

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-12_____

DOCKET NO. UG-12_____

DIRECT TESTIMONY OF

TARA L. KNOX

REPRESENTING AVISTA CORPORATION

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I. INTRODUCTION

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

A. My name is Tara L. Knox and my business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Senior Regulatory Analyst in the State and Federal Regulation Department.

Q. Would you briefly describe your duties?

A. Yes. I am responsible for preparing the regulatory cost of service models for the Company, as well as providing support for the preparation of results of operations reports.

Q. What is your educational background and professional experience?

A. I am a graduate of Washington State University with a Bachelor of Arts degree in General Humanities in 1982, and a Master of Accounting degree in 1990. As an employee in the State and Federal Regulation Department at Avista since 1991, I have attended several ratemaking classes, including the EEI Electric Rates Advanced Course that specializes in cost allocation and cost of service issues. I have also been a member of the Cost of Service Working Group and the Northwest Pricing and Regulatory Forum, which are discussion groups made up of technical professionals from regional utilities and utilities throughout the United States and Canada concerned with cost of service issues.

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

A. My testimony and exhibits will cover the Company's electric and natural gas cost of service studies performed for this proceeding. Additionally, I am sponsoring the

1 electric and natural gas revenue normalization adjustments to the test year results of
 2 operations and the proposed retail revenue credit rate to be used in the Energy Recovery
 3 Mechanism and associated retail revenue credit pro forma adjustment. A table of contents
 4 for my testimony is as follows:

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15 **Q. Are you sponsoring any exhibits in this case?**

16 A. Yes. I am sponsoring Exhibit No.__(TLK-2), which illustrates the proposed
 17 retail revenue credit rate and the related adjustment calculation. Related to the electric cost
 18 of service study, I am sponsoring Exhibit No.__(TLK-3), the electric cost of service study
 19 process description, and Exhibit No.__(TLK-4), the electric cost of service study summary
 20 results.

21 Finally, related to the natural gas cost of service study, I am sponsoring Exhibit
 22 No.__(TLK-5), the natural gas cost of service study process description, and Exhibit No.__(
 23 (TLK-6), the natural gas cost of service study summary results.

24 **Q. Were these exhibits prepared by you or under your direction?**

25 A. Yes, they were.

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II. REVENUE NORMALIZATION

Electric Revenue Normalization

Q. Would you please describe the electric revenue normalization adjustment included in Company witness Ms. Andrews pro forma results of operations?

A. Yes. The electric revenue normalization adjustment represents the difference between the Company’s actual recorded retail revenues during the twelve months ended December 2011 test period, and retail revenues on a normalized (pro forma) basis. The total revenue normalization adjustment increases Washington net operating income by \$10,116,000, as shown in adjustment column 2.12 on page 7 of Exhibit No.__(EMA-2). The revenue normalization adjustment consists of three primary components: 1) re-pricing customer usage (adjusted for any known and measurable changes) at base tariff rates presently in effect, 2) adjusting customer loads and revenue to a 12-month calendar basis (unbilled revenue adjustment), and 3) weather normalizing customer usage and revenue¹.

Q. Since these three elements are combined into a single adjustment, would you please identify the impact (before income taxes and revenue related expenses) of each component?

A. Yes. The re-pricing of billed usage comprises the majority of the change in test year revenue. The combined impact of the rate increase effective January 1, 2012², and the elimination of revenue and amortization expense from adder schedules (Schedule 59 Residential Exchange, Schedule 91 Public Purpose Tariff Rider, and Schedule 95 Optional

¹ Documentation related to this adjustment is detailed in the Knox workpapers accompanying this case.
² WUTC Docket No. UE-110876.

1 Renewable Power³), is an increase in net revenue of \$18,310,000. Re-pricing of unbilled
2 calendar usage and elimination of unbilled adder schedule revenue and expense results in a
3 net revenue reduction of \$291,000⁴. Finally, the weather normalization adjustment
4 decreases revenue by \$2,452,000. The combined impact of these elements is an increase of
5 \$15,566,000 which, after revenue-related expenses and income tax, results in the increase to
6 net operating income of \$10,116,000.

7 **Q. Would you please briefly discuss electric weather normalization?**

8 A. Yes. The Company's electric weather normalization adjustment calculates
9 the change in kWh usage required to adjust actual loads during the twelve months ended
10 December 2011 test period to the amount expected if weather had been normal. This
11 adjustment incorporates the effect of both heating and cooling on weather-sensitive
12 customer groups. The weather adjustment is developed from regression analysis of ten
13 years of billed usage per customer and billing period heating and cooling degree-day data.
14 The resulting seasonal weather sensitivity factors (use-per-customer-per-heating-degree day
15 and use-per-customer-per-cooling-degree day) are applied to monthly test period customers
16 and the difference between normal heating/cooling degree-days and monthly test period
17 observed heating/cooling degree-days.

18 **Q. Have the seasonal weather sensitivity factors been updated since the last**
19 **rate case?**

³ City Business and Occupation Taxes and Energy Recovery Mechanism revenues are eliminated in separate adjustments.

⁴ The unbilled adjustment consists of removing December 2010 usage billed in January 2011 from the 2011 test year, adding December 2011 usage billed in January 2012 to the 2011 test year, and re-pricing the net adjustment to usage at January 1, 2012 rates.

1 A. Yes. The factors used in the weather adjustment are based on regression
2 analysis of monthly billed usage per customer from January 2001 through December 2010
3 which is the most recent completed analysis. Autoregressive terms were included in the
4 regressions in order to correct for autocorrelation in the data.

5 **Q. What data did you use to determine “normal” heating and cooling**
6 **degree days?**

7 A. Normal heating and cooling degree days are based on a rolling 30-year
8 average of heating and cooling degree-days reported for each month by the National
9 Weather Service for the Spokane Airport weather station. Each year the normal values are
10 adjusted to capture the most recent year with the oldest year dropping off, thereby reflecting
11 the most recent information available at the end of each calendar year.

12 **Q. Is this proposed weather adjustment methodology consistent with the**
13 **methodology utilized in the Company’s last general rate case in Washington?**

14 A. Yes. The process for determining the weather sensitivity factors and the
15 monthly adjustment calculation are consistent with the methodology presented in Docket No
16 UE-110876. This methodology has been used in every case since it was introduced in
17 Docket No UE-070804.

18 **Q. What was the impact of electric weather normalization on the twelve**
19 **months ended December 2011 test year?**

20 A. Weather was cooler than normal through July, then warmer than normal the
21 remainder of 2011. Overall, the adjustment to normal required the deduction of 296 heating

1 degree-days during the heating season⁵ and the addition of 6 cooling degree-days during the
2 summer season⁶. The total adjustment to Washington sales volumes was a reduction of
3 28,118,714 kWhs which is approximately 0.5% of billed usage.

4 **Natural Gas Revenue Normalization**

5 **Q. Would you please describe the natural gas revenue adjustment included**
6 **in Ms. Andrews pro forma results of operations?**

7 A. Yes. The natural gas revenue normalization adjustment is similar to the
8 electric adjustment and represents the difference between the Company's actual recorded
9 retail revenues during the twelve months ended December 2011 test period and retail
10 revenues on a normalized (pro forma) basis. The adjustment includes the re-pricing of pro
11 forma sales and transportation volumes at present rates using pro forma sales volumes that
12 have been adjusted for unbilled sales, abnormal weather, and any material customer load or
13 schedule changes. The rates used exclude: 1) Temporary Gas Rate Adjustment Schedule
14 155, which reflects the approved amortization rate for prior deferred gas costs approved in
15 the Company's last PGA filing, 2) Public Purposes Rider Adjustment Schedule 191, and 3)
16 Natural Gas Decoupling Rate Adjustment Schedule 159⁷.

17 **Q. Does the Revenue Normalization Adjustment contain a component**
18 **reflecting normalized gas costs?**

19 A. Yes. Purchase gas costs are normalized using the gas costs approved by the
20 Commission in Docket No. UG-120195, the Company's 2012 PGA update filing, as set

⁵ The heating season includes the months of January through June and October through December.

⁶ The summer season includes the months of June through September.

⁷ Documentation related to this adjustment is detailed in the Knox workpapers accompanying this case.

1 forth under Schedule 150. These gas costs, effective March 1, 2012, are applied to the pro
2 forma retail sales volumes so that there is a matching of revenues and gas costs.

3 **Q. Have you determined the impact of each of the components of this**
4 **adjustment?**

5 A. Yes. The re-pricing of billed revenue and gas costs increased margin⁸ by
6 \$3,197,000. Re-pricing unbilled revenue and gas costs increased margin by \$56,000, and
7 the weather adjustment at present rates decreased margin by \$1,540,000.

8 The total net amount of the natural gas revenue normalization adjustment, which
9 includes the related purchase gas cost normalization, is an increase to net operating income
10 of \$1,541,000, as shown in adjustment column 2.01, page 5 of Exhibit No. ___(EMA-3).

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

12 A. Yes. The natural gas weather normalization adjustment is developed from a
13 regression analysis of ten years of billed usage per customer and billing period heating
14 degree-day data. The resulting seasonal weather sensitivity factors (use-per-customer-per-
15 heating-degree day) are applied to monthly test period customers and the difference between
16 normal heating degree-days and monthly test period observed heating degree-days. This
17 calculation produces the change in therm usage required to adjust existing loads to the
18 amount expected if weather had been normal.

19 **Q. In your discussion of electric weather normalization you indicated that**
20 **the adjustment utilized sensitivity factors from the ten year period January 2001**
21 **through December 2010. Is this true for natural gas as well?**

⁸ The term "margin" in this context consists of revenues less gas costs and adder schedule amortization expenses but does not include the effect of revenue related expenses or income taxes.

1 A. Yes, the natural gas weather adjustment utilized updated weather sensitivity
2 factors.

3 **Q. What data did you use to determine “normal” heating degree days?**

4 A. Normal heating degree-days are based on a rolling 30-year average of heating
5 degree-days reported for each month by the National Weather Service for the Spokane
6 Airport weather station. Each year the normal values are adjusted to capture the most recent
7 year with the oldest year dropping off, thereby reflecting the most recent information
8 available at the end of each calendar year.

9 **Q. Is this proposed weather adjustment methodology consistent with the**
10 **methodology utilized in the Company’s last general rate case in Washington?**

11 A. Yes. The process for determining the weather sensitivity factors and the
12 monthly adjustment calculation are consistent with the methodology presented in Docket
13 No. UG-110877. This methodology has been used in every case since it was introduced in
14 Docket No UG-070805.

15 **Q. What was the impact of natural gas weather normalization on the twelve**
16 **months ended December 2011 test year?**

17 A. Weather was considerably colder than normal for the first half of 2011, this
18 was somewhat offset by a warmer than normal October through December. The adjustment
19 to normal required the deduction of 296 heating degree-days from January through June and

1 October through December.⁹ The adjustment to sales volumes was a deduction of 5,276,178
2 therms which is approximately 2.1 percent of billed usage.

3 **III. PROPOSED RETAIL REVENUE CREDIT RATE**

4 **Q. Company witness Mr. Johnson indicates that the proposed retail revenue**
5 **credit rate to be used in the ERM represents the energy classified portion of the fixed**
6 **and variable production and transmission revenue requirement in this filing. How is**
7 **that rate determined?**

8 A. The retail revenue credit rate is determined by computing the proposed
9 revenue requirement on the production and transmission costs contained within Ms.
10 Andrews' Washington electric pro forma total results of operations. The
11 production/transmission revenue requirement amount is then divided by the Washington
12 normalized retail load used to set rates in order to arrive at the average production and
13 transmission revenue requirement-per-kWh embedded in proposed rates. This value is then
14 multiplied by the ratio of energy-classified to total production and transmission costs from
15 the cost of service study to arrive at the proposed Retail Revenue Credit rate.

16 **Q. Do you have an exhibit that shows the calculation of the proposed retail**
17 **revenue credit rate?**

18 A. Yes. Exhibit No. ___(TLK-2) begins with the identification of the
19 production and transmission revenue, expense and rate base amounts included in each of
20 Ms. Andrews' actual, restating, and pro forma adjustments to results of operations

⁹ Heating degree days that occur during July through September do not impact the natural gas weather normalization adjustment as the seasonal sensitivity factor is zero for summer months.

1 (excluding the retail revenue credit adjustment). The “Pro Forma Total” at the bottom of
2 page 1 shows the resulting production and transmission cost components.

3 Page 2 shows the revenue requirement calculation on the production and
4 transmission cost components. The rate-of-return and debt-cost percentages on Line 2 are
5 inputs from the proposed cost of capital. The normalized retail load on Line 10 comes from
6 the workpapers supporting the revenue normalization adjustment. Lines 12 and 13 contain
7 values from the cost of service study (total production and transmission amounts are the sum
8 of column (f) lines 32 and 33 on Page 2 of Exhibit No. ____ (TLK-4), the energy-classified
9 amount is from the supporting schedule containing the functional components of line 23 on
10 Page 3 of the same exhibit). The proposed retail revenue credit rate is shown on Line 14 and
11 represents the energy-classified portion of the average production and transmission revenue
12 requirement-per-kWh proposed to be embedded in Washington customer retail rates.

13 The proposed retail revenue credit rate is \$0.03329 per kWh or \$33.29 per mWh.
14 The calculation of the retail revenue credit rate will be revised based on the final production
15 and transmission costs and rate of return that are approved by the Commission in this case.

16 **Q. You sponsor a “Retail Revenue Credit” adjustment included in Ms.**
17 **Andrews’ electric revenue requirement calculation. What is the basis of this**
18 **adjustment?**

19 A. As Mr. Johnson stated at pages 21 and 22 of his direct testimony
20 (Exh__WGJ-1T):

21 The existing retail revenue credit rate, which is based on the fixed and
22 variable production and transmission costs, is set too high. When retail loads
23 increase, too much new revenue is credited back to customers through the
24 ERM, rather than being available to offset increased costs....

1 By setting the retail revenue credit rate at a lower level, there is more revenue
2 available to offset the aforementioned costs that is not credited back to
3 customers through the ERM. Setting the retail revenue credit at a lower level
4 will also eliminate fixed production and transmission costs from being
5 recovered through the ERM when retail loads decline.

6 The cost changes that are tracked through the ERM are primarily due to
7 changes in the price of energy, or changes to the amount of energy being
8 purchased, sold, or generated. Since the costs being tracked through the
9 ERM are primarily energy related, it is appropriate for the retail revenue
10 credit to be based on the energy-related portion of production and
11 transmission costs reflected in retail rates.

12 Therefore, if the existing method for calculating the retail revenue credit is approved, a
13 shortfall occurs in the rate year because too much new retail revenue has been used to offset
14 variable power costs in the ERM deferral calculation. This adjustment identifies the cost of
15 that excess deferral credit in 2013, given that the existing method is approved rather than the
16 proposed method. Of course, this adjustment would be excluded if the proposed method for
17 determining the retail revenue credit rate is adopted.

18 **Q. How did you determine the cost of the excess deferral credit?**

19 A. The forecasted 2013 retail revenue credit amount was computed using both
20 the proposed retail revenue credit rate, and the rate that would have been produced by the
21 existing method (Exhibit No. ___TLK-2) page 2, line 11). The difference between the two
22 2013 ERM credit amounts is the increase to expense, as shown on Page 3 of Exhibit
23 No. ___(TLK-2). The retail revenue credit adjustment reduces net operating income
24 \$2,255,000, as shown in adjustment column 4.04 on page 10 of Exhibit No. ___(EMA-2).

25 **IV. ELECTRIC COST OF SERVICE**

26 **Q. Please briefly summarize your testimony related to the electric cost of**
27 **service study.**

1 A. I believe the Base Case cost of service study presented in this case is a fair
2 representation of the costs to serve each customer group. The Base Case study shows
3 Residential Service Schedule 1, Extra Large General Service Schedule 25 and Pumping
4 Service Schedule 31 provide less than the overall rate of return under present rates. General
5 Service Schedule 11 and Large General Service Schedule 21 provide substantially more than
6 the overall rate of return under present rates. Street and Area Lights are essentially at parity
7 with the overall rate of return under present rates.

8 **Q. Please identify the Company's electric cost studies presented to this**
9 **Commission in the last five years as required by WAC 480-07-510 (6).**

10 A. Electric cost of service studies were presented to this Commission in Docket
11 No. UE-070804, Docket No. UE-080416, Docket No. UE-090134, Docket No. UE-100467
12 and Docket No. UE-110876.

13 **Q. What is an electric cost of service study and what is its purpose?**

14 A. An electric cost of service study is an engineering-economic study, which
15 separates the revenue, expenses, and rate base associated with providing electric service to
16 designated groups of customers. The groups are made up of customers with similar load
17 characteristics and facilities requirements. Costs are assigned or allocated to each group
18 based on (among other things), test period load and facilities requirements, resulting in an
19 evaluation of the cost of the service provided to each group. The rate of return by customer
20 group indicates whether the revenue provided by the customers in each group recovers the
21 cost to serve those customers. The study results are used as a guide in determining the
22 appropriate rate spread among the groups of customers. Exhibit No. ___(TLK-3) explains

1 the basic concepts involved in performing an electric cost of service study. It also details the
2 specific methodology and assumptions utilized in the Company's Base Case cost of service
3 study.

4 **Q. What is the basis for the electric cost of service study provided in this**
5 **case?**

6 A. The electric cost of service study provided by the Company as Exhibit
7 No.__(TLK-4) is based on the twelve months ended December 2011 test year pro forma
8 results of operations presented by Ms. Andrews in Exhibit No.__(EMA-2).

9 **Q. Would you please explain the cost of service study presented in Exhibit**
10 **No. __(TLK-4)?**

11 A. Yes. Exhibit No. __(TLK-4) is composed of a series of summaries of the
12 cost of service study results. The summary on page 1 shows the results of the study by
13 FERC account category. The rate of return by rate schedule and the ratio of each schedule's
14 return to the overall return are shown on Lines 39 and 40. This summary was provided to
15 Company witness Mr. Ehrbar for his work on rate spread and rate design. The results will
16 be discussed in more detail later in my testimony.

17 Pages 2 and 3 are both summaries that show the revenue-to-cost relationship at
18 current and proposed revenue. Costs by category are shown first at the existing schedule
19 returns (revenue); next the costs are shown as if all schedules were providing equal recovery
20 (cost). These comparisons show how far current and proposed rates are from rates that
21 would be in alignment with the cost study. Page 2 shows the costs segregated into
22 production, transmission, distribution, and common functional categories. Line 44 on page

1 2 shows the target change in revenue which would produce unity in this cost study. Page 3
2 segregates the costs into demand, energy, and customer classifications. Page 4 is a summary
3 identifying specific customer related costs embedded in the study.

4 The Excel model used to calculate the cost of service and supporting schedules has
5 been included in its entirety both electronically and in hard copy in the workpapers
6 accompanying this case.

7 **Q. Given that the specific details of this methodology are described in**
8 **Exhibit No. ___(TLK-3), would you please give a brief overview of the key elements and**
9 **the history associated with those elements?**

10 A. Yes. In general, the cost study follows the methodology established in
11 Docket No. UE-920499 for Puget Sound Power and Light (now Puget Sound Energy).
12 Production and transmission costs are classified to energy and demand by a peak credit
13 analysis. The definition of “peaks” and “peak credit” specific to Avista have been accepted
14 by the Commission for Avista in Docket No. UE-991606 and confirmed in Docket No. UE-
15 050482. As I will discuss later in my testimony, the electric cost of service study presented
16 in this case includes a revision to the Avista-specific peak credit analysis.

17 Distribution costs are classified and allocated by the basic customer theory¹⁰ that was
18 derived directly from the methodology approved for Puget in Docket No. UE-920499.
19 Administrative and general costs are first directly assigned to production, transmission,
20 distribution, or customer relations functions. The Commission found this process acceptable
21 in Avista’s Docket No. UE-991606. The remaining administrative and general costs are

¹⁰ Basic customer theory classifies only meters, services and street lights as customer-related plant; all other distribution facilities are considered demand-related

1 categorized as common costs and have been allocated by a variety of factors as approved by
2 this Commission for Puget in Docket No. UE-920499. The specific factors and items they
3 are applied to are described in detail in Exhibit No. ____ (TLK-3), on pages 5 and 9.

4 **Q. Does the Company’s electric Base Case cost of service study follow the**
5 **methodology filed in the Company’s last electric general rate case in Washington?**

6 A. The methodology presented in this case is the same as that used in the study
7 presented in Docket No. UE-110876. The Base Case cost of service study was prepared
8 using the methodology applied to the study presented in Docket No. UE-050482 through
9 Docket No. UE-090134 except that the peak credit classification of production and
10 transmission costs has been revised. While a revision to the peak credit classification of
11 production and transmission costs was also proposed in both Docket No. UE-100467 and
12 Docket No. UE-110876, the cost of service methodology change was specifically not part of
13 the settlements in either case. Therefore the “Prior Methodology” continues to refer to the
14 study methodology last presented in Docket No. UE-090134.

15 **Q. Why is the Company proposing to revise the method for classifying**
16 **production and transmission costs into energy-related and demand-related**
17 **components?**

18 A. In conjunction with Docket No. UE-100467, the Company had examined the
19 Avista-specific peak credit classification methodology applied to production and
20 transmission functional costs. It was determined that the prior methodology was
21 complicated to compute and apply, unrelated to the actual usage of the system, and has a
22 tendency to shift costs back and forth between energy and demand with changes in the cost

1 of natural gas to fuel combustion turbines. The peak credit method proposed by Avista in
2 this case provides a less complex way to determine a fair apportionment of production and
3 transmission costs between energy and demand, is directly related to our system, and is
4 expected to be stable both during the pendency of a case and over time from case to case.

5 **Q. How was the prior peak credit methodology determined and applied?**

6 A. In the Company's prior cost of service studies, Avista's electric system
7 resource costs were classified to energy and demand using a comparison of the replacement
8 cost per kW of the Company's peaking units, to the replacement cost per kW of the
9 Company's thermal and hydro plants (separately). This analysis created separate peak credit
10 ratios applied to thermal plant and hydro plant. Transmission costs were assigned to energy
11 and demand by a 50/50 weighting of the thermal and hydro peak credit ratios. Fuel and load
12 dispatching expenses were classified entirely to energy, and peaking plant related costs were
13 classified entirely to demand.

14 **Q. What is the Company proposing in this case with regard to the peak**
15 **credit methodology?**

16 A. In this case the Company is proposing to use the system load factor to
17 determine the proportion of the production function that is demand-related.¹¹ This single
18 peak credit ratio is then applied uniformly to all production costs.

19 In Washington, transmission costs have traditionally been treated as an extension of
20 the generation system, therefore, the revised peak credit ratio has also been applied to
21 transmission costs in this study.

¹¹ One minus the load factor equals the demand percentage or peak credit ratio.

1 **Q. Is this the same peak credit calculation proposed in Docket No. UE-**
2 **110876?**

3 A. Yes, it is.

4 **Q. What are the benefits of using the system load factor to determine the**
5 **peak credit ratio?**

6 A. There are several benefits to the system load factor approach for identifying
7 the demand-related proportion of production costs. 1) It is simple and straightforward to
8 calculate, 2) it is directly related to the system and test year under evaluation, and 3) the
9 relationship should remain relatively stable from year to year.

10 **Q. What is the net effect of the proposed change in the peak credit method?**

11 A. The net effect of this change is to slightly increase the overall production and
12 transmission costs that are classified as demand-related. Using the prior method,
13 approximately 30.91% of total production and transmission costs (29% of total production
14 costs and 42% of total transmission costs) were classified as demand-related. Under the
15 proposed method, 34.20% of total production and transmission costs are classified as
16 demand-related. This change shifts costs away from high load factor customer groups
17 (Schedules 21/22 and 25) as well as customer groups which have a limited contribution to
18 system peak usage (pumping and street lighting).

19 **Q. What are the results of the Company's electric cost of service study**
20 **presented in this case?**

1 A. Natural gas cost of service studies were filed with this Commission in Docket
2 No. UG-110877, UG-100468, Docket No. UG-090135, Docket No. UG-080417 and Docket
3 No. UG-070805.

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

5 A. A natural gas cost of service study is an engineering-economic study which
6 separates the revenue, expenses, and rate base associated with providing natural gas service
7 to designated groups of customers. The groups are made up of customers with similar usage
8 characteristics and facility requirements. Costs are assigned in relation to each group's test
9 year load and facilities requirements, resulting in an evaluation of the cost of the service
10 provided to each group. The rate of return by customer group indicates whether the revenue
11 provided by the customers in each group recovers the cost to serve those customers. The
12 study results are used as a guide in determining the appropriate rate spread among the
13 groups of customers. Exhibit No.__(TLK-5) explains the basic concepts involved in
14 performing a natural gas cost of service study. It also details the specific methodology and
15 assumptions utilized in the Company's Base Case cost of service study.

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

18 A. The cost of service study provided by the Company as Exhibit No.__(TLK-6)
19 is based on the twelve months ended December 2011 test year pro forma results of
20 operations presented by Ms. Andrews in Exhibit No.__(EMA-3).

21 **Q. Would you please explain the cost of service study presented in Exhibit**
22 **No.__(TLK-6)?**

1 A. Yes. Exhibit No. ___(TLK-6) is composed of a series of summaries of the
2 cost of service study results. Page 1 shows the results of the study by FERC account
3 category. The rate of return and the ratio of each schedule's return to the overall return are
4 shown on lines 38 and 39. This summary is provided to Mr. Ehrbar for his work on rate
5 spread and rate design. The results will be presented later in my testimony. Additional
6 summaries show the costs organized by functional category (page 2) and classification (page
7 3), including margin and unit cost analysis at current and proposed rates. Finally, page 4 is a
8 summary identifying specific customer related costs embedded in the study.

9 The Excel model used to calculate the cost of service and supporting schedules has
10 been included in its entirety both electronically and hard copy in the workpapers
11 accompanying this case.

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

14 A. Yes, the Base Case cost of service study was prepared using the same
15 methodology applied to the study presented in Docket No. UG-110877.

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

17 A. Allocations of gas costs reflect the current purchased gas tracker
18 methodology. Underground storage costs are segregated proportionately into commodity
19 storage benefits for sales customers and load balancing benefits for all customers. Natural
20 gas main investment has been segregated into large and small mains. Large usage customers
21 that take service from large mains do not receive an allocation of small mains. Meter
22 installation and services investment is allocated by number of customers weighted by the

1 relative current cost of those items. System facilities that serve all customers are classified
2 by the peak and average ratio that reflects the system load factor, then allocated by
3 coincident peak demand and throughput, respectively. Demand side management costs (if
4 any) are treated in the same way as system facilities. General plant is allocated by the sum
5 of all other plant. Administrative & general expenses are segregated into labor-related,
6 plant-related, revenue-related, and “other”. The costs are then allocated by factors
7 associated with labor, plant in service, or revenue, respectively. The “other” A&G amounts
8 get a combined allocation that is one-half based on O&M expenses and one-half based on
9 throughput. A detailed description of the methodology is included in Exhibit No. ____ (TLK-
10 5).

11 **Q. Does this methodology follow previously-approved methods?**

12 A. Yes, with the exception of Company-specific purchased gas and related items
13 that match the PGA assumptions, the methodology I have presented here, and in prior cases
14 before this Commission, replicates the methodology established in Docket No. UG-940814
15 for Washington Natural (now Puget Sound Energy).

16 **Q. What are the results of the Company’s natural gas cost of service study?**

17 A. I believe the Base Case cost of service study presented in this filing is a fair
18 representation of the costs to serve each customer group. The study indicates that the
19 General service schedule (101 – serves most residential customers) and Transportation
20 schedule (146) are providing slightly less than the overall return (unity), and Large General,
21 High Load Factor Large General and Interruptible service schedules (111/112, 121/122 and

1 131/132) are providing slightly more than unity. All schedules are currently providing
 2 return ratios that are relatively close to unity.

3 The following table shows the rate of return and the relative return ratio at present
 4 rates for each rate schedule:

5 **Table 2**

| <u>Customer Class</u> | <u>Rate of Return</u> | <u>Return Ratio</u> |
|---|-----------------------|---------------------|
| General Service Schedule 101 | 5.04% | 0.96 |
| Large General Service Schedule 111/112 | 6.17% | 1.17 |
| Large General Service – High Annual Load Factor Schedule 121/122 | 6.40% | 1.22 |
| Interruptible Service Schedule 131/132 | 5.87% | 1.11 |
| Transportation Service Schedule 146 | <u>5.21%</u> | <u>0.99</u> |
| Total Washington Natural Gas System | <u>5.27%</u> | <u>1.00</u> |

6 The summary results of this study were provided to Mr. Ehrbar as an input into
 7 development of the proposed rates.

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

9 A. Yes.