates is segmented into sections which were designed to address the requirements as fully described in the Company's RFP. As described in the introduction of the Independent Final Report, the evaluation was partly a compliance evaluation and partly a policy evaluation of Avista's Decoupling Mechanisms. Sections 1 through 8 correspond to a specific task and sections 9 and 10 correspond to specific findings and recommendations. So as to not burden the testimony by providing all of the tasks, findings, and recommendations, provided below are the recommendations found in Section 10 of the Report along with Avista's responses to each recommendation. (the other information can be found in Exh. JCA-3):

Section 10 – This section provides a summary of the Independent Final Report recommendations. [Avista has inserted its' response below each recommendation]

(1) **Continuation.** The decoupling mechanisms have worked as expected to stabilize revenue without impacting utility operations and energy efficiency programs. We also found no evidence of adverse impacts to any customer groups. Since the program continues to work as planned in this second evaluation, we recommend the electric and natural gas mechanisms be continued.

Avista Response - This Petition addresses the continuation of the mechanisms through December 31, 2026.

(2) **Direct Consultant for Biennial Program Evaluations to address 5% adder.** In developing this decoupling study, we were not able to specifically address the 5% adder for energy savings since there was not a specific breakout of this in the Biennial Program Evaluations. We recommend that the evaluator for the Biennial Program Evaluations be assigned to specifically address the 5% adder for energy savings in future evaluations, so that this information will be readily available.

Avista Response – Avista will evaluate the possibility of addressing this through Biennial Program Evaluations.

(3) **Direct Biennial Program Evaluations to break out spend by service**. In developing this decoupling study, we note a need for the Biennial Program Evaluations to add a table showing planned and resulting energy savings and conservation spend separately for electric and natural gas conservation annually,

beginning with 2014. Inclusion of a subtask for the evaluator for the Biennial Program Evaluations to report spend separately for electric and natural gas conservation annually, beginning with 2014 would add useful trend information to the evaluations.

Avista Response – Avista will evaluate the possibility of addressing this through Biennial Program Evaluations.

(4) **Direct specific treatment of 5% adder in Conservation planning and achievement reports.** For Conservation planning and Conservation achievement reports, it would be useful for future reports to require specifically addressing the 5% adder for energy savings.

Avista Response – Avista will evaluate the possibility of addressing this through Biennial Program Evaluations.

(5) **Direct reporting of separate spend for Conservation planning and Conservation achievement reports**. It would be useful for future reports to require the addition of a table showing planned and resulting energy savings and conservation spend separately for electric and natural gas conservation annually, beginning with 2014. This would add useful trend information to the evaluations.

Avista Response – Avista will evaluate the possibility of addressing this through Biennial Program Evaluations.

(6) **Operational definition of normal weather:** In a review of Avista's calculations using a 30-year, 20-year, 15-year, and 10-year rolling average as alternative operational definitions of normal weather, we recommend the 20-year period as the longest time window and the 15-year period as the shortest time window for consideration.

Avista Response - The Company is proposing two changes to the weather normalization methodology as discussed in the "Natural Gas Revenue Normalization" section of my testimony. First, the Company proposes to change the definition of "normal" from a 30-year to a 20-year rolling average. Second, the Company proposes to adjust its non-degree day seasonal regression factors from seasonal factors to monthly factors. These two changes are discussed in detail in Company witness Dr. Forsyth's testimony.

Q. Is Avista proposing any modifications to its Decoupling Mechanisms in this case?

A. No, it is not. In our view the mechanisms have been working as intended, after reflecting several modifications in our last reauthorization request, and has been well-reviewed and supported by an independent third party as discussed above.

Q. Does this conclude your pre-filed, direct testimony?

A. Yes, it does.