EXHIBIT NO. ___(DWH-1T)
DOCKET NO. UE-07___/UG-07___
2007 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-07____** **Docket No. UG-07____**

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

DECEMBER 3, 2007

PUGET SOUND ENERGY, INC.

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PUGET SOUND ENERGY, INC.

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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 4th 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. Please summarize the purpose of your testimony.

A. My testimony presents the Company's electric rate spread proposal. 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 is called "parity." The electric cost of service results in this case indicate that two customer classes, the residential and the non-jurisdictional wholesale for resale classes, are significantly below parity, while several other classes are significantly 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 does not rigidly move each class to parity.

I also present the Company's electric rate design proposal. Please see the prefiled testimony of Ms. Janet K. Phelps, Exhibit No. ___(JKP-1T), for the Company's gas rate design proposal. In order to provide increased bill stability and more equitable rates, the Company is proposing a larger than proportional increase in the basic charge for residential and non-residential electric and gas customers, with a corresponding decrease in the kWh and per therm charges. I discuss in detail the benefits to customers of increasing the Basic Charge for residential electric and gas customers.

Similarly, in order to move electric demand charges for non-residential customers closer to their cost of service the Company is proposing a larger than proportional increase to these charges. No other major changes are proposed.

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II. ELECTRIC COST OF SERVICE

A. Background Regarding Electric Cost of Service Studies

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 and 2006 (Docket Numbers UE-040641 and UE-060266).[1] In each of the two prior general rate case filings two separate studies were filed.

Q. Please describe the methodology used in those studies.

A. All studies used the same basic methodology for functionalization of costs. However, there are some differences in how the studies allocated costs among the different rate classes. 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 last litigated electric cost of service study in Docket Nos. UE-920499 and UE-921262 ("1992 Cost of Service Study") without any significant modification to how the calculation was performed. A second version

[1] 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.

of the cost of service studies prepared for the Company's 2004 and 2006 general rate case 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.

Q. What updates have been made to the cost classification factors since the 1992 Cost of Service Study?

A. Energy production costs continue to be classified as demand and energy related using the peak credit method. However, the peak credit factor has been modified as discussed later in my testimony.

Q. What updates have been made to the factors used to allocate generation and transmission costs among rate classes since the 1992 Cost of Service Study?

A. Two significant updates have been made. First, there are two new rate classes added to the cost of service study since the 1992 study—Transportation customers and the Campus Rate. The Campus Rate is Schedule 40 (Large Demand General Service Greater than 3 aMW). Customers on this rate have direct assignment of distribution costs. The Transportation class is not allocated any generation costs in this filing since the members of that class are responsible for procuring their own power.

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The second update is that the demand component of generation costs is allocated to each rate class based upon each class' contribution to the top 75 peak system hours rather than the highest 200 hours.

Q. What updates have been made to the factors used to allocate distribution costs among rate classes since the 1992 Cost of Service Study?

A. As I describe later in my testimony, the Company's filing allocates costs based upon each class' 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 in the 1992 Cost of Service Study in which the cost allocation was based upon an estimate of each class' system aggregate NCP. Another difference, also described later, is that the allocation of the cost of line transformers relies on a direct allocation rather on an aggregate class level contribution to the NCP. Customers on the Campus Rate have direct allocation of all distribution plant costs.

Q. How was the cost of service study performed in this case?

A. This is the same cost of service analysis, updated with current data, as was provided by the Company as its preferred approach in its 2006 general rate case. The analysis in the cost of service study in this case utilizes the basic methodology approved in the 1992 Cost of Service Study, with updates to the actual numbers used in the study based on developments over the last fifteen years.

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 allocation of those costs to each rate class. This allocation is done by first directly assigning to a rate class any costs determined to be caused by that rate class alone. Joint costs that are shared by multiple customer classes are then allocated to various rate 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.

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 study starts with the electric revenue requirement that is set forth in the testimony of Mr. John Story, Exhibit No. ___(JHS-1CT), which represents the Company's costs to provide service to its electric customers.

The first step 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.

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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 facilities that are needed to meet peak demands. While these facilities may not be fully utilized at all times, they must be designed and installed to meet the maximum load that is anticipated for the facilities.

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 by the utility for its electric sales customers.

One of the challenges of the classification of costs into demand, energy, and customer components is that some utility equipment is commonly considered to serve multiple functions. Generation equipment is widely recognized as having both demand and energy components, with some facilities primarily serving peak needs while other facilities primarily provide energy. The demand component reflects the cost of capacity to serve peak demands.

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

Q. Does the Company's cost of service study utilize the methodology for classification and allocation of electric costs that was used in the Company's last general rate case?

A. Yes. In the last general rate case the Company proposed updates to the cost of service methodology that has been in place for many years. All issues regarding cost of service, rate spread and rate design were settled in the 2006 general rate 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. The cost of service study in this case utilizes the same methodology as was used in the last general rate case. This methodology is discussed in more detail in sections C through G below.

Q. What are the results of the cost of service study?

A. The parity and customer costs 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. The customer costs represent the costs classified as "customer" in the cost of service study expressed on a dollar per customer basis.

Customer Class	Parity	Customer Costs per customer
Residential	93%	$9.14
General Service, < 51 kW	101%	$17.03
General Service, 51 – 350 kW	121%	$75.40
General Service, >350 kW	117%	$155.76
Primary Service	105%	$356.02
Campus Rate	103%	$818.30
High Voltage	99%	$1649.91
Lighting Service	110%	$7.89
Transportation	96%	$1328.85
Firm Resale	85%	$473.42
System Total / Average	100%	N/A

Q. Was the model used to develop the cost of service study the same model used in the last general rate case?

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

C. Classification of Generation Costs

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, a method that has a long tradition in this region. The genesis of the method (analyzing capacity cost relative to base load cost) is shared by a number of commonly used cost classification methodologies. One of the advantages of the peak credit method is that it does not require the classification of individual generating unit costs.

Specifically, the peak credit method used by the Company classifies all electric production costs, regardless of the type of generation, as either energy or demand based on the ratio of the cost of a simple cycle turbine ("CT") to a combined cycle combustion turbine ("CCCT"). The calculation of the cost of the CT is based upon using 100% of the capital and fixed cost of the CT plus the fuel costs based upon seventy five hours a year of operation. The calculation of the CCCT is based upon the full costs of a combined cycle turbine operated as a base load unit. Both the numerator and denominator of the ratio are expressed in $/kW year. The fuel cost used in the numerator is based upon firing the unit with natural gas, adjusted to reflect cost of gas during extreme peak periods.

Q. What is the result of the peak credit calculation?

A. The percent of production cost allocated to demand is 26% with 74% allocated to energy. I have provided the calculation in Exhibit No. ___(DWH-3C).

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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, as described in the prior section of my testimony, to classify transmission costs. This results in the classification of transmission costs as 26% demand and 74% energy.

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

A. Yes. Generation-integration transmission is that transmission that brings PSE's remote generation to PSE's integrated transmission system. (The costs of this transmission generally consist of (i) PSE's costs of transmission facilities in Montana acquired in connection with the Colstrip generating facilities and (ii) PSE's 3rd AC Intertie costs.) The segregation of the costs of this type of transmission is necessary because retail rate Schedules 448 and 449 as well as the large customer in the Firm Resale class do not use PSE's remote generation resources. Thus, it is appropriate to exclude them 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.

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E. Allocation of Generation and Transmission Demand Costs

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

A. The Company uses peak demands at 23°F and 16°F to determine peak generation requirements for its cost of service study. In the last general rate case we examined the number of hours in the previous 10 years when the hourly temperature was 23°F or colder and determined the largest number of hours below 23°F in a year was 75 hours. We also reviewed past data to look at the relationship between peak loads and temperatures. While the data did not suggest a clear cut-off point, the top 75 hours have peaks that were within 90% of the system peak. Thus, the Company is using a demand allocation factor tied to historical contribution to system coincident peaks of 75 hours.

F. Distribution Cost Allocation

1. Distribution Substations and Feeder Costs

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

A. The Company assigns the cost of distribution underground circuits, overhead circuits, and substations based upon allocation factors constructed from each class's contribution to the feeder's and substation's peak and the length of the distribution circuit. These allocation factors were constructed from monthly energy and load factors for the twelve-month period ending September 2006.

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

A. Each customer class's contribution to the distribution substation's peak was calculated using average hourly consumption of each class's load on the substation divided by the non-coincident peak (NCP) load factor of that class. The resulting percentage was multiplied by the substation's net plant balance expressed in 2007 dollars to develop the substation cost allocations for FERC accounts 360-362.

Q. How were distribution line costs allocated?

A. The cost of the distribution feeder investment is a function of both load and line miles. The Company used its customer and distribution feeder databases to associate each customer with a feeder. NCP load factors were then used for each customer class to determine each class's contribution to each feeder's non-coincident peak. Each class's contribution to peak was multiplied by the number of overhead and underground miles on the feeder. These allocators were then summed across all the feeders to develop the overhead and underground distribution line cost allocators. 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 have you 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. Line transformers are classified as a customer cost. 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.

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

A. No, there are variations 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 and customer demands are relatively stable. 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. Would you 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 247,500 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).

Q. How were costs of service lines allocated in the Company's cost study?

A. Costs of service lines were allocated based on the number of customers taking service at secondary voltage. Costs of all underground service lines were allocated to the residential class since non-residential secondary voltage customers own their own services. Costs of overhead service lines were allocated based on the number of secondary voltage overhead service customers in each class.

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G. Administrative and General Costs and Other Cost Allocation Factors

Q. How were Administrative and General costs allocated?

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 follow the allocation of salary and wages.

Q. What other direct cost allocations are used in the cost of service study?

A. The Company reviewed historical experience with late payment 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.

Q. What exhibit contains the Company's electric cost of service study?

A. The Company's proposed electric cost of service study is provided as Exhibit No. ___(DWH-4).

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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. Cost of service provides guidance in structuring rates by identifying the customer, demand, and energy components of the revenue requirement.

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. The Company continues to advocate movement towards parity, but 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 ratios shown in the Company's cost of service study and the desire to move towards parity in a gradual manner , the Company proposes to apply the average rate increase to retail classes within 5% of parity, apply a rate increase that is 125% of the average to the rate class that is below 95% of parity (residential class) , apply a rate increase that is 75% of the average to the one class that is more than 5%, but less than 10%, above parity (Lighting), and apply an increase that is 50% of the average to the two classes that are over 10% above parity (Medium Secondary Voltage and Large Secondary Voltage). 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 is moved to full parity so that there is not a cross-jurisdictional subsidy.

The Company proposes to spread a proportion of the rate increase to Schedule 40 based upon the tariff design developed in the 2004 general rate case. This design links the Schedule 40 Production and Transmission charges to the high voltage charge 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. The rate increase resulting from this is approximately 50% of the average increase for all schedules.

A summary of the proposed rate spread proposal follows and the detailed worksheet is Exhibit No. ___(DWH-5).

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Customer Class	Rate Schedule	Parity	Proposed Rate Increase
Residential	7	93%	11.78%
General Service, < 51 kW	24	101%	9.43%
General Service, 51 - 350 kW	25	121%	4.71%
General Service, >350 kW	26	117%	4.71%
Primary Service	31/35/43	105%	9.43%
Campus Rate	40	103%	5.00%
High Voltage	46 / 49	99%	9.43%
Lighting Service	51 - 59	110%	7.07%
Transportation	448 / 449	96%	9.43%
Firm Resale	5	85%	29.47%
System Total / Average		100%	9.51%

IV. ELECTRIC RATE DESIGN

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

A. I was guided by the following seven principles, which are fundamental to a sound rate structure. 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's electric rate design changes include:

- Increasing the basic charges in order to recover more nonvariable costs on a fixed charge basis;
- Increasing the demand charges up to 150% of the class average rate increase in order to move those charges closer to the demand costs identified in the cost of service study, and;
- Linking the rate design of Schedules 26 and 31 as part of the Company's effort to combine the two rates for the large load customers and offer a cost-based differential for customers selecting primary voltage transformation services.

I review each of these changes below and summarize how the rate increase was applied to the current rate structures.

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 Exhibit No. ___(DWH-7). In addition to rate changes, the proposed tariff schedules also include a language change for Schedule 40 to indicate that the schedule will no longer be optional.

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A. <u>Summary of Residential Rate Design</u>

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 of $6.02. The Company proposes to increase the basic charge to $9.00 for single phase and to $22.25 for three phase service. The remainder of the increase allocated to the class was applied on an equal cents per kWh basis to each block.

Q. Why is the Company proposing an increase of $2.98 in the Basic Charge?

PSE's current electric rate schedules rely heavily on volumetric rates to recover fixed delivery and customer costs, as do its gas rate schedules. As a result, customers who use more electricity pay more customer costs than customers who use less electricity, even though their customer costs are no different. Additionally, payments of these costs vary by season and temperature, even though the costs themselves do not vary. Customers will benefit from bill stability and predictability when basic charges are set equal to customer costs. This bill stability and predictability also benefits the Company, resulting in a win-win situation. This is a critical rate design issue that is common to both electric and gas, and is discussed in more detail in a separate section of my testimony.

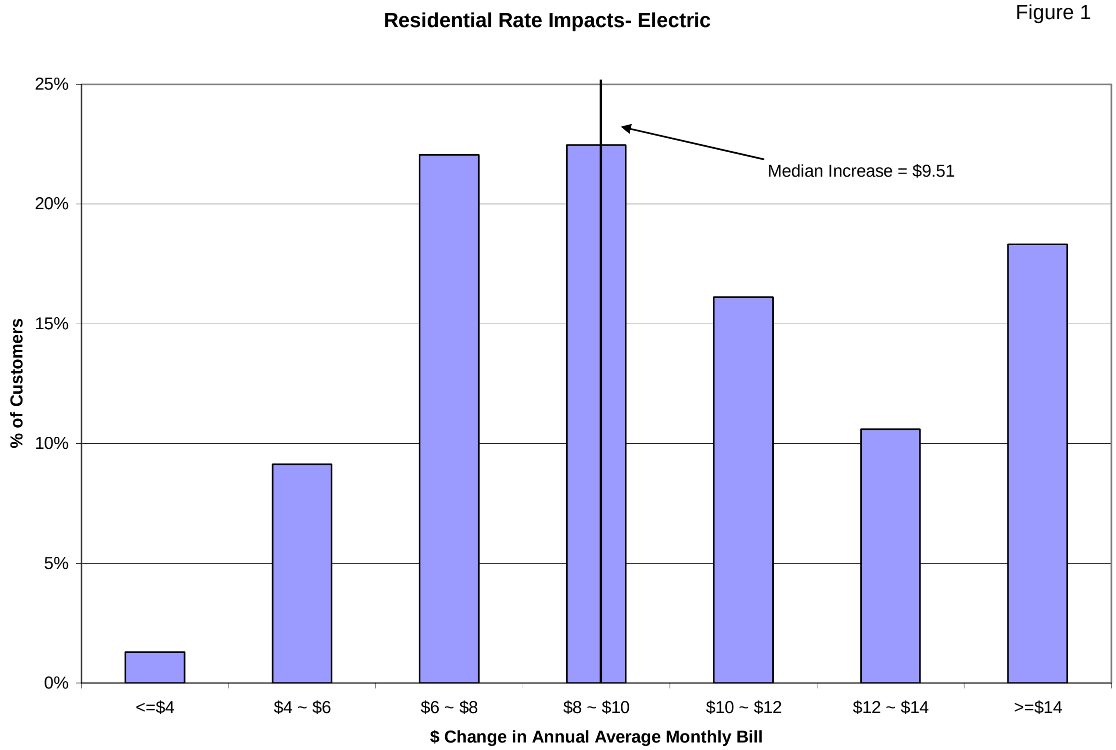
Q. How does PSE's proposed residential basic charge compare with basic charges of other utilities?

A. I reviewed the basic charges of the electric utilities that are close to PSE's service territory, plus the two other investor owned utilities in the state. Of these 25 Washington state electric utilities, all but nine have residential basic charges that are higher than $9.00 a month. The Company's proposal of $9.00 a month would keep the Company's basic charge in the bottom one/third of its neighbors'. These basic charges are shown in Exhibit No. ___(DWH-6).

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

A. The average increase our typical residential customer using an average of 1,000 kWhs a month will see, over a 12 month period, is $10.65 a month. Depending on usage, some bills will increase more, some less. Because of our basic charge proposal, no customer will have an increase that is less than $2.98 a month. One-half of our customers will see an increase of less than $9.51 a month. Over 15% will see increases of greater than $14 a month, but these are customers who already have significantly higher than average loads and bills, because they have higher than average usage. Figure 1 below depicts the impacts of the proposed residential rates on individual customer's bills.

Figure 1



Q. Is the Company proposing to increase bill assistance funding to low income electric customers to help offset the impact of this proposed increase in bills?

A. Yes. As mentioned in the testimony of Mr. Markell, Exhibit No. ___(EMM-1CT), the Company is proposing an increase in funds to support the ability of its low income customers to pay their electric and natural gas bills. The Company proposes to increase the annual level of low-income electric bill assistance by the percent rate increase for the residential electric class that is approved by this Commission. The Company will file for uniform percentage increases to the annual caps in the Schedule 129 tariff riders, along with the resulting surcharge rates, upon receipt of the final order of this Commission.

Q. Is the Company proposing a corresponding increase in bill assistance funding to low income natural gas customers to help offset the impact of this proposed increase in bills?

A. Yes. The Company proposes to increase the annual level of low-income natural gas bill assistance by the percent rate increase to the residential class that is approved by this Commission. The Company will file for uniform percentage increases to the annual caps in the Schedule 129 tariff riders, along with the resulting surcharge rates upon receipt of the final order of this Commission. In addition, as I discuss later, an adjustment to low-income assistance will be made to offset the impacts of the natural gas basic charge increase should the Company's proposal be accepted by the Commission.

B. Summary of General Service Rate Design

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

A. The General Service (Rate Schedule 24) class is not demand metered and has a single block seasonal rate. The Company's proposal is to increase the basic charge rate to $11.75 for single phase and $29.50 for three phase service. These basic charges average about $16.70 a customer, which approximates the customer cost for the class. The remainder of the increase is applied in an equal percentage to the summer and winter energy rate.

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

A. The Small Demand General Service (Rate Schedule 25) class has a two block seasonal energy and demand rate. The first block has no demand charge and the demand component is recovered in the first block of the energy rate. The current basic charge is significantly below customer costs. Under the Company's proposal the basic charge is increased so that there is only a small discrepancy between customer cost and the basic charge. The demand charges were increased by 150% of the class average. All other charges except the second energy block were increased by the average increase of the class. The balance of the revenue requirement was applied to the second energy block.

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 ratios for the two schedules. However, the Company would like to eventually eliminate this parity difference between the two schedules and eventually link the energy rates as well as the demand rates. By applying only 50% of the average rate increase to Schedule 26, as discussed in the rate spread section of my testimony, our proposal in this case continues the movement toward eliminating this parity difference.

Q. Why does the Company want to link 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 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 summarize the proposed Schedule 26 and Schedule 31 rate design.

A. From our rate spread analysis we determined the rate responsibility for each schedule which results in a rate increase applied to Schedule 26 of one-half of the rate increase applied to Schedule 31. This narrows the difference in parity ratios between the two schedules. Further, the demand charges for Schedule 31 were set based on the cost of service study subject to the constraint that the increase in the demand charges is no more than 150% of the average total rate increase to the Schedule 31 class. The Schedule 26 demand charges were then set equal to the Schedule 31 demand charges on a loss adjusted basis. The result of this rate design is that the Schedule 26 demand charges are closer to the demand cost in the cost of service study.

The Schedule 31 and 26 energy rates were then calculated to spread the remaining rate responsibility allocated to each class after applying an average increase to the reactive power charges (VARH). The result is that the Schedule 26 energy rate is still higher than the Schedule 31 energy rate on a loss-adjusted basis because the parity ratios of the two schedules are not yet equal, but that difference has been reduced from approximately 7% to 1%.

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 the 2004 general rate case 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 general rate case following the third year anniversary of that date, which is this case. 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 general rate case proceeding.

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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 for the purposes of the pro forma and proposed rate design.

Q. Please summarize the rate design for Schedule 40.

A. 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 total 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 on the rate and identified several adjustments to the customer-specific distribution costs. One customer requires an adjustment to the distribution line costs as well as transformer cost assignment changes. Additionally, the customer-specific distribution costs for all but one customer had an adjustment to the substation cost assignment based upon plant additions and retirements occurring since the last general rate case.

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 for the purposes of the pro forma and proposed rate design.

E. Summary of High Voltage Rate Design

Q. Please summarize the high voltage rate design.

A. The demand charge for the full requirements non-interruptible high voltage customers (Schedule 49) was based upon the cost of service study subject to the constraint that the demand charge percentage increase does not exceed 150% of the average rate increase assigned to the class. The percentage adjustment in the Schedule 49 demand charge was applied to the Schedule 46 (interruptible high voltage service). The remainder of the increase was spread to the Schedule 46 / 49 energy rates, which are the same for both schedules.

The rate increase was assigned to the Power Supplier Choice and Retail Wheeling Rates (Schedules 448, 449 and 459) in a two-step process. The first step was to calculate any change in the basic charge. The second step was to take the remaining increase to be allocated and calculate that increases on a dollars per kVA basis. This approach was used, rather than an equal percentage approach, to avoid creating further disparities in the parity ratios between the primary and high voltage rates.

F. Power Cost Adjustment Clause: Schedule 95

Q. Is the Company filing a revised Schedule 95 with this rate case?

A. Yes. We are setting all Schedule 95 rates to zero, because the revenues currently being recovered from this rate schedule will be recovered through the general rate schedules.

V. TEMPERATURE ADJUSTMENT

Q. Does the Company's electric cost of service and rate design implement the Company's weather normalization methodology?

A. Yes. The cost of service reflects the temperature adjusted power costs and the rate design reflects the pro forma adjustment of energy sales to reflect that the test year was colder than normal. Based upon the implementation of the Company's weather normalization methodology, 86% of the kWH weather adjustment was applied to the residential class.

Q. Did the Company use the same weather normalization methodology in this case as in the last general rate case?

A. Yes, the same approved methodology was used with updated information.

Q. Please describe how the weather normalization is calculated.

A. The test year pro forma billed loads by schedule shown on Exhibit

No. ___(DWH-5) and at the system level on Exhibit No. ___(JHS-4) have been adjusted for, and thus include 129,434 MWh of temperature adjustment. The system MWh temperature adjustment in Exhibit No. ___(JHS-4) was calculated in total and allocated to each of the applicable schedules by month based on the Company's temperature adjustment methodology presented in the 2006 GRC. The Commission expressed satisfaction with the Company's weather normalization analysis in that docket. *See* Docket Nos. UE-060266 and UG-060267, Order 08, ¶ 163.

Q. Please describe how the Company normalized the test year system level delivered load in this case.

A. As was done in the 2006 GRC, PSE used weather sensitivity coefficients based on actual daily load data and actual Sea-Tac temperature to adjust system level delivered load (Generated Purchased and Interchange, or GPI) for weather. PSE's "normal" weather dataset was developed using data reported at Sea-Tac International Airport over the 30-year period from 1977 through 2006 by calculating daily heating degree days ("HDDs") and cooling degree days ("CDDs") using several base temperatures (45 and 65 degrees for HDDs, 60 and 65 degrees for cooling). The actual HDDs and CDDs were calculated using the average of the 24 hourly temperatures compared against the base temperature. The amount of weather adjustment was calculated by taking the weather sensitivity coefficients and multiplying them by the difference between the actual and normal HDDs and CDDs. This process was done for each base HDD or CDD that appeared in the model.

Q. How did the Company use temperature normalized GPI electric load to calculate the load adjustment that should be made to various customer classes (rate schedules) related to weather effects?

A. PSE used a three-step process to adjust rate schedule pro forma billing determinants for temperature. The first step was to develop linear regression equations to characterize the relationship between temperature and load for each rate schedule. The coefficients of those equations were permitted to vary by month and by class. The data source for this step was a large sample of daily energy readings from PSE's automated meter reading database. The second step was to simulate daily customer loads using the historical heating and cooling degree days and determine the average monthly load for each customer class. The third step was to weight the sample to the population and normalize the class loads to the net-of-losses weather-normalized GPI load. The amount of weather adjustment at the GPI level was allocated to each of the applicable schedules by taking the percentage share of each schedule's weather adjustment amount to total weather adjustment for all schedules as calculated by the rate schedule normalization equations, and then multiplying the system load temperature adjustment by these percentage shares.

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Q. What were the results of this process?

A. Applying the process described above to the test year GPI load of 22,960,863 MWhs resulted in a total adjustment of 138,730 MWhs, or 129,434 MWh delivered load when adjusted for losses. Because the test year was colder than normal, this adjustment resulted in a pro forma delivered system load that is smaller than actual load delivered during the test year.

With regard to rate schedule normalization, when the GPI temperature adjustment was allocated to the rate schedules the load of the residential schedule was decreased by 111,535 MWhs and the loads of most other rate schedules also decreased. The weather normalized loads of one schedule, Large Demand General Service, increased due to the varying temperature pattern experienced over the test year and that schedule's sensitivity to cooling degree days.

VI. BASIC CHARGE

A. Customer and Company Benefits

Q. Please describe the residential Basic Charge.

A. The residential electric and natural gas Basic Charge is a charge applied to each customer each month that does not vary by season or weather. The charge is meant to recover annual costs associated with providing customer service that do not vary by the amount of energy that a customer receives, the maximum amount of capacity the Company must reserve for that customer (through its generation or gas supply capabilities and/or its transmission/distribution capabilities), or the month service is taken. The residential basic charges for both gas and electric service are currently set below the cost of providing this service.

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 customer service, then other charges are set above their cost of service. For residential gas and electric customers, the only other charge is a charge per unit of energy consumed, or volumetric charge. When volumetric rates are increased above their cost of service to include customer costs that are not in the Basic Charge, the amount of Basic Charge (which does not vary with either demand or energy) actually paid by a customer will be larger or smaller depending on the amount of energy that customer consumes in a month, even though customer costs are not larger or smaller in the month. This has several consequences.

1. It results in customers paying more or less customer costs than their neighbors, even though their customer costs are the same as their neighbors'.
2. It results in almost all customers paying more customer costs in the winter, even though their customer costs are not higher in the winter.
3. It results in almost all customers paying less customer costs in the summer, even though their customer costs are not lower in the

summer.

4. It results in customers paying more customer costs when it is cold, even though customer costs do not vary with temperature.

5. It results in the amount of customer costs a customer pays being unpredictable, even though customer costs are actually very predictable.

In summary, setting the basic charge at a rate less than an amount that covers annual customer costs results in rates that are unfair and are unnecessarily variable, volatile and unpredictable.

Q. Is this unfairness, variability, volatility and unpredictability a necessary consequence of the tradeoffs involved in rate making?

A. No. In order to have a tradeoff, there is usually something to be gained and something to be lost by each party. No party as a whole gains by setting basic charges at a rate below customer costs. An individual customer might gain, but as a whole, customers suffer when rates are unfair or unduly variable, volatile and unpredictable. The gain of the individual customer is at the expense of another customer. The Company also suffers, because if bills are variable, volatile and unpredictable, so are revenues. This frustrates the regulatory goal that utilities should have the opportunity to earn their return because the Company has no ability to control this unnecessary revenue fluctuation. Additionally, since any increase in the residential basic charge will decrease the portion of residential margin to be recovered through the volumetric delivery charge, the Company is needlessly exposed to potential declines in net revenues if average usage per customer declines over time. This phenomenon can be addressed in other more complex ways, such as the use of decoupling mechanisms similar to the one proposed by the Company for gas rates in its last general rate case. However, simply decreasing volumetric rates by increasing the portion of 'fixed' costs recovered in basic charges is also an effective tool.

Q. If decreasing the volumetric charges that recover customer costs by increasing the Basic Charge is really such a "win-win" as you describe why are basic charges currently below cost?

A. I am not sure why, but basic charges have historically been set below cost. Unfortunately, it has been very hard to remedy this, because any change in rate design, such as shifting the recovery of customer costs from a volumetric charge to a basic charge, impacts individual customers differently. It is simply impossible to make a change in rate design to make rates more fair, just, reasonable and sufficient, without raising someone's bills by more than they would have been raised had the change not been made. I believe in the past, concern over this relative bill impact has tended to over-rule the objective of making rates fair, just reasonable and sufficient, with the result that basic charges remain below cost. In saying this, I note that this Commission in the Company's last gas general rate case made significant progress toward setting a cost based basic charge for gas. The Company believes that another significant step toward cost based service should be taken in this case.

B. Bill Impacts

Q. Please describe the impacts your Basic Charge proposals will have on customer bills.

A. The impacts on monthly and annual residential bills of our proposals are straightforward. As discussed above, the Company is proposing to increase the Basic Charge for electricity from $6.02 a month to $9.00 month, and as discussed in the testimony of Ms. Phelps, to increase the Basic Charge for gas from $8.25 a month to $18.00 a month. As can be seen below, the most any electric bill will increase over what it would increase if the average class increase was applied to the basic charge is $2.98 a month and the most any similar gas bill will increase is $9.75 a month. These maximum increases will be in bills for customers that have zero kWhs or therms during the month, most likely for service to unoccupied homes. There are very few of these customers. Many of these dwellings are likely to be second residences. For all other customers, the increase in the basic charge will be offset, in part or in whole, by the decrease in the volumetric unit cost, 0.146 and 0.358 cents per kWh for electric and 12.654 cents per therm for gas over what the charge would have been if all charges had been increased by an equal percentage. This is shown in the following charts.

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Puget Sound Energy
Residential Gas Customer Impacts
Schedule 23

Line	**Charge**	**Current Rates**	**Equal Percentage Increase**	**Proposal**	**Difference**
1	Customer Charge	$8.25	$9.66	$18.00	$8.34
2	Delivery Charge	$0.30039	$0.35164	$0.22510	-$0.12654
3	Gas Cost charge	$0.84120	$0.84120	$0.84120	$0.00000
4	**Monthly Bill Impacts - Typical Residential Customer**				
5	**High - January(137 Therms)**				
6	Monthly Bill	$164.65	$173.08	$164.08	($9.00)
7	$ Change over Current		$8.43	($0.57)	($9.00)
8	**Average (68 Therms)**				
9	Monthly Bill	$85.88	$90.77	$90.51	($0.26)
10	$ Change over Current		$4.89	$4.63	($0.26)
11	**Low - August (19 Therms)**				
12	Monthly Bill	$29.94	$32.32	$38.26	$5.94
13	$ Change over Current		$2.38	$8.32	$5.94

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Puget Sound Energy
Residential Electric Customer Impacts
Schedule 07

Line	**Charge**	**Current Rates**	**Equal Percentage Increase**	**Proposal**	**Difference**
1	Customer Charge	$6.02	$6.73	$9.00	$2.27
2	Energy charge - first 600	$0.07756	$0.08669	$0.08523	-$0.00146
3	Energy charge - all over 600	$0.09537	$0.10661	$0.10303	-$0.00358
4	**Monthly Bill Impacts - Typical Residential Customer:**				
5	**High- January (1430 kWh)**				
6	Monthly Bill	$131.71	$147.23	$145.65	$(1.58)
7	$ Change over Current		$15.52	$13.94	$(1.58)
8	**Average (1,000 kWhs)**				
9	Monthly Bill	$90.70	$101.39	$101.35	$(0.04)
10	$ Change over Current		$10.69	$10.65	$(0.04)
11	**Low - August (727 kWhs)**				
12	Monthly Bill	$64.67	$72.28	$73.22	$0.94
13	$ Change over Current		$7.61	$8.55	$0.94

The usage levels on the charts represent the typical usage per month during the last twelve month period as well as the typical usage in January and August of 2007 for residential gas and electric service. As can be seen in the above charts, over a year's time the increase in the basic charge proposed by the Company will have virtually no effect on the amount the typical customer will pay over a twelve month period, will decrease the typical monthly bills for customers in the winter when they are currently overpaying their costs because they use more than the average ($9.00 a month for a typical gas customer in January, $1.58 a month for a similar electric customer) , and increase the typical monthly bills for customers during the summer when they are currently underpaying their costs because they use less than the average ($5.94 a month for a typical gas customer in August, $0.94 a month for a similar electric customer.)

The following tables show the increase in annual bill stability that results from increasing the Basic Charge while correspondingly decreasing the variable charge. The charts show the bill of a typical residential customer. They show that, under the Company proposal, bills are lower in the winter when loads (and bills) are relatively high and higher in the summer when loads (and bills) are relatively low, resulting in less seasonal variation.

Monthly Differences

Bills of average residential gas customer

Month	Therms	Equal Percentage		Company Proposal		Higher/Lower bill	
Sep	27	$	41.87	$	46.79	$	4.92
Oct	58	$	78.84	$	79.85	$	1.00
Nov	101	$	130.14	$	125.70	$	(4.44)
Dec	131	$	165.92	$	157.69	$	(8.24)
Jan	137	$	173.08	$	164.08	$	(9.00)
Feb	100	$	128.94	$	124.63	$	(4.31)
Mar	89	$	115.82	$	112.90	$	(2.92)
Apr	64	$	86.00	$	86.24	$	0.24
May	41	$	58.57	$	61.72	$	3.15
Jun	26	$	40.67	$	45.72	$	5.05
Jul	19	$	32.32	$	38.26	$	5.94
Aug	19	$	32.32	$	38.26	$	5.94
Year	**812**	**$**	**1,084.51**	**$**	**1,081.84**	**$**	**(2.67)**

Monthly Differences

Bills of typical residential electric customer

Month	kWhs	Equal Percentage	Company Proposal	Higher/Lower bill
Sep	766	$ 76.49	$ 77.28	$ 0.79
Oct	958	$ 96.93	$ 97.04	$ 0.11
Nov	1,200	$ 122.73	$ 121.97	$ (0.76)
Dec	1,391	$ 143.11	$ 141.67	$ (1.44)
Jan	1,430	$ 147.25	$ 145.67	$ (1.58)
Feb	1,142	$ 116.57	$ 116.02	$ (0.55)
Mar	1,115	$ 113.62	$ 113.17	$ (0.45)
Apr	941	$ 95.06	$ 95.23	$ 0.17
May	831	$ 83.41	$ 83.98	$ 0.56
Jun	743	$ 74.03	$ 74.91	$ 0.88
Jul	755	$ 75.22	$ 76.06	$ 0.84
Aug	727	$ 72.28	$ 73.21	$ 0.94
Year	**12,000**	**$1,216.71**	**$1,216.21**	**($0.50)**

In addition to modestly flatter bills over the year, our basic charge proposal results in bills that have less volatility. As mentioned above, the Company proposal decreases the per kWh and the per therm charge. As a result, if temperatures are colder than normal for a month, bills will not increase as much as if the average increase was applied to the basic charge. The impact of weather on revenues when fixed costs are recovered over variable therms and kWhs is significant. For instance, during the test year gas revenues were $24 million higher because the year was colder than normal. Of this $24 million, almost $6 million represented "recovery" of costs that did NOT increase due to cold weather last year, but are nevertheless required to cover costs for years that are warmer than normal. This creates volatility in earnings which the Company cannot control and shifts a burden to customers who have to pay the excess revenues due to colder weather to make up for the under recovery of costs from customers during warmer years.

Q. Do you believe that increases in the residential electric and gas Basic Charges by $2.98 and $9.75 a month respectively constitute rate shock?

A. No. The increases are offset, either in total or in part, by decreases in the rate charged per kWh or therm. While customers are aware of the components of the bill, I believe most are more concerned with the total bill.

In summary, I believe the Company proposals to significantly increase the residential basic charge and correspondingly reduce the per kWh and per therm charges for both electric and gas customers would result in acceptable impacts even for those who will see a larger than average increase in their average monthly bills when the benefits of more stable monthly bills, lower winter bills, more predictable bills and bills that more fairly share fixed costs are taken into account.

Q. Will the impact of your proposals on customers with low income be significantly different from the impact on customers generally?

A. According to our most recent data, we expect the impact on low income customers to differ between gas and electric. Low income electric customers should tend to benefit more from our proposal, because our data indicates they tend to use more electricity per household than the general population and thus will benefit from the relatively lower kWh charge. However, the data indicates the opposite is true for low income gas customers. As a result we are asking that the annual cap of $3.536 million under gas Schedule 129, the gas Low Income Program, be adjusted to reflect the rate design changes. The specific change to the cap will be based upon an analysis of the typical bill impact on low income customers associated with the Commission's approval of an increased basic charge and the corresponding reduction in the per therm charge. This adjustment will be included in the proposed adjustment associated with the the overall change in residential rates.

Q. Please describe the usage patterns of bill assisted gas customers in comparison to the Company's customers generally.

A. Figure 2 below compares the bill frequencies of bill-assisted gas customers with those of the Company's customers generally. Bill frequencies describe the percentage of total bills that fall within a certain range, such as between 55 and 70 therms a month. Although the Company does not keep records of income characteristics of its customers, it is possible to identify the test year customers who received bill assistance. The gas usage of these customers is used in this study to analyze bill frequencies of low income customers.

Figure 2

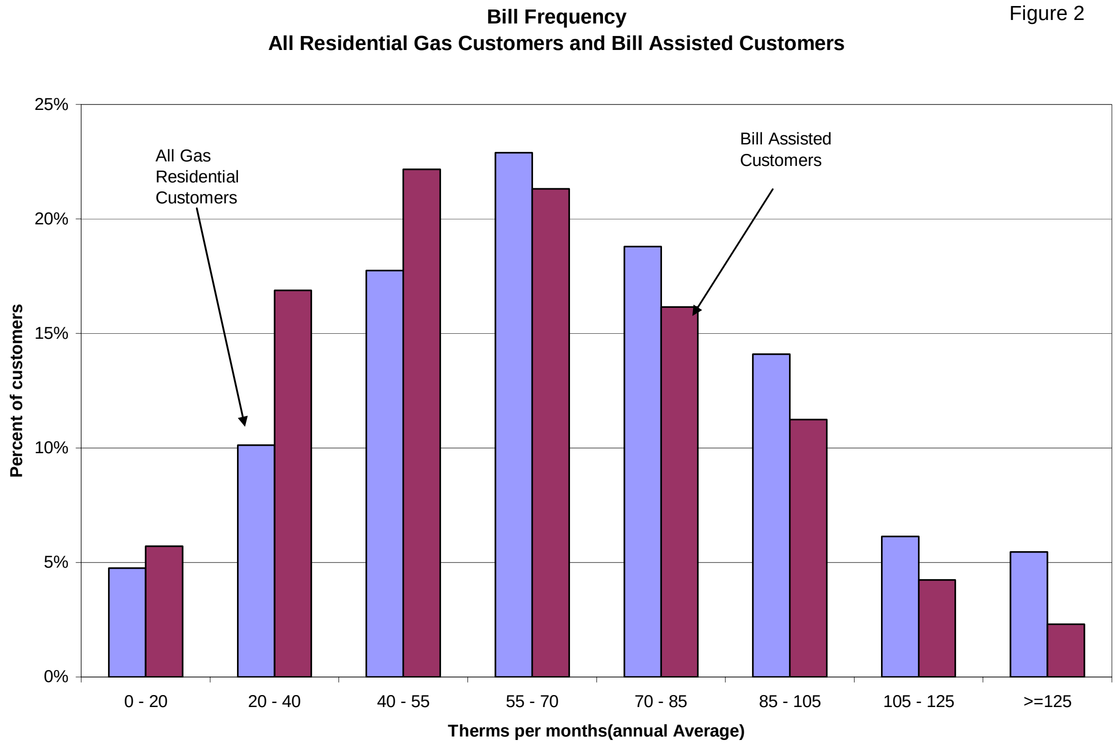
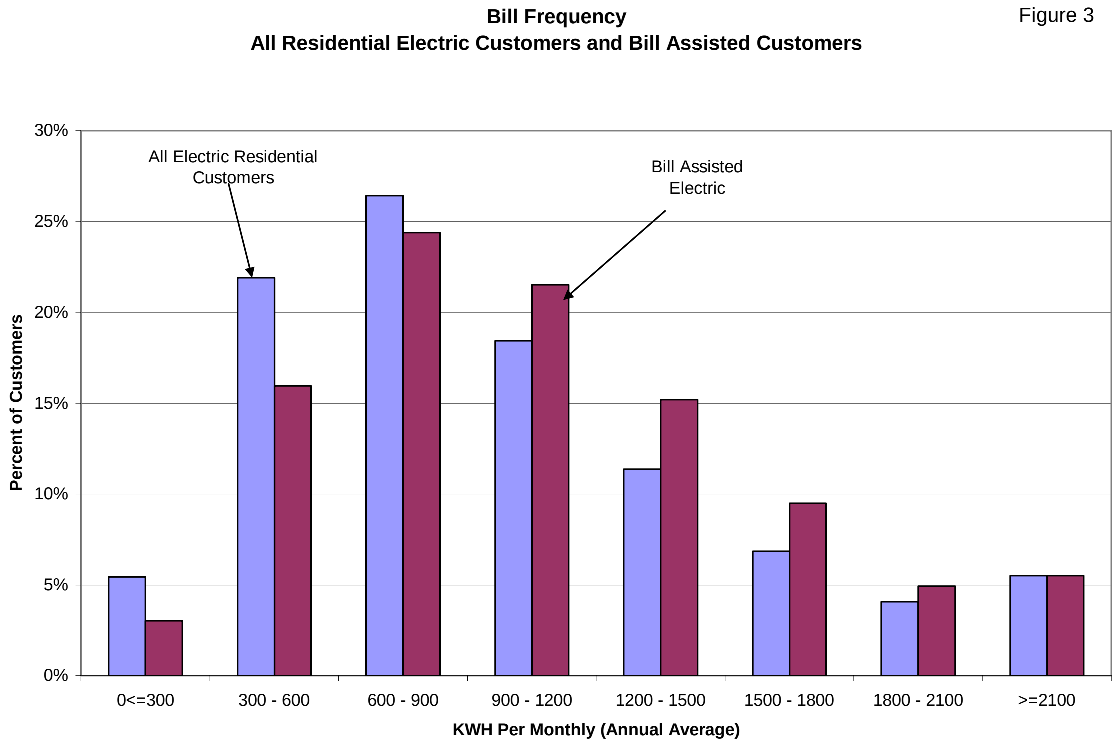


Figure 2 shows that, while the percentage of customers with usage of 0 – 20 therms per month are about the same, a significantly higher percentage of bill assisted customers have consumption between 20 and 55 therms a month than customers in general. These customers will see slightly higher bills under our proposal than under an alternative that would apply the rate increase equally to the basic charge and the per therm charge. Approximately 60% of our bill assisted gas customers use less than the average usage for residential customers. This group of customers will pay approximately $150,000 a year more in total, or approximately $34 per customer, than they would under an equal percentage alternative. The remaining 40% would pay about $95,000 less per year in total, or approximately $35 per customer. The Company's proposal to increase the annual cap gas Schedule 129, the gas Low Income Program, mentioned earlier will offset this adverse impact. Because low income customers are a small segment of our customer population, I believe it is much more efficient to address issues regarding low income directly, rather than resisting movements in rate design that have the potential to provide significant benefits to a very large segment of customers.

Q. Please describe the usage patterns of bill assisted electric customers in comparison to the Company's customers generally.

A. Figure 3 below compares the electric bill assisted customers with electric residential customers in general. The results are the opposite of the results for gas. For electric, bill assisted customers actually tend to use more electricity than their neighbors. Thus the Company's proposal to increase the basic charge by more than the average increase has general positive benefits to this group of customers when compared with an alternative of an equal percentage increase to both the basic charge as well as the per kWh charges.

Figure 3



C. Price Signal

Q. Are there any other issues you would like to discuss regarding the Company's proposal to increase basic charges by a greater than average amount?

A. Yes. Historically, when utilities propose an increase of basic charges to a level that reflects actual customer costs, opponents have raised an issue related to the resulting price signal. As mentioned earlier, an increase in the basic charge by an amount greater than the average increase to the class will result in a per therm or per kWh charge that is lower than what it would have been under an equal percentage alternative. Parties have raised the concern that these lower rates will reduce the incentive for customers to reduce their consumption of energy.

Q. Do you agree with this concern?

A. No. I believe the price signal that results from the Company's proposal is appropriate, and in some ways actually superior to the price signal that results from an equal percentage increase. Regarding the residential electric rates, even with the increase in the basic charge, the per kWh rates increase by up to 10 percent, an amount that is significant enough to send a signal to conserve. For gas, the reduction in the amount of fixed delivery costs recovered from the variable sale of therms does not in any way affect the recovery of the actual cost of the gas being delivered. I would be concerned if the gas cost was being artificially reduced, but it is not. In fact, in my opinion the lower per therm delivery charge sends a price signal that is superior to a price that signals higher costs when costs are in fact not higher.

Q. Please explain why the reduction in the amount of fixed delivery costs recovered from the variable sale of therms does not affect the actual cost (and price) of the gas being delivered and sends a superior price signal.

A. The Company has two separate and distinct charges for gas service – a charge for the gas itself, and a charge for delivery of the gas. The Company's proposal would affect only the latter charge. Gas costs are recovered under a separate rate. The Company's proposal relates to the delivery service provided by the

Company, the costs of which are almost entirely fixed. It is inappropriate to send a price signal that indicates that costs increase or decrease with volume if in fact they do not. The higher the proportion of non-volumetric costs recovered through volumetric rates, the worse the price signal. For example, if the volumetric charge is greater than zero, customers pay more margin when their consumption is higher, as in the winter or during a cold snap, even though the Company's customer costs are not higher in the winter or during a cold snap.

D. <u>Understandability</u>

Q. Please discuss the understandability of basic charges.

A. Rates should make sense and be understandable. The proposed Basic Charges make sense because the charges, like the costs on which they are based, do not increase or decrease if the customer uses more or less energy or has higher or lower demand. To the extent customers pay customer costs through a volumetric charge, they are exposed to over or under-paying of those customer costs–which is not understandable. It is intuitively obvious that a customer should not pay more for fixed costs when the weather is cold, and conversely should not pay less for fixed costs when the weather is warm, given that the actual fixed costs do not vary by season or weather.

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E. **Fairness**

Q. Please summarize the fairness of basic charges.

A. A higher basic charge benefits customers. A higher basic charge is fair because it increases the portion of the (non-volumetric) costs recovered through the (non-volumetric) basic charge. With a higher basic charge, a higher percentage of the non-volumetric costs is paid in equal shares. For example, each customer under the Company's proposed rate design pays the full share of customer cost allocated to him or her. Accordingly, each customer would not, under the Company's proposals, "overpay" or "underpay" his or her share of these customer costs based on the customer's consumption relative to average consumption, would not pay a higher delivery charge in the winter than in the summer, and would not pay a higher delivery charge during a cold spell.

As noted above, the effect of collecting customer costs through volumetric charge can be illustrated by comparing the costs of serving, and bills for service to, a summer home and a principal residence. The costs of service lines and meters necessary to provide service to a house are the same, regardless of whether it is a summer home or a principal residence. However, to the extent that these fixed customer costs are recovered through a volumetric delivery charge, the customer receiving service to the summer home will pay a significantly lower share of the margin.

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VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.