**EXHIBIT NO. ___(JKP-17T)**
**DOCKET NO. UE-072300/UG-072301**
**2007 PSE GENERAL RATE CASE**
**WITNESS: JANET K. PHELPS**

**BEFORE THE**
**WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

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| **WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,**<br><br>**Complainant,**<br><br>**v.**<br><br>**PUGET SOUND ENERGY, INC.,**<br><br>**Respondent.** | **Docket No. UE-072300**<br>**Docket No. UG-072301** |

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

**JULY 3, 2008**

**PUGET SOUND ENERGY, INC.**

**PREFILED REBUTTAL TESTIMONY (NONCONFIDENTIAL) OF JANET K. PHELPS**

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**PUGET SOUND ENERGY, INC.**

**PREFILED REBUTTAL TESTIMONY (NONCONFIDENTIAL) OF JANET K. PHELPS**

## I. INTRODUCTION

**Q. Are you the same Janet K. Phelps who provided prefiled direct testimony in this proceeding on December 3, 2007, and prefiled supplemental direct testimony in this proceeding on April 14, 2008, on behalf of Puget Sound Energy, Inc. ("PSE" or "the Company")?**

A. Yes. On December 3, 2007, I filed direct testimony, Exhibit No. ___(JKP-1T), and twelve exhibits supporting such direct testimony, Exhibit No. ___(JKP-2) through Exhibit No. ___(JKP-13). On April 14, 2008, I filed supplemental direct testimony, Exhibit No. ___(JKP-14T), and two exhibits supporting such direct testimony, Exhibit No. ___(JKP-15) and Exhibit No. ___(JKP-16).

**Q. Please summarize the purpose of your rebuttal testimony.**

A. My rebuttal testimony responds to:

(i) The prefiled direct testimony of Stanley Gent, Exhibit No___(SG-1T), on behalf of Seattle Steam Company ("Seattle Steam");

(ii) The prefiled direct testimony of Glenn A. Watkins. Exhibit No___(GAW-1TC), on behalf of Public Counsel with respect to gas cost of service, rate spread and rate design;

(iii) The prefiled direct testimony of Donald W. Schoenbeck, (DWS-1T), on behalf of Northwest Industrial Gas Users

("NWIGU"); and

(iv) The prefiled direct testimony of Kevin C. Higgins, Exhibit No___(KCH-1T), on behalf of Nucor Steel Seattle, Inc. ("Nucor").

First, I will address concerns raised by various parties with respect to the cost of service study. Then I will address some assertions made by Seattle Steam in its response testimony, and some issues raised by the parties related to rate spread and rate design. I will address issues related to the proposed new transportation tariffs. Finally, I will provide PSE's perspective on the terms of a settlement agreement between some parties in this proceeding with respect to gas rate spread and rate design, which PSE understands is to be filed with the Commission.

## II. COST OF SERVICE STUDIES

**Q. What issues related to gas cost of service have been raised in the response testimony?**

A. Issues have been raised in response testimony regarding the following topics:

(i) The use of a peak and average method as the framework for the cost of service analysis. There appears to be confusion in the response testimony as to what the term "peak and average" means, and there is disagreement about the use of average demand to allocate certain costs to specific customer groups.

(ii) The allocation of Account 376, distribution mains, which is the largest portion of plant included in rate base. There is confusion among the parties about the results of a flow analysis that determined the directly assigned components. And as mentioned above, there are concerns about the use of average demand to allocate a portion of these costs.

(iii) The definition of peak demand. There are differences as to whether the total system peak should be estimated using historical data or design day conditions. And there are differences regarding the various customer classes' contributions to that peak demand.

(iv) The calculation of return under existing rates.

(v) The treatment of income taxes.

(vi) The inclusion of certain costs in the customer charge.

## A. Peak and Average

**Q. Please explain what you mean by the term "peak and average" as used in cost of service studies.**

A. The idea behind peak and average is that capacity costs – which are fixed costs – are allocated partially based on customer classes' contributions to the system peak and partially based on annual throughput. The plant cost is multiplied by the system load factor to arrive at a cost estimate of the capacity necessary to serve customers based on average consumption over the year. This capacity cost is then allocated to classes based on annual throughput. The remaining portion of the plant costs represents capacity that is in excess of what is necessary to serve average loads, but is in existence to meet peak requirements. This portion is then allocated based on customer classes' contributions to peak demand.

**Q. What alternative is there to peak and average?**

A. One alternative is the peak responsibility method, in which capacity costs are allocated based on customer classes' contributions to system peak demand only.

If the peak responsibility method were used, customers who are fully interruptible would receive no assignment of capacity costs, because the system was not sized to serve them on a design day peak and they would be curtailed. PSE offers both firm and interruptible service on Schedules 85, 86, 87 and 57, so those classes would be allocated capacity costs based only on the firm contract demands of customers in those classes.

**Q. Why use peak and average?**

A. The peak and average approach balances the fact that the system is sized to meet peak demand with the way the system is used on an average basis. Use of the peak and average approach acknowledges the fact that while the system is not sized to serve large interruptible loads, those interruptible customers do use the system and therefore should pay a portion of the costs. The fact that their interruptible loads would be curtailed in the event of a design day peak should not exempt interruptible customers from contributing to capacity costs, since the system is used to deliver gas to them, including on many days during the peak season, and they benefit from the system. Simply put, these customers would not be able to receive <u>any</u> interruptible service if the pipes had not been built to serve firm customers; they should not be able to use the mains for free.

**Q. How does the peak and average approach reflect the principle of cost causation?**

A. A strict interpretation of cost causation would indicate use of the peak

responsibility method rather than the peak and average method. Peak and average balances the idea of cost causation with the way the system is used.

**Q. Why has PSE used peak and average in this proceeding?**

A. In previous cases where the Commission has offered guidance on cost allocation, that guidance has indicated that a portion of capacity costs should be allocated based on consumption rather than peak demand. The Company does not have a compelling reason to propose a methodology contrary to this guidance.

**Q. You stated that there appears to be some confusion about what peak and average means. Please explain your understanding of the confusion.**

A. Mr. Stanley Gent, on behalf of Seattle Steam, presents a discussion of the allocation of mains in the Company's 2004, 2006 and 2007 rate cases and, referring to the present case, argues: "The cost allocation for the 'average' day, however, was completely without justification." Exhibit __ (SG-1T), p. 29, l. 4-5. On the next page at lines 9-10, Mr. Gent states: "Had the Company done a true peak and average analysis for its largest customers, such as it did in its 2006 cost of service study, we believe much of the cost attributable to the largest customer classes would have been related to serving the firm demand." I will explain later in my testimony some shortcomings that, in hindsight, PSE has identified with the 2006 methodology and that argue against its use in this case. There seems to be a fundamental misunderstanding of the peak and average concept, which is that capacity costs are allocated partially on the basis of peak and partially on the

basis of throughput. PSE's approach in the current proceeding is more consistent with the peak and average method than the 2006 approach as recommended by Mr. Gent. Nucor witness Kevin Higgins seems to have a similar misunderstanding of the peak and average concept, based on a review of his workpapers. I will address his analysis later in my testimony.

The Company's approach in this proceeding is a peak and average approach. Public Counsel has argued in this proceeding that the Company's approach is actually biased in favor of large customers. *See* Exhibit No.___(GAW-1TC) page 52, lines 11-12 and 19-20. Indeed, if PSE had done a peak and average analysis without the directly assigned component to large customers, as Public Counsel proposes, there would be even greater costs assigned to large customers.

**Q. How does the mixing of firm and interruptible customers on the "interruptible" schedules impact customers in the cost of service process?**

A. PSE does not have a tariff for customers that are exclusively interruptible. Schedules 85, 86, 87 and 57 offer both firm and interruptible service. Many customers on those schedules have firmed a portion, or all, of their load. The Company's gas planning model, SynerGEE, showed that gas does flow to customers in those schedules even under design day conditions. It is not reasonable to treat every customer individually for cost of service and rate design purposes, so customers are grouped together.

Customers in these classes who have firmed up a portion of their load are

responsible for some costs based on their peak demands. Under design day peak conditions the Company would still be obligated to serve those customers at their contract levels. Therefore, these classes should receive some costs based on peak demand.

If all demand related costs were recovered through demand charges, which are charged based on the firm portion of load (contract demand) the allocation of costs based on peak would not impact customers who have no contract demand and thus are fully interruptible. But as Mr. Gent correctly points out, PSE's demand charges are not high enough to fully recover these costs. PSE proposed a 50 percent increase in the demand charge to these classes in this proceeding to address this issue.

## B. Allocation of Account 376 Distribution Mains

**Q. Please explain PSE's approach to allocation of mains in the 2004, 2006 and 2007 general rate cases.**

A. Exhibit No.___(JKP-18) provides visual representations of the allocation of mains in each of the last three cases. I will discuss these studies in the context of the following discussion on the allocation of mains in the current proceeding.

**Q. Is it true that mains less than four inches in diameter "play no part" in serving customers on Schedules 87 and 57, as asserted by Mr. Gent at Exhibit No.___(SG-1T), page 24 lines 18-19?**

A. No. The gas distribution system is more complicated than Seattle Steam and other parties representing large customers assert in their testimony. NWIGU witness Mr. Donald Schoenbeck claims, at page 7 lines 21 through page 8 line 10 of Exhibit No.___(DWS-1T), that "only six percent of total annual throughput delivered to Schedule 85, 87 and 57 customers goes through mains that are less than 4 inches in diameter." His statement represents a misunderstanding of data provided by PSE in response to Seattle Steam's Data Request Nos. 9 through 11. In those data requests, PSE was asked to provide a list of customers whose service lines are connected to distribution main that is smaller than four inches in diameter, with their annual volume. In reality, just because a customer's service line is physically connected to, for example, six-inch main does not mean that gas does not flow through two-inch main en route to the customer's service line. The path the gas takes is a function of other things beyond the diameter of main to which the customer is physically connected (i.e., the location and size of the customer's load; location and size of all customers' loads on the system; pressure at various points on the system; and the length and diameter of all segments of pipe).

The assertion by various parties that large customers do not use small main was based on a faulty interpretation of the results of the flow analysis used by PSE to

identify directly assigned costs.

**Q. Please explain the flow analysis used to develop the costs that were directly assigned to large customers in the present case.**

A. I discussed that analysis at some length in my direct testimony. I will add that the purpose of the SynerGEE software used to conduct the flow analysis is to predict pressure in PSE's distribution system. It also allows the user to trace the flow of gas through various segments of pipe from the city gate to the customer's location at a point in time under certain assumptions. The analysis conducted for the cost of service study was based on assumed loads under design day conditions. The Company's design day has an average daily temperature of 13 degrees, and an hourly low temperature of 10 degrees. The flow analysis was conducted for one hour based on this 10-degree temperature. For the large customers specifically examined, their hourly contract demands were assumed. For all other customers, estimates of loads based on historical usage patterns and weather sensitivity were assumed.

Because the main identified in this flow analysis is limited to flow during just one hour, it does not represent large customers' full usage of the system. The model results are used in the context of a peak and average allocation method, in which the peak is defined based on how the Company designs its system (design day), as modeled by SynerGEE, and the average is based on annual throughput.

Parties in this case have taken this flow analysis to say that the only small main

ever used to serve large customers – or that provides any benefit to those large customers – is the equivalent footage that was identified by the model based on that 10-degree hour. This is an unreasonable interpretation of the analysis.

When the SynerGEE model is run using different load and temperature assumptions, it yields different results as to the equivalent footage of main through which gas flows en route to large customers. To illustrate this fact, summary results from three examples of the model output are provided in Table 1 below. This table summarizes the equivalent footage of main used to transport the gas used by the large customers, assuming a 10-degree temperature. It also provides similar results based on a winter day with a 41-degree temperature, and results based on a summer day with a 65-degree temperature. Equivalent footage is the length of main through which gas flows, adjusted for the customers' portion of gas using it. For example, if a large customer's gas flows through a 10-foot stretch of main and accounts for 100 percent of the gas in that stretch, 10 equivalent feet are counted. But if that customer's gas accounts for only half of the gas in that stretch of pipe, then five equivalent feet are counted. The results presented in Table 1 indicate that not only does the total amount of pipe "used by" the large customers vary based on the temperature, but their use of small main also varies. This information is provided as an illustration that the flow analysis used by PSE is limited and should not be interpreted – as it has been by some parties in this proceeding – to state that large customers do not use small main and therefore should be exempt from paying for any of it. All gas customers are

connected to a system that works as a whole.

**Table 1: Summary of Equivalent Footage Utilized by Large Customers Based on Three Temperature Assumptions**

| Main Size | 10 Degrees F | 41 Degrees F | 65 Degrees F |
|---|---|---|---|
| Less than 4 inch | 27,920 | 210,830 | 638,944 |
| Greater than or equal to 4 inch | 210,518 | 1,007,438 | 1,605,495 |
| **Total** | **238,438** | **1,218,268** | **2,244,439** |

**Q. Is the flow analysis based on 41 degrees, as utilized by NWIGU, appropriate for use in this case?**

A. For purposes of the cost of service study, the flow analysis utilized by NWIGU is inferior to the flow analysis undertaken by PSE in this proceeding. Mr. Schoenbeck used a flow analysis based on a 41-degree temperature. His analysis is similar to that done by PSE in Docket No. UG-040640. A chart of that approach is on page 2 of Exhibit No.___(JKP-18). Using that approach, large customers are assigned costs related only to the results of the flow analysis at a 41-degree temperature. These results serve as a proxy for a peak and average. Instead of defining the peak based on the system's design as PSE has done in the current proceeding, the peak is defined based on a winter day. And, this winter day serves as both the peak and the average pieces of the peak and average approach – there is no additional cost assignment to these classes based on throughput as there is in PSE's approach, where the peak is a design peak and the average is based on throughput.

There are three primary drawbacks to NWIGUs approach. First, a winter day is a poor substitute for either a design day peak or for average consumption throughout the year. NWIGU's analysis concludes that the costs of main specifically identified by the flow analysis on a winter day are the only costs large customers should be responsible for. Under NWIGU's approach, all other customers pay some costs based on their average consumption, but the largest customers do not.

Second, as Public Counsel witness Mr. Watkins points out, assumptions must be made to conduct the flow analysis, and these assumptions are more complicated when any weather conditions other than those related to a design day peak are used. The primary assumptions have to do with load. Load for large customers is very clear on a design day such as PSE used in its analysis – the firm contract demands the Company is obligated to serve are included, and because under those conditions the interruptible portions of those customers' loads would be curtailed, no interruptible volumes are included. On a winter day without curtailment, such as used by NWIGU, loads by customer have to be estimated based on a combination of historical load data and interruptible volumes stated in customers' contracts. This process of estimating loads is much less clear under these conditions and is one of the limitations of using the SynerGEE model.

Third, NWIGU's approach contains inconsistencies between the treatment of large customers and customers in all other classes with respect to the peak demand allocator. For all other classes, demand is defined based on the

customer's estimated contribution to design day peak. For the large customers, there is neither a true peak nor a true average.

**Q. Seattle Steam recommended using the approach that was used in UG-060267. Why did PSE not use that method?**

A. Seattle Steam provided a summary of the allocation of Account 376 from PSE's 2001, 2004, 2006 and 2007 cases in Exhibit No.___(SG-4T). The cost allocations to Schedules 85, 87, 57 and special contracts from these studies are presented in Table 2.

**Table 2: Allocation of Account 376 to Large Customers in Recent Rate Cases**

| General Rate Case | Cost Allocation to Schedules 85, 87, 57, Special Contracts | Percent of Total Cost |
|---|---|---|
| 2001 | $52,971,747 | 9.3% |
| 2004 | $50,894,934 | 7.4% |
| 2006 | $36,542,699 | 4.7% |
| 2007 | $70,025,889 | 6.8% |

This information indicates that 2006 results were out of line with cost allocations from other recent cases. It also indicates that PSE's 2007 results are not unreasonable in the context of previous cases. In the 2006 case, a separate flow analysis was not conducted due to time constraints. The approach was similar to that used in the Company's 2001 case, where the direct assignment included only main less than four inches, and large customers received a general allocation of large main along with all other classes. Data from the flow analysis conducted in the 2004 case were used to identify small main that was dedicated to serving

individual customers who were still on the system during the test year being used in the 2006 case. Because it was not clear how to allocate segments of main that were shared by customers of different classes, only segments dedicated to serving a single customer were included. This restriction caused a reduction in the cost assignment to large customers that, in hindsight, appears inappropriate. A chart of this approach is presented on page 3 of Exhibit No.___(JKP-18).

**Q. How do large customers benefit from the whole system, beyond the equivalent footage identified by the flow analysis?**

A. Improvements to capacity and reliability of the gas system have reduced planned curtailments to interruptible customers. The number of curtailments planned for various predicted system temperatures is one indicator of the system's ability to serve its firm and interruptible customers. At a given temperature, planned curtailments to interruptible customers have declined over the last three years due to investments in system capacity and reliability. These improvements in service are reflected in the temperature at which curtailments are required. The temperatures at which partial and full curtailments would be required have declined, which indicates PSE is able to serve interruptible customers at colder temperatures than in the past. Whereas at the start of the 2004-2005 winter full interruptible customer curtailment might have been required at 23 degrees Fahrenheit, in 2007-2008 full interruptible customer curtailment was not required until the predicted temperatures were significantly cooler. Not only did the level at which full curtailments occur improve for all interruptible customers, but it also

allowed partial curtailments to occur at temperatures that previously required full curtailments. All customers have benefited from this system capacity and reliability improvement.

Even when improvements to capacity and reliability do not reduce curtailments, they do help prevent an increase in curtailments to these interruptible customers. Without these capacity improvements, in general, the level of curtailments would increase over the years to potentially unacceptable levels at warmer weather curtailments. With these system improvements, the temperature at which partial and full curtailment is required has declined.

All customers continue to benefit from the economies of scale associated with having a large interrelated distribution system that serves many customers rather than a small one that serves only a few customers.

**Q. Please address Nucor's proposed allocation of Account 376 mains costs.**

A. Nucor witness Kevin Higgins divides the plant into small (less than four inches diameter) and large main. His proposed allocation of large main contains some errors that cause fewer costs to be allocated to the large customers than would be if the errors were corrected.

**Q. What errors does Nucor make in its allocation of large main?**

A. There are two errors. First, when Mr. Higgins divides the plant into small and large main, he incorrectly calculates that 42.7% of the Company's mains costs are

related to small diameter mains by using an incomplete listing of mains plant. The Company's mains plant, brought to 2007 dollars by use of the Handy-Whitman Index, is $2,071,111,014, rather than the $1,335,893,771 used by Mr. Higgins. Small diameter pipe make up 46.0% of total 2007 mains costs, not the 42.7% calculated by Mr. Higgins. Mr. Higgins' figure excludes some pipe types, even though the complete plant data that should have been used to make this separation was provided to Nucor on March 7 in PSE's Response to Public Counsel Data Request No. 563.

Second, he allocates the large mains costs using the Company's filed peak and average mains allocation factor, PA_MAINS. This is a composite allocation factor that incorporates both the peak and average elements in addition to the direct allocation of mains costs to Schedules 85, 87, 57 and special contracts for use on mains plant as a whole. It cannot be used for an allocation of a subset of the mains costs without adjustment. Before using this factor for allocation of large mains costs, Mr. Higgins should have adjusted this factor to include only large diameter costs. In failing to adjust the PA_MAINS factor, Mr. Higgins under-allocates costs to Schedules 85, 87, 57, and special contracts.

**Q. Please address Nucor's proposed allocation of costs associated with small mains.**

A. At page 11, lines 21-23 of his testimony, Mr. Higgins describes his approach as "constraining the allocation of small mains to Schedules 85, 87, 57, and special

contract customers to the amount of small mains directly assigned to these customers in the allocation of peak demand." His allocation could more accurately be described as "peak and half-peak" instead of peak and average. He calculates $153,929 as the portion of small main costs to be allocated to large customers based on average usage. This is approximately half the amount of small main identified in the flow analysis assuming peak conditions. Mr. Higgins imputed a level of costs for Schedules 85, 87, 57 and special contracts by dividing the value of the directly assigned component, $313,123, by the ratio of 67%/33%. This ratio is the opposite of the load factor divided by the load factor. Mr. Higgins provides no explanation of why he used this ratio or why this calculation represents an appropriate apportionment of the average usage costs.

**Q. What concerns do you have about this assignment of small mains?**

A. I have two concerns. First, Mr. Higgins provides no basis for his choice to constrain the average allocation to half the peak related costs. Second, the flow analysis used by PSE is based on a design day peak, when all interruptible loads are curtailed. Therefore, it cannot be said to represent the use of large customers on an average basis over the year, which is what the average component should do. As I illustrated earlier in my testimony and in Table 1, the results of the SynerGEE analysis vary based on what weather assumptions are used. These results indicate that the foundation for Mr. Higgins adjustment, that large customers "fundamentally do not use" small main (Exhibit No.___(KCH-1T), page 13 line 3), is faulty.

**Q. Have you prepared an exhibit that illustrates Nucor's proposed allocation of Account 376?**

A. Yes. Exhibit No.___(JKP-19) contains a chart of Mr. Higgins' approach that is similar to the charts related to PSE's current and past cases provided in Exhibit No.___(JKP-18).

**Q. What other comments do you have regarding Mr. Higgins testimony?**

A. At page 11, lines 3-6 of Exhibit No.___(KCH-1T), Nucor states that in the Company's 2006 case "there was neither a direct assignment of small mains costs to Schedules 85, 87, 57 and special contract customers, nor an allocation of small mains costs to these customers." This statement is incorrect. PSE's filed cost of service study in Docket Nos. UE-060266 and UG-060267 did include a directly assigned component of small mains to those customer classes.

**Q. What other comments do you have regarding Mr. Higgins testimony?**

A. Given the errors and concerns I have pointed out regarding Mr. Higgins' analysis, his modification to PSE's cost of service study should be rejected.

**Q. Why is PSE's approach in the present case superior to the approaches used in previous cases?**

A. PSE's approach is an attempt to work within the framework previously established by the Commission, which is to use a peak and average approach with a directly assigned component to large customers. The specific application of

those ideas has evolved over time as the Company has become able to use planning tools for cost of service purposes and has had time to evaluate its previous analyses. The proposed approach uses an estimate of peak that is consistent with the way the Company designs its system, and thus incurs costs. It overtly allocates a portion of costs based on average annual usage to all customers, without exempting certain customers simply because they would be curtailed on an extremely cold day. This average allocation reflects the fact that all customers benefit from the system year-round, and it does not limit large customers' cost assignment based on a single winter month – though it does recognize the inferior value of interruptible therms by using minimum volumes instead of total annual volumes for large customers. A chart of the Company's approach is on page 1 of Exhibit No.___(JKP-18).

**C. <u>Peak Demand Allocator</u>**

**Q. Please explain how you arrived at your estimate of peak demand as used in the cost of service study.**

A. In general, there are four components to the Company's daily load. These four components are firm sales, firm transportation, interruptible sales, and interruptible transportation. Because the Company's peak estimate for the cost of service study is based on a design day, which has an average daily temperature of 13 degrees when all interruptible volumes would be curtailed, the Company's peak estimate includes only firm sales and firm transportation. The peak demand

for firm sales was estimated using regression equations based on 52 heating degree days ("HDD"), which is consistent with the 13-degree average daily temperature, and weather normalized throughput for the test year. These equations were developed by looking at the historical relationship between throughput, weather, and peak demand. The coefficients in these equations were applied to test year volumes based on 52 HDD to estimate firm sales on a design day. The resulting estimate included only the firm portion of sales to interruptible schedules (Schedules 85, 86 and 87) as well as sales to all other classes. The firm transportation contribution to peak demand was assumed to be the daily firm throughput specified in transportation customers' service agreements – this is capacity the Company is obligated to provide at all times, including on peak days. The sum of firm sales and firm transportation is the estimated system peak day demand of 9,012,895 therms.

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.

**Q. What criticisms of your peak demand estimate have been made in this proceeding?**

A. At page 54 lines 16-17 of his testimony, Mr. Watkins claims that the design day concept has been rejected by the Commission in past cases, but he fails to provide specific references to support his argument. In the Commission's Order 08 in Dockets UE-060266 and UG-060267 at paragraph 133, the Commission explicitly stated it had no opinion on the subject of design day. At paragraph 135 of the same order, in its discussion of rate spread the Commission stated "the Company's case is, on balance, the stronger and more principled approach. We find it reasonable for purposes of determining rates in this proceeding." While the Commission stated no opinion with regard to design day, it did allow the Company's cost of service study to be used as the basis for making rates. This is not a rejection of the design day concept as Mr. Watkins describes it. This Commission order is the most recent related to PSE's gas cost of service study.

**Q. At page 55 lines 5-12 of his testimony, Mr. Watkins states that PSE's peak estimate does not match that presented in the Company's 2007 Integrated Resource Plan ("IRP"). Please comment on this.**

A. The method used to estimate the firm sales peak in this proceeding is the same method used in the IRP. Figure 4-16 of the IRP presents estimated firm sales peak of 9,363,205 therms in 2007. The Company's estimate in this proceeding of 8,838,626 is 5.6 percent below the IRP figure. The difference is explained by the

fact that the figures in the IRP were based on the Company's load forecast at that time, and the current estimate is based on historical load for the test year in this proceeding.

**Q. What other comments does Mr. Watkins make with respect to your peak demand estimate?**

A. On pages 55 and 56 of his testimony, Mr. Watkins correctly summarizes the methodology PSE used to allocate the peak to customer classes. On page 56 (lines 10-15), he criticizes this approach by saying that classes other than residential (Schedule 23) and commercial/industrial (Schedules 31) are weather sensitive. And, he presents monthly usage for interruptible Schedules 85, 86 and 87 as evidence that these classes should receive a larger allocation of the peak demand. (Incidentally, the weather normalized usage for Schedule 87 in July 2007 presented in Mr. Watkins' Table 18 is incorrect. The correct usage is 1,877 thousand therms rather than 878 as presented in Table 18.)

**Q. Please comment on weather sensitivity.**

A. Mr. Watkins fails to recognize that on a peak day with a low temperature of 10 degrees, Schedules 85, 86 and 87 would experience full curtailment. The billed demands used for those customers for the test year are contract amounts, which the Company is obligated to provide at all times. Any amounts above the firm contract amounts would not be provided. A weather event resulting in a 10-degree low temperature would most likely result in curtailments that lasted a full

day or even longer. Any weather sensitivity of interruptible customers is irrelevant in this scenario, because interruptible customers would be fully curtailed.

**Q. Please comment on Mr. Watkins' criticisms.**

A. PSE's peak demand estimate has the following attributes:

- It is based on actual firm sendout in the test year.
- It utilizes the planning standard of 52 HDD in conjunction with test year sendout.
- It is developed using the same method used in the IRP. Load is forecasted, then peak is estimated based on volume and 52 HDD.
- It is similar in magnitude to 2007 levels in the IRP. Mr. Watkins comments that it differs from the levels in the IRP, but he fails to note that PSE's peak estimate in this case is very close in magnitude to the levels presented in the IRP.
- It is superior to a historical peak for use in the context of a peak and average method, where the average allocation accounts for the average annual use of the system.

**Q. What other estimates of peak demand have been proposed in this proceeding?**

A. Mr. Watkins has proposed an alternative to PSE's peak demand estimate based partially on historical data and partially on contract demands. His estimate of peak day is 645,176 dekatherms, a reduction of 28 percent from PSE's estimate of 901,290 dekatherms.

**Q. At page 58 lines 12-13, Mr. Watkins states that interruptible loads were not curtailed during PSE's actual peak days. Is that correct?**

A. No. There were partial curtailments on four of the five days Mr. Watkins used in his analysis.

**Q. How did Mr. Watkins allocate the peak demand estimate to customer classes?**

A. He allocated the full reduction in peak from PSE's estimate to the residential and commercial/industrial classes.

**Q. Please comment on Mr. Watkins' peak demand estimate.**

A. He provided no theoretical grounds for allocating costs based on historical peak data rather than the day for which the system was designed. As discussed in my direct testimony, historical peaks do not reflect the costs to PSE of having the ability to serve load on very cold days. In the context of a peak and average cost of service study, where a large portion of fixed costs are allocated based on annual throughput, it is particularly important that the peak estimate be based on the cost causation principle.

In fact, Mr. Watkins' peak is a hybrid of the design day and historical data, because he assumed full curtailment of interruptible volumes, but his system peak is much lower than would be experienced in weather conditions that required full curtailment. His peak estimate is representative of neither PSE's design day nor

its historical peaks. If he had used all the load data presented in Table 19 of his testimony his peak would have been more consistent with historical experience. This would have produced a load factor of 40.8 percent as compared to his 46 percent.

**Q. What other evidence is there that Mr. Watkins' peak estimate is questionable?**

A. Mr. Watkins' peak is based on historical data, and as such it should be expected to produce a system load factor consistent with historical experience. In reality, his 46 percent load factor is higher than PSE has experienced historically. Load factors based on actual average daily load and actual peak day loads for the last five years and the test year are presented in Table 3 below.

**Table 3: Comparison of Historical Load Factors and Public Counsel Load Factor**

| Period | Load Factor |
|---|---|
| 2003 | 44.5% |
| 2004 | 38.2% |
| 2005 | 42.0% |
| 2006 | 39.6% |
| 2007 | 41.2% |
| 2003-2007 Average | 41.0% |
| Test Year | 40.6% |
| Watkins | 46.0% |

Mr. Watkins' inflated 46 percent load factor is significant because it is used to determine what portion of mains is allocated to customer classes based on throughput versus peak demand. The higher the load factor, the more cost is allocated on annual throughput, and the more costs are allocated away from residential customers toward large industrial customers.

**Q. Is PSE's proposed 33 percent load factor low?**

A. PSE's 33 percent load factor is based on its estimate of a design day peak, which, as noted earlier in my testimony, is consistent with peaks presented in the IRP. The peaks presented in the IRP are used for planning purposes and are higher than those typically experienced. A very cold day increases the peak dramatically relative to average usage, so the load factor ratio of average day demand to peak day demand is expected to be lower than the level experienced on a historical basis.

## D. Calculation of Return under Existing Rates

**Q. Please discuss Mr. Watkins' assertion on pages 41-42 of his testimony that there was a "slight oversight" in your calculation of class rates of return at present rates.**

A. Mr. Watkins asserts that my class rates of return at present rates are distorted because certain internal allocation factors – which are used to allocate costs based on other items that were previously allocated in the cost of service model –

included certain expenses in the Company's requested rate increase rather than strictly expenses being recovered in today's rates. He asserts that four specific items were included in these internal allocation factors.

**Q. Is Mr. Watkins assertion correct?**

A. Mr. Watkins assertion is only partially correct. Of the four items he identified, one item – $154 ,417 of uncollectibles – was indeed being used in an internal allocation factor called OM. I have rerun PSE's cost of service model correcting for this item and the results are not significantly different from my original results. The other three items Mr. Watkins claims to be included in PSE's internal allocation factors – $19,012,582 of federal income taxes, $2,181,139 of other taxes, and $113,542 of WUTC fees – are not, in fact, included in any internal allocator. Mr. Watkins claim is incorrect.

**Q. Did Mr. Watkins address this issue in his revised testimony filed June 23?**

A. In his revised testimony, Mr. Watkins did not acknowledge that the oversight involves only one of the four items he originally identified in his footnote No. 11. Footnote 11 on page 41 of his revised testimony remains incorrect. He did acknowledge that the oversight was immaterial, and he replaced his Table 14, which originally presented rates of return, with a table that shows the nominal changes in expense and rate base when the oversight is corrected.

## E. Other Comments on Cost of Service Analysis

**Q. What other comments do you have about the cost of service analysis?**

A. Because of the proposed transportation tariffs that parallel sales schedules, transportation customers who are expected to migrate to Schedules 85T and 87T are included with Schedule 85 and 87 sales schedules, respectively, for cost of service purposes. Some customers were assumed to remain in Schedule 57 until a later time, either when it is terminated or sometime prior to that. During the discovery process, PSE developed an additional cost of service study that breaks out Schedules 85T and 87T from their related sales schedules, for purposes of identifying parity ratios for the small (Schedule 85T) and large (Schedule 87T) transportation customers. In all other ways, this study was identical to that proposed by PSE in its original filing. The summary page from this cost of service study is provided as Exhibit No.___(JKP-20). These results indicate that large transportation customers (Schedule 87T) are below parity. Parity ratios from this study are presented in Table 4 below:

**Table 4: Parity Ratios with Schedules 85T and 87T Separated**

| Rate Class | Parity Ratio |
|---|---|
| Total System | 100% |
| Residential (Schedules 23, 16, 53) | 101% |
| Commercial & Industrial (Schedules 31, 61) | 89% |
| Large Volume (Schedule 41) | 156% |
| Interruptible (Schedule 85) | 172% |
| Limited Interruptible (Schedule 86) | 187% |
| Non-exclusive Interruptible (Schedule 87) | 125% |
| Transportation (Schedule 57) and Special Contracts | 122% |
| Compressed Natural Gas (Schedule 50) | 21% |
| Rentals (Schedules 71, 72, 74) | 69% |
| Interruptible Transportation (Schedule 85T) | 172% |
| Non-exclusive Interruptible Transportation (Schedule 87T) | 81% |

PSE provided the results of this cost of service study to all parties in PSE's Response to Nucor Data Request No. 2 on April 25, 2008.

## III. SEATTLE STEAM

**Q. What comments do you have with respect to the testimony of Stanley Gent of Seattle Steam?**

A. There are several assertions in Seattle Steam's testimony about PSE's service that are misleading or inaccurate. In Mr. Gent's discussion of the value of interruptible customers to PSE at page 6 lines 18-20, he states: "large customers

that are interruptible allow Puget to serve more customers with its existing system, including more growth, because at periods of peak demand Puget can free up capacity by curtailing interruptible customers." At page 7 lines 4-7, he states: "large interruptible customers are particularly valuable to a gas utility when it is experiencing significant growth in its customer base, because to at least some extent the Company can meet the needs of an expanding customer base by curtailing interruptible customers instead of being forced to expand its system." These statements imply that interruptible customers add capacity to PSE's system, which is not true. PSE's distribution system is designed to serve firm customers, regardless of the size of interruptible loads also served. If there were no interruptible loads, PSE would be able to serve all of its firm customers. PSE does benefit by having interruptible customers. The benefits are that the system can be used more efficiently and unused capacity can be used to provide revenue, not that interruptible customers add capacity to the system.

**Q. Seattle Steam implies that it should be allocated less of the costs for main repair or replacement because the main that serves it is a sixteen-inch wrapped steel main. Do you agree?**

A. No. At page 7 lines 18-22, Seattle Steam discusses a sixteen-inch main and comments: "Because it is wrapped steel, the Company does not have to replace it, as it has had to replace many of its smaller bare steel and cast iron mains." First, PSE records indicate that Seattle Steam's service lines are physically connected to twelve-inch and six-inch main, not sixteen-inch main as asserted by Seattle

Steam. Second, to imply that any plant will never need to be replaced is incorrect. It will eventually need to be replaced. Also, sometimes PSE needs to relocate or replace mains for reasons other than capacity requirements. Public improvement projects such as road construction will sometimes require relocation or replacement of gas mains. For example, as part of the rebuild/replacement of the Alaskan Way Viaduct, it is likely that the six-inch and twelve-inch mains that are used to serve Seattle Steam will need to be replaced.

**Q. Do you have other concerns regarding Seattle Steam's testimony?**

A. Yes. Seattle Steam seems to assume that all large interruptible customers are like Seattle Steam. For example, at page 8 lines 3-5, Mr. Gent states: "I would expect most of Puget's large industrial customers to be similarly situated along the core trunk of Puget's distribution system." With respect to cost of service and rate design, Seattle Steam is one customer in a group of 47 firm and interruptible sales and transportation customers on Schedules 57 and 87. Many large customers are served with service lines that are physically connected to main that is six inches or smaller in diameter. While they do not tend to be located in residential areas, the assumption that all 47 large customers are served with service lines that are physically connected to main that is also twelve inches in diameter, or even to the high pressure system of eight to sixteen inch main, is overly broad. To conduct a cost of service study that isolates every customer, or even every large customer, would be unreasonable. Similarly, rates are developed for groups of customers who have similar load characteristics. While one of Seattle Steam's service lines

is physically connected to twelve-inch main, it does not mean all customers in the same class are also connected to twelve-inch main. To expect cost of service analysis and rates to be developed on the assumption that all customers in that class are served in the same manner as Seattle Steam is unreasonable.

**Q. Do you agree with Mr. Gent's claims (at page 8 line 28 through page 9 line 2) that capital investments may be delayed or reduced due to the presence of interruptible customers on PSE's system?**

A. No. PSE plans its capital improvements based on only firm loads. Mr. Gent acknowledges this in his statement at page 8 lines 23-24, that "large interruptible customers are simply not the cause of this investment of capital." But he goes too far with his claim that capital investments can be reduced or delayed because of the presence of interruptible customers on the system. Since the presence of interruptible loads is not considered in determining the capacity of the system, interruptible customers simply have no impact on capital investment decisions. The Company is obligated to have the capacity to serve all of its firm customers on a peak day, regardless of whether interruptible customers are present to use excess capacity.

**Q. Please address Seattle Steam's claim that it has not benefited from PSE's investments in system capacity and reliability.**

A. Seattle Steam has directly benefited from PSE's investments in system capacity and reliability through reductions in actual and planned curtailments. Seattle

Steam indicates it was partially curtailed only twice during the 2007-2008 winter (for a total of twelve hours). PSE's records indicate that Seattle Steam was indeed asked to curtail on two occasions during that period (for a total of eight hours).

A better indicator of the system's ability to serve its customers than actual curtailments is the number of curtailments planned for various predicted system temperatures. At a given temperature, planned curtailments to Seattle Steam and other interruptible customers have declined over the last three years due to investments in system capacity and reliability. For Seattle Steam these improvements in service are in two forms, temperature and amount of gas. First, the temperature at which a partial curtailment would be required has declined – which indicates PSE is able to serve Seattle Steam at colder temperatures than in the past. Whereas in 2004-2005 partial curtailment might have been required at 29 degrees Fahrenheit, in 2007-2008 partial curtailment was not required until the temperature was predicted to reach 25 degrees Fahrenheit. Second, the amount of gas Seattle Steam is allowed to use in the event of a partial curtailment increased by 14 percent between the winters of 2006-2007 and 2007-2008.

**Q. Will reductions in curtailments be a "short-term phenomenon" as stated by Seattle Steam at page 11, lines 2-5?**

A. Because the Company attempts to increase capacity in the most economically feasible way, PSE's capacity improvements often result in excess capacity being

temporarily available. Until firm demand increases to use that capacity, it is available for use by interruptible customers. When the excess capacity has been used up, additional investment in capacity projects will occur, creating new excess capacity. Without these capacity improvement projects, the amount of gas service available to interruptible customers would be reduced.

**Q. Please comment on Seattle Steam's statements about the bill impacts to Schedule 41 customers.**

A. First I want to clarify the nature of Schedule 41. At page 18 lines 11 through 12, Mr. Gent refers to "truly interruptible customers" on Schedule 41. Schedule 41 is a firm schedule, so there are no interruptible customers on it. All customers pay the demand charge based on their fixed demand, which is established once a year based on the customer's usage during the system peak month. Mr. Gent also asserts that PSE "is proposing a significant rate decrease," yet he provides no basis for that assertion. The proposed rate spread includes no increase to the class, but because of rate design changes some customers are expected to experience different impacts on their bills than others.

I conducted an analysis of customer bill impacts assuming certain consumption and demand levels. My analysis indicates that bill impacts range from a 1.0 percent decrease to a 12.7 percent increase depending on the customer's consumption and load factor. For instance, assuming a 60 percent load factor, 54 percent of customers would either experience no change or a slight increase as a

result of the proposed changes. For those who are expected to experience decreases as a result of the Company's proposal, the decreases range from 0.4 percent to 1.0 percent. Table 5, below, presents abbreviated results of this analysis at various monthly consumption levels, and Exhibit No.___(JKP-21) provides more complete analysis. For example, a customer whose one-month consumption is 2,000 therms with a demand of 111 therms would experience an increase of 0.3 percent. These impacts can hardly be considered a "significant rate decrease" as characterized by Mr. Gent.

**Table 5: Schedule 41 Estimated Monthly Bill Impacts of Proposed Rate Changes**

| Monthly Consumption (Therms) | Monthly Demand (Therms)[1] | Revenue Change | Percent Change | Customer Count[2] | Percent of Customers[2] | Cumulative Percent[2] |
|---|---|---|---|---|---|---|
| 500 | 28 | $70.70 | 12.7% | 41 | 4% | 4% |
| 1,000 | 56 | $22.89 | 2.2% | 209 | 23% | 27% |
| 2,000 | 111 | $4.98 | 0.3% | 244 | 27% | 54% |
| 3,000 | 167 | $(12.13) | -0.4% | 149 | 16% | 70% |
| 4,000 | 222 | $(30.04) | -0.8% | 78 | 8% | 79% |
| 5,000 | 278 | $(47.15) | -1.0% | 38 | 4% | 83% |
| 10,000 | 556 | $(77.70) | -0.8% | 76 | 8% | 91% |
| 20,000 | 1,111 | $(139.60) | -0.7% | 53 | 6% | 97% |
| 25,000 | 1,389 | $(170.15) | -0.7% | 8 | 1% | 98% |
| 50,000 | 2,778 | $(323.70) | -0.7% | 18 | 2% | 100% |
| 100,000 | 5,556 | $(630.80) | -0.7% | 4 | 0% | 100% |

[1] Demand assumes fixed load factor of 60 percent at all consumption levels.

[2] Count and percent of customers whose average monthly consumption is in the block ending with the indicated consumption. For example, 23 percent of customers' average monthly consumption is between 500 and 1,000 therms.

**Q. Please address Mr. Gent's statement that "Puget appears to be using the regulatory process to unfairly impact the large thermal energy marketplace in Seattle" at page 19 lines 14 through 16.**

A. Mr. Gent seems to be saying that PSE, a regulated utility, is using the regulatory process to unfairly impact Seattle Steam, an unregulated competing utility. This is simply not true. PSE is attempting to develop a cost of service study that (i) is based on industry standard principles; (ii) reflects PSE's distribution system; (iii) respects past Commission guidance; and (iv) treats all customers on a consistent basis. The cost of service study has evolved over time as analytical tools have become available and as PSE has evaluated methodologies used in past cases.

## IV. RATE SPREAD AND RATE DESIGN

**Q. What concerns have been raised in response testimony with respect to rate spread or revenue allocation to customer classes?**

A. Table 6 below presents the rate spread proposed by PSE and intervening parties. I will address the proposed changes to rate spread to Schedule 50 (Compressed Natural Gas ("CNG")), Schedule 87 (Non-exclusive Interruptible), Schedule 57 (Firm and Interruptible Transportation), and Rentals.

**Table 6: Rate Spread Proposals by Party – Percent of Average Increase**

| Customer Class | PSE | WUTC Staff | NWIGU | Nucor | Public Counsel |
|---|---|---|---|---|---|
| Residential (Schedules 23, 16, 53) | 100% | 100% | 100% | 100% | 95% |

| | | | | | |
|---|---|---|---|---|---|
| Commercial & Industrial (Schedules 31, 61) | 145% | 145% | 145% | 145% | 125% |
| Large Volume (Schedule 41) | 0% | 0% | 0% | 0% | 50% |
| Compressed Natural Gas (Schedule 50) | 100% | 100% | 147% | 145% | 150% |
| Interruptible (Schedule 85) | 0% | 0% | 0% | 0% | 85% |
| Limited Interruptible (Schedule 86) | -50% | 0% | -50% | 0% | 0% |
| Non-exclusive Interruptible (Schedule 87) | 130% | 130% | 50% | 0% | 140% |
| Transportation (Schedule 57) | 130% | 130% | 50% | 0% | 130% |
| Rentals (Schedules 71, 72, 74) | 31% | 31% | 150% | 145% | 150% |

**Q. Please comment on Schedule 50, Compressed Natural Gas.**

A. Schedule 50 no longer exists. Subsequent to its December 3, 2007 filing of the present case, PSE discontinued CNG service. There were only three regular customers taking service on Schedule 50, and CNG service had become available from other service providers in the area. In Docket No. UG-080064 (which has been consolidated with this docket), PSE requested and received permission from the Commission to discontinue Schedule 50. The $5,187 increase proposed by the Company will simply be lost by the Company if the proposed rate spread is approved. To allocate additional revenue responsibility to this class as proposed by NWIGU, Nucor and Public Counsel is akin to reducing PSE's requested increase and is not appropriate.

**Q. What are your comments on revenue allocation to the rental customers?**

A. PSE's proposed revenue allocation was equal to the system average increase to all

other customers when gas costs are included in the calculation, which was 5.3 percent in the initial proposal. This class has had significant rate increases in the last three cases (17.3 percent, 14.5 percent and 10.6 percent implemented in 2002, 2005 and 2007, respectively), and its parity ratio has improved over time. PSE is concerned that an increase larger than originally proposed is too much. Please see pages 24-26 of Mr. Karl Karzmar's Prefiled Direct Testimony for a discussion of the basis for PSE's proposed increase to the rental class.

**Q. What have parties proposed related to Schedules 87 and 57?**

A. Nucor and NWIGU propose a revenue allocation of zero and 50 percent of the average increase, respectively, compared with PSE's proposal of 130 percent of the average increase for both schedules. Commission Staff witness Mr. Thomas E. Schooley concurs with PSE's proposed 130 percent of the average increase for both schedules. Public Counsel proposes 140 percent of the average increase for Schedule 87 and 130 percent for Schedule 57.

**Q. Please comment on these proposals.**

A. Nucor and NWIGU's proposals are based on modifications to the cost of service study that I discussed earlier in my testimony and are not appropriate. PSE's cost of service study provides a better basis for rate spread than any other cost of service study presented in this proceeding. The parity ratios presented in Table 4 above provides specific evidence that large transportation customers, as represented by Schedule 87T, are below their cost of service levels, and that small

transportation customers, as represented by Schedule 85T, are above their cost of service levels. The parity ratios for Schedule 57 do not reflect the need for an increase because Schedule 57 contains a combination of small transporters, who are above their cost of service, and large transporters, who are below their cost of service. Schedule 57 rates continue to be tied to Schedule 87 rates, so any change to 87 directly affects Schedule 57. This problem of mixing small and large customers in a class will be resolved after the new transportation tariffs are implemented and customers are grouped into classes that parallel the sales schedules.

**Q. What concerns have been raised in response testimony related to rate design.**

A. Seattle Steam expresses concern that costs related to firm loads are being borne by interruptible customers instead of firm customers, because fixed costs are recovered through volumetric rates. NWIGU argues that fixed costs should not necessarily be recovered through fixed charges, and opposes increases to the demand and customer charges. Public Counsel opposes increases to customer charges.

**Q. In his discussion of the Company's proposed customer charges, Commission Staff witness Mr. Schooley comments that, should an increase be allowed, general plant and administrative and general ("A&G") costs should be excluded from the customer charge. Please comment on this.**

A. PSE witness Mr. David Hoff discusses both the gas and electric customer charges in his rebuttal testimony. I will add that, if A&G and general plant costs were excluded from the calculation, the residential customer costs would be $14.83 per customer per month.

**Q. Please comment on the demand charge.**

A. NWIGU witness Mr. Schoenbeck states at page 22, line 1 of his response testimony: “This Commission long ago soundly rejected the fixed-variable costing method,” yet he provides no basis for his claim. At page 22 line 26, he also argues that Schedule 85 and 87 customers provide a larger share of revenue on a fixed cost basis than residential customers do. PSE’s efforts to increase fixed cost recovery through fixed charges are not limited to large interruptible customers, as evidenced by proposed increases to customer charges and demand charges in other schedules. Customers on interruptible schedules have the option to firm up a portion of their load, but the demand charge does not reflect the full cost to PSE of providing firm service. A substantial portion of fixed costs are included in volumetric rates. Because the customers on these schedules range from fully firm to fully interruptible, including a large portion of fixed costs in the

volumetric charge is not fair to customers whose loads are fully interruptible. These customers are different from the residential class with respect to the mixing of firm and interruptible customers on a schedule.

Nucor witness Mr. Higgins recommends that the relationship between existing demand and volumetric charges be maintained regardless of the revenue allocation to the large interruptible classes.

Seattle Steam supports an increase to the demand charge that is even greater than that proposed by PSE.

PSE's proposed increase of the demand charge for Schedules 85, 86, 87 and 57 from $1.02 to $1.50 is appropriate. Cost of service results support an even higher demand charge, and the Company's proposal is movement toward fixed cost recovery without moving all the way in that direction.

## V. PROPOSED TRANSPORTATION TARIFFS

**Q. What issues related to PSE's proposed transportation tariffs were raised by parties in their response testimony?**

A. No parties oppose the implementation of the proposed transportation tariffs, but parties have raised concerns about the terms and conditions associated with the proposed tariffs. At issue are the requirement that interruptible customers use gas as an exclusive fuel during times of non-curtailment, the requirement that interruptible customers have backup equipment for use in the event of a

curtailment, and minimum monthly charges on Schedules 85 and 87.

**Q. Why are these terms and conditions proposed by PSE?**

A. As I discussed in my direct testimony, the proposed tariffs make sales and transportation service more consistent with each other. These terms and conditions are consistent with those of the existing interruptible sales schedules.

**Q. Please discuss the backup requirement.**

A. The interruptible schedules include a requirement that interruptible customers have backup equipment for use in the event of a curtailment. This requirement was put in place on interruptible sales schedules in 1967. PSE's understanding of the history is that the Commission is concerned about public welfare. If large employers and schools are not able to function because of a gas curtailment, and employees and students are sent home, there could be harm to the public.

As indicated on page 12 of my direct testimony, PSE has made exempt from the backup requirement current transportation customers who move to Schedule 85T, 86T or 87T as a result of the elimination of Schedule 57. In addition, the tariff allows customers to request waivers of the requirement from the Commission. These allowances should address the concerns about the backup requirement.

If the Commission chooses to eliminate this requirement as part of this proceeding, PSE requests the opportunity to modify language in its tariffs related to the Company's responsibility and have customers sign agreements holding the

Company harmless in the event of curtailments.

**Q. Please discuss the minimum charges on Schedules 85 and 87.**

A. Minimum monthly charges as they exist today were implemented on Schedule 85 in 1994. They are in place for two reasons. First, without minimum charges there would be incentive for customers to switch from Schedule 86, which has higher rates than Schedule 85 and is intended for a very specific type of customer. Without minimum charges there would be no barriers to prevent this movement between schedules. Second, Schedule 85 is intended for high load factor customers, and the monthly minimum charges discourage low load factor customers from taking service on Schedule 85.

In the context of the rate decreases small transportation customers should experience as a result of PSE's proposal, minimum charges that primarily affect customers with low load factors should not be a major concern.

## VI. CONCLUSION

**Q. Are you aware of a settlement between other parties in this proceeding related to gas rate spread, rate design, and transportation tariffs?**

A. Yes, shortly before PSE's prefiled rebuttal testimony was to be filed, the Company learned that a group of parties had come to a settlement agreement on these issues and is filing joint testimony in support of the settlement.

**Q. Please comment on the proposed settlement.**

A. PSE is not opposed to some provisions of the settlement as we understand it, based on information provided to the Company on June 24, 2008. The Company does have concerns about some aspects of the settlement, however.

**Q. What portions of the proposed settlement do you agree with?**

A. PSE does not oppose the following aspects of the parties' settlement proposal, as we understand it.

- Operating terms of Schedule 57 would be incorporated into Schedules 87T and 85T with the addition of minimum annual charges. Schedules 87T and 85T would have:
  - no exclusive fuel requirement
  - no backup fuel requirement
  - no monthly minimum charges.
- The exclusive fuel and back up fuel requirements on sales Schedules 87 and 85 would be removed.
- Schedules 87, 85, 87T and 85T would have annual minimum charges instead of monthly minimum charges.
- Schedule 57 would be eliminated immediately.
- PSE would hire an independent consultant to address natural gas cost of service, rate spread and rate design. The consultant would be selected by consensus of all interested parties and would assist the parties in an effort to reach agreement on those topics before PSE's next general rate case; however, PSE's timing for filing a general rate case is not contingent on reaching an agreement. In the event agreement cannot be reached, all parties would retain the right to litigate those issues using the experts of their own choosing.

- Customer charges to Schedules 85, 87 and 57 would be increased by the overall percentage increase to Schedules 87 and 57.

- The procurement charges for Schedules 85 and 87 would remain unchanged at $0.00650 for Schedule 85 and $0.00500 for Schedule 87.

**Q. What aspects of the settlement does the Company believe need to be modified or clarified by the Commission?**

A. There are aspects of the rate spread that the Commission should modify if it accepts the parties' settlement. The table below demonstrates those portions of the settlement that need modification.

| Customer Class | Percent of Average Increase | PSE's Recommendation |
|---|---|---|
| Residential (23,53,16) | 98.46% | Accept parties proposal |
| Commercial/industrial (31,36,51,61) | 142.35% | Accept parties' proposal |
| Large Volume (41) | 12.50% | Accept Parties' proposal |
| Compressed Natural Gas (50) | 0.00% | Accept Parties' proposal |
| Interruptible (85) | 12.50% | Accept Parties' proposal |
| Limited Interruptible (86) | 0.00% | Accept Parties' proposal |
| Non-exclusive Interruptible (87) | 50.00% | Accept Parties' proposal |
| Transportation (57) | 50.00% | Accept Parties' proposal |
| Contracts | As allowed by contracts given rate design on transportation schedules. | |
| Rentals (71,72,74) | Percentage increase equal to system increase including gas. | |
| Residual | Spread to all classes except rentals. | |

As I discussed earlier in my testimony, the Company's proposed increase to rentals is consistent with the system average increase to all other customers when gas costs are included in the calculation. However, given the proposal to assign only 50 percent of the average increase to Schedules 87 and 57, this will result in

approximately one million dollars being allocated to the other schedules. This amount should be spread to all other classes consistent with the rest of the increase.

**Q. What are the Company's concerns about contracts and the treatment of any residual?**

A. The proposed settlement assigns more cost to the Company's special contract customers than those customers' contracts will allow, and makes no provision for modifying the increase to other customer classes so that the full increase can actually be collected. The amount of the increase assigned to contract customers should be no greater than amounts allowed by the contracts. Contracts are based in part on the rate design of transportation tariffs. Once the final rate change, rate spread and rate design are determined by the Commission, the amount that goes to special contract customers should be calculated based on their contracts. Any difference between the allowable amount and the amount assigned by rate spread should then be allocated to all other classes except rentals. PSE expects this amount to be small.

With respect to any residual that exists as a result of the proposed spread, the settlement proposes to assign the entire residual to commercial and industrial customers on Schedule 31, who have already been assigned the largest increase of any customer group. This amount should be spread to all classes other than rentals. Again, this amount is expected to be relatively small.

**Q. Are there other modifications and clarifications that PSE believes should be made to the settlement?**

A. Yes. PSE proposes the following three items:

- Annual minimum charges on Schedules 85, 87, 85T and 87T would be established by PSE.

- As I discussed earlier in my testimony and as Seattle Steam pointed out, the current demand charge on Schedules 85, 87 and 57 is considerably below cost of service levels, and PSE proposes an increase to $1.50. Should the Commission have concerns about an increase of this magnitude, the demand charge should be increased to $1.30 or higher. The $1.30 level would represent improvement from the existing $1.02 level.

- The second block delivery charge on Schedule 85 would be modified so that the relationship between the three blocks is consistent with PSE's initial proposal. The purpose of this is to create block rates that decline more evenly than the current rates of $0.10000 for the first block, $0.05127 for the second block, and $0.04921 for the third block. Any additional revenue change required by the proposed rate spread would be accomplished through equal percentage changes to the volumetric charge once this adjustment has been made. The current initial block rate of $0.10 was prescribed in the Commission's order in UG-060267. The third block rate of $0.04921 is tied to the third block rate on Schedule 87. As a result, when PSE filed its compliance filing in UG-060267 there was little choice but to reduce the middle block rate so that in total, the Schedule 85 rates collected the proper amount of revenue. This resulted in uneven differences between the block rates, as described above. PSE attempted to correct this inconsistency with its initial proposal in this case and with this proposal.

**Q. Does that conclude your prefiled rebuttal testimony?**

A. Yes, it does.