EXHIBIT NO. ___(JKP-1T)
DOCKET NO. UE-06___/UG-06___
2006 PSE GENERAL RATE CASE
WITNESS: JANET K. PHELPS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-06____** **Docket No. UG-06____**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF
JANET K. PHELPS
ON BEHALF OF PUGET SOUND ENERGY, INC.

FEBRUARY 15, 2006

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF
JANET K. PHELPS

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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 Janet K. Phelps, and my business address is 10885 N.E. Fourth Street, Bellevue, Washington 98004. I am employed by Puget Sound Energy ("PSE" or "the Company") as a Senior Regulatory Analyst in Pricing and Cost of Service.

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

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

Q. What is the purpose of your testimony?

A. I will present the pro forma revenue from gas operations proposed in this filing, the gas cost of service study, and the Company's proposed rate spread and rate design for gas service.

II. PRO FORMA REVENUE FROM NATURAL GAS OPERATIONS

Q. Why is it necessary to develop pro forma revenue?

A. Pro forma revenue is developed to ensure that the test year revenue used in calculating the revenue deficiency: (1) reflects only those price schedules that are being considered in the present case; (2) encompasses any rate changes that took place during the test year; and (3) is consistent with the normalized test year revenue requirement.

Q. Please describe the process used to develop pro forma revenue.

A. Developing pro forma revenue involves: (1) removing revenue that is not related to base rates in order to identify revenue from base price schedules; (2) making restating adjustments to test year volume and corresponding revenue; and (3) estimating what revenue would have been had current rates been in effect throughout the test year. The Company's adjustments to test year natural gas throughput[1] for this case are summarized on page 1 of my Exhibit No. ___(JKP-3), and corresponding adjustments to test year revenue are summarized on page 2 of Exhibit No. ___(JKP-3).

Column B of page 1 of Exhibit No. ___(JKP-3) shows the volume of sales and

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[1] Throughput, sometimes also called "sendout", is the total volume of natural gas that is delivered to customers through the system during a particular period of time.

transportation for the test year ended September 2005 included in the Company's Sales of Gas report. The restating adjustments in column C include an out of period adjustment and an unbilled volume adjustment. The out of period adjustment corrects usage associated with billing corrections by moving the consumption from the period in which it was corrected into the period in which it should have been billed. The unbilled volume adjustment adjusts for the fact that customers' bills are issued throughout the month and do not correspond to calendar months. PSE's income statement for a given month includes revenue from sales that were billed during that month, removes the portion of that revenue that was consumed in the previous month, and adds an estimate of revenue from sales that occurred during the calendar month but were not yet billed. In the adjustment to unbilled volume, the unbilled portion of sales was updated to reflect sales that actually took place during each calendar month, by rate schedule. The revenue related to these adjustments was calculated based on the rates that were in effect during the test year, and is presented in column F of page 2 of Exhibit No. ___(JKP-3).

The weather normalization adjustment to volume presented in column D is discussed in the testimony of Dr. Jeffrey Dubin, Exhibit No. ___(JAD-1T). Pro forma volume used for calculating pro forma revenue is presented in column F of page 1 of Exhibit No. ___(JKP-3).

The revenue included in the test year income statement is presented in column B of page 2 of Exhibit No. ___(JKP-3). Revenue related to municipal taxes was removed in column C. Revenue from penalty charges and revenue related to contributions in aid of construction was transferred from revenue from sales to other operating revenue in column D. Revenue related to conservation, the low income program, and Schedule 106 (the amortization of deferred gas supply costs) was removed in column E, because the revenue requirement for these programs is addressed through separate tariff schedules that directly pass the costs through to customers. The entries in column F correspond to those in column C of page 1, and reflect out of period adjustments to sales volume and related revenue as well as the unbilled revenue adjustment. The out-of-period corrects revenue associated with billing corrections by moving the consumption and related revenue from the period in which they were corrected into the period in which they should have been billed. The unbilled revenue adjustment adjusts for the fact that customers' bills are issued throughout the month and do not correspond to calendar months. PSE's income statement for a given month includes revenue from sales that were billed during that month, removes the portion of that revenue that was consumed in the previous month, and adds an estimate of revenue from sales that occurred during the calendar month but were not yet billed. In the adjustment to unbilled revenue, the unbilled portion of sales was updated to reflect sales that actually took place during each calendar month, by rate schedule, and the related revenue was calculated based on the rates that were in effect during the test year.

The adjustment for March 2005 rates in column G increases test year revenue to include revenue collected as a result of the rate increase that was implemented in March pursuant to the Company's 2004 general rate case, Docket Nos. UG-040640 et al. In this adjustment, revenue from sales for the October 1, 2004 through February 2005 period was increased to reflect the rates that were implemented in March 2005. The adjustment for October 2005 rates in column H reflects the implementation of new gas rates on October 1, 2005. Both of these adjustments restate revenue as if the new rates had been in effect throughout the test year.

The weather normalization adjusts revenue based on weather normalized gas volumes presented on page 1 of Exhibit No. ___(JKP-3) and rates in effect October 1, 2005.

Q. What is the impact of the weather normalization on load and revenue for the test year?

A. As indicated on page 1 of Exhibit No. ___(JKP-3), weather normalization increased test year therms by 24,669,218 therms to 1,038,450,901. This had the effect of increasing pro forma revenue by $24,848,546, as shown on page 2 of Exhibit No. ___(JKP-3).

Q. What is the Company's resulting pro forma revenue?

A. Total pro forma revenue for the test year of $960,901,702 is presented in column L. The gas cost associated with this revenue of $631,255,371 is presented in column N.

III. COST OF SERVICE PRINCIPLES

Q. What is the purpose of a cost of service study?

A. The purpose of a cost of service study is to apportion the Company's total cost of service, or revenue requirement, to the respective customer classes. This cost analysis then provides guidance for the determination of the revenue responsibility for the individual customer classes.

Q. What are the guiding principles of cost of service analysis?

A. Cost causation is the fundamental principle of cost of service analysis. The question that must be answered is: which customer or group of customers causes the utility to incur particular types of costs? To answer this question, a connection must be made between customer requirements and usage characteristics, and costs incurred to meet those requirements.

Some components of the revenue requirement can be directly assigned to specific customers or customer classes because those costs are incurred solely for the benefit of those customers. For example, certain portions of the Company's mains are dedicated to specific large customers; the costs related to these mains are directly assigned to the appropriate customer classes because those costs are incurred only for their benefit. Costs that are incurred for the benefit of all customers are allocated to the customer classes on the basis of common usage-related or customer-related characteristics.

Q. How is a cost of service study performed?

A. There are three broad steps to a cost of service study: (1) functionalization; (2) classification; and (3) allocation.

Q. What is the first step, functionalization?

A. Functionalization separates plant and expenses into major categories based on the major functions of the utility, which for PSE's gas business are production, storage, transmission, and distribution of natural gas.

Q. Please describe the second step in a cost of service study, classification.

A. Classification further separates costs into categories based on the utility operation for which the plant is constructed and expenses are incurred. The Company's distribution system is designed to perform three primary tasks: (1) to provide distribution services to *customers* entitled to be served by the system; (2) to serve peak day *demands* of all customers; and (3) to deliver the natural gas *commodity* sold to or transported for its customers. There are costs associated with each of these services, and in the cost-of-service study costs are categorized as either related to customer, demand, or commodity.

Customer-related costs include, at a minimum, the costs of the service line and meter, meter reading and billing, and maintaining the customer accounting system. They may also include costs associated with minimum size distribution mains. Customer costs vary with the number of customers on the system, regardless of how much gas those customers consume.

Demand or capacity costs are associated with the costs of designing, installing, and operating the system to meet maximum hourly gas flow requirements. The system must be sized to meet peak requirements, even though average daily loads are below peak levels. Otherwise the system would not be adequate to serve customers' demand for gas on the coldest, peak load days. Demand costs vary with the size of the system peak demand or individual customers' peak demands. Demand costs are incurred whether all the capacity is used or not.

Commodity costs vary with the amount of gas transported over the Company's system, either the gas commodity sold to customers or transported for customers who purchase gas from providers other than PSE. Over a one year period, the average daily volume of gas transported through the system is considerably less than the volume on a peak day.

Given these three different primary functions of the gas system, classification answers the question: "Why was the cost incurred - to serve the customer, to meet peak demand, or to provide the commodity?" Another way to ask this is:

"Does the cost vary with the number of customers, the peak demand on the system, or the volume of gas sold or transported over the system?"

Q. Please describe the third step in a cost of service study, allocation.

A. Allocation is the final step in the assignment of costs to customer classes. Unless a cost can be directly assigned to a customer class, it is allocated based on an allocation factor that is related to that type of cost. In general: (1) customer-related costs are allocated based on the number of customers; (2) demand-related costs are allocated based on peak demand; and (3) commodity-related costs are allocated to customer classes based on throughput. There are many variations of these allocation factors based on the specific costs and plant items being allocated, and some costs may be allocated based on a combination of allocation factors.

IV. PSE'S NATURAL GAS COST OF SERVICE STUDY

A. <u>Overview of the Company's Proposed Gas Cost of Service Study</u>

Q. Is the methodology employed in the Company's cost of service study for its natural gas service in this case consistent with the "Commission Basis" cost of service study for the Company?

A. The methodology of the last Commission-approved natural gas cost of service study for the Company – commonly referred to as the "Commission Basis" methodology – was determined in Washington Natural Gas Docket Nos. UG-

940034 and UG-940814. This was the last time the Company's gas cost of service study was fully litigated through to a Commission order. Subsequent cases have resolved cost of service study disputes through settlements.

In most respects, the Company has conducted the cost of service study in this case consistent with the Commission Basis methodology. However, the Company believes that some of the methods approved in a case that was litigated over a decade ago should be modified. Therefore, some changes have been incorporated into the study that the Company is filing in this case. I will address these changes later in my testimony.

For informational purposes, the Company has also conducted its cost of service analysis using the Commission Basis method, and I provide this analysis in my workpapers.

Q. Did the Company conduct its preferred cost of service analysis in more than one way?

A. Yes, consistent with past cases, the Company conducted the analysis both including and excluding gas commodity costs. Normally, the study that includes gas costs is informational, only, because the Company's Purchased Gas Adjustment ("PGA") Mechanism passes through the changes in commodity costs. This means that natural gas general rate cases focus on the revenue requirement deficiency that is caused by changes in costs *other than* gas costs. Unless otherwise noted, I will refer to the cost of service analysis that excludes gas costs throughout the remainder of my testimony.

However, in this case the cost of service analysis that includes gas costs is relevant to one set of issues: the Company's proposed revision to the allocation of gas costs among the Company's customers that is set forth in the PGA Mechanism. This proposal is discussed later in my testimony.

Summary schedules for the cost of service scenario with and without gas costs appear in Exhibit No. ___(JKP-4), and the supporting detailed output from the study is included in Exhibit No. ___(JKP-5).

Q. What model did the Company use for its cost of service study?

A. The Company is using the Navigant Consulting, Inc. Cost of Service Model ("NCI Model"). This model is an updated version of the model used in the Company's 2001 general rate case. Mr. Ron Amen describes this model in his prefiled direct testimony, Exhibit No. ___(RJA-1T).

Q. Mr. Amen states in his prefiled direct testimony that the load characteristics of a utility's customers are an important element in determining the costs incurred by the utility in serving its customers. What are the load characteristics of the Company's customer classes in the cost of service study?

A. The relevant load characteristics of the Company's various customer groups are shown in Exhibit No. ___(JKP-6). In reviewing this information, it is important to point out that for each class of service, the absolute and relative level of certain of these load characteristics have a direct influence on the type and level of costs incurred by the Company in serving its customers.

Q. What are the implications of class load characteristics for purposes of allocating joint costs associated with serving PSE customers?

A. Annual load factor is an important indicator of how a customer utilizes PSE's system capacity. Higher load factor customers have higher average daily consumption relative to their peak demand, so their load is more steady over time and they use the Company's system capacity more efficiently than lower load factor customers. Exhibit No. ___(JKP-6) indicates that even though the residential class is responsible for approximately 50 percent of the Company's annual throughput, it has a low annual load factor of 24 percent.

In addition, peak-hour demand is a key element in the sizing of the Company's facilities and in determining the level of costs incurred in serving its customers, because the Company designs its system to meet a peak hour load during cold weather. Although the day-to-day utilization of the Company's facilities by its customers is measured by their annual gas consumption, this measure does not have a bearing on the types and costs of specific facilities installed to serve specific customers. This is due to the significant differences between peak flows, which the system must be designed for, and the average annual gas consumption. If the system were designed based on average annual loads, it would be a much smaller system and would not be able to meet customers' peak demands. Because of this difference between average consumption and peak demand, certain costs are defined as demand related and others are defined as commodity related for purposes of cost allocation.

B. <u>Classification and Allocation of Distribution Main Costs</u>

Q. Please describe how investment in distribution mains was classified and allocated.

A. The investment in distribution mains is a demand-related cost, and the Company used the modified peak and average method for allocating this portion of its demand-related costs, consistent with previous general rate cases. This method allocates demand costs based on a combination of peak demand and average demand. Average demand is essentially another term for average throughput. The Company used an estimate of the system load factor to determine how much of the demand-related costs would be allocated based on peak demand and how much would be allocated based on average demand or average annual throughput.

Q. How were the peak demand and system load factor developed?

A. In this case, the Company is proposing to use the system design day as its peak demand allocator. This is a change from the Commission Basis methodology, in which the Company's peak demand was estimated based on the five highest load days that were experienced during a recent three year period. I discuss the reason the Company is proposing this change after I describe the way in which the Company developed the peak demand and system load factor using the system design day.

The system design day is based on 52 heating degree days ("HDD"), as explained in the Company's 2005 Least Cost Plan.[2] The system load factor was calculated based on this estimate of peak demand and weather normalized annual volume. The resulting 33 percent load factor was used to divide these demand-related costs into peak demand and average demand for purposes of allocating the costs to customer classes. This resulted in these costs being allocated 33 percent on average demand and 67 percent on peak demand.

This modified peak and average approach to allocation of demand costs reflects a balance between the way the system is designed (to meet peak demand) and the way it is utilized on an annual basis (throughput based on gas usage that occurs during all conditions, not only peak conditions).

Q. Why did you use the Company's design day peak demand to allocate demand-related costs instead of using actual peak data from a recent three year period?

A. As I discussed earlier in my testimony, cost causation is the primary consideration

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[2] The relevant sections of the 2005 Least Cost Plan are provided as Exhibit No. ___(WFD-9) and Exhibit No. ___(WFD-10).

in cost of service analysis. Design day peak is a better indicator of cost causation than historical peak demands. The Company designs its system to meet a design day peak demand, which is based on cold weather conditions. Regardless of how often those design day conditions occur, the Company incurs the costs associated with being able to provide natural gas service on a design day. PSE is obligated to provide reliable service, and customers expect that reliability, especially during cold weather.

Design day peak also provides a more stable allocation factor than historical peak volumes provide. Historical volumes change from year to year, yet these changes are not related to the costs of the Company's system. If historical data is used, cost allocation depends on weather conditions that happened to prevail during the period considered rather than the cost of the system itself. This could result in greater volatility of cost assignments from one cost study to the next.

The importance of using design day as the basis for the peak allocator is also discussed in the prefiled direct testimonies of Mr. Amen and Mr. William Donahue, Exhibit No. ___(WFD-1CT).

Q. Was any portion of distribution mains directly assigned?

A. Yes. The Company's analysis indicated that most commercial and industrial customers are served off of distribution mains four inches or larger in diameter, therefore the Company separated the distribution main investment into two subgroups: mains four inches or greater and mains less than four inches in diameter. The Company conducted an analysis of facilities used to serve its largest customers, which are those in Rate Schedules 85, 87, 57 and the special contract customers. Each customer's location on the Company's distribution system was determined and the amount of main that serves only that customer was identified. This plant data was combined with data on the cost of mains to identify the original cost of the distribution mains dedicated to serve the customer. The costs of the dedicated mains were then directly assigned to the largest customer groups. The remaining plant balance for small diameter mains was allocated to all customer groups except Rate Schedules 85, 87, 57 and special contract customers based on the peak and average allocation factors, as discussed above. Mains four inches or greater in diameter not dedicated to specific customers were allocated to all customers that are served by the underground pipeline distribution system.

Q. Why did the Schedule 85, 87, 57 and special contract customers not receive an allocated share of the costs associated with distribution mains less than four inches in diameter?

A. The analysis described above specifically identified the amount of small diameter main that is dedicated to these customers, and this portion was directly assigned to them. Aside from these dedicated mains, these customers do not typically utilize the Company's small diameter distribution mains.

C. <u>Classification and Allocation of Other Plant Costs</u>

Q. Were other facilities identified that could be directly assigned to larger customers?

A. Yes. The Company conducted a similar analysis to identify the cost of customer service lines in Federal Energy Regulatory Commission ("FERC") Account 380 that are dedicated to customers in Rate Schedules 85, 87, 57 and the special contract customers. This portion of plant in Account 380 was directly assigned to these customers, and the remainder was allocated to all other customers based on weighting factors. Different customer classes require different sizes and types of services, which vary in cost. The number of customers was weighted based on unit cost data, and these weighted customer counts were used to allocate costs across customer classes. The use of weighting factors takes these unit cost differences into account when assigning costs to the customer classes.

Q. How were other customer-related costs allocated to classes?

A. Meters and meter installations (Accounts 381 and 382), house regulators and installations (Accounts 383-384), and industrial measuring & regulating station equipment (Account 385) were allocated on the basis of special studies. These studies used property system data to group the equipment by the equipment types and sizes typically used by the various customer classes. The resulting cost groupings were used to allocate the amounts in the accounts to the customer classes.

Q. For each of the aforementioned plant accounts, how did you determine the type and size of facility that should be attributed to each customer group?

A. Based on its historical installation and operating experience, the Company has established engineering and operational standards. These standards were the basis for identifying the typical size and type of service line for each customer group. With regard to meters, industrial measuring and regulatory station equipment, the Company analyzed data contained in its customer information system to identify the type and size of meter for each customer it serves. This analysis also was used to determine the type and size of equipment, by customer class, for house regulators and to assign the installation costs of meters and house regulators to specific customer classes.

Q. How did the study allocate distribution-related operation and maintenance expenses?

A. Other than directly assigned expenses, these expenses follow the cost allocation of the corresponding plant accounts.

D. <u>Classification and Allocation of Purchased Gas Expenses</u>

Q. Were there any changes to the way purchased gas expenses were allocated?

A. The Company made modifications to some of the allocation factors used to allocate gas costs. As part of the Washington Natural Gas 1994 rate restructuring case, composite factors were developed for allocating certain purchased gas costs.

The Company's system has grown and its resources have changed significantly since that time, so we reevaluated these allocation factors in light of the Company's current resource mix. Some allocators have not changed other than to reflect current data, such as the commodity allocators. New composite allocators that are designed to reflect the Company's current resources were developed to allocate Jackson Prairie storage costs and related TF-2 pipeline costs, and TF-1 pipeline capacity. These allocators were based on the analysis described in Mr. Donahue's testimony. The components of the Company's gas costs and the allocation factors used to allocate those costs are provided in Exhibit No. ___(JKP-5) at 56-65.

Q. How did the study allocate purchased gas expenses?

A. The Company's study classifies purchased gas costs into two components: demand and variable. Variable costs include interstate pipeline transportation variable costs, gas supply contract commodity, spot market gas costs, the net cost of gas injected into and withdrawn from storage, and the associated volumetric-based fees for these services. Demand-related costs include interstate pipeline demand charges, leased underground storage (Clay Basin and Jackson Prairie) and liquefied natural gas storage service LS-1 demand charges, and fixed charges related to gas supply contracts. A discussion of the components of the Company's gas supply portfolio, including the interstate pipeline transportation and underground storage resources utilized to deliver supply to the PSE distribution system, is included in Mr. Donahue's testimony.

The various demand and variable cost components of the gas supply portfolio were allocated to the Company's customer classes according to annual sales volumes, winter sales volumes, and design peak demand allocation factors, as well as the composite allocation factors composed of design peak demands, winter season sales and annual sales as discussed above.

Q. Please describe the methods used to allocate fixed demand-related gas costs.

A. The reservation charges associated with winter firm and peaking supply contracts were classified as demand costs and allocated on a winter season and peak day basis, respectively. Interstate pipeline transportation demand costs (TF-1) were allocated on the basis of a composite allocation factor that represents the proportionate year-round, winter season and system design peak requirements served by the underlying pipeline capacity. This is one of the allocators that was developed based on Mr. Donahue's analysis. The Company used the annual, winter and design peak pipeline capacity percentage requirements derived through Mr. Donahue's analysis by weighting the applicable customer usage characteristics, that is, the class-by-class contributions to annual sales, winter season sales, and the system design peak day, and applied the result to the various pipeline demand charges in the Company's supply portfolio. Pipeline transportation (TF-2) demand charges related to the delivery of liquefied natural gas storage withdrawals to the Company's city gates were allocated using the design day peak. Clay Basin storage costs were allocated based on winter sales volumes. The portion of Jackson Prairie storage costs and related pipeline transportation (TF-2) demand charges not related to balancing (78%) were allocated on a weighted winter season and design day peak basis, consistent with the methodology outlined by Mr. Donahue. Finally, the portion of Jackson Prairie demand charges related to its balancing function (22%) was allocated to all classes on a system average throughput basis.

Q. How were the variable gas costs allocated?

A. All variable gas supply costs were classified as commodity costs. Peaking supply-related charges were allocated on a design peak day basis. Pipeline variable costs related to Jackson Prairie storage delivery (TF-2) were allocated using a composite allocator consistent with the allocation of fixed costs related to Jackson Prairie. Storage withdrawal and injection costs were allocated on the basis of winter sales. The rest of the variable costs related to purchased gas supplies or pipeline fuel use charges were allocated on the basis of annual gas sales, with the exception of those costs related to Jackson Prairie balancing, which were allocated on system average throughput (including transportation volumes).

E. <u>Classification and Allocation of Administrative and General Expenses</u>

Q. How did the study allocate administrative and general expenses and income taxes to each customer class?

A. Administrative and general ("A&G") expenses were allocated on an account-by-account basis. Items related to labor costs, such as employee pensions and benefits, were allocated based on labor costs. Items related to plant, such as maintenance of general plant and property taxes, were allocated based on plant. Items related to revenue, such as regulatory commission expense, were allocated based on revenue. All other A&G costs, which are related to the overall operation and maintenance of the utility, were allocated based on O&M expenses. This represents a modification of the Commission Basis gas cost of service method, wherein half of certain A&G accounts were allocated based on O&M expense and the other half of such accounts were allocated based on system throughput.

Q. Why did the Company use this method of allocating A&G expenses?

A. The *Gas Distribution Rate Design Manual* published by the National Association of Regulatory Utility Commissioners ("NARUC") states that "administrative and general expenses may be allocated in accordance with the composite allocation of all other operating and maintenance expense, excluding the cost of gas." The Company's change to use of O&M expense for allocating all A&G costs that cannot be specifically allocated based on labor, plant and revenue is more consistent with industry cost allocation standards and the operation of the Company. Allocation of A&G costs based on O&M expenses is also consistent with the Company's treatment of these costs in its electric cost of service study in this proceeding.

F. Results of the Cost of Service Study

1. Parity (revenue-to-cost) ratios

Q. Please summarize the results of the cost of service study filed by the Company.

A. The parity or revenue-to-cost ratios and class rates of return under current rates, excluding gas costs, are summarized in the following table. The parity ratio indicates what portion of the cost of service customers pay under current rates. These results are also provided in the summary of results from the cost of service study as Exhibit No. ___(JKP-4) at 1, line nos. 17 and 18.

Rate Class	Parity Ratio	Rate of Return
Residential (Schedules 23, 16, 53)	86%	6.1%
Commercial & Industrial (Schedules 31, 36, 51, 61)	85%	6.1%
Large Volume (Schedule 41)	114%	12.7%
Interruptible (Schedule 85)	138%	19.3%
Limited Interruptible (Schedule 86)	167%	25.2%
Non-exclusive Interruptible (Schedule 87)	134%	17.8%
Transportation (Schedule 57)	165%	25%
Transportation Special Contracts	101%	9.9%
Compressed Natural Gas (Schedule 50)	2%	-16.2%
Rentals (Schedules 71, 72, 74)	56%	-7.9%

2. Fixed customer costs versus current customer charges

Q. Have you prepared an analysis of the Company's costs to provide different types of customers with natural gas service, even if a customer within a particular customer class were to use little to no gas?

A. Yes, I have. The unit cost analysis on page 4 of Exhibit No. ___(JKP-4) presents the customer costs on a unit cost basis. Customer-related costs include operating expenses such as meter reading, customer accounting and billing, customer service, and certain distribution operating and maintenance costs, as well as related administrative and general (A&G) expenses. I should note that it is not unusual from a cost of service perspective to include a customer-related component of distribution mains in customer cost. However, PSE has not defined these as customer costs in this case. If a portion of distribution mains had been included, the customer costs would be higher than those presented in Exhibit No. ___(JKP-4). In other words, the basic cost to provide service to customers set forth in Exhibit No. ___(JKP-4) and in the table below actually understates the costs of providing such service.

The following table compares the Company's current monthly customer charges to what the monthly customer charges would be if they included all costs defined in the Company's study to be customer related.

Class	Schedule	Current Customer Charge	Cost-Based Customer Charge
Residential	23	$6.25	$17.50
Commercial & Industrial General Service	31	$15.00	$51.85
Commercial & Industrial Heating	36	$30.00	$51.85
Commercial & Industrial Large Volume	41	$70.00	$103.10
Multiple Unit Housing Service	51	$6.25	$51.85
Propane	53	$5.50	$17.50
Interruptible	85	$500.00	$1,097.09
Limited Interruptible	86	$100.00	$141.80
Non-exclusive Interruptible	87	$500.00	$1,346.56
Transportation	57	$800.00	$1,111.50
Transportation Special Contracts	99/199/299	$800.00	$1,855.04
Compressed Natural Gas	50	$150.00	$797.30

V. RATE SPREAD AND RATE DESIGN

A. Overview of Rate Spread and Rate Design and their Relation to the Cost of Service Study

Q. How do the cost of service study results relate to rate spread and rate design?

A. The cost of service study is the Company's best indicator of what it costs to serve each class of customer. The parity ratios presented on page 1 of Exhibit

No. ___(JKP-4) and discussed earlier in my testimony indicate that some classes currently pay less than it costs to serve them, and other classes pay more than it costs to serve them. As a result, some classes essentially subsidize other classes. In addition, the Company's earned return varies by customer class. By adjusting rate spread, class members can be brought closer to paying the costs that the Company actually incurs to serve the class. When such adjustment is combined with adjustments to rate design, class revenues can be brought closer to cost of service levels, and class level rates of return can be brought closer to the system average rate of return.

Q. What other factors did the Company consider in developing the revisions to rate schedules that are proposed in this case?

A. There are several criteria for allocating revenues to classes and designing rates. Principles of revenue allocation and rate design are discussed in Mr. Amen's testimony. In this case, the primary considerations were: (1) cost of service results; (2) each class's contribution to present revenue levels; (3) customer impacts; (4) providing appropriate price signals to customers; and (5) revenue stability.

B. Summary of the Company's Proposed Rate Spread and Rate Design

Q. How does the Company propose to allocate the rate increase to the customer classes?

A. PSE's long-term goal is to move its rates toward cost of service levels for each class, but to move all the way to cost based rates in a single step would cause larger impacts on certain customers than may be reasonable. The Company proposes to allocate the predominant share of the revenue increase to those classes that are currently paying between 85 percent and 115 percent of their allocated cost of service, with the following constraints: (1) no class should receive more than 150 percent of the system average increase; and (2) all classes contribute to the recovery of the revenue increase at some level. The proposed revenue allocation by rate class is presented on page 1 of Exhibit No. ___(JKP-7) and is summarized in the following table:

Customer Class	**Parity Ratio**[1]	**Proposed Rate Increase**
Residential	86%	4.95%
Commercial & Industrial	85%	4.10%
Large Volume	114%	0.82%
Compressed Natural Gas	2%	7.37%
Interruptible	138%	0.36%
Limited Interruptible	167%	0.30%
Non Exclusive Interruptible	134%	0.19%
Transportation	165%	1.38%
Contracts	101%	0.10%
Rentals	56%	14.60%
System Total / Average	100%	4.21%

[1]At existing rates

Q. How can the results of the cost of service study be used for rate design within each class?

A. The unit cost table presented on page 4 of Exhibit No. ___(JKP-4) serves as a guide to the appropriate levels of the demand, commodity, and customer charges for each customer class.

Q. Has the Company prepared new natural gas tariff schedules reflecting the proposed changes?

A. Yes. The revised tariffs are presented in Exhibit No. ___(JKP-11).

Q. Please summarize the proposed changes to the Company's natural gas tariff schedules.

A. The Company proposes the following changes:

1) Modest increases to some of its customer charges.

2) Increases to the balancing charge paid by transportation customers and the procurement charge paid by interruptible customers to bring these charges to cost of service levels indicated by the cost of service study.

3) An increase to the delivery demand charge from $0.50 to $1.00 for Schedule 41 customers, and a reduction in the volumetric delivery charges for these customers.

4) Changes to the delivery and demand charges to produce revenues consistent with each class's revenue requirement.

5) Revision of the allocation of gas supply-related costs among the customer classes served under Schedules 101 and 106 based on results of the cost of service study.

C. Increasing the Customer Charges to Better Recover Fixed Costs

Q. Why does the company propose to raise customer charges?

A. Under PSE's current natural gas tariff schedules, PSE relies on volumetric, or per therm, rates to recover a large portion of its costs, but many costs do not vary based on the volume of gas sold. Instead, they vary based on either capacity or the number of customers on the Company's system. PSE incurs these costs for each customer whether that customer purchases gas or not. Many of PSE's capital and operating costs are related to meeting design peak demand or providing service to customers, regardless of the volume of gas customers purchase. For example, in the residential class prior to any rate changes, 76 percent of margin revenue is derived from volumetric, or per therm, charges. In contrast, 1.6 percent of the Company's distribution cost is related to the volume of gas the Company sells or transports. Yet most revenue is derived from volumetric rates. Because of this, the Company's revenue stream is vulnerable to changes in customer usage patterns, weather, and conservation efforts. A major concern of the Company is this continuing practice of recovering fixed costs through volumetric rates – not only customer costs but demand costs as well.

Increasing the customer charge starts to address the need to recover customer-related costs through fixed charges. Even with the proposed increases in customer charges, a large portion of customer-related costs will continue to be recovered through volumetric rates. The proposed customer charges reflect the need to move toward cost of service, but do so in small steps.

Q. To what levels do you propose to adjust the customer charges?

A. The Company's current and proposed customer charges are summarized in the following table, along with the cost-based rates indicated by the cost of service study.

Class	**Schedule**	**Current Customer Charge**	**Cost-Based Customer Charge**	**Proposed Customer Charge**
Residential	23	$6.25	$17.50	$8.25
Commercial & Industrial General Service	31	$15.00	$51.85	$20.00
Commercial & Industrial Heating	36	$30.00	$51.85	$35.00
Commercial & Industrial Large Volume	41	$70.00	$103.10	$85.00
Multiple Unit Housing Service	51	$6.25	$51.85	$8.25
Propane	53	$5.50	$17.50	$8.25
Interruptible	85	$500.00	$1,097.09	$500.00
Limited Interruptible	86	$100.00	$141.80	$100.00
Non-exclusive Interruptible	87	$500.00	$1,346.56	$500.00
Transportation	57	$800.00	$1,111.80	$800.00
Transportation Special Contracts	99/199/299	$800.00	$1,855.04	$800.00
Compressed Natural Gas	50	$150.00	$797.30	$150.00

Q. How do PSE's customer charges compare to those of other utilities?

A. Exhibit No. ___(JKP-8) contains a comparison of customer charges and percentile rankings for residential service from 145 natural gas distribution utilities throughout the country. These are distribution companies who are members of the American Gas Association ("AGA") and who participate in AGA's quarterly rates survey. These utilities represent all areas of the contiguous United States, and are a comprehensive group for comparison purposes. The customer charges for standard residential service range from a low of $2.00 per month at National Fuel Gas in New York to $20.00 per month at Oklahoma Natural Gas. The average customer charge is $8.88 per month. By comparison, PSE's current residential customer charge of $6.25 per month is only 70 percent of the average customer charge and is in the 18th percentile of the 145 companies. In other words, 82 percent of the other distribution companies in the country have residential customer charges higher than PSE's charge. Utilities in Washington State have among the lowest residential customer charges in the nation.

Q. Are there customer benefits to higher customer charges?

A. Yes. In addition to any customer benefits that flow from increasing the Company's revenue stability, higher customer charges also provide bill stability benefits to the customer. During cold weather, with corresponding higher gas heating requirements, the customer faces a higher bill for the increased volume of gas used during that period. Smaller variable distribution rates result in smaller bill increases during cold periods and may help customers better budget for their natural gas bills.

Adjusting the customer charge so that it is closer to cost of service levels also reduces the cross-subsidization within rate classes. Because the Company only recovers a small portion of its fixed costs through its fixed charge, customers who use small quantities of gas can fail to pay their fair share of costs because they do not consume enough gas to compensate for the fixed costs that are not included in the customer charge. This forces higher-use customers to subsidize low-use customers.

Q. How do the proposed increases in customer charges fit with the Company's decoupling proposal?

A. Without the decoupling proposal that is included in this case, the Company would be proposing much higher increases to its customer charges. Generally, decoupling does not solve all of the problems that are caused by customer charges that are set too low to recover fixed costs. Instead, decoupling primarily addresses the revenue stability problems that are caused when actual customer usage is too low to permit the Company to recover its costs.

Raising the customer charge does not address the fact that there are other fixed costs in addition to customer-related costs that are being recovered on a volumetric basis. Decoupling also addresses the need to recover these fixed costs.

In terms of how these proposals interact to impact customers, increasing the customer charge reduces the variability in customers' bills even with a decoupling mechanism, because more fixed costs are recovered on a fixed charge basis. The closer the customer charge is to cost of service levels, the smaller the decoupling adjustment will be, and the less variability in customers' bills.

If the Company's decoupling proposal is not accepted, it would be appropriate for the customer charge to be increased by a greater amount than has been proposed as part of the Company's overall filing in this case.

Q. If the Company's decoupling proposal is not implemented, how high should the customer charges be?

A. If the Company's decoupling proposal is rejected, a residential customer charge of $17.00 per month would be warranted, consistent with the cost of service study results. The customer charges for other customer classes also could be increased to the cost of service levels indicated in the table at the end of Section IV of my testimony.

D. <u>Additional Rate Schedule Comments</u>

Q. What changes are being proposed to the PGA Mechanism allocation factors?

A. The Company proposes to revise the allocation of gas costs among the customer classes served under Schedules 101 and 106.

Q. Why is the Company proposing to change these allocation factors?

A. During the Company's annual PGA Mechanism filings, the Schedule 101 and 106 rates are adjusted up or down based on allocation factors that have not been reviewed in relation to cost of service study results for a number of years. The Company's analyses in this case showed that the adjustment to the commodity rate in Schedule 101 for revenue sensitive items should be changed from the current 1.04454% to 1.04569%. The analysis supporting the revised rates is presented in Exhibit No. ___(JKP-9), and the revised tariffs are included in Exhibit No. ___(JKP-11).

Q. Have you prepared a tariff sheet to implement PSE's Depreciation Tracker proposal?

A. Yes, Schedule 124 is filed with an effective date of January 1, 2007. The methodology used to calculate the rate is provided in Exhibit No. ___(JKP-10).

Q. Please describe the rate design associated with the Depreciation Tracker.

A. The revenue requirement to be included in the tracker is allocated to each class according to the allocation of transmission and distribution depreciation expense in the cost of service study. The per-therm rate is developed by dividing the allocated revenue requirement by projected volumes for the rate year, which is 2007. The specific allocation factors will be based upon the compliance cost of service results filed following the Commission's decision in this rate case.

Q. Why is the Company proposing to cancel Schedule 119, the Capital Structure Tracker Rate Adjustment?

A. This is a housekeeping matter to cancel the capital structure penalty mechanism that was added to the Company's tariff schedules as part of the settlement of PSE's 2001 general rate case, Docket Nos. UE-011570 et al., two rate cases ago.

VI. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

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