EXHIBIT NO. ___(JKP-1T)
DOCKET NO. UE-11____/UG-11___
2011 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-11____ Docket No. UG-11____

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

JUNE 13, 2011

PUGET SOUND ENERGY, INC.

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CONTENTS

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, Inc. ("PSE") as a Regulatory Consultant 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 the First Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-2).

Q. What is the purpose of your testimony?

A. I will present PSE's pro forma revenue from gas operations, the gas cost of service study, and PSE's proposed rate spread and rate design for gas service. Although the methodologies discussed in my testimony are consistent with the methodologies used in past general rate cases, I have provided a summary of these methodologies again in this case. I will also follow up on the commitment in the settlement agreement from PSE's 2010 gas tariff increase proceeding, Docket No. UG-101644, regarding PSE's review of its gas tariffs as they relate to recovery of costs from firm and interruptible customers on Schedules 85, 86, 87, 85T, 86T and 87T.

II. PRO FORMA REVENUE FROM NATURAL GAS OPERATIONS

Q. What is pro forma revenue?

A. Pro forma revenue is an estimate of test year revenue based on test year billing determinants (*e.g.*, volume, contract demand, number of bills) and the rates that are in place at the time of filing for a rate change. It is developed to ensure that the test year revenue used in calculating the revenue deficiency (1) reflects only those rate schedules that are being considered in the present case, (2) encompasses any rate changes that have taken place during or since the test year, and (3) is consistent with the normalized test year revenue requirement and loads. The calculation and billing determinants used to produce pro forma revenue are also used to estimate the revenue from proposed rates.

Q. Have you prepared an exhibit that demonstrates PSE's development of its pro forma revenue?

A. Yes, I have. It is the Second Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-3).

Q. Please explain page one of Exhibit No. ___(JKP-3), Adjustments to Volume (Therms) by Rate Schedule.

A. As mentioned above, pro forma revenue is based on test year billing determinants, which include gas throughput. Developing pro forma revenue involves making adjustments to test year throughput. PSE's adjustments to test year natural gas throughput for this case are summarized on page one of Exhibit No. ___(JKP-3). Column B of page one shows the volume of sales and transportation for the test year in this proceeding, which is calendar year 2010.

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. The volume in column B, which underlies PSE's income statement, reflects sales for a given month that were billed during that month, removes the portion of that volume that was consumed in the previous month, and adds an estimate of sales that occurred during the calendar month but were not yet billed. In the adjustment to unbilled volume included in column C, this estimate of the unbilled portion of sales was updated to reflect sales that actually took place during each calendar month, by rate schedule, after the whole month's consumption was actually billed.

The Schedule 41T/86T migration adjustment in column D is an adjustment to volume for customers currently on Schedule 41T, Large Volume High Load Factor Transportation Service, and Schedule 86T, Limited Interruptible Transportation Service. Both schedules received an influx of customers from other schedules during the test year, and the adjustment annualizes the billing determinants of new customers on these schedules. The schedules from which these customers migrated during the test year also are adjusted to reflect these exiting customers, so there is no net change to total volume.

The Schedule 41 migration adjustment in column E reflects estimated movement away from Schedule 41, Large Volume High Load Factor Service. As described later in my testimony, PSE proposes to implement a minimum volume requirement of 12,000 therms per year on Schedules 41 and 41T as part of this proceeding. This will require that 482 customers on Schedule 41 move from Schedule 41 to 31 when the volume requirement is implemented, and the volume adjustment is the test year volume of the customers who will be served on Schedule 31 in the future.

The weather normalization adjustment to volume presented in column F removes the effect of non-normal temperatures from test year loads, so that test year loads and revenues are more reflective of normal operating conditions. This adjustment is described in the Prefiled Direct Testimony of Dr. Chun K. Chang, Exhibit No.___(CKC-1T).

Pro forma volume that reflects all of these adjustments and is used for calculating pro forma revenue is presented in column H on page one of Exhibit No. ___(JKP-3).

Q. Please explain page two of Exhibit No. ___(JKP-3), Reconciliation of Revenue by Rate Schedule.

A. Page two of Exhibit No. ___(JKP-3) presents explanations of the differences between test year revenue, as presented in PSE's income statement, and pro forma revenue, as calculated based on billing determinants and rates. The revenue included in the test year income statement is presented in column B of page two, and pro forma revenue based on billing determinants and current rates is in column P. The items presented in columns C through N are explanations of the differences between the income statement and pro forma revenue. These items are related to either:

1. removal of revenue from adjusting price schedules, municipal taxes, penalty charges and new customer charges (columns C-E);

2. other restating adjustments that correspond to the previously-discussed restating volume adjustments, specifically the billing corrections and the change in unbilled revenue adjustment (column F);

3. adjusting for price changes that took place during or after the test year, specifically the 2010 purchased gas adjustment ("PGA") and implementation of rates approved in PSE's 2009 general rate case ("GRC") and 2010 gas tariff increase proceeding (columns G, H and I);

4. an adjustment to revenue associated with a change in the calculation method for the annual minimum charges on

Schedules 85 and 85T, which was implemented in November 2010 (column J);

5. a schedule migration adjustment that reflects both customer movement onto Schedules 41T and 86T that took place during the test year and an estimate of the customer impacts to Schedules 31 and 41 of the proposed new minimum volume requirement on Schedules 41 and 41T (column K);

6. an adjustment to revenue to reflect the weather adjustment to volume (column L), or

7. the effect on revenue of updating the Revenue Adjustment Factor on Schedule 101 gas rates to be consistent with the proposed revenue requirement, and removal of storage rental revenues described in the Prefiled Direct Testimony of Michael J. Stranik, Exhibit No. ___(MJS-1T) (columns M-N).

Q. What are PSE's resulting pro forma volume and revenue?

A. The total pro forma volume for the test year is 1,089,556,625 therms, and is presented in column H of page one of Exhibit No. ___(JKP-3). The total pro forma revenue is $1,055,321,057, and is presented in column P of page two. The gas cost associated with this revenue is $600,935,094, and is presented in column R of page two.

III. COST OF SERVICE CONSIDERATIONS

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

A. The purpose of a cost of service study is to apportion the utility's total cost of service, or revenue requirement, to the respective customer classes and to group costs so that individual rates can be properly set. This cost analysis then provides guidance for the determination of the revenue responsibility for the individual customer classes and for rate design.

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. Please describe the first step in a cost of service study, 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 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. PSE's distribution system is designed to perform the following three primary tasks: (1) to provide distribution services to *customers* served by the system; (2) to serve peak *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 according to customer, demand, or commodity.

Given these three 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 for which the system was designed, or the volume of gas sold or transported over the system?"

Q. Please describe customer-related costs.

A. Customer-related costs are those costs that would be needed to serve customers at minimal load conditions. These 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.

Q. Please describe demand-related costs.

A. Demand, or capacity, costs are those costs associated with 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 peak demand for which the system was designed. Demand costs are incurred whether all the capacity is used or not.

Q. Please describe commodity costs.

A. Commodity costs, such as the cost of gas itself, vary with the amount of gas transported over PSE'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. Gas distribution systems have very low commodity-related costs aside from purchased gas.

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 is unique to a specific customer class and can be directly assigned to that 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. Previous Cost of Service Studies

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

A. PSE filed cost of service studies in its 2006, 2007 and 2009 general rate cases and its 2010 gas tariff increase filing. The approach used in this proceeding, which I will discuss later in my testimony, is consistent with that used in PSE's 2009 and 2010 cases. As explained below, the 2010 methodology reflects adjustments that evolved from PSE's 2006 GRC. The primary departures from the 2006 method in subsequent studies relate to the allocation of the costs of distribution mains. In 2006, mains were allocated based on data developed using SynerGEE, which is PSE's gas planning model. The portion of distribution mains less than four inches in diameter that was dedicated to serving a single customer on Schedules 85 (Interruptible), 87 (Non-exclusive Interruptible), 57 (Transportation) and special contracts was identified using SynerGEE and directly assigned to those customer classes. The remaining mains smaller than four inches were then allocated using the peak and average method to all classes except Schedules 85, 87, 57 and special contracts, and the large mains were allocated using the peak and average method to all classes. In PSE's 2007 GRC, SynerGEE was again used to identify costs to directly assign to Schedules 85, 87, 57, 85T, 87T and special contracts, but in a different way than had been done in the 2006 case (85T and 87T are new transportation schedules approved in the 2007 case). In other respects the 2007 study was consistent with the 2006 study. In PSE’s 2009 GRC, the allocation of mains was changed in response to concerns raised in PSE's 2007 GRC, and SynerGEE was not used. The 2010 approach was consistent with the 2009 study. The allocation of mains in this proceeding is consistent with the method used in 2009 and 2010.

B. Overview of PSE’s Proposed Gas Cost of Service Study

Q. Why did PSE conduct its cost of service analysis both including and excluding gas commodity costs?

A. PSE conducted the analysis both including and excluding gas commodity costs to ensure that the cost of service study is consistent with the total revenue requirement including gas costs presented in the testimony of Michael J. Stranik, Exhibit No. ___(MJS-1T), and to be consistent with past cases. The study that includes gas costs is informational only, because PSE’s PGA mechanism addresses changes in commodity costs. This proceeding addresses 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.

Q. Have you prepared exhibits that present PSE's cost of service study for its natural gas service in this proceeding?

A. Yes. The Third Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-4), presents the summary results proposed in this proceeding, excluding gas costs. The Fourth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-5), presents the summary results proposed in this proceeding, including gas costs. The Fifth, Sixth and Seventh Exhibits to my Prefiled Direct Testimony, Exhibit Nos. ___(JKP-6, 7 and 8), present supporting details of PSE's proposed study, including gas costs.

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

A. PSE used the same model that it used in its 2006, 2007, 2009 and 2010 rate cases.

C. <u>Peak and Energy Allocation Factors</u>

Q. What was the basis for allocating commodity costs?

A. PSE used weather-normalized volume for the test year, which was developed for the calculation of pro forma revenue and is discussed earlier in my testimony.

Q. How did PSE develop the peak demand allocator for demand-related costs?

A. PSE used the system design day to develop its peak demand allocator. The system design day is based on 52 heating degree days ("HDD"), as explained in

PSE's draft 2011 Integrated Resource Plan.[1] In broad terms, peak requirements include the firm loads of sales and transportation customers. To estimate the total peak demand of customers on firm sales schedules, PSE developed regression equations to characterize the relationship between firm peak loads and monthly firm volume considering the difference between peak and monthly temperatures. The total peak demand of customers on firm sales schedules was then estimated using the estimated regression coefficients, the system design day of 52 HDD and weather normalized throughput for the test period. The transportation and interruptible sales customers' peak was equal to either those customers' contract demands (for Schedules 85, 85T, 86, 86T, 87, 87T, and contracts), which represent the firm demand PSE is obligated to serve, or their fixed demand (for Schedule 41T), which is established annually and billed every month. The total system peak was the sum of the peak demand of customers on firm schedules and the contract or fixed demands of customers on transportation or interruptible sales schedules.

Q. How was the peak allocation factor for firm sales schedules developed at the customer class level?

A. The firm sales component of the peak demand allocation factor described above was allocated to Schedules 16, 23, 31, 53, and 41 based on a combination of fixed demands and consumption in the peak month of the test year. Schedule 41

[1] *See* PSE's 2011 Integrated Resource Plan, Appendix H: Demand Forecasts, page H-24, on file with the Commission and publicly available at www.pse.com.

customers have fixed demands that are established annually, based on the customers' usage in the system peak month, and billed every month. These fixed demands were used to estimate Schedule 41 customers' contribution to the system peak. Of the total peak of firm sales schedules, the portion not assigned to Schedule 41 based on those customers' fixed demands was allocated between Schedules 16, 23 and 53 (Residential and Propane) and Schedule 31 (Commercial and Industrial), based on those schedules' actual volume during the peak month in the test year.

Q. Why did PSE use only the contract demands of interruptible customers?

A. PSE's interruptible gas rate schedules currently allow customers to take firm service under the same schedule. Contract demands represent those customers' firm load on these interruptible schedules, and any use in excess of their contract demand is interruptible. PSE's system is designed to serve firm load. Capacity projects are undertaken for the purpose of serving firm loads, not interruptible loads, so allocating peak-related costs to interruptible customers based on interruptible loads would not be consistent with the way costs are incurred by PSE. PSE's system capacity planning relies on design day weather conditions, when all interruptible loads of transportation and sales customers are assumed to be curtailed, to ensure that PSE is able to serve its firm load. Many interruptible customers have both firm and interruptible components to their loads, and during design day weather conditions the only service to interruptible customers is assumed to be their firm component. Because the contract demand represents the firm portion of their loads, it is the best estimate of their contribution to the costs of meeting the system peak.

Q. Why did PSE use its design day peak demand to allocate demand-related costs instead of using a peak based on actual weather data from a recent historical period?

A. There are two primary reasons design day peak is a better choice than historical peak for cost allocation:

1. Design day peak is a better indicator of cost causation than historical peak demands.
2. Design day provides a more stable estimate of peak than historical peaks provide, and provides more stable cost of service results over time.

Q. Why does design day peak better reflect the costs that are incurred than a historical peak does?

A. Cost causation is the primary consideration in cost of service analysis, and PSE 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, PSE incurs the capacity costs associated with being able to provide natural gas service on a design day. PSE uses the design day standard in its capacity investment decisions and builds capacity to meet that standard. As discussed in the Prefiled Direct Testimony of Susan McLain, Exhibit No. ___(SML-1T), PSE is obligated to provide reliable service, and customers expect that reliability, especially during cold weather. If PSE built the system based on a peak that occurred in a given historical period, the capacity might not be sufficient to serve customer needs in extreme weather. The design day standard was developed in PSE's Integrated Resource Plan process and has been accepted by the Commission. An estimated peak based on historical weather conditions during a particular period would not necessarily reflect PSE's costs associated with meeting its peak demand.

Q. Why does design day peak provide a more stable estimate of peak than a peak based on historical temperatures does?

A. Weather, volumes and peak demands change from year to year, yet these changes do not represent the costs of designing and building PSE's system. If historical data were used, cost allocation would depend on weather conditions that happened to prevail during the period considered rather than the conditions for which the system was designed, which do not vary considerably from one year to the next the way weather does. The historical peak might also include some interruptible loads, which would vary over time based on both weather conditions and the amount of excess capacity in the system available to serve those loads. These factors could result in greater volatility of cost assignments from one cost study to the next. The design day standard is a more stable determinant of planned capacity.

With respect to stability over time, use of design day is consistent with the use of weather normalized volume in cost allocation. If actual volume were used, allocation among the classes would change from year to year based on the weather because some customer classes exhibit greater weather sensitivity than other classes. Use of weather-normalized volume avoids these swings in cost allocation from one rate case to the next. Similarly, design day is a more stable basis for cost allocation because it does not depend on the weather that actually occurred during a recent period.

D. Allocation of Plant Costs and Operating Expenses

Q. Were facilities identified that could be directly assigned to specific customer groups?

A. Yes. PSE conducted an analysis to identify the cost of services in Federal Energy Regulatory Commission ("FERC") Account 380 that are dedicated to customers on Rate Schedules 85, 85T, 87, 87T and special contracts. This portion of plant in Account 380 was directly assigned to these customer classes, and the remainder was allocated to all other customer classes 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 cost data for various sizes and types of services, and these weighted customer counts were used to allocate costs across customer classes. The use of weighting factors takes these 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 and 384), and industrial measuring and regulating station equipment (Account 385) were allocated based on the actual types of meters used to serve customers in different customer classes and the current costs of those meters and their installation.

Q. How were distribution-related operation and maintenance ("O&M") expenses allocated?

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

Q. How were administrative and general ("A&G") expenses and taxes allocated to each customer class?

A. 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 O&M 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 expenses, were allocated based on revenue. All other A&G costs were allocated based on operation and maintenance expenses.

E. Classification and Allocation of Distribution Main Costs

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

A. Following a long-standing practice, including PSE's 2009 GRC and 2010 gas tariff increase proceeding, PSE used the peak and average method for allocating distribution main costs. This method allocates demand costs based on a combination of peak demand and average demand. Average demand is essentially another term for average throughput. PSE used an estimate of the system load factor to determine how much of these demand-related costs would be allocated based on average demand and how much would be allocated based on peak demand. A system load factor was calculated based on weather-normalized throughput and design day peak demand, which were discussed earlier in my testimony. The load factor is the ratio of average load to peak load, and when multiplied by the plant investment, provides an estimate of costs that can be attributed to average use rather than peak use. 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, with the costs being allocated 33 percent on average demand and 67 percent on peak demand. The load factor provides a reasonable basis for determining what portion of these costs should be allocated based on average demand.

This 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). It also acknowledges previous Commission guidance that some portion of demand costs should be allocated based on energy use.

Q. How was the peak and average method of cost allocation applied to distribution mains?

A. A diagram of the allocation of mains is presented on page one of the Eighth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-9). The cost of mains was allocated in the following steps:

First, the total distribution mains plant was divided into the portion to be allocated based on peak demand and the portion to be allocated based on average demand using the system load factor described above. This resulted in $442 million (33 percent) of plant to be allocated based on average demand and $898 million (67 percent) to be allocated based on peak demand.

Second, the 67 percent to be allocated based on peak demand was allocated to all customer classes based on their estimated contributions to the system design day peak demand.

Third, the 33 percent based on average demand was split into three groups: 1) large main (greater than or equal to four inches in diameter); 2) medium main (two to three inches in diameter); and 3) small main (less than two inches in diameter). Large main was allocated to all customer classes based on annual weather normalized throughput, and small main was allocated to all classes except Schedules 85, 85T, 87, 87T and contracts based on annual weather normalized throughput. Medium main was allocated 33 percent to all classes and 67 percent to all classes except 87, 87T and contracts, based on annual weather normalized throughput.

Q. Why were small mains, those less than two inches, not allocated to all classes?

A. The smallest main is in isolated locations on PSE's system and is unlikely to provide benefits to the large commercial and industrial loads served on Schedules 85, 85T, 87, 87T and contracts.

Q. Why were medium mains, those two to three inches in diameter, split into two groups?

A. Parties in PSE's 2007 GRC raised different concerns regarding the allocation of mains. In general, two different ways of looking at the benefits to customers were presented in discussions about the allocation of mains costs, and these two viewpoints are diametrically opposed. One view is founded on a belief that customers only benefit from pipe through which gas molecules flow, or might flow, to reach their locations, and thus should only be allocated a share of the cost of those specific pipes, nothing more. The other view is that the gas distribution network provides an integrated system that benefits all customers, regardless of the customers' locations on that system and regardless of the actual (or modeled) flow of molecules. Giving the largest interruptible customers a full allocation of costs emphasizes system benefits, and exempting them from the cost of medium main emphasizes customers' physical connections and the flow of gas. PSE's use of both of these approaches for medium mains balances the two perspectives.

Q. Why did PSE choose the one-third, two-thirds split, with one-third of medium main being allocated to all customers and two-thirds to all except Schedules 87, 87T and Contracts?

A. PSE considered the historical treatment of Schedules 87, 87T and contracts customers and the benefits associated with being part of the gas distribution system. Historically, these customers had some assignment of costs related to medium main, but that assignment was small. Prior to PSE's 2004 GRC, Docket No. UG-040640, when PSE introduced the use of SynerGEE into its cost of service study, the only assignment of medium main given to those largest customers was based on a direct assignment. The two-thirds weighting of the exemption of these customers is an acknowledgement that, in the past, the Commission approved very limited cost assignments to this group of customers. The one-third weighting of assigning the cost of medium main to all customers acknowledges the benefits to all customers of being part of a distribution system. So while their cost assignment of medium main should be small, it should not be zero. This methodology is consistent with PSE's 2009 GRC and 2010 gas tariff increase proceeding.

Q. Why did PSE choose two inches as the point for exempting large customers?

A. Large main (four inches and greater) is the backbone of the system, and medium to small main (three inches and smaller) is used to deliver gas to most customers. Main smaller than two inches is located mostly in isolated locations on the system and is unlikely to provide benefits to large commercial and industrial loads, whereas medium main is ubiquitous throughout the distribution system. Three-inch main is grouped with two-inch main, but there is very little three-inch main in the system.

Q. Please summarize the benefits of PSE's approach to allocating mains.

A. There are five benefits to PSE's approach. First, this method recognizes that all customers benefit from the gas system of medium to large mains as a whole, not only from the stretch of main through which gas flows to reach the individual customer. The system is a network of pipes that provides benefits to customers in addition to providing the stretch of pipe through which molecules flow to reach the individual customer. Second, in previous general rate cases some parties have opposed the use of a customer's physical location on the system to determine the costs that should be assigned to that customer. The proposed method avoids this practice. Third, by exempting large customers from the cost of the smallest diameter main (less than two inches), this approach acknowledges the fact that the smallest main is in isolated locations on the system and is unlikely to benefit large commercial and industrial customers. Fourth, PSE's approach addresses concerns regarding cost responsibility for two-inch main by allocating a portion of it to all customers and excluding the largest interruptible customers from a portion of it. Fifth, PSE's approach is relatively transparent and easy to understand.

F. Results of the Cost of Service Study

Q. Please summarize the results of the cost of service study conducted by PSE.

A. The parity percentages under current rates, excluding gas costs, are summarized in Table 1 below. The parity percentage indicates what portion of the cost of service customers pay under current rates, relative to other customer classes. These results are also provided in the summary of results from the cost of service study on page one, line 36, of Exhibit No. ___(JKP-4).

Table 1: Summary of Parity Percentages

Customer Class	Parity Percentage
Total System	100%
Residential (Schedules 23, 16, 53)	98%
Commercial & Industrial (Schedules 31, 31T, 61)	96%
Large Volume (Schedules 41, 41T)	124%
Interruptible (Schedule 85, 85T)	121%
Limited Interruptible (Schedule 86, 86T)	157%
Non-exclusive Interruptible (Schedule 87, 87T)	87%
Special Contracts	73%
Rentals (Schedules 71, 72, 74)	197%

V. REVIEW OF INTERRUPTIBLE TARIFFS

Q. The settlement agreement in PSE's 2010 gas tariff increase proceeding describes PSE's review of its natural gas tariffs as they relate to recovery of costs from firm and interruptible customers on Schedules 85, 86, 87, 85T, 86T and 87T.[2] What was the scope of this review?

A. The scope of the review was to consider whether changes to the provision of firm and interruptible service to customers on interruptible schedules are warranted, both in the tariffs and the cost of service study. Currently, PSE's interruptible schedules are described as interruptible service with a firm option. Customers exercise the firm option by establishing daily contract demands, subject to approval by PSE's planning department to ensure that the requested firm capacity exists. The customer pays for the contract demand through a demand charge. Through use of contract demands, customers on interruptible schedules can take gas sales or transportation service that is effectively fully firm, fully interruptible, or a combination of both. Concerns with the current approach to interruptible service are: 1) the demand charge does not fully recover allocated capacity costs; 2) for remaining capacity costs, interruptible customers pay the same volumetric rates that firm customers pay; and 3) customers take firm service on interruptible schedules with lower rates than firm schedules have.

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[2] *See* Docket No. UG-101644, Attach. A to Order 04 at ¶11 (March 15, 2011).

Q. Please summarize the status and results of the review.

A. The review revealed that there are alternative ways to provide interruptible service that could address the concerns related to provision of interruptible service. At the present time, PSE's preferred option is to have some tariffs provide fully interruptible service, and to require customers who want a mixture of firm and interruptible service to be served on two schedules, one fully firm and the other fully interruptible. Customers with no contract demands could be served on fully interruptible schedules, and customers with a mixture of firm and interruptible service could pay the same rates for firm service that fully firm customers pay on firm schedules. PSE is considering implementing these and related changes in a future rate proceeding; however, there are several issues that would need to be addressed before PSE can develop a formal proposal to implement this approach.

Q. The settlement agreement in PSE's 2010 gas tariff increase filing states that PSE agreed to meet with rate case participants prior to filing its next gas rate case to inform them of the progress and preliminary findings of this review. Have you done this?

A. PSE proposed a meeting with the rate case participants for May. There were schedule conflicts among the parties, and the parties agreed to a meeting in June, understanding that this meeting could occur after PSE's planned general rate case filing. PSE is scheduled to meet with participants on June 3, 2011.

VI. GAS RATE SPREAD AND RATE DESIGN

A. Rate Spread

Q. What is meant by the term rate spread?

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. The cost of service study is PSE's best indicator of what it costs to serve each class of customer, and it provides guidance to the rate spread process.

Q. Please summarize PSE's gas rate spread proposal.

A. Based on the parity percentages shown in Table 1 and the desire to move toward full parity over time, PSE proposes to: 1) apply the system average increase to those classes with parity percentages between 90 percent and 110 percent (Schedules 23, 16, 53, 31, 31T and 61); 2) apply 50 percent of the average increase to those classes between 110 and 150 percent of parity (Schedules 41, 41T, 85 and 85T); 3) apply no increase to those above 150 percent of parity (Schedules 86, 86T, 71, 72 and 74); and 4) apply 150 percent of the average increase to those below 90 percent of parity (Schedules 87 and 87T). The proposed revenue allocation by rate class of the proposed $31,864,884 increase is presented on page one of the Ninth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-10), and the resulting increases are summarized in Table 2.

Table 2: Proposed Rate Increases

Customer Class	Proposed Rate Increase*	Proposed Margin Increase
Residential (Schedules 23, 16, 53)	3.4%	8.0%
Commercial & Industrial (Schedules 31, 31T, 61)	3.0%	8.0%
Large Volume (Schedules 41, 41T)	1.1%	4.0%
Interruptible (Schedule 85, 85T)	1.7%	4.0%
Limited Interruptible (Schedule 86, 86T)	0.0%	0.0%
Non-exclusive Interruptible (Schedule 87, 87T)	2.7%	12.0%
Rentals (Schedules 71, 72, 74)	0.0%	0.0%
System Total / Average	3.0%	7.6%
*Including gas costs		

B. Rate Design

Q. What principles are fundamental to a sound rate design?

A. The following seven principles 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 describe PSE's current rate structure for distribution service.

A. The Residential (23) and General Service Commercial/Industrial (31, 31T) schedules have only the basic charge and single-block delivery charges, whereas the Large Volume Commercial/Industrial schedule (41, 41T) and the interruptible schedules (85, 85T, 86, 86T, 87 and 87T) have demand charges and multiple block delivery charges in addition to basic charges. Interruptible sales schedules also have a single-block, volumetric procurement charge.

Q. Please describe the proposed changes to PSE's natural gas tariff schedules.

A. For each schedule that receives an increase, PSE proposes to increase all charges related to distribution services by an equal percentage. For example, for Schedule 31, Commercial and Industrial General Service, the basic charge and delivery charge would increase by the same percentage. The exceptions to this rule are for situations where a rate component is tied to the same component on another schedule. For example, Schedules 41, 85, 86, 87, 41T, 85T, 86T and 87T all have the same demand charge. The proposed level for all schedules is based on the increase to Schedule 87. Increases to the other rate components may vary slightly to achieve the assigned revenue. The proposed rates from basic, demand and volumetric charges are provided in Exhibit No. ___(JKP-10).

Q. Please describe the residential basic charge.

A. The residential natural gas basic charge is applied to each customer each month, and 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 PSE must reserve for that customer (through its gas supply capabilities and/or its distribution capabilities), or the month service is taken. The residential basic charge for gas service of $10.00 is currently set below the $20.10 cost of providing this service.

Q. What costs are identified as customer-related in the cost of service study?

A. PSE's cost of service study includes the costs of service lines, meters and regulators and related installation, a portion of general plant, operating and maintenance costs associated with these plant items, customer accounts expenses, a portion of administrative and general costs, and related taxes.

Q. Do these customer-related costs include all fixed delivery costs?

A. No. They only include those delivery costs that have been identified as customer-related in the cost of service study. Most other delivery costs have been identified as demand-related, which means they vary with the capacity of the distribution system, although most of these costs will continue to be recovered through volumetric rates under PSE's proposal. These costs are also fixed, but they are not included in the $20.10 per month of customer-related costs. If all fixed distribution costs were included in a monthly basic charge the rate would be considerably higher.

Q. What changes does PSE propose to the residential basic charge?

A. Applying the proposed equal percentage increase to the residential class will increase the monthly basic charge to $10.80 from its current rate of $10.00.

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

A. The Tenth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-11), contains a comparison of basic charges and percentile rankings for residential service from 215 natural gas distribution utilities throughout the country. These data were collected from the tariffs of the utilities, which are members of the American Gas Association. These utilities represent all areas of the contiguous United States, and are a comprehensive group for comparison purposes. The basic charges for standard residential service range from a low of $3.00 per month at Washington Gas Light Company to $26.88 per month at Missouri Gas Energy. The average basic charge is $11.17 per month. By comparison, PSE's current residential basic charge of $10.00 per month is in the 46^{th} percentile of the 215 companies. In other words, 54 percent of the other gas distribution companies in the country have residential basic charges higher than PSE's charge.

C. Bill Impacts

Q. What are the proposed rates for Residential Schedule 23?

A. The proposed equal percentage increase changes the basic charge from $10.00 to $10.80 per month and the delivery charge from $0.37372 per therm to $0.40367 per therm.

Q. Has PSE prepared an analysis of customer bill impacts based on the proposed rate design?

A. Yes. Page one of the Eleventh Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-12), presents a comparison of a residential bill based on various usage levels, at existing and proposed rates. Increases to the total bill range from 3.0 percent for a customer using 180 therms to 5.2 percent for a customer using 10 therms. Increases vary by usage levels even though PSE proposes an equal percentage increase to all delivery rates because gas costs, which are charged on a volumetric basis, are included in the bills. Page two presents the annual bill impacts on a customer who uses the average volume from the test year. This indicates the typical residential customer will experience a 3.4 percent increase in the total bill based on the proposed rates.

D. <u>Tariff Changes</u>

Q. Does PSE propose any other changes to its natural gas tariffs?

A. Yes. PSE proposes to implement annual minimum volume requirements on Schedules 41, 41T, 85 and 85T.

Q. Please explain the proposed annual minimum volume requirement on Schedules 41 and 41T.

A. Schedule 41 is Large Volume High Load Factor Service, and Schedule 41T is the related transportation schedule. PSE proposes to implement a minimum volume requirement of 12,000 therms per year on Schedules 41 and 41T. As the name indicates, the schedule is intended for customers with relatively large loads and flat load profiles. However, there is nothing to prevent customers with small, weather-sensitive loads from taking service on the schedule. There is substantial overlap in customer load size between Schedule 41 and Schedule 31, Commercial and Industrial General Service. In theory, customers are grouped onto different schedules based on load characteristics, and cost of service studies indicate different average costs for different types of customers. Significant overlap of customer types between schedules dilutes cost of service results, and having no minimum volume requirement provides an opportunity for customers to shop for the lowest cost schedule between rate cases when PSE has no ability to reflect those customer migrations in its revenue requirement. The proposed minimum volume requirement is intended to make a clearer distinction between customers on Schedules 31 and 41.

Q. How will customers be affected by the proposed annual minimum volume requirement?

A. Based on test year customer data, the proposal will require that 482 customers currently served on Schedule 41 move to Schedule 31 when the volume requirement is implemented. Analysis of test year customer data at current rates indicates that 355 of these customers would pay less on Schedule 31 than they currently pay on Schedule 41, and the other 127 would pay more. The pro forma revenue adjustment discussed earlier in my testimony reflects this migration. After the minimum is established, customers will not be allowed to move onto the schedule unless they meet the minimum volume requirement. Schedule 41 and 41T customers' consumption will be reviewed on an ongoing basis, and those who do not meet the minimum volume requirement will be notified that they are being transferred to Schedule 31 or 31T.

Q. Describe the rate design of Schedules 41 and 31.

A. Schedule 31 has a monthly basic charge of $32.32 and a delivery charge of $0.31527 per therm. Schedule 41 has a monthly basic charge of $111.92, a demand charge of $1.14 per therm of fixed daily demand, and a two-block delivery charge of $0.14354 per therm for the first 5,000 therms per month and $0.11714 for all remaining therms. Schedule 41 also has a minimum delivery charge of $129.19 per month based on 900 therms per month at the first block delivery charge. The 900 therms per month sums to 10,800 therms per year.

Q. Can the distinction between schedules be made using rate design?

A. Until now, PSE has relied on rate design to signal to customers which schedules they should take service on, but there are drawbacks to this approach. Despite

PSE's movements to strengthen the price signals in the last few years, the rate design has not yet evolved to the point where it provides price signals that are completely consistent with Schedule 41's purpose, and changing rate design can be a slow process. A significant portion of demand related costs continues to be collected in the energy charge rather than the demand charge. This encourages low load factor customers to migrate from Schedule 31 to Schedule 41. The fact that 376 of the 482 customers who will be moved off Schedule 41 as a result of this proposed change consumed less than 10,800 therms during the test year, and paid the monthly minimum charge in at least one month, indicates that stronger measures are needed to delineate customer groups. Customers do not always respond as expected to rate design changes, so clearer signals are needed.

Q. Please explain the proposed annual minimum volume requirement on Schedules 85 and 85T.

A. Schedule 85 is Interruptible Gas Service with Firm Option, and Schedule 85T is the related transportation schedule. These schedules have an annual minimum charge of 180,000 therms, but no minimum volume threshold for taking service. PSE proposes to retain the annual minimum charge and to add an annual minimum volume requirement of 150,000 therms. This would prevent customers with annual loads below 150,000 therms from migrating onto or starting service on Schedules 85 and 85T.

Q. Why does PSE propose the minimum volume requirement on Schedules 85 and 85T?

A. For two reasons, which are related. First, as described in the discussion about Schedule 41, an annual minimum volume requirement will create a clearer distinction between customer groups by preventing smaller-volume customers from taking service on Schedules 85 and 85T. Second, PSE provides interruptible service so that it has operational flexibility to manage the gas system during peak conditions. Allowing relatively small customers to take service on interruptible schedules does not provide substantial value to PSE or its customers with respect to the ability to curtail customers during peak load conditions. Implementation of the minimum volume requirement is a step toward providing interruptible service only to customers with loads large enough to provide meaningful curtailment value during peak conditions. Most customers currently on Schedules 85 and 85T are above the proposed 150,000 therm threshold.

Q. How will customers be impacted by the minimum volume?

A. PSE proposes to provide a grandfather clause that allows customers currently on Schedules 85 and 85T to remain there, so they will not be impacted by the change. In the test year, only three of the 132 customers on these schedules consumed less than 150,000 therms. However, customers below the 150,000 therm threshold would not be allowed to migrate onto these schedules.

VII. CONCLUSION

Q. Has PSE prepared new natural gas tariff schedules reflecting the proposed changes to rates?

A. Yes. The revised tariffs are presented in the Twelfth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-13).

Q. Does this conclude your direct testimony?

A. Yes, it does.