EXHIBIT NO. ___(DWH-1T)
DOCKET NO. UE-09___/UG-09___
2009 PSE GENERAL RATE CASE
WITNESS: DAVID W. HOFF

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-09____** **Docket No. UG-09____**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF
DAVID W. HOFF
ON BEHALF OF PUGET SOUND ENERGY, INC.

MAY 8, 2009

PUGET SOUND ENERGY, INC.

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PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF DAVID W. HOFF

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David W. Hoff. I am manager, Pricing and Cost of Service with Puget Sound Energy, Inc. ("PSE" or the "Company"). My business address is 10885 NE Fourth Street, P.O. Box 97034, Bellevue, WA 98009-9734.

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(DWH-2).

Q. What is the purpose of your testimony?

A. My testimony presents the Company's electric cost of service study and the Company's proposed rate spread and rate design for electric service.

Q. Please summarize your testimony.

A. As with past cases, the Company continues to advocate for a rate spread proposal that aligns cost causation with cost recovery. The theoretical point where costs assigned to a customer class equal the revenues collected from that customer class (once all classes are adjusted for system over or under recovery) is called "parity," and the parity percentage at this point is 100%. The electric cost of service results in this case indicate that there are no major customer classes that are significantly (more than 5%) below parity,[1] but there are several classes significantly (greater than 5%) above parity. The Company acknowledges that the determination of parity is not absolute and that parity is dependent on the methodology used to allocate joint costs. As a result, the Company's proposal in this case, while increasing rates for some classes more than others, does not rigidly move each class to parity.

Regarding electric rate design, the Company does not propose any change in this filing. In general, all rates within a customer class have been increased by the class percentage, with the exception of the choice/retail wheeling and campus rate classes. As a result, the proposed rates will increase the monthly bill of virtually every customer within a class by the same percentage, regardless of season or usage. Rates for the choice/retail wheeling and campus rate classes were set in accordance with the Multiparty Settlement Agreement approved by the Commission in Docket No. U-072375.

[1] Customer classes that are below 5% parity are Campus Rate and Firm Resale/Special Contracts.

II. ELECTRIC COST OF SERVICE

A. <u>Background Regarding Electric Cost of Service Studies</u>

Q. Please summarize the purpose of a cost of service study.

A. A cost of service study is used to identify the costs that are incurred to serve a particular customer class. Identifying the cost responsibility of each class requires an analysis of the Company's costs and then an allocation of those costs to each customer class. This allocation is done by first directly assigning to a customer class any costs determined to be caused by that class alone. Joint costs that are shared by multiple customer classes are then allocated to various classes on a pro rata basis, based on factors appropriate to the costs being allocated.

The ultimate objective of the cost allocation process is to create a just, fair, reasonable and sufficient allocation of costs to different customer classes. This cost of service information is then used to allocate the revenue requirement determined in a rate case to the different customer classes. Historically, the Commission has treated the cost of service study as a guidepost for the allocation of the revenue requirement and has eschewed a mechanical application of the cost of service study.

In order to provide the benefits of cost analysis to individual customers in addition to customer classes, the cost of service study also serves as a guide for the rate design process. For example, the basic charge has historically been based, in part, upon customer costs determined in the cost study. Similarly, demand charges have historically been guided by demand costs determined in the cost study.

Q. Please summarize the process for preparing the electric cost of service study.

A. The cost of service study starts with the electric revenue requirement that is set forth in the Prefiled Direct Testimony of John Story, Exhibit No. ___(JHS-1T), which represents the Company's costs to provide service to its electric customers.

The first step of this study is to separate these costs into the major electric utility functions: generation, transmission, and distribution. This process is referred to as functionalization of costs.

The second step is to further divide the costs associated with each of the major functions into customer, demand and energy components (which are explained below). This process is referred to as classification.

The third step is to allocate each of the cost components to the individual rate classes.

Q. What are customer, demand, and energy costs?

A. Customer-related costs are incurred to connect a customer to the electric distribution system and include costs for meters and meter reading, billing, and customer service. Customer costs are a function of the number of customers served and are incurred whether or not the customer uses any electricity.

Demand-related costs are those costs associated with electric plant that is designed, installed and operated to meet maximum hourly or daily electric capacity requirements, such as transmission and distribution cables and related structures or portions of generation units that are needed to meet peak demands. While these structures or units may not be fully utilized at all times, they must be designed and installed to meet the maximum load that is anticipated.

Energy related costs are those costs that vary with the amount of electricity sold to, or transported for, customers. Costs related to electric supply are classified as energy related to the extent they vary with the amount of electricity purchased or generated by the utility for its electric sales customers.

One of the challenges of classifying costs into demand, energy, and customer components is that some utility equipment is commonly considered to serve multiple functions. For example, generation equipment is widely recognized as having both demand and energy components.

Q. Please identify all electric cost of service studies conducted by the Company in the last five years.

A. In addition to the electric cost of service study conducted in this case, the Company conducted fully allocated embedded cost of service studies to support general rate case filings in 2004, 2006 and 2007 (Docket Numbers UE-040641, UE-060266 and UE-072300).[2] In the 2004 and 2006 general rate cases ("GRC"), two separate studies were filed.

Q. Please describe the methodology used in those studies.

A. Each of the cost of service studies referenced above used the same basic methodology for functionalization of costs. However, there are some differences in how the studies classified and allocated costs. For instance, one version of the cost of service studies prepared for both the Company's 2004 and 2006 general rate cases relied on cost classification and allocation factors used in the prior litigated electric cost of service study in Docket Nos. UE-920433, UE-920499 and UE-921262 ("1992 Cost of Service Study") without any significant modification to how the calculation was performed. A second version of the cost of service studies prepared for the Company's 2004 and 2006 general rate cases used the same approach but modified the calculation of the cost classification and allocation factors in order to reflect (1) changes in PSE's generation and delivery system since 1992, and (2) access to more detailed data to provide a more accurate allocation of costs. The latter version was also used in PSE's 2007 GRC.

Q. What were the changes and modifications adopted in the Company's 2006 GRC and used in the Company's 2007 GRC filing?

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[2] Also, the Company used cost allocation studies to set rates in power cost only rate cases ("PCORC") in Docket Nos. UE-031725, UE-050870 and UE-070565. However, in each of the PCORC proceedings the Company relied on the power cost allocation factors from the cost of service study conducted in the rate cases that immediately preceded the PCORC proceeding.

A. The 2006 GRC implemented the following updates and modifications to the Company's methodology:

- modifications of the approach used to classify generation costs into demand and energy components,
- modification of the approach used to classify transmission costs into demand and energy components,
- allocation of distribution substation and line costs relative to each class's share of the load on these specific facilities,
- direct allocation of line transformer costs to each of the customer rate classes, and
- classification of the transformer cost as customer-related rather than demand related.

All issues regarding cost of service, rate spread and rate design were settled in that case, and all parties agreed to allocate any rate increase that the Company had in proportion to the Company's proposed rate spread, which was based on the Company's cost of service analysis. These modifications were then adopted by the Company for the 2007 general rate case, which was also settled.

Q. Regarding specific elements of the cost of service analysis, what updates have been made to the cost classification factors in the last five years?

In each filing energy production and transmission costs have been classified as demand and energy related using the peak credit method. In each filing the peak credit factor has been modified to reflect current planning assumptions. The history of these modifications and the update for this filing is discussed in the Prefiled Direct Testimony of Jon Piliaris, Exhibit No.___(JAP-1T). In addition, the Company classifies line transformer costs as customer related, as first proposed and adopted in PSE's 2006 GRC.

Q. What updates have been made to the factors used to allocate generation and transmission costs among rate classes in the last five years?

A. Two significant updates have been made. First, one new rate class has been added: the Campus Rate. This rate is Schedule 40 (Large Demand General Service Greater than 3 aMW). Second, beginning with PSE's 2006 GRC, the demand component of generation and transmission costs has been allocated to each rate class based upon each class's contribution to the highest 75 hourly system loads, rather than the highest 200 hourly loads.

Q. What updates has the Company made in this proceeding to the factors used to allocate distribution costs among rate classes in the last five years?

A. As I describe later in my testimony, the Company has allocated distribution costs based upon each class's contribution to the distribution circuit and distribution substation non-coincident peak ("NCP"). More specifically, the distribution circuit cost allocations at the feeder level are weighted to a total system allocation based upon distribution circuit miles. This alternative is used in place of the distribution allocation factors used previously in which the cost allocation was based upon an estimate of each class's system aggregate NCP. Another difference, also used in the past several proceedings and also described later, is that the allocation of the cost of line transformers relies on a direct allocation, rather than on an aggregate class level contribution to the NCP. Customers on the Campus Rate are directly assigned all the distribution plant costs.

B. Overview of the Company's Electric Cost of Service Study

Q. Does the Company's cost of service study in this proceeding utilize the methodology for classification and allocation of electric costs that PSE used in its 2007 GRC?

A. Yes. All issues regarding cost of service, rate spread and rate design were resolved through settlement in PSE's 2006 GRC, and all parties agreed to allocate any rate increase that the Company had in proportion to the Company's proposed rate spread, which was based on the Company's cost of service analysis. PSE used the same cost of service methodology in its 2007 GRC, which was also settled by agreement of all parties. The cost of service study in this case utilizes the same methodology as PSE used in its last two GRCs. This methodology is discussed in more detail in sections C through H, below.

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

A. The parity percentages by customer class that result from the cost of service study are shown in the following table. Parity reflects the relative relationship between revenues currently recovered in rates to the revenue required based upon the cost of service analysis. Parity over 100% indicates that the customer class is currently paying more than its share of allocated costs (once all classes are adjusted for system over or under recovery).

Customer Class	Rate Schedule	Parity Percentage
Residential	7	95%
General Service, < 51 kW	24	107%
General Service, 51 – 350 kW	25	112%
General Service, >350 kW	26	105%
Primary Service	31/35/43	109%
Campus Rate	40	89%
High Voltage	46/49	98%
Lighting Service	51 - 59	109%
Choice/Retail Wheeling	448/449	94%
Firm Resale/Special Contract	5	88%
System Total / Average		**100%**

Q. Was the model used to develop the cost of service study the same model used in the Company's most recent general rate case?

A. Yes. The model used for this study is the same model used in the last two general rate cases.

C. <u>Classification of Production Costs</u>

Q. Please describe how generation costs were classified into energy and demand components in the Company's cost of service study.

A. The Company utilized the "peak-credit" methodology to divide generation costs into demand and energy components. Based on the Company's application of this methodology, the percent of production cost classified as demand is 21%, with 79% classified as energy. The derivation of these percentages and an explanation of the peak credit method used by the Company is provided in Mr. Piliaris's Prefiled Direct Testimony, Exhibit No. ___(JAP-1T).

D. Classification of Transmission Costs

Q. How are transmission costs classified in the Company's cost of service study?

A. The Company is using the peak credit method, described above, to classify transmission costs. Using the peak credit method, 21% of transmission costs are classified as demand and 79% are classified as energy. These factors are also applied to high voltage distribution, which is the sub-230 kV plant that was classified as transmission prior to reclassification in Docket No. UE-010010.

Q. Does the Company distinguish between generation-integration transmission and other transmission?

A. Yes. Generation-integration transmission brings PSE's remote generation to PSE's integrated transmission system.[3] One must segregate the costs of generation-integration transmission from other transmission because retail rate

[3] The costs of generation-integration transmission generally consist of PSE's transmission costs related to (i) facilities in Montana acquired in connection with the Colstrip generating facilities (ii) the 3rd AC Intertie, (iii) the Northern Intertie, (iv) Wild Horse, (v) Hopkins Ridge, (vi) Frederickson, and (vii) Goldendale, as well as costs related to integrating the Mint Farm facility that are not included in the Mint Farm production costs.

Schedules 448 and 449, as well as the large customer in the Firm Resale/Special Contract class, do not use PSE's remote generation resources. Thus, it is appropriate to exclude these customers from the allocation of costs for transmission lines used for integration of remote resources. However, these classes continue to receive an allocation of PSE's other transmission costs.

E. <u>Classification of Distribution Costs</u>

Q. How are distribution costs classified in the Company's cost of service study?

A. With three exceptions, all distribution costs are classified as demand related. The three exceptions are the costs of meters, service lines and distribution line transformers. These are classified as customer related and are discussed in Sections G(2) and G(3).

F. <u>Allocation of Generation and Transmission Demand Costs</u>

Q. How are generation and transmission demand costs allocated in the cost of service study?

A. The Company uses estimated peak demands at 23°F to determine peak generation requirements for a temperature normal year in its Integrated Resource Plan. The Company reviewed hourly temperature data over the last 14 years and determined that the largest number of hours in any one year that the hourly temperature was 23°F or colder was 75 hours. Therefore, as in the past two GRCs, the Company is allocating generation and transmission demand costs based on an average of hourly class loads that occurred coincident with the top 75 system hours during the test year.

G. Allocation of Distribution Costs

1. Distribution Substations and Feeder Costs

Q. How did the Company allocate distribution substations and feeder costs in its cost of service study?

A. The Company assigned the cost of distribution underground circuits, overhead circuits, and substations based upon allocation factors constructed from each class's contribution to feeder and substation peak loads and the length of the distribution circuit. These allocation factors were constructed from monthly energy and load factors for the twelve-month period ending December 2008.

Q. Would you please describe specifically how substation costs were allocated?

A. For each month, each customer class's contribution to the peaks, as a percent of those peaks, of individual distribution substations was calculated using the average hourly consumption of each class's load on the substation, divided by the non-coincident peak ("NCP") load factor of that class in that month. Each class's contribution to the peak load on each individual substation was then averaged across the months of the year. This average monthly contribution to each substation's peak load was then multiplied by the booked cost of the individual substation in 2008 dollars to derive the allocated cost of each substation. These allocated substation costs were then summed by customer class and compared with the Company's total substation investment in 2008 dollars to develop the substation cost allocations for FERC Accounts 360-362.

Q. How did PSE allocate distribution line costs?

A. The Company used its customer and distribution feeder databases to associate each customer with a feeder. Monthly NCP load factors were then used for each customer class to determine each class's contribution to each feeder's monthly NCP as a percent of each month's peaks. Each class's contribution to monthly peak load was multiplied by the number of overhead and underground miles on the feeder. These load-weighted line miles were then added across all the feeders to develop the total load-weighted overhead and underground distribution line miles allocated to each class. Allocation factors for overhead and underground lines were then developed by dividing the total load-weighted line miles attributable to each class by the total load-weighted line miles for all classes. The overhead allocators were applied to FERC Accounts 364 and 365, and the underground allocators were applied to FERC Accounts 366 and 367.

Q. Why has PSE incorporated miles of distribution lines into the cost allocation?

A. The cost of building overhead or underground distribution lines is primarily a function of distance, with cost adjustments for capacity. Cost is driven by the number of miles of trench excavated, miles of conductor required, number of poles installed, etc. There is an incremental cost for load, but it is relatively small, particularly because the Company uses only a few standard wire sizes for overhead and underground feeders and taps in order to reduce ordering, inventory, and record-keeping costs.

2. Distribution Line Transformer Costs

Q. Please describe how the Company classifies and allocates line transformer costs in its cost of service analysis.

A. As in PSE's previous two cases, line transformers are classified as a customer cost because line transformers are installed specifically to serve a particular customer or group of customers. Once installed, the transformer represents a fixed cost of providing service to the customer or group of customers. For example, in the typical residential subdivision developments being constructed today, the Company installs a 37.5 kVA pad-mounted transformer for every twelve homes.

Q. Are the transformer costs the same for each customer?

A. No. Transformer costs vary due to density of customers, and for large load customers the transformer is sized for the anticipated load. However, once a transformer is placed in service, it is normally there for the life of the transformer.

The Company uses standard transformer sizes in order to reduce ordering, inventory and record keeping costs.

In summary, transformer sizes are standardized, transformers are sized to serve a particular customer or group of customers, and transformers are rarely re-sized for a particular customer or a group of customers. Therefore, transformer costs are appropriately characterized as customer related costs as opposed to demand related costs.

Q. Is it appropriate to classify a piece of utility equipment as customer-related even though it serves multiple customers?

A. Yes. The appropriateness of the classification depends on the function the equipment serves, not the number of customers served. There are many examples of costs that are universally accepted as customer costs that serve many customers, such as the costs of billing systems and meter reading systems. The test is not whether the cost is dedicated to a single customer or a group of customers, but whether the cost is best characterized as varying with the number of customers, the customers' demands or the customers' usage.

Q. Please describe how the line transformer cost allocation factor was developed.

A. The Company used its customer database to associate each line transformer with the customers using the transformer. This resulted in allocating approximately

250,500 transformers to the different classes by type and size. Approximately 91% of the line transformers are used by a single class and thus were directly assigned. The remaining transformers were assigned to each class based upon the class's relative contribution to the transformer's load. The transformers were priced at current costs, including installation, to determine each class's contribution to embedded line transformer costs (FERC Account 368). The embedded line transformer costs in the FERC account reflect the Company's line extension policy and have been reduced by an allocated amount of customer contributions.

3. Service Line and Meter Costs

Q. How were service line and meter costs allocated in the Company's cost study?

A. Service line costs were allocated based on the number of customers taking service at secondary voltage. Costs of all underground service lines were assigned to the residential class because non-residential secondary voltage customers own their underground services. Costs of overhead service lines were allocated based on the number of secondary voltage overhead service customers in each class. Meters were allocated based on the current cost of meters assigned to customers in each class.

H. Administrative and General Costs and Other Cost Allocation Factors

Q. How did PSE allocate administrative and general costs?

A. The majority of administrative and general costs were assigned based upon adjusted production, transmission, distribution, and customer costs. Property insurance allocations were based upon allocated plant, and pensions and employee insurance followed the allocation of salary and wages.

Q. What other cost allocations did PSE use in its cost of service study?

A. The Company reviewed historical experience with late payments and assigned the costs to each class. Other miscellaneous revenues associated with non-sufficient fund checks and reconnects are allocated to each class based upon a historical analysis of revenues received from these sources.

Q. Has the Company provided a summary of its electric cost of service study in this proceeding?

A. Yes. The Company's proposed electric cost of service study is summarized in the Second Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(DWH-3).

III. ELECTRIC RATE SPREAD PROPOSAL

Q. Would you briefly describe rate spread and its relationship to cost of service?

A. Rate spread is the process of determining what portion of the total revenue requirement should be allocated to each customer class for recovery in that class's rates. Rate spread is guided by the results of the cost of service study.

Q. What rate spread policy factors did the Company consider in developing its electric rate spread recommendation?

A. The Company's proposal emphasizes two factors: the customer class relationship to parity and customer impacts. The Company's proposal is influenced by the results of the cost of service study and continues movement towards parity. But the Company is also concerned about the relative impact on different classes of customers.

Q. Would you please summarize the Company's proposed rate spread?

A. Based upon the parity percentages shown in the Company's cost of service study and the desire to move towards full parity (a parity percentage of 100%) in a gradual manner, the Company proposes to 1) apply, with one exception, an adjusted average rate increase to retail classes within 5% of full parity; 2) apply a rate increase that is 75% of the adjusted average to the three classes that are more than 5% but less than 10% above full parity (General Service less than 51 kW, Primary Service, and Lighting); and 3) apply an increase that is 50% of the average to the one class that is 10% or more above full parity (General Service, 51 – 350 kW). No retail class will receive a rate increase greater than the adjusted average rate because in this study there are no classes that fall below the parity percentage band of 95% - 105%.

The one exception mentioned above is Choice/Retail Wheeling (schedules 448/449). The parity percentage for this class is 94.46%, barely outside the band of plus or minus 5%. Because it is so close to being within the band, PSE proposes that this class receive the average increase.

As discussed below, rates in Schedule 40 (Large Demand General Service Greater than 3 aMW) are tied to rates in the high voltage schedules, such that the rate increase for that schedule is not independently determined.

The Wholesale for Resale/Contract class is allocated an amount that would move it to full parity so that there is not a cross-jurisdictional subsidy.

The adjusted average rate increase is the average rate increase after accounting for the effect of less than average increases to certain classes. Since there are no classes that receive a greater than adjusted average increase, the adjusted average increase of 8.37% is greater than the Company average retail increase of 7.40%.

As in PSE's last rate case and consistent with the Merger Agreement approved in Docket No. U-072375, the Company proposes to spread a proportion of the rate increase to Schedule 40 based upon the tariff design developed in its 2004 GRC. This design links the Schedule 40 production and transmission charges to those found in the High Voltage schedule and establishes a distribution charge based on customer-specific information. This results in a calculated rate spread amount for this class, rather than a rate spread based on class specific cost of service and rate spread analysis.

A summary of the Company's proposed rate spread is provided below. Please also see the Third Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(DWH-4), for a detailed worksheet of PSE's rate spread proposal.

Customer Class	**Rate Schedule**	**Parity Percentage**	**Proposed Rate Increase**
Residential	7	95%	8.37%
General Service, < 51 kW	24	107%	6.28%
General Service, 51 - 350 kW	25	112%	4.19%
General Service, >350 kW	26	105%	8.37%
Primary Service	31/35/43	109%	6.28%
Campus Rate*	40	89%	8.68%
High Voltage	46/49	98%	8.37%
Lighting Service	51 - 59	109%	6.28%
Choice/Retail Wheeling	448/449	94%	8.37%
Total Jurisdictional Retail Sales	**n/a**	**n/a**	**7.40%**
Firm Resale/Special Contract	5	88%	22.35%**
System Total/Average		**100%**	**7.41%**

*Campus Rate increase proposal reflects customer-specific distribution rates according to agreement.

**Reflects allocation of portion of system rate increase to non-jurisdictional rates.

IV. ELECTRIC RATE DESIGN

Q. What rate design principles guided you in your rate development?

A. Rates should: (1) provide for recovery of the total revenue requirement; (2) provide revenue stability and predictability to the utility; (3) provide rate stability and predictability to the customer; (4) reflect the cost of providing service; (5) be fair; (6) send proper price signals; and (7) be simple and understandable. These principles are consistent with those presented in "Principles of Public Utility Rates," by James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, 2nd Edition, 1988.

Q. Please summarize the changes the Company proposes to make to electric rate design.

A. The Company is not proposing any changes in this case to the design of existing rates. With only minor exceptions, all rates in a customer class will be increased by the class average percentage increase. The exceptions are Schedule 25, where the demand rate is tied to Schedule 31; Schedule 40, where, according to agreement, customer specific distribution rates are charged; and Schedules 448/449, where, according to agreement, the methodology of PSE's 2007 GRC was used and the rate increase applied on an equal dollar per kVA basis rather than equal percentage.

Q. Has the Company prepared new tariff schedules based upon the cost of

service study results and consistent with its rate design proposals in this case?

A. Yes, the proposed tariff schedules are presented in the Fifth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(DWH-6).

A. Summary of Residential Rate Design

Q. Please summarize the Company's proposed residential rate design.

A. The current rate is a two-block energy rate with a monthly basic charge (single phase) of $7.00, a first block rate of 8.4233 ¢/kWh, and a second block rate of 10.2042 ¢/kWh. The Company proposes to increase all three charges by the class percentage of 8.37%, adjusted for rounding. This results in a proposed basic charge (single phase) of $7.59 a month, a first block rate of 9.1275 ¢/kWh and a second block rate of 11.0584 ¢/kWh.

Q. How does PSE's proposed residential basic charge compare with basic charges of other utilities?

A. I reviewed the basic charges of national and local investor-owned electric utilities and government and customer-owned utilities in Washington state that are close to PSE's service territory. The 223 basic charges of national electric utilities average $7.63 a month, almost exactly the amount proposed in this filing. Of the 25 Washington state electric utilities surveyed, seventeen have residential basic charges that are higher than $7.59 a month, and the average basic charge for all

26 utilities (including PSE) is $10.33. These basic charges are shown in the Fourth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(DWH-5).

Q. What are the bill impacts of your proposed increase in residential rates?

A. Please see the Prefiled Direct Testimony of Lorin Molander, Exhibit No. ___(LIM-1T), for a discussion of the bill impacts of the Company's proposal to residential rates.

B. Summary of Small and Medium General Service Rate Design

Q. Please summarize the proposed rate design for small load general service.

A. The Small Load General Service (Rate Schedule 24) class is not demand metered and has a single block seasonal rate. The Company's proposal is to increase all rates, including the basic charge, by the class average increase.

Q. Please summarize the proposed rate design for medium load general service.

A. The Small Demand General Service (Rate Schedule 25) class has a basic charge rate, two block seasonal energy rates and a two-block seasonal demand rate. The first 50 kW block has no demand charge and the demand-related costs are recovered in the first block of the energy rate. Under the Company's proposal, all Schedule 25 rates are increased by roughly the same percentage, the class average increase.

C. Summary of Large General Service Rate Design: Schedules 26 and 31

Q. Please summarize the proposed large general service rate design.

A. There are two rates in this group: Large Secondary (Rate Schedule 26) and Primary General Service (Rate Schedule 31). The demand rates of the two schedules are linked such that the lower rate for Schedule 31 reflects both the cost savings to the Company of not providing primary voltage transformation service and a discount for Schedule 31 energy and demand based on lower transformer losses (since Schedule 31 meters are located on the high side of the line transformer). The energy rates are not directly linked due to differences in parity percentages for the two schedules.

Q. Why does the Company link the demand rates of the two schedules?

A. For a number of years the Company has been moving these two rate schedules towards comparable rates because the loads and load factors are comparable. The drive towards a cost-based differential between the two rates schedules is to create an end-point where customer motivation to take primary service will be based upon customer needs rather than a desire to qualify for the schedule with the lower rate.

Q. Please describe the proposed Schedule 26 and Schedule 31 rate designs.

A. PSE increased all Schedule 31 rates by the class average increase. Due to the class parity percentage, this class average increase is 75% of the adjusted average for all classes. PSE increased the Schedule 26 basic charge by the class average, which is 100% of the adjusted average for all classes. The reactive power charge for each schedule was increased by the class average increase for that schedule. The Schedule 26 demand charges were then set equal to the Schedule 31 demand charges on a loss adjusted basis. PSE then increased the Schedule 26 energy rate by an amount that will recover the remainder of the rate responsibility of the Schedule 26 rate class.

Because of the demand rate linkage, the percentage increase in demand rates for Schedule 26 will differ from the percentage increase in energy rates for that schedule. As a result, not all customers in the Schedule 26 class will see the exact same percentage increase in their monthly bills.

D. <u>Campus Rates: Schedule 40</u>

Q. Please describe the purpose of Schedule 40.

A. This rate, Large Demand General Service Greater than 3 aMW, was developed in PSE's 2004 GRC in response to customers with large loads that are either typically in a campus configuration or share a distribution feeder with other customers. The rate first became effective on March 17, 2005 and was voluntary until the GRC following the third anniversary of that date, which is this proceeding. The rate requires a cost study to be performed by the Company to establish a customer-specific distribution charge, and customers can only be added in a GRC.

Q. Has the Company identified any customers that should be added to Schedule 40 in this case?

A. Yes. As noted above, Schedule 40 is now mandatory once a qualifying customer has been identified and approved for Schedule 40 service in a general rate case. There is one additional customer who now qualifies for this rate. This customer has been included in Schedule 40.

Q. Please summarize the rate design for Schedule 40.

A. Rates for Schedule 40 are calculated using the current calculated rate methodology, as required under Paragraph 61 of Appendix A of the Multiparty Settlement Agreement approved by the Commission in the Company's merger proceeding, Docket No. U-072375. Schedule 40 has customer-specific distribution rates and a bundled energy and transmission rate that is based upon Schedule 49 after an adjustment for losses. The distribution rate is designed to recover customer-specific distribution costs on a levelized basis. The bundled production and transmission energy and demand rates are linked to the parity-adjusted high voltage rates because the aggregated load of each of these customers is comparable to the load of high voltage customers.

The Company reviewed the distribution rates of the customers and adjusted their distribution costs, transformer costs, and substation costs based on plant additions and retirements that have occurred since the Company's 2007 GRC.

As stated earlier in my testimony, there is one additional customer who now qualifies for Schedule 40, and this customer has been included in Schedule 40.

E. Summary of High Voltage Rate Design

Q. Please summarize the high voltage rate design.

A. All rates for the full requirements non-interruptible high voltage customers (Schedule 49) and the interruptible high voltage customers (Schedule 46) were increased by the class average increase.

All rates for the Power Supplier Choice and Retail Wheeling Rates (Schedules 448 and 449) were increased using the same methodology used in PSE's 2007 GRC, pursuant to Paragraph 60 of Appendix A of the Multiparty Settlement Agreement, approved by the Commission in the Company's merger case, Docket No. U-072375. Under such methodology, the basic charge is set at its cost of service, and the allocated amount remaining is recovered on an equal dollars per kVA basis.

V. ADJUSTMENTS TO LOAD

Q. Does the Company's electric cost of service and rate design incorporate any adjustments to loads made in this case?

A. Yes. The cost of service reflects weather normalization of power costs and the rate design reflects weather normalization of test year loads (and billing determinants). Based upon the implementation of the Company's weather normalization methodology, 88% of the kWh weather adjustment was applied to the residential class. These weather normalization adjustments are discussed in Ms. Molander's Prefiled Direct Testimony, Exhibit No. ___(LIM-1T), and Mr. Story's Prefiled Direct Testimony, Exhibit No. ___(JHS-1T). In addition, the cost of service and rate design reflect the adjustment to test year loads (and billing determinants) for the phasing in of Company-funded conservation programs during the test year. The conservation phase-in adjustment is discussed by Mr. Piliaris in his Prefiled Direct Testimony, Exhibit No. ___(JAP-1T).

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.