BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE - 99- __
DOCKET NO. UG - 99- __

EXHIBIT T-58
TESTIMONY OF BRIAN J. HIRSCHKORN
REPRESENTING THE AVISTA CORPORATION

WUTC
DOCKET NO. UE-991606
EXHIBIT # T-490
ADMIT ☑ W/D ☐ REJECT ☐

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

A. My name is Brian J. Hirschkorn and my business address is East 1411 Mission Avenue, Spokane, Washington. I am presently assigned to the Rates Department as a Senior Rate Accountant.

Q. Would you briefly describe your duties?

A. My primary areas of responsibility include electric and gas rate design, customer usage and revenue analysis, and tariff administration.

Q. Would you briefly describe your educational background?

A. I graduated from Washington State University in 1978 with Bachelor degrees in Business Administration and Accounting.

Q. Have you previously testified before the Commission?

A. Yes. I have testified before this Commission in several prior rate proceedings as a revenue and rate design witness.

DOCKET NO. UE-99-___ / ELECTRIC SERVICE

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

A. My testimony in this proceeding will cover the spread of the proposed annual revenue increase of $26,253,000, or 10.4%, among the Company's electric general service schedules in the State of Washington and the design of the proposed rates within each of the schedules. I am also responsible for the revenue normalization adjustment, which includes the weather normalization and unbilled revenue adjustments.

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes. I am sponsoring Exhibit Nos. 59, 60, and 61, which were prepared under my supervision and direction.

Q. Would you please explain what is contained in Exhibit No. 59?

A. Exhibit No. 59 is a copy of the Company's present rates governing electric service in the State of Washington, which are on file with this Commission as a part of the Company's tariff, WN U-28.

Q. Turning now to Exhibit No. 60, would you please state what is contained in that Exhibit?

A. Exhibit No. 60 contains the proposed electric rates and schedules which are being filed with the Commission as a part of our revised tariff, WN U-28.

Q. Could you please explain what is contained in Exhibit No. 61?

A. Exhibit No. 61, contains information regarding the Company's proposed rate spread and rate design, which is discussed in more detail later in my testimony.

REVENUE NORMALIZATION ADJUSTMENT

Q. Would you please describe the "revenue normalization adjustment" which you have referred to?

A. The revenue normalization adjustment represents the difference between the company's actual recorded retail revenues during the test period and retail revenues on a forward-looking basis based on known and measurable changes (pro forma). The total revenue normalization adjustment increases Washington revenues by $2,544,000 and net operating income by $1,555,000, as shown in column PF8 on page 9 of Exhibit No. 28. The adjustment consists of three primary components: 1) repricing customer usage (adjusted for known and measurable changes) at present tariff rates in effect, 2) adjusting customer loads and revenue to a calendar-year basis (unbilled revenue adjustment), and 3) weather normalizing customer usage and revenue. The rates used to reprice recorded customer usage are the present tariff rates in effect including Energy Efficiency Rider Adjustment Schedule 91. The most significant factor reflected in the repricing portion of the adjustment is reflecting the expiration of the Company's Direct Access and Delivery Service (DADS) and More Options for Power Service (MOPS) pilot programs by repricing the usage for those customers at "full service" tariff rates. The repricing portion of the revenue normalization adjustment increases revenue by $1,860,000.

Q. Would you briefly describe the unbilled revenue portion of the revenue normalization adjustment?

A. Billed / recorded usage and revenue for the test period does not represent actual usage by customers during the calendar test period, i.e., customer bills issued in January 1998 include some level of usage in December 1997. Therefore, the unbilled revenue adjustment is necessary to estimate actual consumption during the calendar year. The adjustment results from a detailed examination of billed consumption during the beginning and end of the test year. The net unbilled revenue determined for the test year is then compared to the net unbilled revenue actually recorded during the year. The unbilled revenue component of the revenue normalization adjustment decreases revenues by $984,000.

Q. Why is the amount of the pro forma unbilled revenue different from the amount which was recorded on an actual basis?

A. The pro forma unbilled revenue is a more detailed estimate as compared to the amount recorded on an actual basis and utilizes the present tariff rates in effect to determine the amount of the revenue adjustment.

Q. Could you please describe the weather normalization portion of the revenue normalization adjustment?

A. The determination of the amount of kilowatt-hour (kwh) usage associated with abnormal weather during the test period is described in Company Witness Knox's testimony. I am responsible for determining the amount of revenue associated with the adjustment. For service schedules with only a single energy rate, that rate (present or proposed) is used to determine the amount of the adjustment under present and proposed rates. For Residential Schedule 1, which has multiple energy rates, a "weather sensitive rate" is determined based on the average rate for all consumption which exceeds customers' "base-load usage", or the estimated monthly amount of customer usage with no heating or cooling effect. The weather normalization portion of the revenue normalization adjustment increases revenue by $1,668,000.

RATE SPREAD

Q. Would you please describe the Company's present rate schedules and the types of electric service offered under each?

A. Yes. The Company presently provides electric service under Residential Service Schedule 1, General Service Schedules 11 and 12, Large General Service Schedules 21 and 22, Extra Large General Service Schedule 25, and Pumping Service Schedules 31 and 32. Additionally, the Company provides Street Lighting Service under Schedules 41-46, and Area Lighting Service under Schedule 47 and 48. Schedules 12, 22, 32, and 48 exist for residential and farm service customers who qualify for the Bonneville Power Administration "Residential Exchange" program. As the Company is presently not receiving any credits from the program, the rates for these schedules are identical to the rates for Schedules 11, 21, 31, and 47, respectively, therefore, the information presented for these schedules throughout the remainder of my testimony and exhibits is combined. The following table shows the type of customer and the number of customers served (as of August 1999) under each of the schedules (except street and area lighting):

Schedule	Type of Customer	No. of Customers
Residential Sch. 1	Residential	177,000
General Sch. 11&12	Small Commercial / less than 50 kw	22,400
Lge. General Sch. 21&22	Med. - Lge. Comm. & Industrial / over 50 kw	3,100
Ex. Lge. General Sch. 25	Lge. Comm. & Industrial / over 3,000 kw	21
Pumping Sch. 31&32	Agriculture & other water pumping	1,400

Q. Does the Company serve any retail special contract customers in Washington?

A. Yes, but only one. The Company provides standby electric service to the City of Spokane Waste-to-Energy Plant under a special contract, which was approved by the Commission in 1991.

Q. Could you please explain how the Company proposes to spread the overall revenue increase of $26,253,000 among the various service schedules?

A. Yes. The Company is proposing the following revenue/rate increase by service schedule:

Proposed Increase by Rate Schedule

Residential Service Schedule 1	14.0%
General Service Schedule 11	7.0%
Large General Service Schedule 21	7.9%
Extra Large General Service Schedule 25	12.6%
Pumping Service Schedule 31	12.0%
Street & Area Lighting Schedules 41-48	9.8%

This information is also shown on Page 1 of Exhibit No. 61.

Q. What rationale did the Company use in its proposed spread of the overall revenue increase to the various rate schedules?

A. The Company utilized the results of the cost of service study, as sponsored by Company Witness Knox, as a guide in developing the proposed rate spread. The primary goal of the proposed rate spread is to move the rates of return of the individual schedules closer to the Company's overall rate of return (unity) so that all customers contribute fairly to the cost of service.

The table below shows the relative rates of return by schedule before and after the proposed increases are applied. The relative rate of return is determined by dividing the rate of return for each schedule by the overall rate of return for the Company's Washington electric operations. This information is also shown on Page 2 of Exhibit No. 61.

Relative Rates of Return by Rate Schedule

	Before Increase	After Increase
Residential Service Schedule 1	0.59	0.72
General Service Schedule 11	1.67	1.45
Large General Service Schedule 21	1.56	1.37
Extra Large General Service Schedule 25	0.89	0.93
Pumping Service Schedule 31	1.02	1.02
Street & Area Lighting Schedules 41-48	1.16	1.10

As shown, the relative rates of return for all of the service schedules move approximately one-third of the way toward unity (1.00) after application of the proposed revenue increase by schedule, with the exception of Schedule 31, which is already near unity.

Q. Why isn't the present rate of return under Residential Schedule 1 closer to unity?

A. As the Commission is aware, the Company has not had a general electric rate increase since 1990. Since that time, natural gas has become the predominant fuel choice for space-heating by customers. Where electricity was the primary heating source for most residential customers in the early 1980's, it is now the primary heating source for only 21% of residential customers, whereas natural gas is the primary source for 61%. As a result, average electric use per customer has decreased by 8% since 1986, from 13,518 to 12,411 kwhs per year. During that same time, the number of residential customers served by the Company has increased by 17% whereas total residential energy and revenue has increased only 7%. With the addition of new customers, the average fixed cost of providing service to residential customers has increased. With a present basic charge of only $3.00, most of the fixed costs of providing service must be recovered through the energy charges. As average energy use (and revenue) per customer has declined and average fixed costs have increased, the rate of return for residential service has fallen from approximately 8% in 1986 to 4.6% today.

Q. Is the Company concerned with the level of increase which it is proposing to Residential Schedule 1 ?

A. Yes it is. However, as stated in Company Witness Turner's testimony, while prices for other goods and services have increased by 47% during the past 12 years, the Company's electric rates have increased by less than 4%. If the Company would have implemented an annual rate change for Residential Schedule 1 during the past twelve years, the total of which equates to the proposed increase in this filing, that annual increase would have amounted to about 1.1% per year, which would have gone relatively unnoticed in customers' bills on a year-to-year basis. During that same time period, the cost to provide electric service to residential customers has been subsidized by the rates charged to nearly all commercial and industrial customers (Schedules 11 and 21), and it is appropriate to begin to reduce this degree of subsidization in the future. While the Company is concerned with the level of the proposed increase to Schedule 1, as well as the proposed increase for Schedule 25 customers (average 12.6% increase), it is also concerned about the level of the proposed increases to commercial and industrial customers served under Schedules 11 and 21. These customers are presently paying rates well in excess of the cost of providing service, based on the Company's cost of service study. The Company faces competition for service to many new commercial and industrial customers from public utilities throughout the area it serves. The commercial and industrial rates offered by these utilities are lower than the Company's present rates, whereas their residential rates are generally higher than those offered by the Company. The proposed increases to Schedules 11 and 21, of 7.0% and 7.9% respectively, will make the Company's rates for these customers even less competitive.

Q. What would the relative rates of return by schedule be if the Company spread the proposed increase on a uniform percentage basis?

A. Shown below is a comparison of the relative rates of return under present rates, the proposed revenue increase of $26,253,000 applied on a uniform percentage basis (11.1%), and the proposed spread of the revenue increase:

	Relative Rate of Return		
	Present	Equal %	Proposed
Residential Service Sch. 1	0.59	0.67	0.72
General Service Sch. 11	1.67	1.57	1.45
Large General Service Sch. 21	1.56	1.45	1.37
Extra Large General Service Sch. 25	0.89	0.90	0.93
Pumping Service Sch. 31	1.02	1.01	1.02
Street & Area Lighting Schs. 41-49	1.16	1.13	1.10

As shown, spreading the proposed revenue increase on a uniform percentage basis would result in a slight movement toward unity in the rates of return for the individual service schedules, whereas the proposed spread results in additional movement toward unity.

Q. Why isn't the Company proposing rates which result in all rate schedules contributing a rate of return equal to the Company's proposed return (unity)?

A. The Company also considered other factors such as rate and revenue stability in its proposed spread of the overall revenue increase. The Company believes that the proposed rate spread achieves the goal of moving the individual schedule rates of return closer to unity without compromising these other rate design considerations. The following table shows the revenue increase (decrease) percentage to each schedule which would be necessary to achieve unity:

Residential Service Sch. 1	27.9%
General Service Schedule 11	(9.2)%
Large General Service Schedule 21	(7.0)%
Extra Large General Service Schedule 25	16.0%
Pumping Service Schedule 31	10.8%
Street & Area Lighting Schedules 41-49	5.6%

As shown, with an increase to Schedule 1 of approximately 28% in order to achieve unity, a phase-in toward unity will result in more rate stability for customers served under this Schedule. The Company proposes a two- or three-part phase-in of rates necessary to result in rates of return by schedule which are at or near unity, with this filing reflecting the first part of this phase-in. Because of the present disparity in the rates of return among the various schedules, coupled with the level of the total proposed revenue increase in this filing, the Company believes that the proposed (one-third) movement toward unity is reasonable in this proceeding. Additionally, different cost-of-service studies can utilize different allocation methodologies for major cost categories. As shown in Exhibit No. 52 sponsored by Company Witness Knox, the proposed rate spread will yield results which are similar when applied to other reasonable cost-of-service study results, i.e., Residential Schedule 1 will not achieve or exceed unity under a different study.

Q. When would you propose that the second part of this "two- or three-part rate phase-in" occur?

A. Further adjustment of rates toward unity could be accomplished either through future general filings or limited issue (rate spread/rate design) proceedings.

Q. Is there additional information which you propose that the Commission consider regarding the spread of the proposed increase?

A Yes. If the Commission approves a revenue increase that is less than the increase requested, the Company proposes that the Commission consider a rate spread which moves the rates of return for the Company's general service schedules closer to unity in this proceeding than the proposed one-third movement proposed by the Company.

RATE DESIGN

Q. Could you please describe what is shown on Page 3 of Exhibit No. 61?

A. Yes. Page 3 shows a comparison of the present and proposed rates within each of the Company's electric service schedules. Both the present and proposed rates include Energy Efficiency Rider Adjustment Schedule 91 and BPA Tracking Adjustment

Schedule 52. Schedule 52 was approved by the Commission in Docket No. UE-900093, effective July 1, 1990, resulting from increased costs to the Company under its WNP-1 Exchange Agreement with BPA. The Company is filing a revised Schedule 52 in this Case which is included as part of Exhibit No. 60, whereby the present rates under the Schedule have been zeroed-out and included in the Company's proposed general service tariffs.

Q. Could you please explain what is shown on Page 4 of Exhibit No. 61?

A. Page 4 shows information taken from the cost of service study sponsored by Company Witness Knox. This page shows cost per billing unit (kwh, kw, and no. of customers) information for each service schedule based on the cost allocation / assignment on the basis of energy, demand, or number of customers. Comparing these costs to the present and proposed rates under each of the Company's service schedules shown on Page 3, it is clear that much of the costs which are allocated based on demand or number of customers are recovered through the energy charges of the various schedules.

Q. Could you please describe the present rate design within Residential Schedule 1?

A. Yes. Residential Schedule 1 is presently a three-block inverted rate structure with the three blocks being from 0-600 kwhs (3.892 cents/kwh), 601-1,300 kwhs (4.673 cents/ kwh), and all kwhs over 1,300 (5.628 cents/kwh). The present monthly basic/customer charge is $3.00.

Q. Is the Company proposing to increase the basic charge?

A. Yes. The Company is proposing that the basic charge be increased to $5.00 per month.

Q. Why is the Company proposing to increase the monthly basic charge to $5.00?

A. As shown on Page 4 of Exhibit No. 61, the customer (fixed) cost assigned and allocated to each residential customer is $14.70 per month. Therefore, compared to the present basic charge of $3.00, most of the fixed costs of providing service are recovered through the energy charge(s). Further, because of the present inverted rate structure under Residential Schedule 1, much of the fixed costs of providing service to low usage customers are actually recovered from other higher usage customers served under the Schedule.

The proposed increase in the basic charge would serve to recover a more reasonable portion of the fixed costs of service from all customers. As shown on Line 5, Page 5, of Exhibit No. 61, the proposed monthly basic charge of $5.00 per month would approximately recover the average embedded cost for a service line, a meter, meter reading, and billing. The Company is not purporting that these should be the only costs recovered through the basic charge, but rather, given the total changes proposed to Schedule 1, that it is a reasonable level to establish in this case.

Q. How does the proposed level of $5.00 per month compare to the residential basic charge recently approved by the Commission for other electric utilities in the state?

A. According to their tariff dated January 1, 1999, Puget Sound Energy (PSE) presently has an effective residential basic charge of $5.28 per month.

Q. Is the Company proposing any changes to the present rate structure under Residential Schedule 1?

A. Yes. The Company is proposing a reduction in the number of energy rate blocks from three to two; the present energy tail-block (over 1,300 kwhs) would be eliminated and the proposed rate blocks would be 0-600 kwhs and over 600 kwhs.

Q. Why is the Company proposing to reduce the number of rate blocks from three to two?

A. The present inverted rate structure does not reasonably reflect the cost of providing service to residential customers. As a result of the inverted structure, many of the fixed costs of providing service are recovered through the higher-rate second and third blocks under the schedule. The Company has had the present three-block inverted rate structure in effect since 1981. This rate structure was implemented to send a price signal to residential customers that reflected the higher incremental cost of new generating resources at that time, however, the present inverted rates are no longer representative of the incremental cost of energy.

Since 1986, use per residential customer has declined by 8%. Much of this decrease was the result of a general shift from electricity to natural gas as the economical heating fuel of choice. Presently, 61% of the Company's Washington residential customers use natural gas as their primary heating fuel, while only 21% use electricity. During the mid-1980s, these numbers were essentially reversed. Where natural gas is available, nearly all new homes install gas heating equipment. Further, as gas prices fell over the past decade, many existing customers switched their heating equipment from electric to gas.

Since 1986, the number of residential customers served by the Company has increased by 17% whereas energy usage and revenue have increased only 7%. However, total energy consumption in the higher-rate second and third blocks has not increased at all since 1986. As a result, many of the costs which would be recovered through the second and third block rates assuming constant customer consumption are not being recovered at all.

Although over 61% of Washington residential customers use natural gas as their primary heating fuel, over 39,000 customers (21%) still use electricity as their primary home-heating source. Many of these customers either do not have natural gas available or cannot afford to convert to another fuel source. Applying the proposed increase to the present inverted rate structure would further increase winter heating bills for these customers, as opposed to reducing the present rate inversion as proposed.

Additionally, much of the customer usage that occurs in the second and third blocks of the Schedule is weather-sensitive, and can vary from year-to-year depending on the weather. As a result, the present inverted rate structure leads to a higher level of revenue volatility to the Company from year-to-year as compared to a flat or declining-block rate structure. This higher level of revenue volatility caused by the present inverted rate structure only exacerbates the effect which weather has on the Company's operating results.

Q. Do any other investor-owned utilities, who provide electric service in Washington, presently have an inverted residential rate structure?

A. Both PSE and Pacificorp have a two-block inverted rate structure in effect, similar to that proposed by the Company.

Q. Why isn't the Company proposing a flat/single energy rate, rather than moving only to a two-block inverted rate structure?

A. With the overall amount of the proposed increase to residential customers, together with the proposed basic charge of $5.00 per month, the Company believes that moving part way to a flat energy charge in this proceeding is reasonable. A two-part transition to a flat energy charge would phase in the effect on customers' bills over time. However, if the Commission does not approve the Company's entire proposed increase in this case, it may be reasonable to consider moving to a single energy charge in this proceeding.

Q. How did the Company determine the level of the proposed energy rates under Residential Schedule 1?

A. First, a weighted-average rate for the present second- and third-block rates was calculated. Next, the revenue increase from the proposed basic charge of $5.00 per month was subtracted from the total proposed revenue increase under the Schedule to determine the revenue increase to be spread to the energy charges. This revenue increase was then spread to the two energy block-rates on a uniform cents per kwh basis to determine the proposed energy rates.

Q. Has the Company estimated the increase to a typical residential customer based on the proposed rates?

A. Yes. Page 6, of Exhibit No. 61 shows the estimated monthly and annual increase for a typical electric heat and non-electric (gas) heat customer. As shown, the increase for an electric heat customer using 18,039 kwhs per year is estimated to be an average of $10.36 per month, and $7.13 for a non-electric (gas) heat customer using 9,842 kwhs per year.

Q. Is the Company proposing rate structure changes to any of its other service schedules?

A. The only additional rate structure change which the Company is proposing to implement is a monthly basic charge for Pumping Schedule 31, which presently contains no monthly minimum charge.

Q. Turning to General Service Schedule 11, could you please explain the present rates and charges under the Schedule and how the Company is proposing to spread the proposed increase of 7.0% among those rates and charges?

A. General Service Schedule 11 generally serves small commercial customers whose monthly peak demand is less than 50 kilowatts. The Schedule presently contains a monthly basic charge of $3.85, an energy charge of 6.360 cents/kwh, and a demand charge of 3.30/kw for kilowatts in excess of 20 each month.

The Company is proposing to increase the monthly basic charge from the present level of $3.85 per month to $5.75 per month. As shown on line 10, Page 5 of Exhibit No. 61, $5.75 per month recovers only the fixed monthly costs associated with a service line, a meter, meter reading, and billing for a Schedule 11 customer. The proposed basic charge would not contribute to any other system fixed costs. The Company is also proposing to increase the present demand charge of $3.30 per kw to $3.50 per kw. As shown on line 8, column (b) on Page 4 of Exhibit No. 61, costs which are allocated to Schedule 11 on a demand basis total $8.63/kw (at 9.93% rate of return). The proposed increase to the energy charge under the Schedule is 0.333 cents per kwh, or 5.2%.

Q. Could you please explain the present rates and charges under Large General Service Schedule 21 and how the Company is proposing to spread the proposed increase of 7.9% among those rates and charges?

A. Large General Service Schedule 21 serves commercial and industrial customers whose peak demand is between 50 and 3,000 kw per month. The present rates under the Schedule contain a monthly minimum charge of $190 for the first 50 kilowatts or less, an energy charge of 4.191 cents/kwh, and a demand charge of $2.20/kw for all kilowatts in excess of 50 each month. Primary voltage customers (served at 11 kilovolts or higher) receive a discount of 10 cents per kw.

The Company is proposing to increase the monthly minimum charge from $190 to $225 per month, and the present demand charge from $2.20/kw to $2.75/kw. As shown on line 8, column (c) on Page 4 of Exhibit No. 61, costs which are allocated to Schedule 21 on a demand basis total $8.09/kw (at 9.93% rate of return). The proposed increase to the energy charge is 0.218 cents/kwh or 5.2%. The Company is proposing to increase the present primary voltage discount from 10 cents per kw to 20 cents per kw.

At the present voltage discount rate of 10 cents per kw, there is no economic incentive for customers to take service at primary voltage, where feasible. In those instances where a customer is served at primary voltage (11 kilovolts or higher), they are required to own and maintain electric facilities (step-down transformers, conductor, etc.) on their side of the metering point. Based on a customer taking primary service with a peak demand of 1,000 kw and a 50% load factor, the customer's bill would be about $140/month higher compared to taking service at secondary voltage because of transformer losses. Additionally, as the customer is required to own and install the facilities on their side of the metering point, they will want to recover their investment through the voltage discount, which in this case, could exceed $10,000. The amount of the present monthly primary voltage discount for this customer would be about $100. Increasing the discount to the proposed level of 20 cents/kw would provide additional economic incentive for a new customer to take service at primary voltage.

Q. How many primary voltage customers does the Company presently serve?

A. The Company presently serves only 25 customers under Schedule 21 who take service at primary voltage, compared to over 3,100 total customers who take service under the Schedule. All twenty-one Schedule 25 customer accounts are served at primary voltage.

Q. Could you please explain the present rates and charges under Extra Large General Service Schedule 25 and how the Company is proposing to spread the proposed increase of 12.6% among those rates and charges?

A. Extra Large General Service Schedule 25 requires a minimum monthly demand level of 3,000 kilovolt-amperes (kva); eighteen customers (twenty-one accounts/ metering points) are presently served under the Schedule. The Schedule contains a monthly minimum charge of $5,500 for the first 3,000 kva or less, an energy charge of 3.015 cents/kwh, and a demand charge of $1.10 for all kva in excess of 3,000. There is an annual minimum charge of $397,650, which is based on 11 million kwhs multiplied by the energy rate plus the monthly minimum charge ($5,500) multiplied by 12 (months). Schedule 25 also contains a present primary voltage discount of 10 cents per kva.

The Company is proposing to increase the monthly minimum charge from $5,500 to $7,500 per month. Dividing the proposed minimum charge by the first 3,000 kva covered by the minimum charge yields an implied demand charge of $2.50 per kva. The proposed demand charge for all kva in excess of 3,000 is $2.25, as compared to the present level of $1.10/kva. Compared to the demand-related costs from the cost of service study, as shown on Page 4 of Exhibit No. 61, this implied charge is still far below the cost of service ($6.87/kw). The proposed demand charge will provide customers with a more reasonable indicator of demand-related costs and encourage them to further improve their load factor. The proposed increase to the energy charge under the Schedule is 0.233 cents/kwh or 7.7%. The proposed annual minimum charge has also been increased to $447,280 based on the same formula as the present charge. The primary voltage discount is proposed to increase from 10 cents to 20 cents/kva, as discussed above.

Q. Could you please explain the present rates and charges under Pumping Service Schedule 31 and how the Company is proposing to spread the proposed increase of 12.0% among those rates and charges?

A. Pumping Service Schedule 31 provides service for pumping water (and water effluents) for irrigation, municipal systems, and other purposes. The Schedule contains a two-block declining rate structure, with the first block being 5.526 cents/kwh and the second block being 3.722 cents/kwh. The amount of energy billed under each block is dependent upon the customer's peak demand and load factor (kwhs per kw of demand).

As Schedule 31 presently contains no monthly minimum charge, the Company is proposing to implement a monthly basic charge of $6.00. As shown on line 15 of Page 5 of Exhibit No. 21, the proposed basic charge will recover about 83% of the costs associated with a service line, a meter, meter reading, and billing. The remainder of the proposed revenue increase to the Schedule is spread equally to the two energy blocks under the Schedule, resulting in an increase of 0.411 cents/kwh.

Q. Turning to Street and Area Light Schedules 41-48, could you please explain the present rates for service and how the proposed increase of 9.8% was spread among those rates?

A. Street and Area Light Schedules contain monthly fixed charges for different light types and sizes, as well as pole types. Company-owned street lights are offered under Schedules 41 and 42, maintenance and energy for customer-owned lights is offered under Schedules 43 and 44, and energy only service is offered under Schedules 45 and 46. Company-owned area lights are offered under Schedule 47 and 48. The proposed increase of 9.8% was applied uniformly to present rates and charges for all street and area lights.

Q. Is the Company proposing any other changes to its tariffs for electric service in this case?

A. No, it is not.

DOCKET NO. UG-99-___ / NATURAL GAS SERVICE

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

A. My testimony in this proceeding will cover the spread of the proposed annual revenue increase of $4,899,000, or 6.5%, among the Company's gas general service schedules in the state of Washington and the design of the proposed rates within each of the schedules. I am also responsible for the revenue normalization adjustment, which includes the weather normalization and unbilled revenue adjustments, as well as the purchase gas cost adjustment.

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes. I am sponsoring Exhibit Nos. 62, 63, and 64, which were prepared under my supervision and direction.

Q. Would you please explain what is contained in Exhibit No. 62 entitled "Gas Rates on File and Presently in Effect"?

A. Exhibit No. 62 is a copy of the Company's present rates governing gas service in the state of Washington, which are on file with this Commission as a part of the Company's tariff, WN U-29.

Q. Turning now to Exhibit No. 63, would you please state what is covered in that Exhibit?

A. Exhibit No. 63, entitled "Proposed Gas Rates as Filed", contains the proposed gas rates and schedules which are being filed with the Commission as a part of our revised tariff, WN U-29.

Q. Would you please describe what is contained in Exhibit No. 64?

A. Exhibit No. 64 contains supplemental information regarding the spread of the proposed revenue increase to the Company's gas service schedules and the proposed rates within the schedules, which will be referred to throughout my testimony.

Revenue Normalization Adjustment

Q. Would you please describe the "revenue normalization adjustment" which you have referred to?

A. The revenue normalization adjustment represents the difference between the company's actual revenues during the test period and revenues on a forward-looking basis based on normalizing/pro forma adjustments. The adjustment includes the repricing of pro forma sales and transportation volumes at present rates using pro forma sales volumes which have been adjusted for unbilled revenue, abnormal weather, and any material customer load or schedule changes. The adjustment also includes the normalization of purchase gas costs based on pro forma retail sales volumes. The total amount of the adjustment is $1,516,000 on a net operating income basis, as shown on Page 8 of Exhibit No. 30.

The adjustment includes the elimination of "Buy-Sell" (capacity release) revenues billed to certain transportation customers and the repricing of the adjusted (pro forma) customer loads at the present rates in effect. "Buy-Sell" revenues result from releases of pipeline capacity which the Company holds title to. These releases were made to numerous Company transportation customers at 100% of Northwest Pipeline rates, prior to FERC Order 636. Because the Company bills these customers for the use of this pipeline capacity, these billings are recorded as revenue by the Company. This revenue is deferred and credited to sales customers in the Company's PGA filings, thereby reducing pipeline transportation costs. As these revenues are deferred and passed to customers, it is appropriate to eliminate them as part of the adjustment.

The rates used to price pro forma sales volumes include Schedule 150 – Purchase Gas Cost Adjustment, as this tariff represents a "permanent" change in rates. The rates used exclude temporary Gas Rate Adjustment Schedule 155, which reflects the approved amortization of deferred gas costs approved in the Company's last PGA filing.

Q. Would you please briefly describe the unbilled revenue adjustment?

A. As billed usage for the test period does not represent actual usage by customers during the calendar test period, the unbilled revenue adjustment is necessary to estimate actual consumption during the calendar year. The estimated amount of unbilled revenue is based on a detailed examination of billed consumption and meter reading days during the beginning and end of the test year. The adjustment for unbilled revenue results from subtracting this detailed estimate of unbilled revenue from the net amount of unbilled revenue actually recorded during the year.

Q. Why is the amount of the pro forma unbilled revenue adjustment different from the amount shown in the Company's actual operating results?

A. The pro forma adjustment is a more detailed estimate of unbilled revenue as compared to the estimate recorded in the Company's actual operating results. Additionally, the pro forma adjustment utilizes the present rates in effect to determine the amount of the revenue adjustment.

Q. Could you please describe the weather normalization portion of the revenue normalization adjustment?

A. The determination of the amount of gas usage associated with abnormal weather during the test period is described in Company Witness Knox's testimony. I am responsible for determining the amount of revenue associated with the adjustment using present rates in effect. The weather normalization portion of the revenue normalization adjustment increases revenue by $7,101,000, reflecting the fact that 1998 was significantly warmer than normal.

Q. Would you please explain the purchase gas cost adjustment made by the company in this filing?

A. Pro forma purchase gas costs were determined by multiplying pro forma customer usage for the test period by the purchase gas cost(s) per therm, which were approved by the Commission in the Company's last PGA filing, effective February 15,

1998. The purchase gas cost adjustment is then determined by subtracting actual gas costs during the test year from pro forma gas costs. By making this adjustment, there is a matching of the approved level of gas costs with pro forma usage for the test period. Any differences in gas costs are reflected in the Company's annual PGA filing.

Q. Is the Company proposing any changes to its present (Commission approved) allocation of purchase gas costs by service schedule in this Case?

A. No, it is not.

Rate Spread

Q. Would you please review the Company's present rate schedules and the types of gas service offered under each?

A. Yes. The Company's present Schedules 101, 111, and 121 offer firm sales service. Schedule 101 generally applies to residential and small commercial customers who use less than 200 therms/month. Schedule 111 is generally for customers who consistently use over 200 therms/month and Schedule 121 is generally for customers who use over 10,000 therms/month and have a high annual load factor. Schedule 131 provides interruptible sales service to customers whose annual requirements exceed 250,000 therms.

Schedule 146 provides transportation/distribution service for customer-owned gas for customers whose annual requirements exceed 250,000 therms. Schedule 148 is a transportation service schedule for large-requirements customers with competitive options to taking transportation/distribution service from the Company, i.e., pipeline direct-connection. It is a banded-rate schedule with the rates for service being negotiated between the Company and the customer within the rate-band. The Company has only four customer accounts served under Schedule 148: Kaiser Aluminum-Mead, Kaiser Aluminum-Trentwood, Lamb-Weston, and Mutual Materials. I will discuss these service agreements in more detail later in my testimony.

Q. The Company also has rate schedules 112, 122, and 132 on file with the Commission. Could you please explain what customers are eligible for service under these schedules?

A. Schedules 112, 122, and 132 are in place to provide service to customers who at one time were provided service under Transportation Service Schedule 146. The rates under these schedules are the same as those under Schedules 111, 121, and 131 respectively, except for the application of temporary Gas Rate Adjustment Schedule 155. Schedule 155 is a temporary rate adjustment to amortize the deferred gas costs approved by the Commission in the prior PGA. As part of the PGA, transportation service customers are analyzed individually to determine their appropriate share of deferred gas costs. If those customers switch back to sales service, the Company continues to analyze those customers individually, otherwise, those customers would receive amounts of gas costs deferrals which are not due them, thus the need for Schedules 112, 122, and 132. There are presently only five customers in total served under these Schedules.

Q. How many customers does the Company serve under each of its rate schedules?

A. As of August 1999, the Company provided service to the following number of customers under each of its schedules:

Schedule	Type of Customer	No. of Customers
General Service 101	Residential & Sm. Commercial	115,600
Lg. General Service 111	Comm. & Ind. over 200 therms/mo.	2,465
Ex. Lg. Gen. Service 121	Comm. & Ind. over 10,000 therms/mo.	41
Interruptible Service 131	Interruptible over 250,000 therms/yr.	1
Transportation Service 146	Transportation of Customer-owned Gas	34
High-Volume Transport 148	Negotiated Rate for Transpotation	4

Q. How does the Company propose to spread the overall revenue increase of $4,899,000 among its general service schedules?

A. The Company is proposing the following revenue/rate changes by rate schedule:

General Service Schedule 101	7.5%
Large General Service Schedule 111/112	4.4%
Extra Large General Service Schedule 121/122	4.6%
Interruptible Sales Service Schedule 131/132	0.0%
Transportation Service Schedule 146	8.6%
Banded Rate Transportation Schedule 148	0.0%

This information is also shown on Page 1 of Exhibit No. 64.

Q. What rationale did the Company use in its proposed spread of the overall revenue increase to the various rate schedules?

A. The Company utilized the results of the cost of service study, as sponsored by Company witness Knox, as a guide in developing the proposed rate spread. A primary goal of the proposed rate spread is to move the rates of return of the individual schedules closer to the Company's overall rate of return (unity) so that all customers contribute fairly to the cost of service and contribute a reasonable return on operating plant. The proposed spread of the increase results in a movement of the rate of return for each of all of the service schedules toward unity.

Page 2 of Exhibit No. 64 shows the rates of return for each of the Company's gas schedules before and after application of the proposed increases. Column (d) shows the relative rates of return under present rates and column (f) shows the relative rates of return under proposed rates. The relative rate of return is determined by dividing the rate of return for each schedule by the overall rate of return for the company's Washington gas operations.

The relative rates of return before and after application of the proposed increases by schedule are as follows:

	Before	After
Schedule 101:	0.95	0.98
Schedule 111:	1.15	1.08
Schedule 121:	0.77	0.89
Schedule 131:	1.57	1.18
Schedule 146:	1.19	1.08
Schedule 148:	1.15	0.86

As shown, the relative rates of return for all schedules move closer to unity (1.00), with the exception of Transportation Schedule 148, which I will discuss later in my testimony.

Q. What would be the increase in the typical residential customer's bill based on the Company's proposed increase for Schedule 101?

A. The increase for a typical residential customer using 80 therms of gas per month would be $2.74 per month, or an increase from $36.04 per month to $38.78 per month.

Q. How do the Company's proposed rates for Schedule 101 compare to the residential rates for other utilities who provide gas service in the state of Washington?

A. Page 3 of Exhibit No. 64 shows the monthly bill for a residential gas customer using 80 therms under the present rates for each of the gas utilities serving in the state, as well as the proposed rates in this case. Also shown is the average margin (rate less gas costs) per residential therm for each of the utilities. As shown, even under the proposed rates for Schedule 101, the average monthly bill, as well as the resulting margin, for an Avista residential customer would still be considerably lower than that for the other gas utilities providing service in the state.

Q. Why isn't the Company proposing any overall revenue increase to Interruptible Service Schedule 131 or (Banded-Rate) Transportation Schedule 148?

A. Presently there is only one customer being served under Interruptible Service Schedule 131. As previously shown, the present rate of return being provided by this customer is 57% higher than unity. Even after application of the overall proposed increase, with no increase applied to Schedule 131, the rate of return for the Schedule would still be 18% above unity. Further, the present rate for service under Interruptible Service Schedule 131 is higher than the present tail-block rate under firm sales service Schedule 121. Obviously, it makes no sense for a customer to pay a higher rate for a lower level of service. Under the proposed rates, the rate for service under Schedule 131 is slightly lower than the tail-block rate under Schedule 121, thereby better aligning the rates with the level of service provided. With regard to Schedule 148, the rates for the four customer accounts served under the Schedule are fixed during the terms of those Agreements and the Company does not have the ability to alter those rates except for any adjustments as provided for under the Agreements. The rates charged to these customers were negotiated in good faith based on the estimated cost for the customer to bypass the Company's distribution system and direct-connect to the nearest pipeline transporter. The Agreements for the two Kaiser Aluminum Plants served under Schedule 148 were approved by the Commission in its Third Supplemental Order in Docket UG-901459, issued March 9, 1992. Those Agreements are for a term of nine years, expiring in 2001, at a distribution rate of 2.8¢/therm. The Agreement with Lamb-Weston, which is a food-processor located near Connell, Washington, had a primary term of five years, September 1993 through August 1998, at a distribution rate of 3.35¢/therm. The Agreement is presently on a year-to-year basis at a distribution rate of 3.50¢. The Agreement with Mutual Materials, which is a masonry manufacturer located in the Spokane Valley, is a seven-year agreement which was negotiated in 1998, and provides for distribution rates of 3.168¢/therm for the first 2.5 million therms/year and 2.1¢/therm for all volumes used over 2.5 million. These Agreements, as well as related supporting documents, are provided as part of my workpapers submitted with this filing.

Schedule 148 customers provide revenues which not only recover their direct costs of providing service, but they make a substantial contribution to the fixed costs of providing service to all gas customers; for example, annual A&G expenses allocated to Schedule 148 in the company's cost of service study are $613,000.

Q. If all four Schedule 148 accounts were lost to the Company via their direct-connection to a pipeline transporter, what would be the lost revenue/margin to the

Company?

A. If all four accounts were lost to direct-connect, the lost revenue/margin would be approximately $1.3 million per year, most of which are fixed costs which would need to be recovered from other customers.

Rate Design

Q. Could you please explain what is shown on Page 4 of Exhibit No. 64?

A. Yes. Page 4 shows a comparison of the present and proposed rates within each of the Company's gas service schedules. The rates contained in Purchase Gas Cost Adjustment Schedule 150 have been incorporated into the present and proposed rates shown on Page 4. Further, a revised Schedule 150 is filed as part of Exhibit No. 63, whereby the present rates under the Schedule have been zeroed-out and included in the Company's proposed general service tariffs.

Q. Could you please explain the present rate design of the Company's gas service schedules?

A. General Service Schedule 101 generally applies to residential and small commercial customers who use less than 200 therms/month. The schedule contains a single rate per therm for all gas usage and a monthly customer/basic charge.

Large General Service Schedule 111 has a three-tier declining-block rate structure and is generally for customers who consistently use over 200 therms/month. The schedule consists of a monthly minimum charge for the first 200 therms or less, and block rates for 201-1,000 therms/month and usage over 1,000 therms/month.

Extra Large General Service Schedule 121 has a four-tier declining-block rate structure with a monthly minimum charge for the first 500 therms or less, and block rates for 501-1000 therms/month, 1,001-10,000 therms/month, and usage over 10,000 therms/month. There is also an annual minimum of 60,000 therms under the schedule and a minimum load factor requirement of approximately 58%.

Interruptible Sales Service Schedule 131 has a single rate for all usage and an annual minimum charge based on a usage requirement of 250,000 therms per year.

Transportation Service Schedule 146 consists of a two-block rate structure for all volumes with a monthly customer charge of $164.88 and an annual minimum charge based on 250,000 therms per year.

Transportation Service Schedule 148 is a banded rate schedule with a monthly customer charge of $200 per month and individually negotiated rates for customers with competitive options which must fall within the rate band.

Q. Is the Company proposing any changes to the present rate structures contained in its gas service schedules?

A. Yes, but only one. The Company is proposing a four-tier declining-block rate schedule for Transportation Service Schedule 146, in place of the present two-block rate structure. I will discuss this proposed change in more detail later in my testimony.

Q. You stated earlier in your testimony that the Company is proposing an overall increase of 7.5% to the rates of General Service Schedule 101. Is the Company proposing an increase to the present basic/customer charge of $4.00/month under the schedule?

A. Yes, it is. The Company is proposing that the basic charge be increased from $4.00 to $5.00 per month. Approximately half of the cost of providing gas service to sales customers represents costs other than the cost of the gas itself, many of which are fixed costs which do not vary with customer usage. Page 5 of Exhibit No. 64 shows the monthly cost associated only with meters, meter reading, billing, and service lines, as extracted from the Company's cost of service study. The service line provides a connection from the distribution main, which typically runs along side the street in front of a customer's residence, to the customer's meter. As shown, these costs average $10.17 per customer per month; therefore, the proposed basic charge of $5.00 would only recover about half of these basic fixed costs required to provide service. The Company believes that the basic charge should, at a minimum, recover these costs. However, given the level of the overall increase proposed in this filing, the Company believes that the proposed increase is reasonable.

Q. Given the proposed increase to the basic charge, what is the resulting increase to the rate per therm under Schedule 101, in order to achieve an overall revenue increase of 7.5%?

A. The proposed increase to the energy rate under the schedule is 2.167 cents per therm, or a 5.4% increase in the rate.

Q. Could you please explain the proposed changes in the rates for Large and Extra Large General Service Schedules 111 and 121?

A. The present rates for Schedules 101, 111, and 121 provide a clear and logical distinction for customer placement: customers who use less than 200 therms/month should be placed on Schedule 101, customers who use between 200 and 10,000 therms per month should be placed on Schedule 111, and only those customers who use over 10,000 therms per month should be placed on Schedule 121. Not only do the rates provide a guide for customer schedule placement, they provide a reasonable classification of customers for analyzing the costs of providing service.

The Company's proposed rates for Schedules 111 and 121 will maintain the rate structure within the schedules and continue to ensure appropriate schedule placement for customers and provide a reasonable classification for cost analysis. The proposed minimum charge for Schedule 111 for 200 therms or less was derived by multiplying the proposed Schedule 101 rate per therm by 200 and adding the proposed customer charge of $5.00. The remaining proposed revenue increase for Schedule 111 was then spread on an equal cents per therm basis (1.32 cents) to the remaining two rate blocks under the Schedule.

For Schedule 121, the minimum charge for 500 therms or less was derived by multiplying the proposed Schedule 101 rate per therm by 500 and adding the proposed customer charge of $5.00. The second and third block rates were then set equal to the corresponding block rates under Schedule 111. The remaining revenue increase for the Schedule was then used to determine the increase to the tail-block rate under the Schedule (1.506 cents).

Q. You mentioned previously that the Company is proposing a change in the rate structure for Transportation Service Schedule 146. Could you please explain the proposed change.

A. As shown on Page 4 of Exhibit No. 64, the Company is proposing a four-tier declining-block rate as compared to the present two-block structure. In addition, the Company is proposing that the monthly customer charge be increased from the present level of $164.88 to $200.00, which matches the present customer charge under Banded-

Rate Transportation Schedule 148. The proposed rates and structure under Schedule 146 will more reasonably reflect the margins (rate less embedded gas costs) provided under the rates for sales service Schedules 111 and 121, thereby reducing the potential margin effects (gain or loss) of customers shifting between sales and transportation service.

The Company presently serves approximately eighteen firm sales customers who qualify for transportation service (250,000 therms/year). Under present rates, the Company could potentially lose approximately $140,000 in annual margin if those customers were to switch to transportation service. Comparing the margins under the proposed sales rates to the present transportation rates, if all of those customers switched to transportation the Company could potentially incur an annual lost margin of approximately $247,000. Under the proposed rate structure for Schedule 146, the potential lost margin is reduced to $91,000 per year. The proposed transportation rates provide nearly an equal amount of margin as compared to the proposed rates under Schedule 121 for a customer using 250,000 therms per year, which is the minimum annual usage requirement under Transportation Schedule 146.

Q. Do all of the other gas utilities operating in Washington have declining-block rates with several steps under their transportation service schedules?

A. Yes, they do.

Q. Have you estimated the effect of the proposed rates for Schedule 146 on the annual bills of your various transportation customers?

A. Yes. Page 6 of Exhibit No. 64 shows the estimated effect on each of our 29 transportation customers annual gas bill, based on their 1998 usage. Column (b) shows the estimated increase (decrease) in their total gas bill on a percentage basis, including an estimated commodity price of 25¢/therm (delivered to Avista's system). As shown in column (b), the estimated effect ranges from a decrease of 0.8% to an increase of 8.9%.

Q. Does the proposed rate structure for Schedule 146 reasonably reflect the cost of providing service to the various customers served under the Schedule?

A. Yes. As previously mentioned, the proposed rates under Schedule 146 are similar to the proposed rates/margins and rate structure under the Company's sales schedules. All transportation revenue contributes to the recovery of Company gas distribution and other operating costs, as the Company does not purchase gas to serve these customers. Smaller-use customers are more expensive to serve on a per therm basis as compared to larger-use customers as there is a significant fixed amount of distribution investment required to serve even a small customer. The investment required to serve a customer is not linear with the amount of the customer's usage, in fact, the incremental amount of investment required for each additional therm of use is a declining curve, which is generally the rationale for declining-block rates.

Q. Is the Company proposing any other changes to Transportation Schedule 146?

A. Yes. Because of the proposed four-block rate structure, a modification to the present annual minimum under the Schedule is necessary. Under the proposed Schedule, customers failing to use the annual minimum requirement of 250,000 therms will be billed an annual minimum deficiency based on 250,000 therms less their actual usage multiplied by 6.4 cents/therm, which is the proposed second-block rate.

Q. Is the Company proposing any other changes to its tariffs for natural gas service?

A. Yes. Northwest Pipeline has recently received FERC approval of revised daily overrun and underrun penalties. Prior to these revisions, Northwest Pipeline did not have underrun penalties and overrun penalties were a fixed rate per therm based on the degree/percentage of daily overrun. The level of overrun penalties included in the Company's present tariffs (Schedules 131, 132, 146, and 148), are based on two times Northwest Pipeline's previous fixed rate per therm penalties (as proposed by the Commission Staff and approved by the Commission in Docket No. UG-901459). The overrun penalties contained in the Company's proposed tariffs (Schedules 131, 132, 146, and 148) maintain the (two-times) fixed rate per therm penalty imposed by Northwest Pipeline and add the additional penalty provisions contained in the recently revised Pipeline tariffs. The revised Pipeline penalty provisions for underruns are included verbatim in the Company's proposed transportation Schedules 146 and 148.

Q. Does that complete your direct testimony in this proceeding?

A. Yes, it does.