Exhibit No. ___(PDE-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-11_____

DOCKET NO. UG-11_____

DIRECT TESTIMONY OF

PATRICK D. EHRBAR

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Patrick D. Ehrbar and my business address is 1411 East Mission Avenue, Spokane, Washington. I am presently assigned to the State and Federal Regulation Department as Manager of Rates and Tariffs.

Q. Would you briefly describe your duties?

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

Q. Please briefly describe your educational background and professional experience?

A. I am a 1995 graduate of Gonzaga University with a Bachelors degree in Business Administration. In 1997 I graduated from Gonzaga University with a Masters degree in Business Administration. I started with Avista in April 1997 as a Resource Management Analyst in the Company's DSM department. Later, I became a Program Manager, responsible for energy efficiency program offerings for the Company's educational and governmental customers. In 2000, I was selected to be one of the Company's key Account Executives. In this role I was responsible for, among other things, being the primary point of contact for numerous commercial and industrial customers, including delivery of the Company's site specific energy efficiency programs.

I joined the State and Federal Regulation Department as a Senior Regulatory Analyst in 2007. Responsibilities in this role included being the discovery coordinator for the Company's rate cases, line extension policy tariffs, as well as miscellaneous regulatory issues. In November 2009, I was promoted to my current role.

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 electric revenue increase of $38,274,000, or 9.1%, among the Company's electric general service schedules. This represents an overall increase of 8.7% in billed revenues as explained below. With regard to natural gas service, I will describe the spread of the proposed annual revenue increase of $6,207,000, or 4.0% on both a base and billed basis, among the Company's natural gas service schedules. My testimony will also describe the changes to the rates within the Company's electric and natural gas service schedules, as well the proposed increase in the basic charge for electric rate Schedule 1 and natural gas rate Schedule 101. I will also describe the Company's proposed Energy Efficiency Load Adjustment as well as address the rate schedule applicability in the Company's Natural Gas Decoupling Mechanism. Finally, I will provide an overview of the items required of the Company in Order No. 7, and the related Settlement Stipulation, in Dockets UE-100467 and UG-100468.

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

A. Yes. I am sponsoring Exhibit Nos.___(PDE-2), ___(PDE-3), and ___(PDE-4) related to the proposed electric increase, and Exhibit Nos.___(PDE-5), ___(PDE-6), and ___(PDE-7) related to the proposed natural gas increase. I am also sponsoring Exhibit No. ___(PDE-8) relating to the Company's proposed Energy Efficiency Load Adjustment. These exhibits were prepared by me or under my supervision.

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II. EXECUTIVE SUMMARY

Proposed Electric Increase

Q. What is the proposed electric revenue increase in this case and how is the Company proposing to spread the total increase by rate schedule?

A. The proposed electric increase is $38,274,000, or 9.1% over present base tariff rates in effect. The proposed general increase over present billing rates, including all other rate adjustments (DSM and Residential Exchange), is 8.7%. The proposed general increase of $38,274,000 has been spread by rate schedule using the Company's cost of service study results, as discussed by Company witness Ms. Knox, as a guide. The proposed percentage increase by rate schedule is as follows:

Table 1 - Proposed % Electric Increase by Schedule

Rate Schedule	**Increase in Base Rates**
Residential Schedule 1	9.4%
General Service Schedule 11	8.9%
Large General Service Schedule 21	9.1%
Extra Large General Service Schedule 25	7.9%
Pumping Service Schedule 31	9.5%
Street & Area Lights Schedules	9.1%
Overall	**9.1%**

This information is shown with more detail on page 1, of Exhibit No.___(PDE-4).

Q. What is the proposed increase for a residential electric customer with average consumption?

A. The proposed increase for a residential customer using an average of 977 kWhs per month is $7.13 per month, or a 9.3% increase in their electric bill. The present bill for 977 kWhs is $77.01 compared to the proposed level of $84.14, including all rate adjustments. The Company is also proposing to change the basic charge from $6.00 per month to $9.00 per month.

Q. Is the Company proposing any changes to the present rate structures within its electric service schedules?

A. No. The Company is not proposing any changes to the present rate structures within its electric schedules.

Q. Where do you show the proposed changes in rates within the electric service schedules?

A. This information is shown in detail on page 3 of Exhibit No.___(PDE-4).

Proposed Natural Gas Increase

Q. How is the Company proposing to spread the overall natural gas increase of $6,207,000, or 4.0% by service schedule?

A. The Company is proposing the following base revenue changes by rate schedule[1]:

Table 2 - Proposed % Natural Gas Increase by Schedule	
Rate Schedule	**Increase in Base Rates**
General Service Schedule 101	5.0%
Large General Service Schedule 111	1.1%
Ex. Lg. General Service Schedule 121	1.5%
Interruptible Sales Service Schedule 131	1.8%
Transportation Service Schedule 146	4.4%
Overall	**4.0%**

This information is also shown on page 1 of Exhibit No.___(PDE-7). The Company utilized the results of the natural gas cost of service study, sponsored by Witness Knox, to spread the overall revenue increase to its natural gas service schedules.

Q. What is the proposed monthly increase for a residential natural gas customer with average usage?

A. The increase for a residential customer using an average of 67 therms of natural gas per month would be $3.26 per month, or 5.1%. A bill for 67 therms per month would increase from the present level of $63.45 to a proposed level of $66.71. The Company is also proposing to change the basic charge from $6.00 per month to $9.00 per month.

III. PROPOSED ELECTRIC REVENUE INCREASE

Summary of Electric Rate Schedules and Tariffs

Q. Would you please explain what is contained in Exhibit No.___(PDE-2)?

[1] For Schedule 146, including an estimate of 40.0 cents per therm for the cost of gas and pipeline transportation, the proposed increase to Schedule 146 rates represents an average increase of 0.7% in those customers' total gas bill.

A. Yes. Exhibit No.___(PDE-2) contains a copy of the Company's present electric tariffs/service schedules.

Q. Could you please describe what is contained in Exhibit No.___(PDE-3)?

A. Yes. Exhibit No.___(PDE-3) contains the proposed electric tariff sheets incorporating the proposed changes included in this filing.

Q. What is contained in Exhibit No._(PDE-4)?

A. Exhibit No.___(PDE-4) contains information regarding the proposed spread of the electric revenue increase among the service schedules and the proposed changes to the rates within the schedules. Page 1 shows the proposed general revenue and percentage increase by rate schedule compared to the present revenue under base tariff and billing rates. Page 2 shows the rates of return and the relative rates of return for each of the schedules before and after application of the proposed general increase. Page 3 shows the present rates under each of the rate schedules, the proposed changes to the rates within the schedules, and the proposed rates after application of the changes. These pages will be referred to later in my testimony.

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 Schedules 47-48. Schedules 12, 22, 32, and 48 exist for residential and farm service customers who qualify for the Residential

Exchange Program operated by the Bonneville Power Administration. The rates for these schedules are identical to the rates for Schedules 11, 21, 31, and 47, respectively, except for the Residential Exchange rate credit.

The following table shows the type and number of customers served in Washington (as of December 2010) under each of the service schedules:

Table 3 - Customers by Service Schedule

Rate Schedule	No. of Customers
Residential Schedule 1	202,151
General Service Schedule 11/12	27,700
Large General Service Schedule 21/22	3,232
Extra Large General Service Schedule 25	22
Pumping Service Schedule 31/32	2,388

Proposed Electric Rate Spread

Q. How does the Company propose to spread the total general revenue increase request of $38,274,000 among its various rate schedules?

A. The Company is proposing that the overall requested revenue increase be spread on the following basis:

Table 4 - Proposed % Electric Increase by Schedule

Rate Schedule	Increase in Base Rates
Residential Schedule 1	9.4%
General Service Schedule 11	8.9%
Large General Service Schedule 21	9.1%
Extra Large General Service Schedule 25	7.9%
Pumping Service Schedule 31	9.5%
Street & Area Lights Schedules	9.1%
Overall	**9.1%**

This information is shown with more detail on Page 1 of Exhibit No.___(PDE-4).

Q. What rationale did the Company use in developing the proposed general increase by rate schedule?

A. The Company used the results of the cost of service study (sponsored by Ms. Knox) as a guide to spread the general increase. The spread of the proposed increase generally results in the rates of return for the various service schedules moving approximately one-fifth closer to the overall rate of return (unity). The table below shows the relative rates of return (schedule rate of return divided by overall rate of return) before and after application of the proposed general increase, as well as the relative rate of return based on the application of the base rate increase on a uniform percentage basis (9.1%) to all rate schedules:

Table 5 -Present & Proposed Relative Rates of Return

Rate Schedule	Present Relative ROR	Proposed Relative ROR	Uniform Percentage ROR
Residential Schedule 1	0.63	0.71	0.70
General Service Schedule 11	1.96	1.77	1.78
Large General Service Schedule 21	1.49	1.39	1.39
Extra Large General Service Schedule 25	0.74	0.79	0.83
Pumping Service Schedule 31	0.92	0.93	0.92
Street & Area Lights Schedules	1.47	1.32	1.32
Overall	**1.00**	**1.00**	**1.00**

As shown, for those schedules where the present rates are substantially above or below the cost of service, the proposed rate spread provides some movement towards unity (1.00).

Q. Looking at the results in the table above, it appears that the relative rates of return aren't substantially different under the Company's proposed rate spread compared to a uniform percentage application. Why isn't the Company just proposing to spread the general increase on a uniform percentage basis to the rate schedules?

A. As explained by Ms. Knox, Avista completed a load study in 2010, and incorporated the results of that study into its cost of service study. In addition, Ms. Knox also explains a change to the peak credit methodology for demand allocation. While we believe it is reasonable and appropriate to use the cost of service study results as the basis for rate spread, we have tempered the amount of movement toward unity proposed in this case due primarily to the overall level of the proposed increase. Our proposal represents approximately a one-fifth movement toward unity, and slightly greater movement toward unity than would occur with the application of a uniform percentage increase across rate schedules. The Company would plan to propose additional movement toward unity in future proceedings.

Proposed Rate Design

Q. Where in your Exhibit do you show a comparison of the present and proposed rates within each of the Company's electric service schedules?

A. Page 3 of Exhibit No.___(PDE-4) shows a comparison of the present and proposed rates within each of the schedules, which I will describe below. Column (a) shows the rate/billing components under each of the schedules, column (b) shows the base tariff rates within each of the schedules, column (c) shows the present rate adjustments applicable under each schedule, and column (d) shows the present billing rates. Column (e) shows the proposed general rate increase to the rate components within each of the schedules, column (f) shows the proposed billing rates and column (g) shows the proposed base tariff rates.

Q. Is the Company proposing any changes to the existing rate structures

within its rate schedules?

A. No, it is not.

Q. Turning to Residential Service Schedule 1, could you please describe the present rate structure under this schedule?

A. Yes. Residential Schedule 1 has a present customer or basic charge of $6.00 per month and three energy rate blocks: 0-600 kWhs, 601-1,300 kWhs and over 1,300 kWhs. The present base tariff rate for the first 600 kWhs per month is 6.627 cents per kWh, 7.710 cents per kWh for the next 700 kWhs and 9.037 cents for all kWhs over 1,300.

Q. How does the Company propose to spread the proposed revenue increase of $17,659,000 to Schedule 1?

A. The proposed increase to the energy rate for the first block is 0.398 cents/kWh, 0.463 cents per kWh for the second block and 0.542 cents per kWh for the tail-block. The proposed rates for the three block rates reflect a uniform percentage increase of 6.0%.

Q. Why is the Company proposing to increase the monthly customer charge from $6.00 to $9.00 per month?

A. A substantial portion of the Company's costs are fixed and do not vary with the amount of energy used by customers. As reflected in this filing, the cost of operating and maintaining our electric system is increasing. The Company believes it is important that rates better reflect these increasing costs to serve customers. Later in my testimony I will provide greater detail as to why the Company believes the monthly customer charge should increase by $3.00 per month.

Q. What is the average monthly electric usage for a residential customer, and what is the effect of the proposed increase on a customer's bill?

A. The average monthly usage for a residential customer is approximately 977 kWhs. Based on the proposed increase, the average monthly increase would be $7.13, or 9.3%. The present monthly bill for 977 kWhs of usage is $77.01 and the proposed monthly bill would be $84.14.

Q. Turning to General Service Schedule 11, could you please describe the present rate structure and rates under that schedule?

A. Yes. The present rate structure under the schedule includes a monthly customer charge of $10.00, an energy rate of 10.037 cents per kWh for all usage up to 3,650 kWhs per month, and an energy rate of 9.393 cents per kWh for usage over 3,650 kWhs per month. There is also a demand charge of $5.00 per kW for all demand in excess of 20 kW per month. There is no charge for the first 20 kW of demand.

Q. How is the Company proposing to apply the proposed general revenue increase of $3,877,000 to the rates under Schedule 11?

A. The Company is proposing that the customer charge be increased by $2.00, from $10.00 to $12.00 per month. In addition, the Company is proposing that the demand charge (over 20 kW) be increased $0.75 per kW, from $5.00 to $5.75. The Company is proposing not only to recover the remaining revenue requirement in the first block, but is also proposing to move additional revenue recovery from the second block to the first block. The proposed rate for the first block is $0.11198 per kWh, an increase of $0.01161 per kWh, and the proposed rate for the second block $0.08312 per kWh, a reduction of $0.01081 per kWh. Finally, the Company is proposing to increase the minimum charge for 3-phase service from $13.10 to $19.35.

Q. Please explain the proposed changes to the block rates for Schedule 11?

A. Currently, present rates under Schedule 11 result in a higher average kWh charge to larger-use customers than smaller-use customers with the same load factor. Generally, larger-usage customers under the Schedule are less costly to serve than smaller-usage customers on a cost per kWh basis, as fixed costs are spread over a larger base of usage. A lower incremental or average rate for service to larger use customers under a Schedule generally is supportable on a cost of service basis. The proposed changes to the rates in Schedule 11 will resolve this issue. Table 6 below shows the average rate per kWh for several different demand, load factor and energy-usage scenarios, which I will refer to as customer scenarios:

Table 6 - Present and Proposed Schedule 11 Bills & Effective kWh Rates

Line #	kW Demand	Load Factor	Monthly kWhs	Bill Under Present Rates	Effective kWh	Bill under Proposed Rates	Effective kWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	20	25%	3,650	$376.35	$0.10311	$420.73	$0.11527
2	30	25%	5,475	$597.77	$0.10918	$629.92	$0.11505
3	40	25%	7,300	$819.20	$0.11222	$839.12	$0.11495
4	20	50%	7,300	$719.20	$0.09852	$724.12	$0.09919
5	30	50%	10,950	$1,112.04	$0.10156	$1,085.00	$0.09909
6	40	50%	14,600	$1,504.88	$0.10307	$1,445.89	$0.09903

Column (e) shows the average rate per kWh under present rates and column (g) shows the average rate under the proposed rates. Lines 1-3 show three different customer scenarios with different usage levels, but all with a 25% load factor. Lines 4-6 show three customer scenarios with different usage levels, but with a 50% load factor. As shown in column (e), a higher-use customer always pays a higher average rate than a smaller-use customer with a similar load factor. Not only does it not seem fair to charge a higher effective kWh rate to higher-use customers, but it may also drive these customers to use more energy than they otherwise would have for purposes of qualifying for Schedule 21 which could result in a lower effective kWh rate.

Q. What are the causes of this rate design problem for Schedule 11?

A. I believe there are two primary causes. First, since the Company instituted the second block for Schedule 11 in January 2006, the rate differential between the first block and the second block has been relatively small on a percentage basis. For example, the differential based on current base rates between the blocks for Schedule 11 is approximately 6.4%. For comparison purposes, the rate differential for Schedule 21, which is also a two block declining rate structure, is approximately 10.6%. The result of the current rate structure is that as a customer moves into the second block, they do not receive much of a rate discount, even though generally a larger-use customer is less expensive to serve than a smaller-use customer.

The second cause of this problem is the current rate structure as it relates to demand charges. Schedule 11 customers are not charged for their first 20 kW of demand. Demand in excess of 20 kW are charged $5.00 per kW in current rates. Under the current rate structure, high use customers pay the incremental demand charge, and when coupled with a relatively narrow rate spread between the blocks, this results in a higher average rate for higher-use customers than smaller-use customers.

Q. What is the rate impact to customers on Schedule 11 from the Company's proposed rate design?

A. Table 7 below shows the impact to various customers on Schedule 11:

Table 7 - Schedule 11 Bill Impact

kW Demand	Load Factor	Monthly kWhs	Bill Under Present Rates	Bill Under Proposed Rates	% Increase
20	25%	3650	$376.35	$420.73	11.8%
30	25%	5475	$597.77	$629.92	5.4%
40	25%	7300	$819.20	$839.12	2.4%
20	50%	7300	$719.20	$724.12	0.7%
30	50%	10950	$1,112.04	$1,085.00	-2.4%
40	50%	14600	$1,504.88	$1,445.89	-3.9%

The proposed rate design results in a bill decrease for larger-use customers on Schedule 11, and a slightly higher bill increase for lower use customers than the Company's overall requested percentage increase in this case.

Q. Does the proposed rate design change improve a customer's transition from Schedule 11 to Schedule 21?

A. Yes, it does. Currently the difference in the present rates under Schedule 11 and Schedule 21 is substantial. There are a number of large customers served under Schedule 11 that are similar in size and usage to smaller Schedule 21 customers. Because of this rate differential, a customer switching from Schedule 11 to Schedule 21 can see a lower annual energy bill under present rates, which represents a revenue/margin loss to the Company until it is recovered as a result of a general rate change. This rate disparity may also cause customers to increase their usage in order to qualify for Schedule 21, which is inconsistent with the goals of energy efficiency. Therefore, the Company's proposed rate design change will result in lower effective per kWh rates for larger customers which are closer to Schedule 21 effective per kWh rates.

Q. Does the proposed rate design change for Schedule 11 result in an inappropriate price signal in the second block for customers?

A. No, it does not. Column (g) of Table 6 shows the effective kWh rate for the various customer scenarios discussed earlier. Even with the proposed rate design changes, the effective kWh rate for larger Schedule 11 customers is 9.9 cents per kWh. In looking at the second block in isolation, the rate of 8.3 cents is higher than the Company's levelized 20 year new resource cost forecast of 7.9 cents per kWh[2].

Q. Why is the Company proposing a 15% increase to the demand charge for Schedule 11?

A. The system allocated demand cost from the cost of service study is approximately $16.41 per kilowatt (kW) month[3]. The Company's present monthly demand charges range from $4.75–$5.75/kW, depending on service schedule. While the exact level of costs classified as demand-related can be debated, clearly the levels of demand charges will continue to be well below demand-related costs.

In addition, the Company's transmission and distribution system is constructed to meet the collective peak demand of its customers. Further, the Company must have adequate resources available to meet peak demand. If customers reduce their peak demand, it will reduce the need for additional investment in these facilities and resources. Customers need to receive the proper price signal to encourage a reduction in their peak demand, i.e., higher demand charges.

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[2] 2009 Avista Electric Integrated Resource Plan, Page 7-1. (See Exhibit No. ___(RJL-2)) The forecast shows $79.56 per mWh.

[3] Exhibit No. ___(TLK-4), page 3, line 28

For these reasons, the Company believes that it is important to increase the demand charge in this case for Schedule 11, as well as for Schedules 21 and 25, by a percentage greater than that applied to the energy rates. If demand charges are not increased at least proportionately with energy charges, customers who have a poor load factor (high peak demand compared to average energy use) would see a lower percentage increase in their bill than a comparable customer with a good load factor (low peak demand compared to average energy use). This result would not send the appropriate price signal to commercial and industrial customers, nor would it reflect the fact that the Company's demand charges are well below the costs associated with meeting customers' peak demand.

Q. Turning to Large General Service Schedule 21, would you please describe the present rate structure under that schedule and how the Company is proposing to apply the increase of $11,051,000 to the rates within the schedule?

A. Yes. Large General Service Schedule 21 consists of a minimum monthly charge of $350.00 for the first 50 kW or less, a demand charge of $4.75 per kW for monthly demand in excess of 50 kW, and two energy block rates: 6.572 cents per kWh for the first 250,000 kWhs per month, and 5.876 cents per kWh for all usage in excess of 250,000 kWhs.

The Company is proposing that the present minimum demand charge (for the first 50 kW or less) be increased by $50 per month, from $350.00 to $400.00, and the demand charge for kW over 50 per month be increased by $0.50 per kW, from $4.75 to $5.25, for reasons provided previously in my testimony. The remaining revenue increase for the schedule is proposed to be recovered through a uniform percentage increase of approximately 8.2% applied to the two energy block rates. The proposed increase for the first 250,000 kWhs used per month under the schedule is 0.538 cents per kWh, and an increase of 0.482 cents per kWh for usage over 250,000 kWhs per month.

Q. Turning to Extra Large General Service Schedule 25, would you please describe the present rate structure under that schedule and how the Company is proposing to apply the increase of $4,283,000 to the rates within the schedule?

A. Yes. Extra Large General Service Schedule 25 consists of a minimum monthly charge of $12,500.00 for the first 3,000 kVa or less, a demand charge of $4.00 per kVa for monthly demand in excess of 3,000 kVa, and three energy block rates: 5.218 cents per kWh for the first 500,000 kWhs per month, 4.695 cents per kWh for the next 5.5 million kWhs and 4.327 cents per kWh for all usage in excess of 6 million kWhs.

The Company is proposing that the present minimum demand charge under the schedule be increased by $1,250 per month, from $12,500 to $13,750, and the demand charge for kVa over 3,000 per month be increased by $0.75 per kVa, from $4.00 to $4.75. The remaining revenue increase for the schedule is proposed to be recovered through a uniform percentage increase of approximately 6.4% applied to the three energy block rates. The proposed energy rate increase for the first 500,000 kWhs used per month is 0.335 cents per kWh, 0.302 cents per kWh for the next 5.5 million, and 0.278 cents per kWh for all usage over 6 million kWhs per month.

Q. What changes is the Company proposing to the rates under Pumping Schedule 31 to recover the proposed general revenue increase of $832,000?

A. The Company is proposing that the customer charge be increased by $2.25, from $7.75 to $10.00 per month, with the remaining revenue increase spread on a uniform percentage increase of 9.0% to the two energy rate blocks under the schedule. The proposed increase in the first block rate is 0.789 cents per kWh and the increase in the second block rate is 0.563 cents per kWh.

Q. How is the Company proposing to spread the proposed revenue increase of $572,000 applicable to Street and Area Light schedules to the rates contained in those schedules (Schedules 41-48)?

A. The Company proposes to increase present street and area light (base) rates on a uniform percentage basis. The proposed increase for all lighting rates is 9.1%. The (base tariff) rates are shown in the tariffs for those schedules, contained in Exhibit No.___(PDE-3).

Q. Are you proposing any other changes to the Company's electric service tariffs?

A. Yes. The Company is proposing to add language under Extra Large General Service Schedule 25 that would require a customer to execute a special contract for service of a new incremental load requirement of 25 MVA or greater. Specifically, under the "Special Terms and Conditions" section of the tariff, the proposed language states:

> A new or existing customer with an incremental electric demand requirement of 25,000 kVa or greater must execute a special contract for service, wherein the rates, terms and conditions for service may be different than those set forth under this schedule. The special contract will be subject to approval by the Washington Utilities and Transportation Commission (WUTC), and if the Company and the customer cannot agree on the rates, terms and conditions of service, the matter will be brought before the WUTC for resolution.

Q. Did the Company propose this same language in its last general rate case (Docket UE-100467)?

A. Yes, this is the same language that the Company proposed in that Docket. As a part of the settlement, the Company withdrew its request for the tariff modifications.

Q. What is the Company's rationale for this proposed provision?

A. The incremental cost associated with serving a new load of 25 megawatts or more could be substantial. Under the present Schedule 25 tariff, there is no provision limiting service at the rates set forth under this schedule. A customer with a new load requirement of 25, 50, or even 100 megawatts could request, and perhaps demand, service at Schedule 25 rates. The proposed provision would allow the Company and the Commission to consider the incremental costs required to provide the requested service.

Q. Does the Company have a similar provision in its Idaho tariff?

A. Yes, however, the provision in the Idaho Schedule 25 tariff states that customers whose total demand requirement exceeds 25,000 kVa may be served under a special contract. This provision has been in effect in Idaho since 1992. The only customer the Company serves in Idaho that exceeds this level is Clearwater Paper.

Q. Why isn't the Company proposing specific service rates or a banded-rate associated with this incremental load provision?

A. The rates for service to an incremental load of this size should consider all of the specific load characteristics unique to that customer/load that could have a substantial effect on the cost of service. These factors would include estimated energy usage and peak demand by month, day and hour, potential interruptibility, and distribution facility requirements, etc.

Q. Even though there are no specific rates associated with the proposed provision, could the provision itself be considered "unduly discriminatory" when the

Company is already serving customers whose load requirements exceed 25 megawatts (25,000 kVa)?

A. No. The provision states that, "the rates for service may be different than those set forth under this Schedule". The provision does not state that the rates will be different. If the Company were to be presented with a new large load over 25,000 kVa, there would be opportunity to determine whether the characteristics of the new load warrant service rates different than those set forth under Schedule 25. Any special contract proposed under this provision would be subject to Commission review to determine if the rates for service are fair, just, reasonable and sufficient, and are not unduly discriminatory.

Q. Are there any other changes to Schedule 25 being proposed in this case?

A. Yes. The Company is proposing to revise the language relating to the Annual Minimum. Currently, the language states:

> Any annual minimum deficiency will be determined during the April billing cycle for the previous 12-month period. For a customer who has taken service on this schedule for less than 12 months, the annual minimum will be prorated based on the actual months of service.

The proposed language states:

> Any annual minimum deficiency will be determined during the April billing cycle for the previous 12-month period. For a customer who has taken service on this schedule for less than 12 months, the annual minimum will be prorated based on the actual months of service. The annual minimum will also be prorated if base rates change during the 12-month period. The annual minimum is based on 916,667 kWh's per month (11,000,000 kWhs annually), plus twelve months multiplied by the monthly minimum demand charge for the first 3,000 kVA of demand. The annual minimum reflected above is based on base revenues only. Any other revenues paid by customers in their billed rates (such as the DSM Tariff Rider Schedule 91) do not factor in to the annual minimum calculation.

Q. Why is the Company proposing this change to the annual minimum language?

A. There are two main reasons for the requested change. First, it was not clear to customers as to what the base level of kWh's were for purposes of determining the annual minimum. Second, it was not clear in the tariff language that the annual minimum relates to base revenues, not billing revenues. The annual minimum language needs to reflect the fact that other tariff schedules that impact billed rates do not impact the annual minimum, and are not included in the annual minimum calculation.

IV. PROPOSED NATURAL GAS REVENUE INCREASE

Q. Can you please explain what is contained in Exhibit No.___(PDE-5)?

A. Yes. Exhibit No.___(PDE-5) contains a copy of the Company's present natural gas tariffs presently on file with the Commission.

Q. Please describe what is contained in Exhibit No.___(PDE-6)?

A. Exhibit No.___(PDE-6) contains the proposed natural gas tariff sheets incorporating the proposed changes included in this filing.

Q. Please explain what is contained in Exhibit No.___(PDE-7)?

A. Exhibit No.___(PDE-7) contains information regarding the proposed spread of the natural gas revenue increase among the service schedules and the proposed changes to the rates within the schedules. Page 1 shows the proposed revenue and percentage increase by rate schedule. Page 2 shows the rates of return and the relative rates of return for each of the schedules before and after the proposed increases. Page 3 shows the present rates under each of the rate schedules, the proposed changes to the rates within the schedules, and the proposed rates after application of the changes. These pages will be referred to later in my testimony.

Summary of Natural Gas Rate Schedules and Tariffs

Q. Would you please review the Company's present rate schedules and the types of natural 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 banded-rate transportation tariff that allows for a negotiated service rate with large customers that have an economic alternative to taking distribution service from the Company.

Q. The Company also has rate Schedules 112, 122 and 132 on file with the Commission. Could you please explain which 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 used to amortize the deferred gas costs approved by the Commission in the prior PGA. Because of their size, 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 gas costs deferrals which are not due them, thus the need for Schedules 112, 122 and 132. There are presently only ten customers served under these schedules.

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

A. As of December 2010, the Company provided service to the following number of customers under each of its schedules:

Table 8 - Customers by Service Schedule

Rate Schedule	No. of Customers
General Service Schedule 101	145,837
Large General Service Schedule 111/112	2,340
Ex. Lg. General Service Schedule 121/122	28
Interruptible Sales Service Schedule 131/132	1
Transportation Service Schedule 146	33

Proposed Rate Spread

Q. How does the Company propose to spread the overall revenue increase of $6,207,000, or 4.0%, among its natural gas general service schedules?

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

Table 9 - Proposed % Natural Gas Increase by Schedule

Rate Schedule	**Increase in Base Rates**
General Service Schedule 101	5.0%
Large General Service Schedule 111	1.1%
Ex. Lg. General Service Schedule 121	1.5%
Interruptible Sales Service Schedule 131	1.8%
Transportation Service Schedule 146	4.4%
Overall	**4.0%**

Q. Is the proposed percentage increase for Transportation Schedule 146 comparable to the increase for the other service schedules?

A. No. The proposed percentage increase for Transportation Schedule 146 is not comparable to the proposed increases for the other (sales) service schedules, as Schedule 146 revenue does not include an amount for the cost of gas or pipeline transportation, whereas the other sales schedules include these costs. Transportation customers acquire their own gas and pipeline transportation. Including an estimate of 40.0 cents per therm for the cost of gas and pipeline transportation, the proposed increase to Schedule 146 rates represents an average increase of 0.7% in those customers' total gas bill.

Q. What information did the Company use to develop the proposed spread of the overall increase to the various rate schedules?

A. The Company utilized the results of the cost of service study, as sponsored by Ms. Knox, as a guide in developing the proposed rate spread. The relative rates of return before and after application of the proposed increases by schedule are as follows:

Table 10 -Present & Proposed Relative Rates of Return

Rate Schedule	Present Relative ROR	Proposed Relative ROR
General Service Schedule 101	0.95	1.00
Large General Service Schedule 111	1.18	1.00
Ex. Lg. General Service Schedule 121	1.12	1.00
Interruptible Sales Service Schedule 131	1.04	1.00
Transportation Service Schedule 146	1.14	1.00
Overall	**1.00**	**1.00**

Page 2 of Exhibit No.___(PDE-7) shows this information in more detail.

The Company believes that, given the results of the Cost of Service study sponsored by Ms. Knox, all of the rate schedules should be moved to unity. General Service Schedule 101 was the only schedule that has a present relative rate of return that is currently below cost of service. Given their proximity to unity, the Company believed that a full movement was in order, which would relieve the subsidization of Schedule 101 by the other four service schedules.

Proposed Rate Design

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

A. Yes. 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 plus a usage charge for the first 200 therms or less, and block rates for 201-1,000 therms/month, and over 1,000 therms/month.

Extra Large General Service Schedule 121 has a five-tier declining-block rate structure with a monthly minimum charge plus a usage charge for the first 500 therms or less, and block rates for the next 500 therms, the next 9,000 therms, the next 15,000 therms, and usage over 25,000 therms/month. There is also an annual minimum requirement of 60,000 therms under the schedule and a minimum load factor requirement of approximately 58%.

Interruptible Sales Service Schedule 131 has a four-tier declining-block rate structure for the first 10,000 therms, the next 15,000 therms, the next 25,000 therms, and usage over 50,000 therms per month. The schedule also has an annual minimum deficiency charge based on a usage requirement of 250,000 therms per year.

Transportation Service Schedule 146 contains a $225 per month customer charge and a five-tier declining-block rate structure for the first 20,000 therms, the next 30,000 therms, the next 250,000 therms, the next 200,000 therms, and usage over 500,000 therms per month. The schedule also has an annual minimum deficiency charge based on a usage requirement of 250,000 therms per year.

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

A. No, it is not.

Q. Where in your Exhibits do you show the present and proposed rates for the Company's natural gas service schedules?

A. Page 3 of Exhibit No.___(PDE-7) shows the present and proposed rates under each of the rate schedules, including all present rate adjustments (adders). Column (e) on that page shows the proposed changes to the rates contained in each of the schedules.

Q. You stated earlier in your testimony that the Company is proposing an overall increase of 5.0% to the rates of General Service Schedule 101. Is the Company proposing an increase to the present basic/customer charge of $6.00/month under the schedule?

A. Yes. The Company is proposing to increase the basic/customer charge from $6.00 to $9.00 per month, as the Company believes that the customer/basic charge should recover a reasonable portion of the fixed costs of providing service. Later in my testimony I will provide greater detail as to why the Company believes the monthly customer charge should increase by $3.00 per month.

Q. What is the proposed change to the rate per therm under Schedule 101 in order to achieve the total proposed revenue increase for the schedule?

A. The Company, as shown in column (e), page 3 of Exhibit No.___(PDE-7), has proposed to change the per therm rate for Schedule 101 customers by $0.00393 per therm, from the current rate of $0.86979 per therm to $0.87372 per therm.

Q. What would be the increase in a residential customer's bill with average usage based on the proposed increase for Schedule 101?

A. The increase for a residential customer using an average of 67 therms of natural gas per month would be $3.26 per month, or 5.1%. A bill for 67 therms per month would increase from the present level of $63.45 to a proposed level of $66.71.

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

A. Yes. The present rates for Schedules 101, 111, and 121 provide a clear 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 generally use over 10,000 therms per month should be placed on Schedule 121. Not only do the rates provide guidance 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 provide guidance for appropriate schedule placement for customers and a reasonable classification for cost analysis. The proposed increase to the minimum charge for Schedule 111 (for 200 therms or less) of $3.79 per month is a function of the basic charge increase of $3.00 under Schedule 101 as well as the increased Schedule 101 variable rate[4]. This methodology maintains the present relationship between the schedules, and will minimize customer shifting. The remaining proposed revenue increase for Schedule 111 was then spread on a uniform percentage increase of 0.9% to the remaining two rate blocks under the schedule, resulting in an overall revenue increase of 1.1% for the schedule.

For Schedule 121, the increase in the minimum charge (for 500 therms or less) is $5.29 for a total charge of $370.93. The minimum charge is derived by adding the proposed Schedule 101 basic charge of $9 to the product of 500 therms multiplied by the difference between the rate in Schedule 101 and the minimum rate under Schedule 121.

[4] Schedule 11 Minimum Charge increase equals the $3 increase in Schedule 101 Basic Change plus 200 therms multiplied by the change in the variable rate (200*$0.00393 = $0.79).

Below is the calculation:

500 Therms	500
*	
(101 Rate - 121 Minimum Rate)	
(0.87372 - 0.14986)	$0.72386
+	
Schedule 101 Basic Charge	$9.00
=	**$370.93**

The second, third, and fourth block rates were increased by a uniform percentage of approximately 1.8% to maintain consistency between the rates for Schedules 111 and 121. The fifth block was not adjusted in order to provide a more meaningful spread between the rate blocks, resulting in an overall revenue increase of 1.5% for the schedule.

Q. How is the Company proposing to spread the proposed increase of $8,000 to the rates under Interruptible Schedule 131?

A. The Company proposes to increase the present four block rates under the schedule by a uniform percentage increase of approximately 1.8%.

Q. Could you please explain the proposed changes in the rates for Transportation Schedule 146?

A. Yes. The Company is proposing to adjust the basic charge by $15 per month, which is an increase from $225 to $240 per month. For the remaining revenue requirement, the Company is proposing to spread the increase on a uniform percentage basis of approximately 4.2% to each of the present five block rates under the schedule. The proposed increase to each of the block rates, as well as the present and proposed rates, are shown at the bottom of page 3 of Exhibit No.____(PDE-7).

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

schedules?

A. Yes. The rates contained in Purchase Gas Cost Adjustment Schedule 150 have been incorporated into the present and proposed rates shown on Page 3 of Exhibit No.___(PDE-7). Further, a revised Schedule 150 is filed as part of Exhibit No.___(PDE-6), whereby the present rates under the schedule have been zeroed-out and included in the Company's proposed general service tariffs.

V. BASIC CHARGE

Q. Why is the Company proposing to increase the <u>electric</u> monthly customer charge from $6.00 to $9.00 per month?

A. A significant portion of the Company's costs are fixed and do not vary with customer usage. These costs include distribution plant and operating costs to provide reliable service to customers. Upon evaluation of the <u>total customer allocated costs</u>, as shown in Exhibit No. __(TLK-4), page 4, line 25, those costs are <u>$10.88</u> per customer per month. Factoring in <u>distribution demand cost</u> per customer per month of <u>$18.97</u>, as shown in Exhibit No. __(TLK-4), page 4, line 27, the total customer and distribution demand monthly cost is <u>$29.86</u>. These are essentially fixed costs that are allocated based on the number of customers served. Given the large disparity between the level of customer and demand costs and the present level of the basic charge, the Company believes that it is appropriate to recover a more reasonable level of these fixed customer costs through the basic charge.

Q. Why is the Company now proposing an increase of $3.00 per month in this filing?

A. One of the arguments against higher residential basic charges in the past was one of customer understandability and acceptance. We believe it is increasingly important that our charges to customers more accurately reflect the actual costs to serve customers. With regard to fixed charges, many other utility assessments (phone, television, internet) are generally a flat monthly fee. Typically, there is little correlation between the level of use and the monthly amount paid for service related to these other utilities/services. Consumers understand that most of the costs associated with these other utilities/services are fixed, and have become accustomed to paying a relatively constant monthly fee for service or system access.

Publicly-owned electric utilities have been charging higher monthly customer charges for years in order to more accurately reflect (and recover) the fixed costs of providing service. For example, Avista's nearest neighbors in Eastern Washington and North Idaho, Inland Power and Light and Kootenai Electric Cooperative, have a monthly basic charge of $16.80 and $16.50 respectively.

Q. Turning now to natural gas, why is the Company proposing to increase that monthly customer charge from $6.00 to $9.00 per month?

A. Upon evaluation of the total customer allocated costs, as shown in Exhibit No. __(TLK-6), page 4, line 24, those costs are $16.32 per customer per month. Included in the fixed costs included in the $16.32 noted above are the cost of the meter and service, and the costs associated with billing and providing customer service, which amounts to $11.66 per customer per month, as shown in Exhibit No. __(TLK-6), page 4 line 22.

Q. What is the consequence to a customer of a Basic Charge that is priced below the cost of providing customer services to that customer?

A. Because rate design is a "zero sum game", if customer charges are set below the cost of providing those services, then other charges are, by definition, set above their cost of service. For residential gas and electric customers, the only other charge is the volumetric charge. When volumetric rates are increased above their cost of service to include customer costs that are not in the Basic Charge, several consequences ensue:

- It results in almost all customers paying more per-customer related costs in the winter, even though their customer costs are not higher in the winter, and vice versa in the summer;
- It results in the amount of customer costs a customer pays being unpredictable, even though customer costs are actually very predictable.
- A portion of fixed costs of providing service to low usage customers is actually recovered from other higher usage customers served under the same schedule.

In summary, setting the basic charge at a rate substantially less than an amount that covers annual customer costs results in rates that are not equitable and are unnecessarily variable.

Q. But won't increasing the Basic Charge send the wrong price signal through the energy rates?

A. No. Conservation of electricity and natural gas is important for customers and for the Company, and one might argue that a lower basic charge results in higher commodity prices and a stronger price signal related to volume usage. However, sending a price signal to customers through a residential rate design that contains a three tier increasing block rate for electric (natural gas has just one volumetric rate) was developed for just such a reason. The more electricity that is used, the higher the rate, and therefore the higher the overall customer bill. The important distinction in this filing is that the

Company is not requesting to decrease the energy rates, nor is it proposing to reduce the degree of inversion between the rates. As such, the volumetric pricing components will still send a very clear price signal to conserve. It is just not necessary to continue to use an inequitable basic charge to send price signals.

Q. Do you have any additional comments related to "price signals"?

A. Yes. Sending a proper price signal is important as I noted above, and I believe that the proper price signal is being maintained. One measure of this it to look to the Company's IRP's to see what the incremental cost of electricity and natural gas is on a forward looking basis, as compared to retail rates. For electricity, the proposed tail-block rate of $0.09802 (usage over 1,300 kWh's) is well above the Company's levelized 20 year new resource cost forecast of $0.07956 per kWh.[5] For natural gas, the Company included several forecasts in its 2009 Integrated Resource Plan which, for the most part, all show forecasted natural gas prices at Henry Hub over the next ten years being lower than Avista's retail rate[6].

Q. Have you prepared an analysis to show what impact the proposed rate design changes would have on customers?

A. Yes. The Company completed an analysis showing the impact on low, average, and high use electric and natural gas customers. The comparison shows the difference in a customer's bill based on the Basic Charge and volumetric rates being increased on a uniform percentage basis, versus the Company's proposed changes. Table 11 below details results of that analysis for electric customers:

[5] 2009 Avista Electric Integrated Resource Plan, Page 7-1. (see Exhibit No. ___(RJL-2)) The forecast shows $79.56 per mWh.
[6] 2009 Avista Natural Gas Integrated Resource Plan, Page 1.5 (See Exhibit No. ___(KJC-2))

Table 11

Avista - Bill Impacts for Low, Medium and High Electric Customers					
Monthly Bill Impact	Current Billed Rate	Equal Percentage	Avista Proposed	Difference bet. Equal % and Proposed	Percent. Difference
750 kWh/mo Customer	$59.00	$64.39	$65.08	$0.69	**1.1%**
977 kWh/mo Customer	$77.01	$84.04	$84.14	$0.10	**0.1%**
1500 kWh/mo Customer	$121.15	$132.22	$130.86	-$1.36	**-1.0%**

Table 12 below details the analysis for natural gas customers:

Table 12

Avista - Bill Impacts for Low, Medium and High Natural Gas Customers					
Monthly Bill Impact	Current Billed Rate	Equal Percentage	Avista Proposed	Difference bet. Equal % and Proposed	Percent. Difference
50 therms/mo Customer	$48.87	$51.36	$52.07	$0.70	**1.4%**
67 therms/mo Customer	$63.45	$66.68	$66.71	$0.02	**0.0%**
90 therms/mo Customer	$83.17	$87.41	$86.52	-$0.89	**-1.0%**

As you can see, the impact of the Company's proposed change to the basic charge varies based on monthly consumption. For an electric customer who uses less than the average 977 kWh's and/or 67 therms per month, the percentage impact will be slightly higher than for those customers who use more than the average. We believe the improvement in matching customer payment of fixed costs with the fixed costs to serve customers, together with removing part of the inequity among customers on the amount of fixed costs paid, warrants this relatively small bill impact.

Table 13 below shows a comparison of monthly bills for an electric customer with average usage for a 12-month period. It shows the difference in the monthly bills with a uniform percentage increase to the basic charge and volumetric rates, versus the

Company's proposal. The table illustrates the reduction in payment of fixed costs in the winter months, and increased payment in the summer, with the net result being improved alignment of payment of fixed costs by customers with the fixed costs to serve customers, with no significant annual difference in overall payment.

Table 13

Monthly Bills of an Average Electric Customer

Month	kWh's	Equal Percentage	Avista Proposed	Higher / Lower Bill
January	1,349	$116.35	$116.06	($0.29)
February	1,151	$99.11	$98.75	($0.36)
March	1,042	$89.67	$89.60	($0.07)
April	904	$77.72	$78.01	$0.29
May	720	$61.79	$62.56	$0.77
June	749	$64.30	$65.00	$0.70
July	801	$68.80	$69.36	$0.56
August	931	$80.06	$80.28	$0.22
September	756	$64.91	$65.59	$0.68
October	857	$73.65	$74.07	$0.41
November	1,044	$89.84	$89.77	($0.08)
December	1,415	$123.63	$122.53	($1.10)
	11,719	**$1,009.84**	**$1,011.58**	**$1.74**

Table 14 below provides a similar comparison for a 12-month period for a natural gas customer with average usage. The net result is similar to the electric results above, namely a better alignment of payment of fixed costs by customers with the fixed costs to serve customers.

Table 14

Monthly Bills of an Average Natural Gas Customer				
Month	Therms	Equal Percentage	Avista Proposed	Higher / Lower Bill
January	143	$135.18	$132.17	($3.01)
February	111	$106.34	$104.61	($1.73)
March	88	$85.61	$84.80	($0.81)
April	64	$63.98	$64.12	$0.14
July	30	$33.34	$34.84	$1.50
August	19	$23.43	$25.37	$1.94
September	17	$21.62	$23.64	$2.02
October	16	$20.72	$22.78	$2.06
November	19	$23.43	$25.37	$1.94
October	54	$54.97	$55.51	$0.54
November	100	$96.43	$95.13	($1.29)
December	147	$138.78	$135.61	($3.17)
	808	**$803.82**	**$803.95**	**$0.13**

Q. Has the Commission recently commented on what they believe an appropriate basic charge should be?

A. Yes. In 2007, in Puget Sound Energy Dockets UE-060266 and UG-060267 (consolidated), the Commission approved a $8.25 natural gas basic charge (subsequently increased to $10) and stated:

> This will result in the Company recovering about one-fourth of its fixed costs allocated to residential customers via a fixed charge on each customer's bill. This is about eight to ten percent of an average customer's total bill, considering both fixed and variable costs. This seems to us the right balance point for the recovery of fixed costs via the customer charge.[7]

Avista's proposed $9 basic charge is approximately 13.1% of the proposed average bill for natural gas customers and 10.7% for electric customers. I believe this is well within the range of reasonableness, especially when viewed as a percentage of base rates.

[7] Order No. 08, Dockets UE-060266 and UG-060267, Para. 139

Q. Please discuss your view of the impacts of this request on your limited income customers.

A. There are two different implications of the Company's proposal. The first implication is for <u>limited income electric customers</u>, many whom would <u>benefit</u> from the Company's proposal. Traditional thinking might lead one to believe that a low income electric customer would tend to be a low user of electricity. Although the Company has not conducted a demographic survey of its customers in recent years, the limited data that we do have would suggest that just the opposite is true.

A majority of our customers have natural gas for space and water heating, and therefore may have low average electric usage during the winter. However, many <u>low income</u> customers, I believe, tend to still <u>use electricity for space and water heating</u>. These customers, in my view, tend to live in apartments (which in Avista's service territory predominantly have electric space and water heat), live in areas where natural gas is not available, or live in areas with natural gas, but cannot afford to convert. These low income customers, with electric space and water heat, can have electric usage in the tail-block (above 1,300 kWh's) during the winter months. Having a lower basic charge and higher tail-block rate penalizes these customers, as these customers are more susceptible to use in the tail-block. A higher basic charge, on the other hand, would result in lower volumetric rates (than would otherwise be the case), providing some relief to these high use customers during the winter months.

Q. What are the implications for limited income natural gas customers?

A. Average-use limited income natural gas customers would tend to pay slightly higher natural gas bills than they would under the equal percentage methodology used by the Company as shown in the examples earlier in my testimony. Data gathered as part of the review of the Company's Natural Gas Decoupling Mechanism showed that limited income natural gas customers tend to use slightly less natural gas (58 therms per month[8]) than the traditional residential customer (67 therms per month). As shown in the table below, while there is an impact, it is relatively small both on a dollar and percentage basis (between 0% and 0.7%).

Table 15

Avista - Residential/Limited Income Natural Gas Customer Impact					
	Current Rates	Equal Percentage	Avista Proposed	Difference bet. Equal % & Proposed	Percent. Difference
Customer Charge	$6.00	$6.30	$9.00	$2.70	
Billing Rate	$0.85739	$0.90123	$0.86132	-$0.03991	
Monthly Bill Impact					
58 Therm/mo Customer	$55.73	$58.57	$58.96	$0.38	**0.7%**
67 Therm/mo Customer	$63.45	$66.68	$66.71	$0.02	**0.0%**

VI. ENERGY EFFICIENCY LOAD ADJUSTMENT

Q. Would you briefly describe the Company's proposed Energy Efficiency Load Adjustment?

A. Yes. Avista's proposed Energy Efficiency Load Adjustment (Load Adjustment) restates the weather-normalized test year loads of the Company's retail electric customers to reflect the impact of the Company's programmatic electric energy efficiency efforts. The purpose of this adjustment is to directly address the reduction of retail revenues associated with the Company-sponsored conservation that occurred during

[8] Titus "Evaluation of Avista Gas Decoupling Mechanism Pilot", Page 81, Table K10. See Docket UG-060518.

the test year (2010), as well as the level of conservation savings that will occur in 2011 and 2012.

Q. Why is the Company proposing this adjustment in this case?

A. Effective January 1, 2010, the Company is mandated to obtain a certain level of electric energy efficiency savings pursuant to RCW Chapter 19.285, the Energy Independence Act. Under this act, Avista is required to "identify its achievable cost-effective conservation potential through 2019"[9], and beginning in January 2010, "establish and make publicly available a biennial acquisition target for cost-effective conservation consistent with its identification of achievable opportunities … and meet that target during the subsequent two-year period"[10]. Given that this law went into effect during the test year (2010), and is in effect during 2011 and the rate year of 2012, the Company believes that the mandated savings should be reflected in the Company's test year loads.

Q. Did the Company "establish and make publicly available" its biennial electric conservation target?

A. Yes, on January 29, 2010, the Company filed with the UTC its first "Ten-year Achievable Conservation Potential and Biennial Conservation Target Report" which included the Company's first two-year biennial electric conservation target with the UTC. On April 16, 2010, "Avista identified a ten-year conservation potential of 873,302 megawatt-hours and a biennial 2010-11 conservation target of 128,603 megawatt-hours. The overall numbers were the same as those identified in the Initial Report, but Avista clarified that its biennial conservation target included a minimum of 125,982 megawatt-

[9] RCW 19.285.040
[10] Id.

hours from conservation measures that do not rely on electric-to-natural gas fuel switching."[11]

Q. Did the Commission approve the Company's biennial target of 128,603 megawatt-hours ?

A. Yes, on May 13, 2010, the UTC approved Avista's biennial conservation target as filed on April 16, 2010.

Q. The Company has also included conservation savings from 2012 in this adjustment. How was the savings target for 2012 developed given that it is outside of the first biennial period?

A. For the derivation of the 2012 estimated energy savings target, while the Company has not yet filed its projected biennial savings target for the 2012/2013 period, the Company used its 2012 Northwest Power and Conservation Council's 6th Power Plan target. In addition to that target, and consistent with the derivation of the first biennial conservation target, the Company included one-half of the estimated electric to natural gas fuel switching target for the 2012-2013 time period. The resulting conservation savings target for 2012 is 73,550 megawatt-hours.

Q. Does the Company have the necessary funding to obtain the mandated conservation targets?

A. Yes, it does. On April 29, 2011, pursuant to Order No. 1 in UE-100176, Avista filed its annual report[12] related to, among other things, the required funding levels needed for the twelve-month period starting July 1, 2011. In that filing the Company demonstrated that the current level of dedicated funding for electric energy efficiency

[11] Docket UE-100167, Order No. 1, Paragraph 17
[12] See Docket UG-110790

measures was sufficient, and that there was no need to adjust up or down the current Schedule 91 tariff rider. As stated in the Company's filing:

> However, no changes are proposed to Schedule 91 at this time due to expected program expenditures over the next twelve months projected to meet goals associated with the conservation portion of "I-937", also known as WAC 480-109, "Acquisition of minimum quantities of conservation and renewable energy as required by the Energy Independence Act (chapter 19.285 RCW)." Avista is on target to achieve its stated targets as described in Docket No. UE-100176.

Q. Does the Company have the programs in place in order to meet its conservation targets?

A. Yes. Company witness Mr. Folsom provides testimony in this case regarding the Company's energy efficiency programs. In short, he states that the Company's energy efficiency offerings include over 300 measures that are packaged into over 30 programs for customer convenience. The Company has the necessary funding and program offerings in place in order to meet its electric conservation targets.

Q. What happens if the Company does not meet its targets under the Energy Independence Act (EIA)?

A. Under the EIA, the Company must acquire a certain level of electric energy efficiency savings, and to the extent that the Company fails to meet its electric efficiency targets, would pay a $50 per megawatt hour penalty[13].

Avista is required by law to obtain a certain level of electric efficiency savings, some of which has already occurred in the test year (2010), some in 2011, and more in 2012. It is appropriate, therefore, to adjust weather-normalized test year loads to reflect

[13] RCW 19.285.060 - A qualifying utility that fails to comply with the energy conservation or renewable energy targets established in RCW 19.285.040 shall pay an administrative penalty to the state of Washington in the amount of fifty dollars for each megawatt-hour of shortfall.

these mandated savings. This adjustment to retail loads will result in a proper matching of revenues and expenses on a proforma basis for the test period. If the electric savings are not met, the Company would be penalized, protecting customers from the potential for an over-collection of costs.

Q. How is the Energy Efficiency Load Adjustment calculated?

A. As previously noted, the purpose of the Load Adjustment is to adjust the test year billing determinants to reflect the impact resulting from the Company's programmatic energy efficiency efforts. The first step in the calculation of the Load Adjustment is to determine the level of electric energy efficiency savings from the Company's DSM programs. In 2010, customers who took part in the Company's DSM programs saved 52,768,908 kWhs annually. Table 16 below shows the savings by rate schedule:

Table 16 – 2010 Electric Energy Savings by Rate Schedule

Rate Schedule	2010 Savings	% of Total Savings
Schedule 1	17,950,789	34.0%
Schedule 11	4,861,018	9.2%
Schedule 21	25,029,152	47.4%
Schedule 25	4,416,390	8.4%
Schedule 31	511,559	1.0%
	52,768,908	**100%**

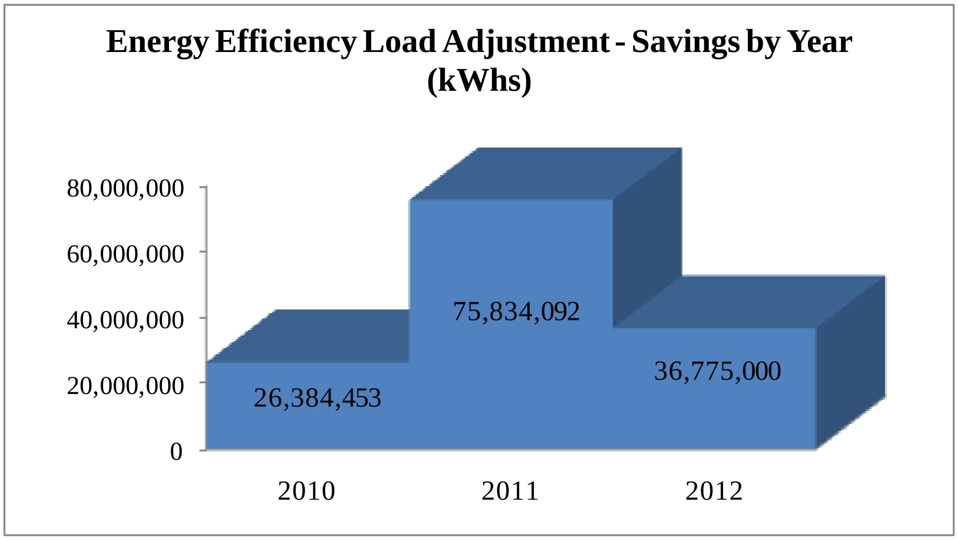
Because customers installed energy efficiency measures throughout 2010, approximately one-half of the annual savings were already included in the normalized test year usage. Therefore, for the first year, only 26,384,453 kWh's would need to be adjusted out of the test year billing determinants to reflect the other half of the kWh's that customers saved.

Q. How were 2010, 2011 and 2012 electric energy efficiency targets determined?

A. As discussed earlier, the Company's electric energy efficiency targets are based on Avista's Ten-Year Achievable Conservation Potential and Biennial Conservation Targets. These targets were filed with the Commission in Docket UE-100176, and were later approved in Order No. 01 on May 13, 2010. At paragraph 53, the Commission approved a 2010-2011 biennial conservation target of 128,603 megawatt-hours. Given that the level of savings in 2010 was 52,769 megawatt-hours, the target for 2011 is 75,834 megawatt hours.

As I discussed earlier, for the derivation of the 2012 estimated energy savings, while the Company has not yet filed its projected biennial savings target for the 2012/2013 period, the Company used its 2012 Northwest Power and Conservation Council's 6th Power Plan target, plus one-half of the estimated electric to natural gas fuel switching target for 2012-2013, to arrive at an annual savings figure of 73,550 megawatt-hours. For purposes of this adjustment, the Company only included one-half of the 2012 target, or 36,775 megawatt hours. Illustration 1 below includes a chart showing the savings included in this adjustment by year:

Illustration No. 1



Q. How were 2011 and 2012 electric energy efficiency savings spread by rate schedule?

A. For purposes of spreading the energy savings by rate schedule, the Company used the same percentage spread as was achieved in 2010, i.e., Schedule 1 received 34.0% of 2010, 2011, and 2012 savings based on 2010 actual results as shown in Table 16 above. Table 17 below shows the savings by rate schedule that have been incorporated into the Load Adjustment:

Table 17 – Load Adjustment Electric Energy Savings by Rate Schedule

Rate Schedule	2010 Savings (1/2 of Year)	2011 Savings (Full Year)	2012 Savings (1/2 of Total)	% of Total Savings
Schedule 1	8,975,394	25,783,591	12,503,500	34.0%
Schedule 11	2,430,509	6,976,736	3,383,300	9.2%
Schedule 21	12,514,576	35,945,360	17,431,350	47.4%
Schedule 25	2,208,195	6,370,064	3,089,100	8.4%
Schedule 31	255,779	758,341	367,750	1.0%
	26,384,453	**75,834,092**	**36,775,000**	**100%**

Q. Is the use of 2010 results by rate schedule appropriate for purposes of allocating 2011 and 2012 estimated savings?

A. Yes. The Company continues to have similar energy efficiency programs in place, as it had in 2010, and does not have plans to significantly alter the mix of electric energy efficiency programs as it relates to residential and commercial/industrial customers. Therefore, the 2010 actual results provide a reasonable basis upon which to spread the 2011 and 2012 energy savings.

Q. Did the Company factor in demand savings as a part of the adjustment?

A. Yes. For the demand savings component of the Company's energy efficiency programs, the Company developed an Excess Demand Ratio, which is a ratio of each Schedule's (11, 21 and 25) excess billed demand (beyond the demand embedded in the fixed demand charges) to total normalized energy usage. This ratio, when applied to the kWh savings by rate schedule, provides an estimate of the demand savings that correspond with the electricity savings, For example, with Schedule 21, the calculated Excess Demand Ratio of 0.171% multiplied by the total 2010-2012 calculated savings of 65,891,286 kWh's results in a reduction in customer demand of 112,668 kW. Further information regarding the calculation of the Excess Demand Ratio, and resulting demand reductions, can be found in Exhibit No. ___(PDE-8), Page 1.

Q. Please continue with your discussion of how the Energy Efficiency Load Adjustment was calculated?

A. Having calculated the reduction in demand (kW) and energy (kWh) by rate schedule, the results were then input into in the Company's rate design model. Average retail rates were then applied to those units in the same manner they are applied to the "Unbilled Adjustment" and the "Adjustment to Actuals", both components of the Company's Revenue Normalization Adjustment. This provides a revised Pro Forma Revenue at present rates of $422,706,000 million versus the Revenue Normalization Adjustment sponsored by Company witness Ms. Knox which shows normalized Pro Forma Revenue at Present Rates of $433,007,000. The difference is ($10,301,000), which is the energy efficiency revenue adjustment.

Q. Did the Company include a proforma adjustment for the corresponding change in power supply costs?

A. Yes. The energy efficiency kWh savings, grossed up to a system level amount, were provided to the Power Supply group for integration into their power supply model. That data consisted of an hourly load adjustment determined by DSM program load shape characteristics. After rerunning their power supply adjustment, Washington's share of Pro Form Sales for Resale Revenue Increased from $27,056,000 to $30,234,000, or $3,178,000. Pro Forma Purchased Power (Washington share) decreased from $72,207,000, as detailed in Company witness Mr. Johnson's PF1 adjustment, to $69,658,000. Taking into account the reduction in retail revenues due to DSM, and the resulting savings in Power supply expense, and including all of the other revenue related expenses and taxes, the impact of this adjustment is a reduction to Net Operating Income of $2,677,000. Table 18 below shows a summary of the Energy Efficiency Load Adjustment (in thousands):

Table 18 – Energy Efficiency Load Adjustment Summary

	Normalized	with EELA	Adjustment
Pro Forma Revenue at Present Rates	$ 433,007	$ 422,706	$ (10,301)
Pro Forma Sales for Resale Revenue	$ 27,056	$ 30,233	$ 3,178
Total Revenue Adjustment			**$ (7,123)**
Pro Forma Purchase Power Expense	$ 72,207	$ 69,658	$ (2,549)
Revenue Related Expenses			$ (456)
Total Expense Adjustment			**$ (3,005)**
Federal Income Tax			**$ (1,441)**
Net Operating Income			**$ (2,677)**

This adjustment was provided to Ms. Andrews for purposes of her final Revenue Requirement calculation.

VII. DECOUPLING - RATE SCHEDULE APPLICABILITY

Q. With regard to the Company's natural gas Decoupling Mechanism, please address whether the program should recover DSM-related lost margin from all natural gas rate schedules?

A. On pages 12-13 of the Settlement Stipulation in Docket Nos. UE-100467 and UG-100468, the Company agreed to address whether the natural gas Decoupling program should recover DSM-related lost margin from all natural gas rate schedules. This issue stems from Order 10 in Docket Nos. UE-090134, UG-090135 & UG-060518 (consolidated), where the Commission stated at page 119, paragraph 303:

> By reducing the Company's natural gas load, including its peak requirements, Avista's conservation program benefits all customers. In fact, the decoupling program includes conservation from all rate schedules in setting its targets and determining its success. Even so, as now put in place, the program's lost margin is

only collected from Schedule 101 customers. Following the principle of costs following benefits discussed above, we expect the parties to address whether the program should recover DSM-related lost margin from all rate schedules in Avista's next general rate case.

With regard to the principle of costs following benefits for Schedule 101, the costs associated with these programs, specifically DSM lost margin, is recovered only from Schedule 101 customers, and therefore there is alignment of costs and benefits for Schedule 101.

Q. Is the Company proposing a mechanism to recover DSM lost margin from large commercial and industrial customers?

A. Not at this time. While the Company believes that it would be appropriate to recover programmatic and non-programmatic lost margin from these customers, the amount of lost margin, at least for programmatic savings, is not material enough at this time to warrant a change to the current decoupling mechanism. Based on the verified 2009 DSM savings for large commercial and industrial customers, the annual lost margin (using present margins), as shown in Table 19 below, would be approximately $63,457.

Table 19 – Lost Margin for Large Commercial & Industrial Customers

Rate Schedule	Verified Energy Savings	Margin Rate (TailBlock)	Lost Margin
111/112	411,911	$0.15300	$ 63,022.40
121/122	4,475	$0.09720	$ 434.93
131/132	0	$0.09763	$ -
Total	**241,740**		**$ 63,457.33**

If the lost margin becomes a more significant amount, the Company would plan to address the issue at that time.

VIII. SUMMARY OF UE-100467/UG-100468 ORDER 7 REQUIREMENTS

Q. There were several requirements the Company agreed to in the Settlement Stipulation in Dockets UE-100467 and UG-100468 and which were approved by the UTC. Would you please provide a summary of those items and how they have been addressed by the Company in this rate case?

A. Yes. Table 20 below lists the items that the Company committed to as a part of the Settlement Stipulation approved in Order No. 7. The list details the requirement, the page number and paragraph where the item is located in the Stipulation, and the witness that addresses the issue in this docket.

Table 20 – UE-100467 & UG-100468 Settlement Stipulation Requirements

Item	Requirement	Page Number in Settlement Stipulation	Witness
1	The Company will review its non-executive incentive compensation programs and provide testimony in its next general rate case: (1) quantifying the programs' benefit(s) to ratepayers; and, (2) explaining how the programs comply with the Commission's Final Orders in previous Avista general rate cases.	Page 8 (Paragraph 5h)	Feltes
2	Whether the natural gas decoupling program should recover DSM-related lost margin from all rate schedules	Page 12 (Paragraph 7)	Ehrbar
3	Jackson Prairie Underground Storage balancing assignment of costs	Page 15 (Paragraph 11b)	Christie
4	Rebate Processing Procedures for DSM Programs	Page 17 (Paragraph 15)	Folsom
5	Evaluation, Measurement, and Verification ("EM&V") of Avista's Limited Income Weatherization program	Page 17 (Paragraph 16)	Folsom
6	Independent, External Review of Data Management Strategy	Page 18 (Paragraph 17)	Folsom
7	Policies/Procedures Regarding Cost Allocations	Page 19 (Paragraph 20)	Andrews
8	Internal Audit of Certain Accounting Policies Regarding Allocations	Page 19 (Paragraph 21)	Andrews
9	Employee Training for Avista employees to comply with required accounting and allocation practices	Page 20 (Paragraph 23)	Andrews
10	Review of Accounting Procedures Relating to Optional Renewable Power Rate Program	Page 21 (Paragraph 24)	Andrews

In addition, there was one item that the Commission required the Company to address in this docket that was detailed in Order No. 7. Below is the requirement, the page number and paragraph where the item is located in Order No. 7, and the witness that addresses the issue.

Table 21 – UE-100467 & UG-100468 Order No. 7 Requirements

Item	Requirement	Page Number in Order No. 7	Witness
1	Parties asked to investigate the apppropriateness of Avista's hedging strategies in the next GRC or before in a separate proceeding.	9 (Footnote 26)	Lafferty

Q. Were all the requirements in Order No. 7 and the Settlement Stipulation met by the Company prior to filing this general rate case?

A. Yes, all of the items that were required of the Company in Order No. 7 and the Settlement Stipulation were completed prior to filing this general rate case.

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

A. Yes it does.