

Exhibit No. ___ (CTM-1T)
Dockets UE-140188/UG-140189
Witness: Christopher T. Mickelson

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

**WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,**

Complainant,

v.

AVISTA CORPORATION,

Respondent.

**DOCKETS UE-140188 and
UG-140189
(Consolidated)**

TESTIMONY OF

CHRISTOPHER T. MICKELSON

**STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION**

*Electric Cost of Service, Revenue Allocation, and Rate Design
Natural Gas Cost of Service, Revenue Allocation, and Rate Design*

July 22, 2014

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Exhibit No. ___ (CTM-3)	Electric Revenue Allocation and Rate Design
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Exhibit No. ___ (CTM-7)	Natural Gas Cost Classifications and Allocations
Exhibit No. ___ (CTM-8)	Allocation of Natural Gas Distribution Mains

1 I. INTRODUCTION

2
3 **Q. Please state your name and business address.**

4 A. My name is Christopher Thomas Mickelson. My business address is the Richard
5 Hemstad Building, 1300 S. Evergreen Park Drive S.W., Olympia, Washington
6 98504.

7
8 **Q. By whom are you employed and in what capacity?**

9 A. I am employed by the Washington Utilities and Transportation Commission
10 (“Commission”) as a Senior Regulatory Analyst in the Energy Section of the
11 Regulatory Services Division. Among other duties, I am responsible for analyzing
12 financial, accounting, and revenue allocation and rate design issues in general rate
13 cases, accounting petitions, and other tariff filings, as they pertain to the electric and
14 natural gas companies under the jurisdiction of this Commission.

15
16 **Q. How long have you been employed by the Commission?**

17 A. I have been employed by the Commission since June 2007.

18
19 **Q. Would you please state your educational and professional background?**

20 A. I graduated from the University of Washington in 2002, receiving a Bachelor of Arts
21 degree in Business Administration. While attending college, I performed the duties
22 of accounts payable and subcontracting accounting for Sellen Construction
23 Company. In 2006, I was employed as a fraud auditor for the Washington State

1 Department of Labor & Industries. Since joining the Commission, I have attended
2 several regulatory courses, including the 49th Annual National Association of
3 Regulatory Utility Commissioners Regulatory Studies Program held at Michigan
4 State University.

5 I have participated in the development of Commission rules, prepared
6 detailed statistical studies for use by commissioners and other Commission
7 employees, and examined utility and transportation company reports for compliance
8 with Commission regulations. I have also presented Staff recommendations at
9 numerous open public meetings.

10
11 **Q. Have you previously testified before the Commission?**

12 A. Yes. Recently, I testified on uncollectible expenses, net-to-gross conversion factor,
13 electric cost of service, revenue allocation, rate design, and service charges in
14 PacifiCorp d/b/a Pacific Power & Light Company's general rate case ("GRC"),
15 Docket UE-130043. I also filed testimony on Aldyl-A pipe replacement accounting
16 treatment, electric and natural gas cost of service, revenue allocations and rate design
17 in Avista Corporation's ("Avista" or "Company") GRC, Dockets UE-120436 and
18 UG-120437.

19 I testified on the treatment of planned major maintenance activities, hydro
20 production operating and maintenance expense, the handling of United States
21 Department of the Treasury Grants, other power cost issues and calculations, revenue
22 allocation, and rate design in Puget Sound Energy, Inc.'s ("PSE") Power Cost Only
23 Rate Case ("PCORC"), Docket UE-130617; and the allocation of proceeds from the

1 sale of the assets to Jefferson County Public Utility District #1 in PSE's accounting
2 petition, Docket UE-132027; and on natural gas revenue requirement, revenue
3 allocation and rate design in PSE's GRC, Docket UG-111049.

4 I was the lead analyst in numerous other tariff applications, including GRCs
5 of Murrey's Disposal Company, Inc., Docket TG-090097; American Disposal
6 Company, Inc., Docket TG-090098; Washington Water Service Company, Docket
7 UW-090733; and Waste Management of Washington, Inc., Dockets TG-091933 and
8 TG-101080.

9
10 **II. SCOPE AND SUMMARY OF TESTIMONY**

11
12 **Q. What is the purpose of your testimony?**

13 A. My testimony presents Staff's recommendations for cost of service studies and
14 allocating Staff's recommended revenue requirement to Avista's rate schedules for
15 both electric and natural gas service. I also present Staff's recommended rate
16 designs to implement that allocation for both electric and natural gas services.

17 I respond to the Company's cost of service, revenue allocation, and rate
18 design proposals sponsored by Ms. Knox (Electric Cost of Service), Mr. Miller
19 (Natural Gas Cost of Service), and Mr. Ehrbar (Electric and Natural Gas Rate
20 Designs).

21
22 **Q. Please summarize your recommendations with respect to the electric cost of**
23 **service study, revenue allocation, and rate design.**

1 A. Staff makes multiple recommendations for classifying and allocating capital
2 investments and operating expenses. The principle difference between Staff's cost
3 of service studies and Avista's are the classifying and allocating of: (1) general plant
4 costs and administrative and general ("A&G") expenses; (2) production costs; (3)
5 transmission costs; and (4) wind costs. For both general plant costs and A&G
6 expenses, Staff uses the Company's blended 4-part factor allocator. For production
7 costs, Staff uses the average and excess demand method, with the excess allocated on
8 the basis of non-coincident peak demand. For transmission costs, Staff applies a 12
9 coincidental peak and average method. For wind costs, Staff used 100 percent
10 generating level consumption. In addition, Staff recommends creating a new
11 schedule, Schedule 26, for ultra large usage customers.

12 Staff did not use the Company's electric cost of service study because that
13 study did not reasonably or fairly functionalize, classify, and allocate capital
14 investments and operating expenses to each rate schedule.

15 With respect to revenue allocation, Staff proposes a rate spread that is
16 consistent with Staff's cost of service study results and principles of cost causation.
17 Staff recommends General Schedules 11 and 12 receive a 5.00 percent decrease,
18 Large General Schedules 21 and 22 receive a 2.15 percent decrease, Extra-Large
19 General Schedule 25 receives a 2.29 percent decrease, while newly created Ultra-
20 Large General Schedule 26 receives a 5.40 percent decrease, and all other Schedules
21 receive no change to their revenue requirements.

22 As for electric rate design, Staff recommends the Commission increase the
23 basic monthly customer charge to \$8.50 to better reflect the customer-specific fixed

1 costs Avista incurs, Staff further recommends the Commission apply separate
2 uniform percentage decreases for all energy volumetric rates in each schedule¹ and
3 set demand charges equal across all schedules. Lastly, Staff recommends the
4 Commission apply a straight-fixed variable rate design for Schedules 25 and 26,
5 rather than include these two schedules in the decoupling mechanism.

6
7 **Q. Please summarize Staff's recommendations for the natural gas cost of service**
8 **study, revenue allocation, and rate design.**

9 A. Staff makes multiple recommendations for classifying and allocating capital
10 investments and operating expenses. The principle difference between Staff's cost
11 of service studies and Avista's are the classifying and allocating of: (1) gas
12 distribution main costs; (2) general plant and administrative and general ("A&G")
13 expenses; and (3) underground storage plant costs. Staff classifies distribution mains
14 to reflect the fact that large load customers (i.e., Schedules 131, 132, and 146)
15 benefit from the reliability and capacity of the system provided by smaller pipes (less
16 than four inches in diameter). For general plant and A&G expenses, Staff uses the
17 Company's 4-factor allocator. For underground storage plant costs, Staff reflects a
18 20 percent load balancing benefit for all customers and 80 percent commodity
19 storage benefit for sales customers.

20 Staff did not use the Company's natural gas cost of service study because that
21 study did not reasonably or fairly functionalize, classify, and allocate capital
22 investments and operating expenses to each rate schedule.

¹ Except for Residential Schedule 1, this gets a uniform percentage decrease to the first two volumetric block rates.

1 The differences in classifying and allocating of costs leads Staff to
2 recommend a revenue allocation different from the equal percentage proposed by the
3 Company. Staff recommends General Service (Residential) Schedule 101 receives a
4 6.2 percent increase, Transportation Schedule 146 receives a 17.2 percent increase,
5 Interruptible Schedules 131 and 132 receive a 2.7 percent increase, and all other
6 Schedules receive no change to their revenue requirements.

7 As for natural gas rate design, Staff recommends the Commission increase
8 the monthly customer charge to \$8.92 to better reflect the customer-specific fixed
9 costs Avista incurs, decrease the volumetric rates for Schedules 111, 112, 121, and
10 122, and apply a split of 50/50 of the Transportation Schedule's revenue requirement
11 to the customer charge and volumetric rates.

12
13 **Q. Do you sponsor any exhibits in support of Staff's recommendations?**

14 **A.** Yes, I sponsor the following exhibits in support of my testimony:

- 15 • Exhibit No. ___ (CTM-2), Electric Cost of Service
- 16 • Exhibit No. ___ (CTM-3), Electric Revenue Allocation and Rate Design
- 17 • Exhibit No. ___ (CTM-4), Electric Cost Classifications and Allocations
- 18 • Exhibit No. ___ (CTM-5), Natural Gas Cost of Service
- 19 • Exhibit No. ___ (CTM-6), Natural Gas Revenue Allocation and Rate Design
- 20 • Exhibit No. ___ (CTM-7), Natural Gas Cost Classifications and Allocations
- 21 • Exhibit No. ___ (CTM-8), Allocation of Natural Gas Distribution Mains

1 related, demand-related, and energy-related (or commodity-related for natural gas)
2 components.

3
4 **Q. Please describe customer-related costs.**

5 A. Customer-related costs reflect the minimum amount of fixed costs (*i.e.*, equipment
6 and service) the utility needs to supply for customers to access the utility system.
7 These are the cost of meters, service drops, meter reading, meter maintenance, and
8 billing. These are costs that vary with the addition or subtraction of customers.
9 These costs do not vary with usage; therefore, these costs are properly considered
10 customer-related costs rather than demand-related costs or energy-related costs.

11
12 **Q. Please describe demand-related costs.**

13 A. Demand, or capacity, costs are those costs associated with designing, installing, and
14 operating the system to meet maximum hourly electric loads or gas flow
15 requirements. Both electric and gas systems must be sized to meet peak
16 requirements, even though average daily usages are below peak levels; otherwise the
17 system would not be adequate to serve customers' demand for electricity or natural
18 gas on the peak days. Accordingly, while these structures or units may not be fully
19 utilized at all times, they must be designed and installed to meet the maximum peak
20 demand that the utility plans to serve.

1 **Q. Please describe energy- and commodity-related costs.**

2 A. Energy- and commodity-related costs are those costs that vary with the amount of
3 electricity or natural gas sold to, or transmitted for, customers. Costs related to
4 supply are classified as energy-related to the extent they vary with the amount of
5 electricity purchased or generated by the utility for its customers.

6 For example, natural gas distribution systems have very low commodity-
7 related costs aside from purchased gas.

8
9 **Q. Please describe the third step in a cost of service study, allocation.**

10 A. Allocation is a means to ascribe a cost to a particular rate schedule. Costs that are
11 unique to a specific customer class are directly assigned to that customer class.
12 Costs that cannot be directly assigned are allocated based on factors that are related
13 to the type of cost.

14 For example, customer-related costs are allocated based on the number of
15 customers, while demand-related costs are allocated based on peak demand, and
16 energy- or commodity-related costs are allocated to customer classes based on load
17 (electric) or throughput (natural gas).

18 There are many variations of these allocation factors based on the specific
19 costs and plant items being allocated. Some costs may be allocated based on a
20 combination of allocation factors when they serve multiple functions.

21

1 IV. ELECTRIC COST OF SERVICE

2

3 Q. What financial results did Staff use as inputs to the cost of service study?

4 A. Staff used the financial data from the Company’s pro forma cross check study,² after
5 excluding all plant and expense adjustments that go into the rate year. In addition,
6 Staff updated the system load factor for the test period, the 12 months ending June
7 30, 2013, rather than calendar year 2012.³

8

9 Q. Why did Staff use a modified Company cross check study as the basis of its cost
10 of service study rather than Staff’s own attrition study?

11 A. The cost of service study requires information at the level of detail provided by
12 Federal Energy Regulatory Commission (“FERC”) account category. Staff’s
13 attrition study does not reflect this detail. The cross check study, as modified, was
14 the best information available.

15 In addition, by using the cross check study and excluding any adjustments
16 that went into the rate year, Staff would expect for costs the relationship from the
17 past to continue into the future with Staff’s revenue requirement reflecting what the
18 trend line growth would be going into the rate year.

19

² Knox Direct, Exhibit No. ___ (TLK-1T) at 11:1-8.

³ Avista response to Staff Data Request 23.

1 **A. Newly Created Class: Schedule 26**

2

3 **Q. Please describe Staff's proposal to create a new Schedule 26.**

4 A. Staff proposes to create a new rate Schedule 26, called "Ultra-Large General
5 Service," for extremely large usage customers. Customers with consistent monthly
6 usage pattern of at least 55 thousand kilovolt-amp ("KVA") would qualify for this
7 schedule.

8 Currently, Avista has one such customer, called "Customer 9" in the
9 Company's cost of service study.⁴ This customer currently is served under Schedule
10 25.

11

12 **Q. What is the basis for Staff's proposal?**

13 A. Schedule 25 is a poor fit for customers like Customer 9. For example, Customer 9 is
14 the only customer in Schedule 25 that has usage in the third and last rate block,
15 which applies to usage over 6 million kWhs. Customer 9 has usage in this third rate
16 block each month of the test year.

17 In addition, Customer 9's usage equaled approximately half of the load for
18 Schedule 25, and accounted for roughly 40 percent of the demand for that schedule.
19 The peak demand for Customer 9 was seven times greater than the average demand
20 peak within the test year; the closest customer was only twice the average demand
21 peak.

⁴ Avista response to Staff Data Request 87.

1 Also, because the Company was proposing a specific decoupling mechanism
2 for Schedule 25,⁵ it would be unreasonable or unfair to decouple Schedule 25
3 without recognizing the discrepancy in usage and costs to serve Customer 9
4 compared to the remaining Schedule 25 customers.

5 For these reasons, it makes sense to create Schedule 26 for ultra large usage
6 customers and start allocating costs and designing rates based on those
7 characteristics.

8
9 **B. Electric Cost Classifications and Allocations**

10
11 **Q. Did Staff conduct a systematic review of the Company's electric cost of service
12 study for classifying and allocating plant and expenses?**

13 A. Yes. In addition to Staff's own research and review, Staff met with Avista's cost of
14 service experts and conducted a detailed review of the Company's cost of service
15 study to analyze the functionalization, classification, and allocation for each FERC
16 account.

17
18 **Q. What is the result of Staff's systematic review?**

19 A. The result is that Staff made many adjustments, both major and minor, to the
20 Company's electric cost of service study, as shown by FERC account, in my Exhibit
21 No. ____ (CTM-4).

22

⁵ Ehrbar Direct, Exhibit No. ____ (PDE-1T) at 66:3-21.

1 **Q. Are there other reasons why the Commission should take a “hard look” at the**
2 **cost of service study issues in this case?**

3 A. Yes. First, the Company is proposing a decoupling mechanism, which recovers
4 fixed costs on a revenue per customer basis. Therefore, before decoupling, it is
5 appropriate to conduct a systematic review of the entire cost of service study by
6 FERC account, to verify whether the basic principles for functionalization,
7 classification, and allocation are still fair and reasonable; and to propose a rate
8 spread that is consistent with the cost of service study results and principles of cost
9 causation. This assures that each customer class receives a fair share of fixed cost
10 responsibilities.

11 Second, while the industry is changing, the Commission has not conducted a
12 thorough review of Avista’s cost of service studies since the early 1990s.⁶ Since that
13 time, Avista has had a growing amount of new renewable resource and non-
14 dispatchable resources. It is appropriate for the Commission to determine the proper
15 cost of service methods under the current regulatory environment.

16
17 **Q. What minor adjustments did Staff make to the cost of service study for**
18 **allocating plant and expenses?**

19 A. There were several minor adjustments, which had minimal impact on assigning
20 costs, but these adjustments were made based on principles and common sense.
21 Each of these adjustments are reflected in Exhibit No. ____ (CTM-4). For example,
22 the Company’s study assigned meter reading expense to street lighting service,

⁶ All electric utilities use cost of service study methodologies from Docket UE-920499.

1 though street lights are not metered. Street lights are billed based on the number of
2 bulbs or poles involved. Though this is a minor adjustment, in my study, I assign no
3 meter reading costs to street lighting services.

4
5 **Q. What major adjustments did Staff make to the cost of service study for**
6 **allocating plant and expenses?**

7 A. Staff made three major adjustments to the Company's electric cost of service study
8 for classifying and allocating plant and expenses: (1) general plant costs and
9 administrative and general ("A&G") expenses; (2) production costs; (3) transmission
10 costs; and (4) wind costs.

11 For both general plant costs and A&G expenses, Staff used the Company's
12 blended 4-part factor allocator ("4-factor"). Staff used the average and excess
13 demand method, with the excess allocated on the basis of non-coincident peak
14 demand for production costs. For transmission costs, Staff used 12-coincident
15 peak and average methodology. For wind costs, Staff used 100 percent generating
16 level consumption.

17
18 **1. Classification and Allocation of General Plant Costs and Administrative and**
19 **General Expenses**
20

21 **Q. What are the components of the Company's 4-factor you used in this case?**

22 A. The Company's 4-factor weights equally the following components:

- 23 • Customer count.
- 24 • Direct labor to Operations and Maintenance ("O&M").

- O&M expense directly charged to transmission and distribution (less labor).
- Directly assigned net plant.

Q. Please explain how Staff used the 4-factor in the electric cost of service study.

A. Currently, the Company uses the 4-factor to allocate common operating costs and plant between states (Washington, Idaho, and Oregon) and among services (electric and natural gas).⁷ Therefore, it made sense to continue using the 4-factor to allocate to the class schedules because deviating from the 4-factor allocator would have created inconsistent treatment of costs and plant compared to the Company, which allocated based on relative production, transmission, and distribution plant; or relative operating and maintenance expenses.⁸

Q. What items are found in General Plant Costs and A&G expenses?

A. Within general plant are items such as structures and improvements, office furniture and equipment, tools, shop and garage equipment, laboratory equipment, and communication equipment. A&G expenses include such items as A&G salaries, office supplies and expenses, injuries and damages, employee pensions and benefits, general advertising expenses, and maintenance of general plant.

⁷ Avista response to Staff Data Request 166.

⁸ Knox Direct, Exhibit No. ___ (TLK-3) at 5:21-6:6.

1 **Q. What is the benefit of the 4-factor allocator?**

2 A. The primary benefit of the 4-factor is to increase the accuracy of accounting records
3 and allocation between jurisdictions and services. The prior method allocated
4 common costs and plant based on number of customers only.

5 The 4-factor is a common way to allocate these types of costs and plant. In
6 addition, the specific costs and plant items being allocated are recognized as serving
7 multiple functions, therefore, having multiple components to allocate is appropriate.

8 The current 4-factor allocation methodology was developed in a cost
9 assignment study in March 1993, and approved by the Commission through a letter.⁹
10 Avista's other jurisdictions had similar letters accepting the new methodology.¹⁰
11 The Commission implemented the 4-factor in the following general rate case,
12 Dockets, 991606 and 991607. This has been reviewed in the past and it remains a
13 consistent and reasonable approach for allocating across the Company's
14 jurisdictions, and services, for common costs and common general plant.

15

16 **2. Classification and Allocation of Production Costs**

17

18 **Q. Please explain the type of costs that are classified as Production Costs.**

19 A. I follow the explanation used in the Electric Utility Cost Allocation Manual (January
20 1992) published by the National Association of Regulatory Utility Commissioners
21 ("NARUC"):

⁹ Docket No. UT 3-6607 (October 12, 1993).

¹⁰ Under the Company's former name: The Washington Water Power Company.

1 [p]roduction plant costs are either fixed or variable. Fixed production costs
2 are those revenue requirements associated with generating plant owned by
3 the utility, including cost of capital, depreciation, taxes and fixed O&M.
4 Variable costs are fuel costs, purchased power costs and some O&M
5 expenses. Fixed production costs vary with capacity additions, not with
6 energy produced from given plant capacity, and are classified as demand-
7 related. Variable production costs change with the amount of energy
8 produced delivered or purchased and are classified as energy-related.

9
10 The percentage weighting for classification of demand- and energy-related
11 costs and plant in Staff's cost of service study are 30.73 percent demand-related and
12 69.27 percent energy-related.

13
14 **Q. How did Staff determine the appropriate allocator for Production Costs?**

15 A. In addition to reviewing the Company's peak credit method, Staff reviewed several
16 other methodologies, as reflected in my Exhibit No. ___ (CTM-4):¹¹ average and
17 excess demand method, summer and winter peak, 12-coincidental peaks, peak and
18 average, and 12-coincidental peak and average.¹²

19
20 **Q. Please explain the terms "peak," "coincidental peak," and "non-coincidental
21 peak."**

22 A. "Peak" is the highest total hourly demand for all customers served on the utility's
23 system within a specific period (day, month, and year); typically referred to as the
24 'system peak.' "Coincidental peak" is the contribution to demand of each class at
25 the same time as, or coinciding with, the system peak. "Non-coincidental peak" is

¹¹ Mickelson Exhibit No. ___ (CTM-4) is based on Avista response to Staff Data Request 21.

¹² See, National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* (January 1992), for further discussion on all of the methodologies.

1 the maximum demand of a class at any point in time, but not necessarily at the same
2 time as the system peak.

3
4 **Q. What method does Staff recommend the Commission use in this case to allocate
5 Production Costs?**

6 A. Staff recommends the Commission use the average and excess demand method to
7 allocate production costs.

8
9 **Q. Please describe how the average and excess demand method works.**

10 A. Average and excess demand method consists of two parts. The first component of
11 each class's allocation factor is its proportion of total average energy consumption
12 (annual energy usage divided by 8,760 hours) times the system load factor. The
13 second component of each class's allocation factor, called excess demand, is the
14 proportion of the difference between the sum of all classes' non-coincident peaks
15 and the system average demand and multiplied by the remaining proportion of
16 production plant (*i.e.* one minus the system load factor), and then added to the first
17 component to obtain the total allocator.

18
19 **Q. Please provide the formula for the average and excess demand method Staff
20 uses in this case.**

21 A. Yes. The formula is as follows:

22 Average and Excess Demand method = (AE% x SLF%) + [ED% x (1-SLF%)]

23 Where the components are:

- 1 • AE% = each class's share of total average energy consumption (annual MWh
2 divided by 8,760 hours).
- 3 • ED% = each class's share of excess demand, which for each class is the
4 difference between annual non-coincident peak (NCP) less average annual
5 demand (annual MWh divided by 8,760 hours).
- 6 • SLF% = System load factor, which is the system's average megawatt ("aMW")
7 energy (total retail energy divided by annual hours) divided by peak MW
8 demand.

9

10 **Q. Please explain why Staff recommends the average and excess demand method**
11 **for allocating Production Costs.**

12 A. First, the average and excess demand method is stable over a long time period.
13 Second, the excess is allocated on the basis of non-coincident peak, which takes into
14 account system peak-load, individual class peak-load, and the degree of use for each
15 class of service. Furthermore, the average and excess demand method fairly
16 allocates costs to all classes on usage during peak hours and avoids individuals or
17 rate schedules whose rates do not reflect their full cost to service due to select
18 scenarios or design day planning, which has no load at the time of the system peak.

19 More specifically, the average and excess demand method recognizes and
20 gives appropriate weighting to all three factors which must be considered in
21 determining the appropriate allocation methodology for a specific system. First, the
22 average and excess demand method recognizes the non-coincident peak maximum
23 demand. Second, the average and excess demand method recognizes the system

1 peak. The difference between the system peak and the system average is the total
2 excess demand, which is allocated to individual rate classes. Also, by definition, the
3 sum of the average and excess demand of all rate classes is the system peak. Third,
4 the average and excess demand method recognizes load factor or duration of use of
5 the system. By weighting both average and excess demand, this method gives
6 recognition that both types of demand are a cost driver for the utility.

7
8 **Q. Please explain why the average and excess demand method is a stable method.**

9 A. As shown in my Exhibit No. ____ (CTM-4) on pages 4 and 5, the average and excess
10 demand method had a relatively small variance, less than 2.7%,¹³ over the last five
11 general rate cases.

12
13 **Q. Referring to that exhibit and page, are there more stable methods?**

14 A. Yes, there are three methods that are more stable: summer and winter peak method,
15 12-coincident peaks method, and 12-coincident peak and average method. However,
16 each of these methodologies places too much weight on demand, thereby allowing
17 for individuals or rate schedules whose rates do not reflect their full cost to service
18 due to them not being on the system at the time of coincidental peak.

19 The average and excess demand method is a fairer and more balanced
20 approach that applies appropriate weighting to the demand on the system and thus
21 better reflects the system's actual peak duration and its allocation between high load
22 factor and low load factor classes.

¹³ Excluding Schedules 21 and 22, this had a 4.6 percent variance that was likely due to schedule switching over the last couple of general rate cases.

1 Staff initially considered the base-intermediate-peak method and the
2 probability of dispatch method, but these methods are best suited to analyzing cost of
3 service by time periods, which could be beneficial if the Commission chooses to
4 pursue time-of-use or unbundling pricing. However, time-of-use or unbundling
5 pricing mechanisms would require better and more detailed load research data for the
6 customer classes to produce unique allocation of production fixed and variable
7 costs.¹⁴

8

9 **3. Classification and Allocation of Transmission Costs**

10

11 **Q. What types of costs are included as Transmission Costs?**

12 A. These costs relate to FERC plant accounts 350 through 359, and the return on and
13 return of those plant accounts, plus taxes and corresponding O&M expenses and
14 revenues.

15

16 **Q. What method did Staff use for allocating Transmission Costs in the cost of** 17 **service study?**

18 A. Staff used the 12-coincident peak and average method to allocate Transmission
19 Costs.

20

21 **Q. Please describe how the 12-coincident peak and average method works.**

22 A. The 12-coincident peak and average method consists of two components. The first
23 component of each class's allocation factor is its proportion of total average energy

¹⁴ Similar to the detailed load resource data, as provided in Avista response to Staff Data Request 17.

1 consumption (annual energy usage divided by 8,760 hours) times the average energy
2 divided by the sum of the average of the twelve monthly peak demands and the
3 average energy.

4 The second component of each class's allocation factor is its contribution to
5 the average of specified group of system peak demands (e.g. the 12 monthly
6 coincident peaks) for the test period, multiplied by the average of the twelve monthly
7 peak demands, divided by the sum of the average of the twelve monthly peak
8 demands and the average energy, and then added to the first component to obtain the
9 total allocator.

10 Important observations to be drawn are: (1) the number of hours chosen as
11 the basis for the demand allocator can have a significant effect on the revenue
12 allocation, even for a relatively small number of hours, and (2) the greater the
13 number of hours used, the more the allocation will reflect energy requirements.

14
15 **Q. Please provide the formula for the 12 coincident peak and average allocation**
16 **method.**

17 A. The formula is as follows:

18 12-coincident peak and average method = $(AE\% \times ALF\%) + [AD\% \times (1-ALF\%)]$

19 Where the components are:

- 20 • AE% = each class's share of total average energy consumption (annual MWh
21 divided by 8,760 hours).
- 22 • AD% = each class's share of total average monthly coincident peak demand.

- 1 • ALF% = the system's aMW energy (total retail energy divided by annual hours)
2 divided by the average actual demand values registered on the monthly peak days
3 for the test period (January through December), plus the system's aMW energy.
4

5 **Q. Why should the Commission use the 12-coincident peak and average method to**
6 **allocate Transmission Costs?**

7 A. Typically, transmission costs are allocated using production cost allocators because
8 they are considered to be an extension of the production system, which for Staff
9 would have been average and excess demand method.

10 However, the 12-coincident peak and average method provides a more
11 appropriate weighting for demand to energy that reflects how the system is designed
12 and operated, even under adverse operating conditions. In this case, the weighting is
13 57.89 percent demand and 42.11 percent energy, compared to average and excess
14 demand method with a weighting of 30.73 percent demand and 69.27 percent energy.

15 In addition, the highest peak demand is the overriding consideration that
16 drives power supply cost decisions. The majority of Transmission Costs represent a
17 fixed cost, and transmission plant is built to meet the utility's capacity needs at the
18 system's highest peak. The system uses a portion of that transmission capacity on an
19 average basis.

20 Staff used 12-coincident peaks rather than one, to reflect the fact that utilities
21 install transmission facilities to maintain a reasonably constant level of reliability
22 throughout the year; therefore, no single peak demand is of any significantly greater
23 magnitude than any of the other monthly coincident peak demands. In this way,

1 Staff's method considers the relative importance of each month, even though the
2 highest system's peak drives the sizing requirements of the transmission plant;
3 otherwise, the weighting would have been 61.21 percent demand and 38.79 percent
4 energy. Also, the 12-coincident peaks is stable over a long time period by having
5 relatively small variance compared to an ordinary peak and average method, as
6 shown in my Exhibit No. ____ (CTM-4) on pages 4 and 5.

7
8 **4. Classification and Allocation of Wind Costs**
9

10 **Q. What are "Wind Costs?"**

11 A. Wind Costs are non-dispatchable wind-based renewable generation plant and costs
12 related to FERC Accounts 555¹⁵ and 186.

13
14 **Q. How did Staff classify and allocate Wind Costs?**

15 A. Staff classified Wind Costs as energy-related and allocated those costs based on 100
16 percent generation level consumption (i.e., 100 percent energy before line losses).
17 This aligns the way the costs are collected with how the benefits are being provided
18 to customers through the Renewable Energy Credit ("REC") proposal of a uniform
19 rebate across all rate classes.¹⁶

20
21 **Q. Please explain how Avista allocates Wind Costs.**

¹⁵ Avista response to Staff Data Request 165.

¹⁶ Johnson Direct, Exhibit No. ____ (WGJ-1T) at 15:12-13.

1 A. Avista allocates Wind Costs based on production plant, by applying a percentage
2 weighting for classification of demand- and energy-related costs in the Company's
3 cost of service study are 31.27 percent demand-related and 68.73 percent energy-
4 related.

5

6 **Q. Is allocation of Wind Costs based on production plant appropriate?**

7 A. No. Allocating Wind Costs based on production plant does not align costs and
8 benefits, nor does it reflect the way non-dispatchable generation plants such as wind
9 facilities operate.

10 For example, the Company's 2013 Integrated Resource Plan ("IRP") states,
11 "[r]enewable resources are attractive because they have low or no fuel costs and few,
12 if any, direct emissions. However, solar- and wind-based renewable generation has
13 limited or no capacity value for the operations of Avista's system, and their variable
14 output presents integration challenges requiring additional non-variable capacity
15 investments."¹⁷ This means the Company must assign a higher planning reserve
16 margin to wind facilities, which, on average "increase[s] customer rates when
17 compared to resource portfolios without reserves because of the additional cost of
18 carrying additional generating capacity that is rarely used."¹⁸ Reserve resources are
19 typically natural gas-fired peaker plants that "allow the plants to start and ramp
20 quickly, providing regulation services and reserves for load following and to
21 integrate variable resources such as wind and solar."¹⁹

¹⁷ Kinney Direct, Exhibit No. ____ (SJK-2) at 94. (*emphasis added*)

¹⁸ *Id.*, at 62.

¹⁹ *Id.*, at 116.

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Q. Why did Staff allocation only Wind Costs and not Solar Costs?

A. The Company has two solar installations; a 15 kW Rathdrum Solar project and an array of four solar panels on the Company’s headquarters. Rathdrum Solar is funded by participating customers through a voluntary renewable energy program, called “Buck-A-Block,”²⁰ while the four solar panels strictly supply electricity to the Company’s electric vehicles onsite and appear to be de minimis.

Otherwise, Staff would have used the same approach applied to Wind Costs for classifying and allocating to any non-dispatchable generation plants that has limited or no capacity value for the system, such as solar.

C. Company’s Cost of Service Study

Q. Did Staff review the Company’s proposed electric cost of service study?

A. Yes. The Company’s proposed electric cost of service is contained in Ms. Knox’s Exhibit No. ____ (TLK-3).

Q. Does the Company’s electric cost of service study follow the same methodology the Commission has accepted in the past?

A. Yes, with one exception. The Company’s current cost of service study revises the peak credit classification of production and transmission costs. According to Ms. Knox, the Company’s prior method was “complicated to compute and apply,

²⁰ *Id.*, at 51.

1 unrelated to the actual usage of the system, and has a tendency to shift costs back and
2 forth between energy and demand.”²¹

3 Under the prior method, the Company would classify energy and demand
4 using a comparison of the replacement cost for thermal and hydro plants separately,
5 which created separate peak credit ratios. For transmission costs, Avista assigned a
6 50/50 weighting of the separate peak credit ratios to energy and demand while
7 classifying fuel and load dispatching expenses to energy and peaking plant related
8 costs to demand.

9
10 **Q. Has the Company proposed this methodology change in any prior general rate**
11 **case?**

12 A. Yes. In Avista’s three prior electric rate cases, Dockets UE-100467, UE-110876,
13 and UE-120436, the Company proposed this change in methodology. However,
14 each of those dockets was resolved by settlement, and the cost of service study issue
15 was not resolved.

16
17 **Q. Should the Commission accept Avista’s proposed change?**

18 A. No.

19
20 **Q. Did Staff recommend using the Company’s proposed change in methodology in**
21 **the Company’s last general rate case, Docket UE-120436?**

²¹ Knox Direct, Exhibit No. ____ (TLK-1T) at 13:13-15.

1 A. Yes. However, Staff's support was based on the stability of the changed method.
2 New information shows that the Company's new method is not stable. In this case,
3 Staff conducted a longer historical review of the system load factor and peak credit
4 application.²² Based on that review, it is apparent that the proposed method was one
5 of the least stable methods as compared to other allocation methods.

6 The Company's proposed methodology was unstable relative to the prior
7 method as well as various methods that Staff had not previously considered.

8
9 **Q. Please explain what that longer historical review showed.**

10 A. The historical review showed that the peak credit method was the second least stable
11 allocation method out of the six allocation methodologies examined. The peak credit
12 method produced variances up to nine percent over the last five general rate case, as
13 shown in Exhibit No. ____ (CTM-4).

14
15 **Q. Overall, does Staff's cost of service study reasonably and fairly allocate plant
16 and expenses?**

17 A. Yes. Overall, the Staff's cost of service study reasonably functionalizes, classifies,
18 and allocates capital investments and operating expenses to each rate schedule.
19 Staff's electric cost of service study fairly and equitably identifies the costs required
20 to serve each particular customer class.

21

²² Avista response to Staff Data Request 21.

1 **D. Parity Ratios**

2

3 **Q. What is the typical output of a cost of service study?**

4 A. Typically, the outputs of a cost of service study are parity ratios for each customer
5 class.

6

7 **Q. What is a parity ratio?**

8 A. A parity ratio indicates how close a particular rate schedule is to covering its cost of
9 service. For example, if a rate schedule is producing revenues that are 100 percent of
10 its cost of service, as determined by the cost of service study, that rate schedule has a
11 parity ratio of 1.00. If a rate schedule covers only 70 percent of its cost of service, it
12 has a parity ratio of 0.70. If a rate schedule covers 130 percent of its cost of service,
13 its parity ratio is 1.30.

14

15 **Q. How should the Commission use the parity ratios from the cost of service study**
16 **to allocate revenues in this case?**

17 A. The Commission should consider parity ratios as an important part of the revenue
18 allocation decision, especially with a decoupling mechanism. Overall, the
19 Commission should move rate schedules closer to parity ratios of 1.00.

20 However, parity is not the only factor. The Commission should also consider
21 the appearance of fairness, perceptions of equity, economic conditions in the service

1 territory, and rate stability.²³ I discuss each of these considerations later in my
2 testimony.

3
4 **Q. Is it practical to achieve a parity ratio of 1.00 for every rate schedule?**

5 A. No. The assumptions and results of the cost of service study are often controversial,
6 and no cost of service study is “perfect.” It is a matter of informed judgment to
7 determine how much of the average rate increase is fairly apportioned to each rate
8 schedule. Consequently, if a rate schedule is at 95 percent parity or 105 percent
9 parity that usually justifies an equal percentage increase. The Commission should
10 use a target parity range of 95 to 105 percent for all rate schedules in this case.

11
12 **Q. Why should the Commission try to achieve a target parity range of 95 to 105
13 percent?**

14 A. There are many reasons. First, and particularly if the Commission elects to adopt
15 decoupling, it is very important to have the appropriate cost structure in place
16 beforehand. Otherwise, true-ups will exacerbate the inappropriate price signals. For
17 example, assume a rate schedule has rates designed based on a parity ratio of 0.90
18 percent (*i.e.*, below the cost of service), but that same rate schedule is subject to
19 decoupling and is experiencing load growth greater than customer growth. In that
20 scenario, under a revenue per customer decoupling mechanism, the Commission
21 risks establishing credits to that rate schedule greater than the revenue generated per

²³ *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08 (May 7, 2012), at 125.

1 customer. This would result in the Company crediting money back to customers for
2 using more electricity, thereby sending inappropriate price signals.

3 Second, any parity ratio outside of the target range may be considered
4 unreasonable and unfair. A rate schedule under parity can be considered as being
5 subsidized by other rate schedule(s). Again, due to the imprecision and judgment
6 involved in a cost study, this is a serious consideration only when parity ratios are
7 outside the 0.95 to 1.05 range.

8 Third, a rate schedule with a parity ratio above 105 percent (*i.e.*, above the
9 cost of service) puts undue burden on the customers within that rate schedule and
10 may place those customers at a competitive disadvantage; therefore, high parity
11 ratios may degrade economic conditions in the service territory.

12
13 **Q. Have you prepared a table summarizing the results of Staff's cost of service**
14 **study?**

15 A. Yes. Table 1 below sets forth the parity ratios under current rate structure using the
16 Company's cost of service, and Staff's proposal.

Table 1: Summary of Revenue Parity Ratios

Customer Class	Company Current	Staff Current
Total System	1.00	1.00
Residential (Schedule 1)	0.93	0.92
General Service (Schedules 11, 12)	1.15	1.14
Large General Service (Schedules 21, 22)	1.06	1.12
Extra Large General Service (Schedule 25)	0.98	1.08
Ultra Large General Service (Schedule 26)	N/A	1.11
Pumping Service (Schedules 31, 32)	0.98	0.97
Street & Area Lights (Schedules 41-49)	0.97	0.99

Q. What does this table show?

A. This table shows that using the Staff's cost of service study, the following rate schedules have parity ratios outside the 0.95 to 1.05 range: (1) Residential Schedule 1 is covering 92 percent of the cost of service; (2) General Service Schedules 11 and 12 cover 115 percent of the cost of service; (3) Large General Service Schedules 21 and 22 cover 112 percent of the cost of service; (4) Ultra Large General Service Schedule 26 covers 112 percent of the cost of service; and (5) Extra Large General Service Schedule 25 covers 108 percent of the cost of service.

Q. What causes the parity ratios for the Residential and General Service Schedules to be outside the 0.95 to 1.05 range?

A. This is likely due to the equal percentage increases that have been applied in the past several general rate cases, most of which involved settlements. This tends to

1 preserve or even exacerbate the inequities between rate schedules. To help get all
2 schedules within the target range, or even parity, the Commission could direct the
3 Company to reduce the imbalances between rate schedules by half for each general
4 rate case. That way, within two or three general rate case filings, the imbalances
5 would be eliminated.

6 7 **V. ELECTRIC REVENUE ALLOCATION**

8
9 **Q. Please explain the general concept of revenue allocation.**

10 A. Revenue allocation, also known as “rate spread,” is the process of determining the
11 portion of total revenues to be collected from each rate schedule.

12
13 **Q. What is Staff’s recommendation on revenue allocation for electric service?**

14 A. Based on Staff’s recommended overall revenue decrease of 1.71 percent, and in
15 order to move all Schedules closer to parity, Staff recommends the following:

- 16 • Schedule 1, Residential: no change to revenues.
- 17 • Schedules 11 and 12, General Service: decrease 5.00 percent.
- 18 • Schedules 21 and 22, Large General Service: decrease 2.15 percent.
- 19 • Schedule 25, Extra Large General Service: decrease 2.29 percent.
- 20 • Schedule 26, Ultra Large General Service: decrease 5.40 percent.
- 21 • Schedule 30-32, Pumping: no change to revenues.
- 22 • Schedule 41-48, Street & Area Lighting: no change to revenues.

1 **Q. Please explain why Schedules 1, 30, 31, 32, and 41 through 48 get no decrease,**
2 **while Schedules 11, 12, 21, 22, 25 and 26 get a decrease.**

3 A. Staff proposes a gradual move toward parity for those schedules that are outside the
4 0.95 to 1.05 range. Therefore, Staff applied a much more than average decrease to
5 those schedules that have a parity ratio above 1.05, and no decrease to revenues for
6 schedules that have a parity ratio less than 0.95, or even within the target range.

7

8 **Q. By comparison, what rate increases or decreases would be required to move**
9 **each rate schedule to parity?**

10 A. To reach parity at existing rates, the following approximate rate changes would be
11 required:

- 12 • Residential Schedule 1: 14.9 percent rate increase.
- 13 • General Service Schedules 11 and 12: 18.8 percent rate decreases.
- 14 • Large General Service Schedules 21 and 22: 15.5 percent rate decreases.
- 15 • Extra Large General Service Schedule 25: 10.3 percent rate decrease.
- 16 • Ultra Large General Service Schedule 26: 15.1 percent rate decrease.
- 17 • Pumping Schedules 30 through 32: 5.0 percent rate increases.
- 18 • Street and Lighting Schedules 41 through 48: 2.5 percent rate increases.

19

20 **Q. Have you prepared a table showing the results of Staff's revenue allocation**
21 **proposal?**

22 A. Yes. Table 2 below shows the results of Staff's revenue allocation proposal
23 compared to current revenue allocation under Staff's classification and allocation

1 approaches. These results also are provided in the summary of results from the cost
2 of service study on page one, line 55 of my Exhibit No. ___ (CTM-2).

3 Table 2: Summary of Revenue Parity Ratios

4

5 Customer Class	Staff Current	Staff Proposal
6 Total System	1.00	1.00
7 Residential (Schedule 1)	0.92	0.93
8 General Service (Schedules 11, 12)	1.14	1.08
9 Large General Service (Schedules 21, 22)	1.12	1.08
10 Extra Large General Service (Schedule 25)	1.08	1.05
11 Ultra Large General Service (Schedule 26)	1.11	1.05
Pumping Service (Schedules 31, 32)	0.97	0.98
Street & Area Lights (Schedules 41-49)	0.99	0.99

12

13 **Q. How does Staff's proposal reflect consideration of equity, economic conditions**
14 **and rate stability?**

15 A. Staff's recommendation emphasizes the customer class relationship to parity and
16 customer bill impacts. The parity percentages discussed earlier in my testimony
17 indicate that some classes currently pay less than it costs to serve them, and other
18 classes pay more than it costs to serve them. Because this relationship between costs
19 and revenues varies by customer class, the Company's earned return also varies by
20 customer class. By adjusting rate spread, classes can be brought closer to paying the
21 costs incurred to serve them, and class level rates of return can be brought closer to
22 the system average rate of return.

1 Staff's long-term goal is to set rates at parity for each class, and the
2 recommended rate spread is designed to move classes toward those levels without
3 producing unacceptably large customer impacts.

4 Staff also recognizes that the current economic conditions in the Company's
5 service area could not support a complete shift to the cost of service or the
6 accompanying rate instability such an immediate change would cause. Therefore,
7 Staff is applying moderate rate changes which are more reasonable and represent a
8 gradual approach to address parity imbalances

9
10 **Q. What does Avista propose for revenue allocation?**

11 A Avista proposes a uniform percentage increase.²⁴

12
13 **Q. How does Staff's proposed revenue allocation compare to the Company's?**

14 A. Staff's proposed revenue allocation reduces the majority of inequities demonstrated
15 by the disparate parity ratios shown in the table above. The Company's proposed
16 uniform percentage increase perpetuates current disparities in parity ratios, with no
17 meaningful movement toward parity for any of these schedules. The Commission
18 should reject the Company's proposal for these reasons.

19
20 **VI. ELECTRIC RATE DESIGN**

21
22 **Q. Please explain the general concept of electric rate design.**

²⁴ Ehrbar Direct, Exhibit No. ___ (PDE-1T) at 5:22-24.

1 A. Electric rate design takes total allocated revenue for each electric rate schedule and
2 determines the specific charges within the rate schedule, such as the basic charge per
3 month, the demand charge per kilowatt, and the cents per kilowatt-hour (kWh) of
4 energy.

5
6 **Q. What are Staff's electric rate design structure proposals?**

7 A. Staff proposes to use rate year billing determinants²⁵ to reflect Staff witness Mr.
8 McGuire's recommendation for growth rates within the attrition study.²⁶ Staff also
9 proposes to: (1) increase the monthly customer charges to include more fixed costs;
10 (2) increase and set equal the demand volumetric rates for all Non-Residential
11 Schedules; (3) apply separate uniform percentage decreases for all energy volumetric
12 rates in each schedule, except for Residential Schedule 1, which gets a uniform
13 percentage decrease to the first two volumetric block rates; and (4) create a straight-
14 fixed variable ("SFV") rate design for Schedule 25 and newly created Schedule 26,
15 instead of having these customers be part of the decoupling mechanism.

16
17 **A. Monthly Customer Charge**

18
19 **Q. What rate design does Staff propose for the monthly customer charge?**

20 A. While Staff's case identifies a revenue requirement decrease to be assigned to select
21 rate schedules, and proposes no change in residential, extra-large general, pumping,

²⁵ Avista response to Staff Data Request 24, Attachment A.

²⁶ McGuire Direct, Exhibit Nos. ___ (CRM-1T) and ___ (CRM-2).

1 and street light class revenues, certain revenue-neutral changes in rate design are
2 appropriate.

3 Accordingly, Staff proposes to increase the monthly customer charge for
4 Residential Schedule 1 from \$8.00 to \$8.50.

5
6 **Q. Is an \$8.50 monthly customer charge cost based?**

7 A. Yes. I show the cost basis for this price in my Exhibit No. ____ (CTM-2), page 5,
8 lines 31 through 35.

9
10 **Q. Please explain your exhibit.**

11 A. As my exhibit shows, the monthly customer charge, also known as the “basic
12 charge,” covers customer-related costs such as the cost of meters, service drops,
13 meter reading, meter maintenance, and billing.²⁷ As explained earlier, these are costs
14 that vary with the addition or subtraction of customers. These costs do not vary with
15 usage; therefore, these costs are properly considered customer-related costs rather
16 than demand-related costs or energy-related costs

17 My exhibit shows the total customer-related costs for the Residential
18 schedule is \$17.78.

19 Because these costs vary by the number of customers rather than usage, it is
20 appropriate for Avista to recover these costs in the basic charge rather than through
21 usage charges.

22

²⁷ In essence, customer-related costs reflect the minimum amount of equipment and service needed for customers to access the electric grid.

1 **Q. Why is Staff proposing to increase the basic charge from \$8.00 to \$8.50?**

2 A. Staff is proposing to increase the basic charge so that customers will pay an amount
3 that better reflects the fixed costs Avista incurs to serve customers, regardless of the
4 level of energy usage. When customer-related costs are not entirely collected
5 through the basic charge, the Company collects the remaining portion of the
6 customer-related fixed costs through per kWh charges, which ultimately results in
7 cross-subsidization. In other words, if customer-related costs are collected through
8 volumetric rates, those customers with above-average consumption are paying more
9 than their fair share of customer-related fixed costs, thus subsidizing customers with
10 below-average usage who are paying less than their fair share.

11 In addition to the problem of cross-subsidization, the collection of customer-
12 related costs through volumetric charges can lead to over- or under-collection of the
13 fixed costs, because electricity sales fluctuate with weather, the economy, energy
14 efficiencies, conservation, and self-generation.²⁸

15 Removing customer-related costs from volumetric sales is therefore
16 beneficial on three fronts: first, it removes some of the disincentive utilities currently
17 experience regarding the promotion of energy efficiency and conservation; second, it
18 improves the certainty of recovery of customer-related fixed costs; and last, it should
19 reduce the deferral amounts within the decoupling mechanism.

20

21 **Q. Will Staff's proposal to increase the basic charge harm limited income**
22 **customers?**

²⁸ Marry Blake, *Creating the Right Retail Rate Environment for Energy Conservation and Energy Efficiency*, *Management Quarterly* (December 22, 2009) at 6.

1 A. No. In fact, the increase in the basic charge will actually help the average limited
2 income customer. Studies have shown that the housing stock for most limited
3 income customers is relatively inefficient, resulting in above-average usage for most
4 limited income customers.²⁹ Based on national averages, limited income customers
5 have an average monthly usage of 1,091 kWh compared to other customers, who
6 have an average monthly usage of 1,006 kWh.³⁰

7 As I just explained, customers with above-average usage subsidize customers
8 with below-average usage if customer-related costs are included in volumetric
9 charges. Therefore, moving more of the customer-related fixed costs to the basic
10 charge will help limited income customers by reducing the amount they subsidize
11 other customers with lower usage, including customers with non-electric heating (i.e.
12 natural gas, wood, propane, etc.).

13
14 **Q. Will increasing the basic charge send appropriate price signals to customers?**

15 A. Yes. The increase to the basic charge sends the correct price signal because it
16 recovers the actual fixed costs the Company directly to serve that customer, *e.g.*, the
17 service drop and the meter.

18
19 **Q. Is Staff's level of customer charge appropriate?**

20 A. Yes. In a January 2007, rate order for Puget Sound Energy, Inc. ("PSE"), the
21 Commission identified the appropriate level of customer charge as follows:

²⁹ *Ibid.*

³⁰ Ehrbar Direct, Exhibit No. ___ (PDE-1T) at 36:4-11 to 37:1-23.

1 an increase in the customer charge...will result in the Company recovering
2 about one-fourth of its fixed costs allocated to residential customers via a
3 fixed charge on each customer's bill. This is about eight to ten percent of an
4 average customer's total bill, considering both fixed and variable costs. This
5 seems to us the right balance point for the recovery of fixed costs via the
6 customer charge.³¹

7
8 Staff's proposed \$8.50 customer charge for electric customers meets this "balance
9 point" because it represents 24 percent of the fixed costs allocated to residential
10 customers³² and equals 11 percent of an average customer's total bill. These
11 percentages are within the limits the Commission approved in the PSE order quoted
12 above.

13
14 **Q. Please explain what "distributed generation" is, and how it applies in the**
15 **context of the basic charge.**

16 A. Distributed generation, also called on-site generation, is small scale generating
17 technologies (e.g. solar, wind, waste-to-energy, vehicle-to-grid or newer
18 technologies) that are generating electricity at or close to location where it is used
19 and connected to the system. Distributed generation systems allow customers to
20 produce some or all of the electricity they need and use (e.g. for HVAC, consumer
21 electronics, lights, etc.), thereby, effectively reducing their electric load and possibly
22 selling electricity back to the utility provider.

23 Currently, residential retail rates are designed to recover a portion of the
24 system's fixed costs through kilowatt-hour charges, thus a distributed generation

³¹ *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-060266 and UG-060267, Order 08 (January 5, 2007), page 48.

³² Percentage is based on total customer and distribution demand costs.

1 customer will avoid paying some or its entire fair share of the fixed costs of services
2 when supplying power back into the system.

3
4 **Q. Is a higher basic charge necessary to address a perceived problem with**
5 **customers who use distributed generation?**

6 A. No. Distributed generation currently is not a problem for Avista. Avista serves
7 approximately 237,050 customers in Washington. Over the last five years, the
8 Company has experienced an average increase of only 31 customers using
9 distributed generation per year, or 157 customers in total for the five year period.
10 The average thirty-one customers represent 0.013 percent of Avista's total
11 customers,³³ which is significantly less than the Company's expected annual
12 customer growth of approximately 1.1 percent.³⁴ In addition, there are other ways to
13 address the issues of distributed generation without having to increase the monthly
14 customer charge.

15
16 **Q. What does Staff propose for customer charges for non-residential customer**
17 **classes?**

18 A. Staff proposes to increase the customer charges by 6.7 percent to all the non-
19 residential customer classes,³⁵ which provides basic charges within the price levels in
20 my Exhibit No. ____ (CTM-2) at page 5 on lines 31-42.

21

³³ Avista response to Staff Data Request 123.

³⁴ Kinney Direct, Exhibit No. ____ (SJK-2) at 38, Table 2.2.

³⁵ Excluding Schedule 26, this stays at the current monthly charge.

1 **Q. How will increasing the monthly customer charge affect the proposed**
2 **decoupling mechanism?**

3 A. There are two impacts. First, increasing the customer charges decreases the revenue
4 per customer amount, because fixed revenues (customer charges) are removed from
5 the revenue per customer calculation.³⁶

6 Second, increasing the customer charges should reduce the variance in the
7 deferral calculations each month between actual and the determined allowed non-
8 power supply revenue.

9

10 **B. Volumetric Rates**

11

12 **Q. Please summarize Staff's proposed change to the volumetric rates for electric**
13 **service.**

14 A. Staff recommends the Commission: (1) apply separate uniform percentage decreases
15 for all energy volumetric rates in each schedule, except for Residential Schedule 1,
16 which gets a uniform percentage decrease to the first two volumetric block rates; and
17 (2) increase and set the demand rate across all non-residential schedules to \$6.25.

18

19 **Q. Please explain why Staff is proposing a uniform percentage decrease for energy**
20 **volumetric rates.**

21 A. The reason is that this is a "zero-sum-game," where Staff is reflecting the following:
22 (1) Staff's proposed revenue requirement decrease; (2) keeping the schedules

³⁶ Ehrbar Direct, Exhibit No. ___ (PDE-1T) at 55:6-13.

1 revenue-neutral; (3) considering the rate year billing determinants within the
2 volumetric blocks; and (4) recognizing the increases in monthly customer charges
3 and demand volumetric rates.

4 As for Residential Schedule 1, Staff kept the third tier-block rate at its current
5 10.05 cents, which is below the total unit cost in my Exhibit No. ____ (CTM-2) at
6 page 4 on lines 35. Therefore, keeping the third tier-block rate the same and
7 applying the uniform percentage decrease to the first two-tiers, preserves the proper
8 prices signals and increases the rate differential between blocks.

9
10 **Q. Please explain why Staff is proposing to increase and set the demand rate equal**
11 **across all non-residential schedules.**

12 A. By increasing the demand rate and setting it equal across all non-residential
13 schedules, the Commission would support a more appropriate price signal for
14 demand reduction conservation. In addition, plant and operating expenses are
15 allocated on a percentage related to demand. In this case, 30.73 percent is related to
16 demand; therefore, it is appropriate to set the rate equal for all non-residential
17 schedules because all schedules receive an equal percentage of plant and operating
18 expenses based on the same percentage of demand.

19
20 **C. Straight-Fixed Variable Rate Design for Schedules 25 and 26**

21
22 **Q. Please describe the customers who take service under Schedules 25 and 26.**

1 A. These customers have very large usage and unique usage characteristics, unlike any
2 other customers on any other schedule. For example, these customers have
3 approximately 20 percent of the entire system's usage, but only represent 0.0001
4 percent of the customers on the system. In addition, these customers have fairly
5 consistent usage throughout the entire year, compared to other schedules that either
6 peak in the winter or summer.

7

8 **Q. What is Staff's electric rate design structure proposal for Schedules 25 and 26?**

9 A. Staff recommends these schedules have a straight-fixed variable rate design,³⁷
10 instead of being part of a decoupling mechanism.

11

12 **Q. Please explain what "straight-fixed variable" is and how it works.**

13 A. As described in Mr. Boonin's research and policy paper on rate designs for energy
14 efficiency, a straight-fixed variable rate design "places all of the utility's fixed costs
15 into a fixed component of a utility customer's bill, thereby recovering only variable
16 costs, such as fuel and purchased power, on a variable (e.g., per kWh or kW) basis."³⁸

17

18 **Q. What are the primary benefits of the straight-fixed variable rate design for
19 these customers?**

20 A. There are three major categories of benefits to Staff's recommended rate design
21 changes: (1) greater economic efficiencies; (2) removes the problems associated with

³⁷ David Magnus Boonin, *A Rate Design to Encourage Energy Efficiency and Reduce Revenue Requirements*, National Regulatory Research Institute (July 2008).

³⁸ *Id.*, at iii.

1 the ongoing decreases in use per customer that challenges the Company's ability to
2 collect its authorized revenues; and (3) promotes energy efficiency.

3
4 **Q. Please explain why your proposal promotes greater economic efficiencies.**

5 A. A significant portion of the cost of providing electric (or even natural gas) service
6 are fixed costs, while rates are charged using a combination of fixed and variable
7 charges. Correcting the disproportionate recovery of fixed costs in volumetric rates
8 by placing more of those fixed costs into a monthly customer charge decouples per-
9 customer sales volumes from a utility's revenue more efficiently than a decoupling
10 mechanism. Staff's proposal also eliminates the need to continuously true-up a
11 decoupling mechanism through accounting deferrals.

12
13 **Q. Please explain why the straight-fixed variable rate design better enables the
14 Company to collect appropriate levels of revenues.**

15 A. Straight-fixed variable rate design allows the utility to collect its fixed costs through
16 fixed charges, therefore leaving only variable charges set at margin to go up or down
17 based on usage.

18
19 **Q. Please explain why the straight-fixed variable rate design promotes energy
20 efficiency.**

21 A. Staff's straight-fixed variable rate design provides the right price signals for efficient
22 utility system use, and will help remove the disincentive the Company has to actively
23 promote energy efficiency and demand side management for extra-large and ultra-

1 large customers because fixed costs are removed from the volumetric rates where
2 reduction in loads has a sizable impact on earnings erosion.

3
4 **Q. Is a straight-fixed variable rate design appropriate for all rate schedules?**

5 A. No. In his research and policy paper, Mr. Boonin identifies the arguments against
6 this rate design, as “moving revenue from the variable component of a standard two-
7 part tariff to the fixed charge can reduce a customer’s economic incentive to
8 conserve”³⁹ and “moving revenue from the variable component of a standard two-
9 part tariff to the fixed charge adversely affects small users within a class, including
10 possibly low-income customers.”⁴⁰

11 These arguments may apply to rate schedules with smaller usage, but these
12 concerns do not apply to Avista’s Schedule 25 and 26 customers, because of the
13 large and unique usage characteristics that I discussed earlier. Moreover, there are
14 no “small” users or even low-income customers on the extra-large and ultra-large
15 customer schedules for which Staff is recommending this type of rate design
16 treatment be applied.

17 Finally, Staff still sees an economic incentive to conserve through the
18 demand volumetric rates, which are more expensive and thus a more useful and
19 direct target for energy conservation.

20
21 **Q. Are there other items the Commission should consider before accepting the**
22 **straight-fixed variable rate design Staff proposes?**

³⁹ *Id.*, Boonin article, *supra* note 37, at 4.

⁴⁰ *Id.*

1 A. Yes. This is the first time Staff has proposed a straight-fixed variable rate design;
2 however, a similar approach was applied in PSE's natural gas decoupling docket,
3 UG-121705. If the Commission accepts Staff's proposal, the Commission can
4 expect other utilities to propose this rate design for large users, and perhaps others.

5 In addition, Staff removed and imbedded the primary voltage discount rate
6 for 60 kilovolt and 115 kilovolt because it only applied to Customer 9, which now
7 has its own newly created Schedule 26, according to Staff's proposal.

8

9 **D. Other Recommendations**

10

11 **Q. Does Staff have any other recommendations regarding electric rate design?**

12 A. Yes. Staff recommends the Commission direct the Company to examine in its next
13 general rate case filing: (1) its volumetric blocks in Schedule's 11, 12, 21, and 22 to
14 demonstrate whether or not those rate blocks are valid and convey the appropriate
15 price signals; (2) to study all ancillary charges, plus line extension costs, and require
16 the Company to demonstrate for both electric and natural gas services that each
17 ancillary charge and line extension cost is recovering the costs they impose on the
18 system; (3) examine its less than 11 kilovolt primary voltage discount rate to
19 demonstrate whether that rate is valid and appropriate; and (4) to study, and possibly
20 create and implement a tariff to provide incentives or credits for commercial
21 customers that shift power use to periods of low demand (and keep it there), which
22 improves the system load factor and lowers the overall cost of the system.

23

1 **Q. What is the basis for your recommendation to study the non-residential**
2 **volumetric blocks?**

3 A. When the majority of the customers in a rate schedule fall either above or below the
4 first block, it is conceivable the current rate design is not reflecting the appropriate
5 price signals. The Company's data show that for Schedules 11 & 12 and 21 and 22,
6 a majority of customers have usage only in the first block.

7 In particular, for Schedule's 11 and 12, at least 86.1 percent of all billing
8 determinants with volumes of 3,500 kWh or less are below the first block of 3,650
9 kWh; and for Schedule's 21 and 22, at least 59.4 percent of all billing determinants
10 with volumes of 35,000 kWh or less are below the first block of 250,000 kWh.⁴¹

11
12 **Q. What is the basis for Staff's ancillary charge recommendations?**

13 A. The Company's response to Staff Data Request No. 148 stated, in part, "[t]he
14 Company last filed to adjust its reconnection charge... in 2001 (Docket UE-011595).
15 As stated in the Settlement Stipulation approved in that docket...shall remain as
16 approved in the Company's last rate case, UE-991606." Because these charges have
17 not changed for over 15 years, inflation alone eroded these rates' ability to cover
18 their related costs, thus requiring other customers to subsidize these ancillary
19 services.

20 The Company needs to analyze the propriety of these charges.
21

⁴¹ Avista response to Staff Data Request 18, Attachment A.

1 **Q. What is the basis Staff's primary voltage discount rate recommendation?**

2 A. Similar to ancillary charges, it has been over 15 years since the Company has
3 reviewed the primary voltage discount rate.⁴² That is too long. The Company
4 should conduct an analysis to make sure those discount rates are still being applied
5 appropriately and provide the correct incentives.

6
7 **Q. What is the basis for Staff's load shifting tariff recommendation?**

8 A. For this recommendation, Staff recognizes that shifting power use to periods of low
9 demand improves the system's load factor and lowers the overall cost of the system.
10 Staff needs the Company to do the initial research and provide preliminary findings
11 for Staff to analyze. Staff is not certain the Company has the incentive to conduct
12 this type of research without the Commission's direction.

13

14

VII. NATURAL GAS COST OF SERVICE

15

16 **Q. What financial results did Staff use as inputs to the cost of service study?**

17 A. For the reasons I stated earlier in Section IV, Staff used the financial data from the
18 Company's pro forma cross check study,⁴³ after excluding all adjustments that go
19 into the rate year.

20

⁴² Avista response to Staff Data Request 164.

⁴³ Miller Direct, Exhibit No. ____ (JDM-1T) at 9:1-10.

1 **A. Natural Gas Cost Classifications and Allocations**

2

3 **Q. Did Staff conduct a systematic review of the Company’s natural gas cost of**
4 **service study for classifying and allocating plant and expenses?**

5 A. Yes. In addition to Staff’s own research and review, Staff met with Avista’s cost of
6 service experts and conducted a detailed review of the Company’s cost of service
7 study to analyze the functionalization, classification, and allocation of items in each
8 FERC account.

9

10 **Q. Are there reasons why the Commission should take a “hard look” at the cost of**
11 **service study issues in this case?**

12 A. Yes. As for electric service, the Company is proposing a decoupling mechanism to
13 recover fixed costs on a revenue per customer basis for natural gas service. For the
14 same reasons that I laid out Section IV.B for electric service, the Commission should
15 take a “hard look” at cost of service before approving decoupling.

16

17 **Q. What is the result of Staff’s systematic review?**

18 A. The result is that Staff made three major adjustments to the Company’s natural gas
19 cost of service study.

20

21 **Q. What major adjustments did Staff make to the cost of service study for**
22 **allocating plant and expenses?**

1 A. Staff made three major adjustments to the Company's natural gas cost of service
2 study for classifying and allocating plant and expenses: (1) general plant costs and
3 administrative and general ("A&G") expenses; (2) distribution main costs; and (3)
4 underground storage plant costs.

5

6 **1. Classification and Allocation of General Plant Costs and Administrative and**
7 **General Expenses**
8

9 **Q. How did Staff allocate A&G expenses and general plant?**

10 A. Staff used the same 4-factor for both A&G expenses and general plant, as explained
11 in electric's Section IV.B.1 of my testimony. Please refer to that testimony for the
12 justification for the 4-factor.

13

14 **2. Classification and Allocation of Distribution Main Costs**
15

16 **Q. Are distribution mains a significant driver in the cost of service study?**

17 A. Yes. In fact, gas distribution mains are the biggest driver, representing over 34
18 percent of total rate base. This means that small movements in the allocation of
19 these costs can make large differences in the cost to serve each customer class.

20

21 **Q. On what basis does Staff classify and allocate gas distribution mains?**

22 A. Staff classifies gas distribution mains as a demand-related cost. Staff allocates the
23 cost of gas distribution mains on a combination of peak demand and average
24 demand. Specifically, Staff allocates the cost of mains 39.8 percent on average
25 demand and 60.2 percent on peak demand.

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Q. Please define “peak demand” and “average demand.”

A. “Peak demand” is the demand for gas on the average five consecutive peak days of the heating season for the last three years. “Average demand” is the total gas consumption for the year divided by the days in the year.

Q. Why does Staff propose to allocate gas distribution mains using a combination of peak and average demand?

A. The primary reason is because large customers (*i.e.*, on Schedules 131, 132, and 146) benefit from smaller gas distribution mains. (Staff generally views pipes less than four inches in diameter as medium to small gas distribution mains). Because of this benefit, it is appropriate to allocate some of the costs of these smaller distribution mains to large customers.

Q. Please explain how large customers benefit from smaller gas distribution mains.

A. Large load customers (*i.e.*, Schedules 131, 132, and 146) benefit from the reliability and capacity of the system that the smaller pipes deliver, even though Avista may not directly serve such customers with pipe less than four inches in diameter.

The Company’s distribution system is a network of parallel and interconnected pipes that are used to move gas from one point to another.

Regardless whether the Company chooses to use medium diameter pipes to directly serve smaller customers and larger diameter pipes to directly serve larger customers, both types of pipes create capacity on the system.

1 For example, if Avista had fewer medium sized pipes, either it would have
2 additional larger diameter pipes or it would have less capacity available to serve all
3 large and small customers. In other words, from a cost of service perspective,
4 capacity must be evaluated as a whole, and total capacity allows the Company to
5 service large interruptible customers, even though some of the capacity is in the form
6 of medium size mains. Otherwise, more interruptible customers would be curtailed
7 more often due to capacity constraints.⁴⁴

8
9 **Q. Can you provide an analogy to help illustrate this point?**

10 A. Yes. The gas distribution system can be analogized to a network of roads that
11 includes freeways,⁴⁵ arterials and side streets.⁴⁶ During times of normal or low
12 traffic volumes, everything is moving freely in the direction of their destination.
13 Passenger vehicles use the side streets to get to the arterials and the arterials to get to
14 the freeways. Large semi-tractor-trailer rigs generally stay off side streets, except for
15 deliveries to local business, but use arterials to get to freeways. The system works
16 well until traffic gets heavy and the freeways get congested and traffic slows down.
17 At that point, drivers of many cars and some trucks then use more of the arterials and
18 side streets, rather than continuing to add to the freeway congestion.

19 If the arterials and side streets that parallel the freeways are not available, all
20 of that traffic would still try to crowd the freeways, resulting in gridlock. During
21 these times of high traffic volume, the large semis may not use the arterials and side

⁴⁴ Avista response to Staff Data Request 19 – No customer has been interrupted in the last ten years.

⁴⁵ Symbolizes large mains.

⁴⁶ Symbolizes medium and small mains.

1 streets themselves, but they benefit by having other vehicles select those alternative
2 routes. This benefit is very clear during times of high volume, but even during times
3 of average use, the existence of smaller roads allows the freeways to be less
4 congested than they would otherwise be.

5 In short, having arterials and side streets benefits all vehicles, even those who
6 are traveling long distances at high speeds on the freeway. Similarly, the gas
7 distribution system as a whole provides capacity for all customers, including those
8 who are directly connected to large mains.

9 Moreover, the Company and other investor-owned utilities (“IOUs”)⁴⁷ use a
10 planning model by GL Noble Denton called “SynerGEE” that demonstrates that gas
11 may take multiple routes to a given customer depending on temperature, load and
12 outage conditions. This redundancy built into the system provides additional system
13 capacity and allows service to a given customer even if parts of the system are
14 temporarily out of service.

15
16 **Q. How does Staff’s approach respond to this shared use of capacity on the**
17 **system?**

18 **A.** Staff’s approach reflects a balance between the way the system is designed (to meet
19 peak demand) and the way it is used on an annual basis (throughput based on gas
20 usage that occurs during all conditions, not only peak conditions).

21

⁴⁷ *E.g.*, Puget Sound Energy, Inc.

1 **Q. Please describe how Staff classified and allocated gas distribution mains.**

2 A. As I noted earlier, Staff classifies the cost of distribution mains as a demand-related
3 cost. However, Staff does not allocate these costs based solely on peak demand.
4 Instead, Staff used the peak and average method for allocating this portion of
5 demand-related costs. This method allocates demand costs based on a combination
6 of peak demand and average demand. Average demand is essentially another term
7 for average throughput.

8 Staff used the system load factor⁴⁸ to determine how much of the demand-
9 related costs would be allocated based on average demand and how much would be
10 allocated based on peak demand. Staff calculated a system load factor based on
11 weather-normalized throughput and peak demand. The load factor is the ratio of
12 average load to peak load, and when multiplied by the plant investment, provides an
13 estimate of costs that can be attributed to average use rather than peak use.

14 Staff used the resulting 39.8 percent load factor to divide these demand-
15 related costs into peak demand and average demand for purposes of allocating the
16 costs to customer classes, with the demand-related costs being allocated 39.8 percent
17 on average demand and 60.2 percent on peak demand. The load factor provides a
18 reasonable basis for determining what portion of these costs should be allocated
19 based on average demand.

20

21 **Q. Please explain the specific steps in Staff's use of the peak and average method to**
22 **allocate the cost of distribution mains to the rate schedules.**

⁴⁸ Miller Direct, Exhibit No. ___ (JDM-2) at 4:6-8.

1 A. First, I divided total distribution mains plant into the portion to be allocated based on
2 peak demand and the portion to be allocated based on average demand using the
3 system 39.8 percent load factor I described above.⁴⁹ This resulted in \$61.3 million
4 (39.8 percent) of plant allocated based on average demand and \$92.7 million (60.2
5 percent) allocated based on peak demand.

6 Second, I allocated the 60.2 percent based on peak demand to all customer
7 classes based on their estimated contributions to the peak demand.

8 Third, I split the 39.8 percent based on average demand into three groups: (1)
9 large main (greater than or equal to four inches in diameter); (2) medium main (two
10 to three inches in diameter); and (3) small main (less than two inches in diameter). I
11 allocated large main to all customer classes based on annual weather normalized
12 throughput. I allocated small main to all classes except Schedules 131, 132, and 146
13 based on annual weather normalized throughput. I allocated medium main 33.3
14 percent to all classes and 66.7 percent to all classes except 146 based on annual
15 weather normalized throughput.

16 My Exhibit No. ____ (CTM-8) is a chart showing these steps.
17

18 **Q. Why did you not allocate mains less than two inches in diameter to all classes?**

19 A. These smallest mains are located in isolated locations on the Company's system and
20 thus are unlikely to provide the benefits I have described to the large commercial and
21 industrial customers served on Schedules 131, 132, and 146, compared to medium-
22 sized mains, which are located throughout the Company's distribution system.

⁴⁹ *Id.*

1 I also grouped three inch mains with the two inch mains because Avista has
2 few three inch mains in its system. By contrast, large mains (four inch diameter and
3 greater) are the “backbone” of Avista’s system, and Avista uses medium to small
4 mains (two inch diameter and smaller) to deliver gas to most of the customers.

5 Therefore, Staff’s approach acknowledges the fact that the smallest mains are
6 in isolated locations on the system and they are unlikely to benefit large commercial
7 and industrial customers.

8
9 **Q. Why did you split medium mains (those two to three inches in diameter) into**
10 **two groups?**

11 A. Staff did this to reasonably allocate the cost of this plant. Giving the largest
12 interruptible customers a full allocation of the costs of medium-sized mains arguably
13 places too much emphasis on system benefits, yet to use a zero allocation would
14 assume no system benefits whatsoever, which is also wrong. Staff’s approach is a
15 balance between these extremes.

16
17 **Q. Why did Staff choose the one-third, two-thirds split, with one third of medium**
18 **main being allocated to all customers and two thirds to all classes except**
19 **Schedule 146 (interruptible)?**

20 A. Staff considered the historical treatment of these customers and the benefits
21 associated with being part of the gas distribution system for other investor-owned
22 utilities. Historically, Schedule 146 customers and contract customers had some
23 assignment of costs related to medium main, but that assignment was small. Prior to

1 this general rate case, the only medium-sized mains the Company would assign to
2 those largest customers were based on a direct assignment.

3 Staff's two-thirds weighting is an acknowledgement that, in the past, these
4 large customers were assigned very little of the costs of distribution mains. The one-
5 third weighting acknowledges the benefits to all customers of being part of a
6 distribution system. Consequently, while the cost assignment of medium mains to
7 Schedule 146 customers should be small, it should not be zero even though Avista
8 has not curtailed a single Schedule 146 or contract customer for the last decade,⁵⁰
9

10 **Q. Please summarize the benefits of the Staff's peak and average method for**
11 **allocating gas distribution mains.**

12 A. There are three primary benefits to Staff's peak and average method. First, this
13 method recognizes that all customers benefit from the entire gas system of medium
14 and large mains as a whole, not only from the stretch of main through which gas
15 flows to reach the individual customer. The system is a network of pipes that
16 provides benefits to customers in addition to the benefits provided by the stretch of
17 pipe through which molecules flow to reach the individual customer.

18 Second, by exempting large customers from any allocation of the cost of the
19 smallest diameter main (less than two inches), Staff's method acknowledges the fact
20 that these smallest mains are located in isolated locations on the system and are
21 unlikely to benefit large commercial and industrial customers.

⁵⁰ Avista response to Staff Data Request 19.

1 Third, Staff recognizes that the benefits of medium diameter mains to large
2 interruptible customers are less than the benefits to other customers, by allocating
3 only a portion of the cost of two and three inch diameter mains to large interruptible
4 customers.

5
6 **Q. Has Staff's approach to allocation of distribution mains been proposed by other**
7 **investor-owned gas utilities in this state?**

8 A. Yes. A similar approach for allocating distribution mains has been proposed by
9 Puget Sound Energy, Inc. ("PSE") in its last three general rate cases,⁵¹ but the issue
10 was never fully litigated to a Commission decision due to settlements.

11
12 **3. Classification and Allocation of Underground Storage Plant Costs**
13

14 **Q. How did Staff allocate natural gas underground storage plant costs?**

15 A. Staff allocated Jackson Prairie natural gas underground storage plant costs with a 20
16 percent load balancing benefit for all customers and 80 percent commodity storage
17 benefit for sales customers. These are the same percentages Puget Sound Energy
18 ("PSE") used in its natural gas cost of service studies since Docket No. UG-
19 011571.⁵²

20

⁵¹ Dockets UG-090705, UG-101644, and UG-111049, see Direct Testimony of Janet K. Phelps.

⁵² Feingold Direct, Exhibit No. ___ (RAF-1T) at 30-33.

1 **Q. Please explain how Avista currently allocates underground storage plant costs.**

2 A. Avista allocates underground storage plant costs by providing 13 percent load
3 balancing benefits for all customers and 87 percent commodity storage benefits for
4 sales customers. This assignment of costs was agreed to as part of an all-party
5 Settlement Agreement in Docket No. UG-100468.⁵³

6
7 **Q. Is there a reason not to continue to use the agreed split from that prior
8 Settlement?**

9 A. Yes. Staff's 20 percent for balancing (and pressure) and 80 percent for storage is
10 based on a system balancing study by PSE, one of the other co-owners⁵⁴ of the
11 Jackson Prairie storage facility. PSE operates the Jackson Prairie underground
12 storage facility and its system balancing study provides an accurate measure of the
13 benefits of underground storage at Jackson Prairie, to reflect any other percentage
14 would be inaccurate.

15
16 **Q. Overall, does Staff's cost of service study reasonably and fairly allocate plant
17 and expenses?**

18 A. Yes. Overall, the Staff's cost of service study reasonably functionalizes, classifies,
19 and allocates capital investments and operating expenses to each rate schedule.
20 Staff's natural gas cost of service study fairly and equitably identifies the costs
21 required to serve each particular customer class.

22

⁵³ Avista response to Staff Data Request 167.

⁵⁴ Owners are Puget Sound Energy, Avista, and Northwest Pipeline.

1 **Q. Have you prepared a table summarizing the results of Staff's cost of service**
2 **study?**

3 A. Yes. Table 3 below sets forth the parity ratios under current rate structure using the
4 Company's cost of service, and Staff's proposal. As I explained earlier in my
5 discussion of the electric cost of service study, the parity ratios indicates what
6 portion of the cost of service customers pay under each of the rate structures, relative
7 to other customer classes. These results are provided in the summary of results from
8 the cost of service study on page one, line 220 of my Exhibit No. ____ (CTM-5).

9 Table 3: Summary of Margin Parity Ratios

10

11 Customer Class	Company Current	Staff Current
12 Total System	1.00	1.00
13 General Service (Schedule 101)	0.97	0.94
14 Large General Service (Schedules 111, 112)	1.14	1.34
15 Extra Large General Service (Schedules 121, 122)	1.17	1.48
16 Interruptible (Schedule 131, 132)	1.24	1.03
17 Transportation (Schedule 146)	0.95	0.97

18 **Q. What does this table show?**

19 A. This table demonstrates that there are significant disparities in parity ratios, and thus
20 is it necessity to change the rate structure of certain customer classes. Together with
21 Staff's cost of service study, the following rate schedules have parity ratios outside
22 the 0.95 to 1.05 range: (1) General Service (Residential) Schedule 101 is covering 94
23 percent of its cost of service; (2) Large General Service Schedules 111 and 112

1 covers 134 percent of its cost of service; and (3) Extra Large General Service
2 Schedules 121 and 122 covers 148 percent of its cost of service.
3

4 **B. Special Contracts**
5

6 **Q. Are there any other issues Staff recommends the Commission require the**
7 **Company to address in its next general rate case?**

8 A. Yes. As the Commission has previously stated: “[r]ate spread should recognize that
9 rates must be just and reasonable and not cause undue discrimination. To this end,
10 revenue responsibility for any class should be informed by the cost to serve the
11 class.”⁵⁵ Therefore, Staff recommends the Commission require the Company to run
12 its cost of service study and rate design models with Special Contracts as a separate
13 customer class (or column), instead of the credit methodology⁵⁶ the Company
14 currently uses. Alternatively, the Commission should require the Company to
15 demonstrate that each Special Contract is recovering the costs it imposes on the
16 system.

17 This would allow Staff to evaluate the analysis and make sure the amount of
18 revenue collected from Special Contracts customers is appropriate. If not, then the
19 Commission can adjust long-term contracts by imputing revenues within the rate
20 case to prevent harm to other customer classes.
21

⁵⁵ *Utilities & Transp. Comm’n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08 (May 7, 2012), at 120.

⁵⁶ Miller Direct, Exhibit No. ___ (JDM-2) at 6:3-10.

1 **Q. Is any other Commission-regulated utility currently evaluating Special**
2 **Contracts as a separate item in the cost of service study and rate design?**

3 A. Yes. PSE currently runs its cost of service and rate design with Special Contracts
4 represented as a distinct schedule (or column) within both its electric and gas
5 models.⁵⁷ PSE shows the parity ratios for Special Contracts customers, and adjusts
6 the Special Contracts accordingly to ensure Special Contracts customers share the
7 cost of the system and pay their fair share of the costs they impose on the system.
8 Avista should do no less.

9
10 **VIII. NATURAL GAS REVENUE ALLOCATION**

11
12 **Q. What is Staff's recommendation on revenue allocation for gas service?**

13 A. Based on Staff recommended overall gas revenue increases of 4.77 percent, and in
14 order to move gas rate schedules closer to parity, Staff recommends the following
15 increases:

- 16 • Schedule 101, General Service: increase 6.2 percent.
- 17 • Schedules 111 and 112, Large General Service: no change to revenues.
- 18 • Schedules 121 and 122, Extra Large General Service: no change to revenues.
- 19 • Schedules 131 and 132, Interruptible: increase 2.7 percent.
- 20 • Schedule 146, Transportation: increase 17.2 percent.

21

⁵⁷ For Dockets UE-111048 and UG-111049, see Piliaris Direct, Exhibit No. ____ (JAP-1T), and Phelps Direct, Exhibit No. ____ (JKP-1T).

1 **Q. Please explain why Schedules 101 and 146 should receive a higher than average**
2 **increase, while Schedules 111, 112, 121, and 122 should receive no increase.**

3 A. Because Schedule 146 is not part of the decoupling mechanism, Staff believed this
4 schedule needed to reach parity to make sure there are no cross-subsidies between
5 schedules before the decoupling mechanism could be layered on to base rates. While
6 the increase seems extraordinary, one must recall the basis of the increase is only
7 delivery system costs with no actual gas. With an imputed level of gas included, the
8 increase would be 8.5 percent.

9 For the same reasons explained earlier in my discussion of electric revenue
10 allocation as applied to Schedule 101, moderate rate changes are more reasonable
11 and represent a gradual approach to address parity imbalances.

12

13 **Q. By comparison, what rate increases or decreases would be required to move**
14 **each rate schedule to parity?**

15 A. To reach parity at existing rates, the following approximate rate changes would be
16 required:

- 17 • General Service (Residential) Schedule 101: 8.0 percent rate increases.
- 18 • Large General Service Schedules 111 and 112: 5.1 percent rate decreases.
- 19 • Extra Large General Service Schedules 121 and 122: 6.4 percent rate decrease.
- 20 • Interruptible Schedules 131 and 132: 2.7 percent rate increase.
- 21 • Transportation Schedule 146: 17.2 percent rate increases.

22

23 **Q. How are the parity ratios affected by your proposed percentage increases?**

1 A. Table 4 below, shows the results that Schedules receiving above average or no
2 increases move ratios closer to Staff's recommended target parity range of 0.95 to
3 1.05.

4 Table 4: Summary of Margin Parity Ratios

5

Customer Class	Staff Current	Staff Proposal
Total System	1.00	1.00
General Service (Schedule 101)	0.94	0.97
Large General Service (Schedules 111, 112)	1.34	1.18
Extra Large General Service (Schedules 121, 122)	1.48	1.29
Interruptible (Schedule 131, 132)	1.03	1.00
Transportation (Schedule 146)	0.97	1.00

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13 **IX. NATURAL GAS RATE DESIGN**

14

15 **Q. Please explain generally the concept of natural gas rate design.**

16 A. Similar to electric rate design, natural gas rate design takes the total allocated
17 revenue for each rate schedule and determines the specific charges within the
18 schedule, such as the basic charge per month, the demand charge per therm, and the
19 exact cents per therm.

20

21 **Q. What are Staff's natural gas rate design structure proposals?**

1 A. Staff proposes to use rate year billing determinants⁵⁸ to reflect Staff witness Mr.
2 McGuire's recommendation for growth rates within the attrition study.⁵⁹ Staff also
3 proposes to: (1) increase the monthly customer charges to include more fixed costs;
4 (2) decrease volumetric rates for Schedules 111, 112, 121, and 122; and (3) apply a
5 split of 50/50 of the Transportation Schedule's revenue requirement to the customer
6 charge and volumetric rates.

7

8 **A. General Service (Residential) Rates**

9

10 **Q. What rate design does Staff propose for the monthly customer charge, given**
11 **Staff's lower recommend revenue requirement?**

12 A. Staff proposes to increase the monthly customer charge to reflect the costs that are
13 fixed and that vary with the number of customers. For the same reasons I explained
14 earlier in my discussion of electric rate design, these costs vary by the number of
15 customers rather than usage. Therefore, it is appropriate for the Company to recover
16 these costs in the basic charge rather than usage charges. Accordingly, Staff
17 proposes that the monthly customer charge for General Service Schedule 101
18 increase from \$8.00 to \$8.92. The development of this figure is below the minimum
19 customer-related costs of \$11.75 shown in my Exhibit No. ___ (CTM-5), page 4, and
20 line 29.

21

⁵⁸ Avista response to Staff Data Request 24, Attachment B.
⁵⁹ McGuire Direct, Exhibit Nos. ___ (CRM-1T) and ___ (CRM-3).

1 **Q. What costs are covered by the gas monthly customer charge?**

2 A. The gas monthly customer charge includes the cost of meters, service drops, meter
3 reading, meter maintenance, and billing. Mr. Ehrbar's Exhibit No. ____ (PDE-1T),
4 starting on page 29, shows these costs total \$20.02 per customer per month, based on
5 the Company's rate request increase of 8.1 percent. My total customer cost estimate
6 is \$22.72. The differences are mostly due to Staff and Company differences on cost
7 of capital and classification and allocation of rate base.

8
9 **Q. Does Staff propose a change in the per therm rate for Schedule 101?**

10 A. No. The required revenue increase was provided by the increase to the monthly
11 customer charge.

12 In addition, depending on the revenue requirement the Commission
13 ultimately determines, the rate per therm most likely would not need to change
14 because the increase could likely be put into the monthly customer charge and
15 remain below what Staff would deem as a minimum required basic charge.
16 Furthermore, Staff's proposal would reduce any intra-class subsidies, have all
17 residential customers incur an equal share of the increase, and provide the same
18 benefits as discussed earlier within Section VI.A, relating to the potential variance
19 within the decoupling mechanism's deferral calculations.

20

1 **B. Large and Extra Large General Service**

2

3 **Q. What is Staff's natural gas rate design proposal for Schedules 111, 112, 121, and**
4 **122?**

5 A. Due to rate year billing determinants growth rates, Staff recommends revenue-
6 neutral changes in rate design to implement a uniform decrease to volumetric rates
7 for Schedules 111, 112, 121, and 122. Staff's reason for the decrease is to recognize
8 the increase in rate year billing determinant, which shows large load growth
9 compared to the last general rate case in 2012.

10

11 **C. Transportation Rates**

12

13 **Q. How did Staff apply the revenue increase to Transportation Schedule?**

14 A. Staff applied a split of 50/50 of the schedule's revenue requirement to the customer
15 charge and volumetric rates. This would increase the customer charge for
16 Transportation Schedule 146 from \$400.00 to \$500.00; and apply a flat rate increase
17 of 0.5065 cents to all present block rates.

18

19 **Q. Why did Staff use that approach?**

20 A. First, it did not make common sense to Staff for transportation customers to pay
21 lower monthly customer charges and volumetric rates compared to large general
22 service customers under current rates, who are paying more than their cost of service,
23 and who would be part of a decoupling mechanism.

1 Second, applying a split of 50/50 of the schedule's revenue requirement to
2 the customer charge and volumetric rates would be fair and equitable to all
3 transportation customers because they all share an equal portion of the increase in
4 customer charge and each have the opportunity to reduce their delivery system costs.

5 Next, these customers are not part of the decoupling mechanism, but Staff
6 wanted to limit any intra-schedule subsidies.

7 Finally, it appears the five block rate design structure is no longer providing
8 proper price signals since 67.8 percent of usage falls within the first two blocks, and
9 95.8 percent of usage falls within the third block on this schedule.⁶⁰ Thereby
10 applying a flat cent increase will reduce the rate differential between blocks and
11 allow gradualism for Staff's next recommendation in a following general rate case of
12 eliminating or shifting usage blocks or applying a straight-fixed variable rate design
13 similar to electric Schedules 25 and 26 for these customers.

14
15 **D. Interruptible Rates**

16
17 **Q. What is Staff's natural gas rate design proposal for Schedules 131 and 132?**

18 A. Due to rate year billing determinants growth rates, Staff recommends a uniform
19 decrease to volumetric rates for Schedules 131, and 132. Staff's reason for the
20 decrease is to recognize the increase in rate year billing determinant, which shows
21 large load growth compared to the last general rate case in 2012, even with
22 recognizing the 2.7 percent increase to revenues.

⁶⁰ Avista response to Staff Data Request 18.

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Q. Do you have any other rate design recommendations?

A. Yes. Staff recommends the Commission direct the Company to study all interruptible rate (Schedules 131 and 132) offerings and determine whether the discounted rate is justified in their next rate case.

Q. What is the basis for this recommendation?

A. The Company's response to Staff Data Request 19 stated, in part, "[n]either of the Schedule 132 customers (Interruptible Service) has been interrupted in the last ten years." The Commission has expressed concerns about interruptible customers paying their fair share:

We [the Commissioners] expect that the utilities' analyses will include overall costs to the system and load management factors, and we require that each of the studies, as to each of the interruptible rates thus offered, require assurance that customers are not merely given a discount rate. The utilities will study the desirability and feasibility of interruptible rate offerings as well as their acceptability to customers.⁶¹

There may be real system benefits resulting from the Company's interruptible schedules, but the Company needs to provide an analysis which supports the existence of those benefits and includes a methodology for determining when to interrupt customers on interruptible service schedules.

Q. Does this conclude your testimony?

A. Yes.

⁶¹ *Utilities & Transp. Comm'n v. Pacific Power & Light Company, Puget Sound Power & Light Company, and the Washington Water Power Company*, Cause U-78-05, Commission Decision and Order (October 29, 1980), at 9.