EXHIBIT NO. ______ (RJA-1T)
DOCKET NO.____________
2001 PSE RATE CASE
WITNESS: RONALD J. AMEN

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DIRECT TESTIMONY OF RONALD J. AMEN ON BEHALF OF PUGET SOUND ENERGY, INC.

NOVEMBER 26, 2001

PUGET SOUND ENERGY, INC.

DIRECT TESTIMONY OF RONALD J. AMEN

I. BACKGROUND AND WASHINGTON TESTIMONY HISTORY OF WITNESS

Q: Please state your name and business address.

A: My name is Ronald J. Amen. My business address is 200 Wheeler Road, Suite 400, Burlington, MA 01803.

Q: By whom are you employed and in what capacity?

A: I am a Principal with Navigant Consulting, Inc. ("NCI"), formerly Metzler & Associates, and a member of the Regulatory and Litigation Support Practice Area of the Firm. NCI is a leading nationwide provider of consulting services to electric and gas utilities and other energy-related and network businesses.

Q: Please describe NCI's business activities.

A: NCI is a global management consulting firm that provides strategic, financial, management, and expert services to energy-based, network and other regulated industries. From an industry-wide perspective, NCI has extensive experience in all aspects of the North American natural gas and electric industries. Included in NCI's relevant experience are the areas of utility costing and pricing, gas supply and transportation planning, competitive market analysis and regulatory practices and policies gained through management and operating responsibilities at transmission and distribution, gas pipeline and other energy-related companies, and through a wide variety of client assignments. NCI has assisted numerous utility companies located in the U.S. and Canada.

Q: What has been the nature of your work in the utility consulting field?

A: I have over twenty-three (23) years of experience in the utility industry, the last four and one-half (4 1/2) years of which have been in the field of utility management and economic consulting. Specializing in the gas industry, I have advised and assisted utility management and energy marketers in matters pertaining to costing and pricing, regulatory planning and policy development, strategic business planning, organizational restructuring, new business development, and load research studies. Further background information summarizing my education, presentation of expert testimony and other industry-related activities is included in Exhibit RJA-2 to my testimony.

Q: Have you testified previously before the Washington Utilities and Transportation Commission ("the Commission")?

A: Yes. I have testified in Docket Nos. UG-931405 (General Rate Case of Washington Natural Gas Company ("WNG")), UG-940814/UG-940034 (Cost of Service and Rate Design Proceeding of WNG), UG-941246/UG-950264 (WNG Line Extension Policy), UG-950278 (General Rate Case of WNG), UE-960195 (Merger of Washington Energy Company and Puget Sound Power and Light Company) and UG-960520 (WNG Propane Service). I have also previously appeared before the Commission on numerous occasions regarding various rate, customer contract and tariff matters.

II. PURPOSE OF TESTIMONY

Q: For what purpose has NCI been retained by Puget Sound Energy, Inc. ("PSE" or the "Company")?

A: NCI has been retained by PSE as a consultant in the area of utility costing and rate design and related regulatory matters. Specifically, PSE has requested that we assist the Company in conducting a cost of service study to determine the embedded costs of serving its natural gas retail customers, in addition to various costing and pricing studies related to the provision of gas distribution, transportation and storage-related services.

Q: What is the purpose of your testimony in this proceeding?

A: First, I will be describing the level of revenue responsibility between customer classes as a result of the revenue requirement proposed by PSE in this proceeding and as supported by the cost of service study sponsored by Mr. Feingold. Because the results of the cost of service study suggest shifts in revenue responsibility between customer classes, I will be proposing changes in the rates of all the Company's rate schedules that reflect the cost of service study results.

Second, I will discuss the Company's proposals for structural changes to the various gas service rate schedules, including the expansion of monthly customer charges to all gas service schedules and the introduction of a demand charge for the Company's Large Volume High Load Factor Service, Rate Schedule No. 41.

Third, my testimony will describe the proposed modification of the present Purchased Gas Adjustment ("PGA") mechanism to adjust the PGA rates on a monthly basis with the intent to provide customers with more current commodity price signals. I will briefly discuss a new hedged gas supply offering the Company is proposing as a companion to its monthly PGA to provide customers with a fixed price alternative for the duration of the hedge.

Finally, I will present proposed modifications to the gas service tariff. Among the proposals are revised miscellaneous service charges, revisions to the Company's gas line extension policy (Rule No. 7) and the associated facilities standards (Schedule No. 7) and the introduction of a new facilities relocation rule (Rule No. 28).

III. LIST OF EXHIBITS SPONSORED IN TESTIMONY

Q: What Exhibits are you sponsoring in this proceeding?

A: I am sponsoring the following Exhibits:

- Exhibit RJA-3, Proposed Rules and Rate Schedules
- Exhibit RJA-4, Proforma Revenues and Gas Costs
- Exhibit RJA-5, Class by Class Revenue Spread
- Exhibit RJA-6, Monthly Pricing of PGA Rates
- Exhibit RJA-7, Rate Design Schedules
- Exhibit RJA-8, Customer Bill Impact Schedules
- Exhibit RJA-9, Propane Service Costs and Rate Development
- Exhibit RJA-10, Cost Support for Miscellaneous Charges

IV. REVENUE ALLOCATION AND RATE DESIGN PRINCIPLES

Q: How can the Cost of Service Study ("COSS") results presented by Mr. Feingold provide guidelines for rate design?

A: COSS results provide cost guidelines for use in evaluating class revenue levels and rate structures. When evaluating class revenue levels, the rate of return results and resulting revenue-to-cost ratios show that rates charged to certain rate classes recover less than their indicated cost of service. Conversely, rates for other rate classes recover more than their indicated cost of service. By adjusting rates accordingly, class revenue levels can be brought closer to the indicated cost of service, resulting in class rates of return nearer the system average rate of return. Thus, rate levels will be more in line with the cost of providing service.

Q: Do the COSS results provide guidance in establishing rates within each rate class as well?

A: Yes. The classified costs, as allocated to each class of service within the COSS, provide useful cost information in determining the level of customer, demand and commodity charges.

Q: Please explain how the classified costs discussed by Mr. Feingold can be used for rate design.

A: If the classified costs presented by Mr. Feingold in Exhibit RAF-3, the Unit Cost Summary by Function, were used to set three-part rates (Customer, Demand and Commodity), the Company's operating expenses and return on investment in its pro forma revenue requirement would be recovered.

Q: Should other factors be considered that would prevent the company from simply translating the unit costs into rates for the various tariff services?

A: Yes. Completely restructuring a utility company's rates in this manner is usually not possible due to the resulting adverse impact of the revenue allocation on certain customer classes, particularly for smaller, low load factor customers. However, the use of three part rates is becoming more widely accepted as the delivery of utility services continues to evolve. The unit costs do provide useful information for the design of portions of tariff services, in particular for establishing cost-based customer charges. The unit costs also can be used to design demand charges where either demand metering is available, as is the case with PSE's automated meter reading ("AMR") equipment, or algorithm-based billing demands can be determined. Demand based rates provide for a charge based upon the maximum demand imposed by a customer on the utility's system within a specified time period, which establishes both the utility's responsibility to serve and the customer's obligation to pay for that level of service.

Q: Please describe other considerations or criteria that should be used in the design of utility rates.

A: Utility rate design should recognize that rates must be just and reasonable and not cause undue discrimination. Thus, customer impact considerations must be factored into the rate design process. Market conditions within the utility service territory with respect to the general economic environment and competitive fuel prices, where appropriate, should be reviewed. Another important consideration is the financial stability of the utility. Toward this goal, it is generally an unsound ratemaking practice to recover a substantial portion of fixed costs, such as customer related costs which bear no relationship to customer consumption patterns, in the volumetric portion of the rate schedule. Recovery of fixed costs via volumetric rates adversely impacts earnings stability because the revenues generated from customers' volumetric use of gas can be extremely sensitive to the vagaries of weather patterns and changing consumption characteristics. Recovery of utility fixed costs in volumetric rates sends uneconomic price signals to consumers that impede their ability to make well founded energy consumption decisions.

Q: How then are the foregoing guidelines and criteria incorporated into the rate design process?

A: A reasonable balance between the various cost guidelines and other criteria must be established in the process of designing rates, which consists of both the recovery of the revenue requirement from among the various customer classes and the determination of rate structures within tariff schedules. Economic, social, historical, and regulatory policy considerations all impact the rate design process. Both quantitative and qualitative factors must be evaluated in reaching a final rate design. Thus, it is necessary to allow the rate design process to be influenced by judgmental evaluations.

V. RESTATING AND PROFORMA ADJUSTMENTS TO CLASS REVENUES

Q: Please describe Exhibit RJA-4.

A: Exhibit RJA-4 shows the test year booked revenues adjusted for: (1) the elimination of municipal taxes, (2) elimination of certain propane sales, (2) normal degree days; (3) test year base rate levels; and (4) current gas cost levels as approved by the Commission effective September 1, 2001.

Actual test year operating revenue per books was $776,156,944, as indicated in column (f), line 35, of Exhibit RJA-4, sheet 1.

The first adjustment (Column h) of ($28,658,519) removes municipal taxes. The first restating adjustment (Column n) of ($4,587) removes certain legacy propane sales and associated revenues, pursuant to the Commission's Fourth Supplemental Order in Docket No. UG-920840.

The second restating adjustment is made to reflect the revenue difference between the actual rates and the base rates in effect during the test year.

Utilizing the monthly sales and transportation volumes, and pricing them at test year base rates, results in revenues as shown in column (p) of Exhibit RJA-4, sheet 2 of 3. By subtracting column (k), sheet 1, the pro forma base rates adjustment of ($30,027,157) is recorded in column (q), sheet 2 of 3, line 35.

The third restating adjustment is made to reflect consumption expected under normal weather conditions. To calculate normal weather, the Commission has used an 18-year moving average of past annual heating degree days ("HDDs") from a 20-year historical period with the highest and lowest years excluded (Docket No. UG-920840, Fourth Supplemental Order, p. 17). Using this definition, normal weather for the test period is 4,687 HDDs. Actual weather for the test period was 5,074 HDDs. Annual consumption, adjusted to normal year weather, is 1,022,317,996 therms, as shown on line 35, column (r) of Exhibit RJA-4, sheet 2 of 3.

Revenues corresponding to these normalized therms are then calculated by applying the base rates in effect during each month of the test year to the normalized sales and transportation throughput. The sum of the monthly revenue calculations is shown in column (s). The resulting total restating adjustment of ($45,880,400) is shown in column (u) of line 35 as the difference between column (s) and column (p). The total of the three restating adjustments of ($75,912,144) appears in column (v).

The final (pro forma) adjustment equals ($78,848,186), as shown in column (z) on line 35 of Exhibit RJA-4, sheet 3. This adjustment re-prices the normalized monthly therms using gas cost levels effective September 2001. The resulting revenues are $592,378,096, as shown in column (x) of Exhibit RJA-4, sheet 3.

Q: How are these adjustments reflected in the Company's revenue requirement?

A: These adjustments are reflected on Mr. Karzmar's Exhibit KRK-G3, page G3-A, Column 2.01.

VI. PROPOSED REVENUES BY CLASS

Q: What total gas revenue requirement is the Company utilizing in its proposal?

A: The Company has used a gas revenue requirement of $678,616,474, not including municipal additions. This total revenue requirement is shown on Mr. Karzmar's Exhibit KRK-G3, Summary page.

Q: Have you utilized the results of the cost of service study, as described by Mr. Feingold in Exhibit RAF-1T, in establishing the class-by-class revenue responsibility levels?

A: Yes. The proposed class-by-class revenue levels are shown in Exhibit RJA-5.

Q: Have the class rates of return under the Company's present rates been identified?

A: Yes. Mr. Feingold establishes the class-by-class rates of return under the Company's current rates in his Exhibit RAF-3.

Q: Have the identified class rate of return differences been reflected in the Company's proposed revenue levels?

A: Yes. The Company's proposed class-by-class revenue levels, discussed below, are shown in Column (f) of Exhibit RJA-5.

Q: Please describe the approach followed to apportion the proposed revenue requirement of $678,616,474 to the Company's various rate classes.

A: As described earlier, the allocation of revenues among rate classes consists of deriving a reasonable balance between various guidelines and criteria that relate to the design of utility rates. The following criteria were considered in this process: (1) cost of service results, (2) class contribution to present revenue levels, and (3) customer impacts. After evaluating these criteria for each of the Company's rate classes, adjustments were made to class revenue levels so as to design rates that would move class revenue levels closer to the cost of serving those classes.

Q: What class revenue allocation options were considered in determining PSE's interclass revenue proposal?

A: Two primary options were considered for the assignment of the revenue requirement among the Company's rate classes. After consultation with Company personnel, one of those options was selected as the preferred method for an interclass revenue proposal.

The first option that was evaluated as the benchmark for the Company's class revenues was to adjust each of them to the level at which the class rate of return was equal to the system average rate of return, representing a revenue to cost ratio of 1.00. That option resulted in revenue increases to PSE's Residential, CNG and Rental classes. When viewed under the concept of gradualism, the Company deemed the required increases to some of those classes unacceptable. Therefore, as a matter of judgement, this purely cost-based option was not selected as the preferred solution for the Company's interclass revenue proposal. It is, however, important to note that transitioning to a level of class revenues represented by the cost-based results represents an important goal for evaluating future rate design options.

Q: Please explain the adjustments made to the class revenue levels under the Company's approach.

A: As shown in the Earned Return line of Mr. Feingold's <u>Exhibit RAF-3</u>, page 2, the realized rates of return from the Company's current rates range from a -22.85% to 82.4%. As discussed earlier, one of the Company's primary considerations was to narrow the difference between these relative rates of return by class with a goal of approaching the levelized rate of return for the system. At the same time, another primary consideration of the Company was to not create rate shock for any one class of customer.

The bulk of the increase in cost responsibility is borne by the residential class of customers, which results in a 23.52% increase in revenues to this class. However, the greatest impact in relative terms was given to the CNG Service class Rate Schedule No. 50. This group of customers had shown the lowest relative rate of return in the cost of service study of -4.53%. A substantial increase in this group's revenues is necessary merely to move the class to a positive rate of return.

In order to achieve a more acceptable rate of return, it was necessary to increase the revenues to this class by $52,420. While the relative increase to this small customer group appears dramatic, the negative rate of return at this low level of revenue warrants the treatment of this class as shown in the Exhibit.

Q: Have there been other increases to rate schedules as a result of the revenue responsibility changes?

A: Yes. The Rental Service Schedule Nos. 71, 72, and 74 received an increase of $2,179,819 or 26.51%. The realized rate of return for the Rental class of –6.60% is primarily due to an acceleration of the depreciation on the Rental equipment plant, an outcome of the Company’s recent depreciation study.

Q: Have the class revenue levels been affected by any other changes suggested by the cost of service study?

A: Yes. Changes have been reflected to the purchase gas cost rate components shown on Supplemental Schedule No. 101 to reflect the cost responsibility for recovery of the Company's demand-related purchased gas expense, as reflected in the gas cost sub-report of the cost of service study. The resulting changes in class gas cost recovery responsibility have been included in the revenue changes that were made in Exhibit RJA-7. The revised unit demand gas cost rates are shown in Exhibit RJA-6 for each rate class. Therefore, the changes in gas cost recovery responsibility were separate from the revenue increases to the various customer classes I previously described.

Q: Has the Company retained the use of a uniform commodity purchase gas cost recovery rate for all sales rates?

A: Yes. However, as discussed in a later section of my testimony, the Company is proposing to continue its present PGA mechanism, with one important modification. Rather than the historical irregular period updates of the PGA rates, the Company would re-forecast its gas commodity costs and would adjust the

PGA rate on a monthly basis, thereby providing customers with a more current price signal.

VII. PROPOSED RULES AND RATE SCHEDULE/STRUCTURE CHANGES AND RATE DESIGN

Q: Please explain Exhibit RJA-3.

A: Exhibit RJA-3 contains the proposed rules and rate schedules, under which the Company is proposing to continue providing service. No new schedules are proposed at this time.

Elimination of Rate Schedule Nos. 11 and 43

Q: Is the Company proposing to reduce the number of rate schedules?

A: Yes. The Company is proposing to eliminate Rate Schedule No. 11, General Gas Service and Rate Schedule No. 43, Large Volume Armed Forces Service. Rate Schedule No. 11 is a general gas service rate used primarily for cooking in apartment complexes utilizing either central heating and water heating systems or another source of energy for heating purposes, as well as other special small uses of gas, including outdoor cooking events. Rate Schedule No. 11 has been closed to new customers since October 9, 1993. Of the 905 customers that remain under Rate Schedule No. 11, 829 are residential customers and are paying the same monthly service charge and nearly equivalent volumetric rates as residential customers served under Rate Schedule No. 23 (Residential General Service), which was authorized by the Commission in Docket No. UG-940814. Three customers are classified as Industrial, while 73 are Commercial. With the elimination of this schedule, the Company will complete the transition of the customers to their appropriate respective service schedules, Rate Schedule No. 23 and Rate Schedule No. 31 (Commercial and Industrial General Service).

Rate Schedule No. 43 is currently limited to military installations served as of October 9, 1993 and no customers are presently receiving service under this schedule.

<u>Expanded Use of Monthly Customer Charges and Demand Charges</u>

Q: Is the Company proposing any changes at this time to the structure of the rate schedules?

A: Yes. As discussed in more detail below, the Company intends to add a monthly customer charge to Rate Schedule No. 41, Large Volume High Load Factor Service, as well as to each of the three Interruptible Gas Service Schedules 85, 86 and 87. With the addition of monthly customer charges to these schedules, all of the company's gas service schedules will employ monthly service charges for recovery of customer-related costs of providing gas distribution service. This reflects the Company's position, articulated earlier in my testimony, regarding the importance of recovering a portion of fixed costs, such as customer-related costs which bear no relationship to customer consumption patterns, via fixed charges. Structuring rates in this manner sends economic price signals to customers that better reflect the true nature of the cost of utility delivery service. It is also consistent with the Company's use of monthly customer charges in its electric service schedules, for similar classes of customers.

Q: What was the basis for the level of the proposed new monthly customer charges for Rate Schedule Nos. 41, 85, 86 and 87?

A: In structuring the proposed level of monthly customer charges for these rate schedules, the Company utilized the unit cost study from the cost of service model to identify costs related to providing monthly service to the respective service classes. The results from the unit cost study, as presented by Mr. Feingold, are found in <u>Exhibit RAF-3,</u> page 10.

Q: Notwithstanding the consistent use of monthly customer charges for its gas service schedules, has the Company made other structural changes to any of the schedules?

A: Yes. The Company has introduced a demand charge into Rate Schedule No. 41, Large Volume High Load Factor Service.

Q: Please explain the basis for this demand charge proposal.

A: As suggested by the title of the tariff, service under Rate Schedule No. 41 ("R-41") is intended for large, high load factor firm commercial or industrial loads. Because of the favorable pricing provided by this high load factor schedule, it has for many years attracted migrating customers from Rate Schedule Nos. 31 ("R-31") and 86 ("R-86"), an interruptible schedule with its own firm service option. However, as more and more of the low load factor R-31 (heating loads) and R-86 customers (primarily steam or boiler heating loads) migrate to R-41, the underlying favorable economics disappear. An attempt to stem the migration was made by the Company with the support of the Commission staff in 1995, when a minimum load factor requirement was added to the eligibility criteria for R-41. This eligibility "fence" requires at least annual review of R-41 customer consumption patterns by the Company, an unnecessary administrative burden when the use of a demand charge could make the tariff self-policing. The reason for this is the price signal provided by a demand charge will raise the average cost to a low load factor R-31 or R-86 customer and make it uneconomic to remain on R-41.

PSE's expanded deployment of AMR technology for gas as well as electric service now facilitates the introduction of more appropriate price signals for current and prospective R-41 customers, in the form of demand charges, and enables the preservation of the favorable economics of this high load factor class of service.

Q: Would it be appropriate in the future to expand the use of demand charges to the Company's other firm rate schedules?

A: Yes. As discussed earlier in my testimony, demand rates provide for a charge based upon the maximum demand imposed by a customer on the utility distribution system within a specified time period. The relevant time period for a gas distribution utility is generally the 24-hour "gas day," for which the utility must schedule and dispatch the various layers of its supply resource portfolio in order to serve the collective demands of its customers. As with the R-41 example described earlier, demand charges can provide an appropriate price signal that incents customers to gravitate to the tariff service that best matches their load characteristics. Demand rate components can send a conservation message to a broader segment of gas heating customers as well. To the extent these customers can trim their daily consumption during cold weather peak periods, the utility can dispatch less of its most expensive peaking resources. This translates directly into lower dollar-for-dollar gas supply costs for all sales customers. The longer-term benefits provided by reduced peak use of the distribution system include increased system reliability and the ability to forestall expensive capacity reinforcements. In return for their conservation efforts, customers not only receive lower gas costs but also lower their average monthly bill as a result of an improved load factor. Recovering more of the demand related fixed costs via a demand rate component will serve to reduce the subsidization that otherwise occurs within a particular class of service. Those customers who use gas more efficiently will benefit.

Historically, the demand form of rate structures was not used extensively by distribution utilities primarily due to the high cost of demand meters, which utilized recording devices requiring periodic inspection and maintenance on customers' premises. The advent of cost effective AMR technology and web based customer information systems, such as PSE's Personal Energy Management ("PEM") program, now facilitate pricing concepts that encourage consumers to take a more active role in controlling their energy costs. Therefore, it would be entirely consistent with PSE's introduction of electric time-of-use pricing to consider expanding its use of demand rates to more of its gas tariff services in the future.

Increased Level of Monthly Customer Charges

Q: Do the proposed rate schedules include increases to the existing monthly customer charges?

A: Yes. The schedule of proposed rates includes an increase to the residential monthly customer charge of $3.04, from $4.46 to $7.50. In addition, the commercial Rate Schedule Nos. 31 and 36 include an increase in the monthly customer charge from $9.90 to $20.00. The monthly customer charge for Rate Schedule 51 increased from $4.46 to $7.50 per unit. Rate Schedule 50 included an increase in the monthly customer charge from $9.90 to $150.00.

Q: Why is the Company proposing to increase these service charge levels?

A: As mentioned earlier in my testimony, the Company utilized the unit cost study from the cost of service model to identify costs related to providing monthly service to customers. The level of customer-related costs is shown for the residential class of customers in this Exhibit to be $18.66. The corresponding level of customer costs for the commercial classes of customers is shown in Mr. Feingold’s Exhibit to be $34.38.

Establishing higher monthly service charges helps to equalize the contribution each customer within a class makes towards recovery of customer costs attributable to the class. This method of customer cost recovery is preferable to including such costs in the commodity block prices, which has the effect of causing some customers to pay too much while others pay too little.

The service charges provide for recovery of a portion of the Company's fixed customer costs, which are costs incurred solely because of the existence of customers connected to the system. These costs, such as the expense of reading meters and billing, occur regardless of whether gas is consumed and are not related to demands placed on the system.

The proposed service charge increases will also ensure recovery by the Company of a greater portion of its fixed costs of providing service. Inasmuch as customer costs are not related to usage, they should be recovered to the extent possible through a tariff mechanism that does not depend upon volumetric billing.

Q: In view of the level of customer costs suggested by the Company's study, please explain your selection of the customer service charge levels that you have proposed.

A: Given the relatively high level of customer cost shown in Exhibit RAF-3 at page 10, as compared to the Company's current level of customer charges, the Company has chosen to show some progression towards cost of service in setting new customer charges.

Q: At the proposed levels, will the customer charges result in substantial recovery of the customer cost for these classes?

A: No. More than $72 million of fixed customer-related costs representing approximately 60% of total residential class customer costs will still be recovered through the volumetric rates for gas sales.

<u>Interruptible Sales Service – Rate Schedule No. 87</u>

<u>Eliminate the Separate Rate for the Contract Volume Charge</u>

Q: Please describe the Contract Volume Charge contained in Rate Schedule No. 87 ("R-87") and the Company's proposal to eliminate this rate from the schedule?

A: The Contract Volume Charge, currently $0.0099 per therm, is the rate applied to a customer's annual contract volume, a quantity of interruptible gas set forth in the customer's service agreement as a minimum purchase volume during the contract year. Application of the Contract Volume Charge insures the recovery of a minimum level of margin from the interruptible customers served under R-87. However, recovering a portion of the distribution margin in this separately stated volumetric rate has evolved over time to its present state whereby the remaining commodity charge tail block of R-87 (currently $0.54071 per therm) is less than the gas cost component of the rate (currently $0.54592 per therm). The Company's proposed remedy is to collapse the margin recovery heretofore provided by the Contract Volume Charge into the commodity charge block rates and apply the minimum contract volume requirements to the revised tail block of the commodity charge. In other words, the minimum contract volume requirement will remain for R-87 but will be billed using the tail block of the distribution charge instead of a separately stated rate. The necessary revisions to the tariff provisions of R-87 appear on Sheet Nos. 187-A, 187-D and 187-E of <u>Exhibit RJA-3</u>.

<u>Transportation Service – Rate Schedule No. 57</u>

Q: A change has been proposed in the monthly customer charge under Schedule No. 57 ("R-57"). Please describe the customer charge in more detail.

A: The Company is proposing to increase the monthly customer charge of $643.50 to $800.00. The customer charge is based upon customer related costs from the cost of service study as well as the administrative costs related to the provision of transportation service discussed by Mr. Feingold. These cost elements are detailed in Mr. Feingold's Exhibit RAF-3 and described in his testimony, Exhibit RAF-1T.

Q: Is the Company proposing any changes to the conditions for the monthly balancing service contained in its transportation service schedule?

A: No. However, the Company is proposing a change to the per unit cost of balancing service resulting from the cost of service study, as described in Mr. Feingold's testimony. The balancing service unit rate is listed in Section 7: Rates and Charges section of Schedule No. 57, Revised Sheet No. 157-C, under item 8, in Exhibit RJA-3.

Q: Please describe the Company's proposal to eliminate the optional daily balancing service.

A: Balancing service is presently included in the transportation service commodity charge under Rate Schedule No. 57. This service provides daily balancing equivalent to the difference between a customer's daily confirmed nomination and daily delivered volumes. As an alternative, the customer may elect the optional daily balancing service whereby the quantity of daily imbalance greater than 3% overrun or 5% underrun of the customer's daily confirmed nomination receives a charge of $0.02386. Customers electing the optional daily balancing service receive a credit equal to the balancing service unit rate of $0.00099 per therm times the total delivered volumes. The optional daily balancing service was intended to provide a lower cost of balancing to those transportation customers who were particularly adept at managing their daily gas deliveries with daily consumption. However, this "customer choice" feature of the balancing service has not been selected by a single transportation customer since it was implemented in 1995. Therefore, the Company is proposing to eliminate this optional aspect of balancing service.

Q: Is there any other proposed changes to the balancing service provided by the Company under R-57?

A: Yes. The unit cost of balancing service, which currently is included in the transportation service commodity charge, will be separately stated in the rate section of R-57, as a volumetric charge applicable to all delivered therms per month. The balancing service charge will, however, continue to be included in the commodity charge for ease of billing. As mentioned earlier, the balancing service unit rate currently appears in the R-57 schedule as a credit rate (Item 8 on Sheet 175-C), applicable only when the optional daily balancing service referenced earlier is selected by customers. With the proposed elimination of the optional daily balancing, this credit rate will likewise no longer appear in the tariff. However, separately stating the balancing service rate will enable the identification in the tariff of that portion of the balancing rate related to the Company's leased Jackson Prairie storage service, the underlying resource supporting system balancing. This will serve as the basis for transportation customers' use of the Jackson Prairie storage facility for balancing to be reflected as a credit to the Company's PGA filings.

Rate Component Calculations

Q: Have the rate schedules been changed to reflect the new rate levels being proposed by the Company in this proceeding?

A: Yes.

Q: How were the proposed rates for each rate schedule calculated?

A: Detailed schedules showing each rate calculation is included in Exhibit RJA-7. As each page of this Exhibit shows, the targeted total rate schedule revenue will be achieved using the proposed rates and volumes.

The proforma therm sales were priced at the base rates currently in effect. Cumulative frequency curves by rate class, developed from actual consumption, were employed where necessary to distribute total therm sales into the appropriate rate blocks.

Customer Bill Impacts

Q: Have you prepared schedules illustrating the impact of the proposed base rates on individual customer bills?

A: Yes. Pages 1 through 11 of Exhibit RJA-8 show revenue increases by rate schedule for each respective customer group over a range of therm consumption levels.

IX. PROPOSED MODIFICATIONS TO TARIFF PROVISIONS

Q: Please summarize the Company's proposal for recovery of gas supply costs in its PGA.

A: As addressed by Mr. William A. Gaines in his testimony (Exhibit WAG-1T), the Company proposes to modify the present PGA mechanism by adjusting the PGA rates on a monthly basis versus the current practice of irregular periodic updates of the PGA rate. Monthly PGA rate changes would provide customers with a price signal that is more current and more reflective of prices in the underlying gas commodity markets thereby allowing customers to make informed decisions regarding their gas usage.

Q: Please describe the specific modifications to its current PGA mechanism envisioned by the Company to accomplish the monthly adjustments.

A: Under the Company's proposal, the PGA mechanism would continue the two primary demand and commodity cost components and retain many of its existing elements. A Secondary Market Cost component would be introduced into the mechanism. The three components of the revised PGA mechanism are outlined below.

Demand Cost Component – Determined annually, to reflect demand costs associated with pipeline and storage capacity as well as demand related cost of firm supplies:

- The Demand Component would be established in an Annual Filing (September 15th, to be effective November 1st) for the gas supply year (November through October).
- The Demand Component would be subject to an annual true-up/tracker adjustment (which is primarily a sales volume driven variance). The tracker component would be stated on Supplemental Schedule No. 106 (Sheet No. 1106).
- Annually PSE would provide a reconciliation of the demand cost accounts for the 12 months ended June 30th, as a part of the Annual Filing.
- The Annual Filing would include a detailed "Gas Supply Plan" for the forthcoming 12 months, including all contracts and resources expected to be used for the year and supported by a full "U-Plan-G" resource model.
- The Annual Filing would also disclose the forecasted monthly Commodity Component and Secondary Market Component (described below) for each of the following 12 months.

Commodity Cost Component – Changed monthly, to reflect the influence of monthly gas commodity index prices and storage activity on portfolio costs:

- A new Commodity Component would be created monthly (filed on the 27th of each month to be effective on the 1st of the subsequent month) and would replace the monthly commodity rate estimated in the Annual Filing.
- Portfolio costs would be estimated for the subsequent month and divided by expected sales volumes, while giving consideration to expected index prices and storage activity.
- The monthly filing could also forecast expected changes in the Commodity Component for all remaining months in the gas supply year (November - October) as a means of providing updated information regarding commodity market trends.
- The estimated Commodity Component would be subject to the ongoing monthly true-up/tracker, to avoid the need for recovery or refund of any deferrals on substantially different volumes from the time period incurred and to flow the benefits and costs back to customers as soon as possible.
- PSE would estimate "actual" costs for the previous month and estimated recoveries to form an estimate of the deferral for that month.
- The estimated deferral for the previous month (and reconciliation of all prior months) would be divided by estimated volumes for the next month to define the tracker rate, reflecting the same near-term costs and benefits described above (Sheet No. 1106).
- PSE would provide a reconciliation of the commodity cost accounts for the 12 months ended June 30th, as a part of the Annual Filing discussed above.

Secondary Market Cost Component – Changed monthly, to reflect estimated margin on Off-System Sales and Capacity Release Revenue for each month.

- A new rate component created monthly (filed on 27th, to be effective on 1st) to replace the corresponding rate estimated in the Annual Filing).
- The net secondary revenues would be estimated for the subsequent month and divided by expected secondary market volumes, giving consideration to expected index prices, supply basin differentials and other factors.
- A formulaic approach would be defined to determine the cost of the gas sold Off-System.
- Use of a defined average commodity component of purchases and withdrawals for the month would minimize the need to specifically identify "what gas was used where."
- The monthly filing could also forecast expected changes in the Secondary Market Component for all remaining months in the gas supply year (November – October) as a means of providing updated information regarding market trends.
- The Secondary Market Component would be subject to an ongoing monthly true-up/tracker, to avoid the need for recovery or refund of any deferrals on substantially different volumes from the time period incurred and to flow the benefits and costs back to customers as soon as possible.
- PSE will estimate "actual" net secondary market revenues for the previous month and estimated credits given to form an estimate of the deferral for that month.

- The estimated deferral for the previous month (and reconciliation of all prior months) would be divided by estimated volumes for the next month to define the tracker rate (Sheet No. 1106).
- PSE would provide a reconciliation of the Secondary Market accounts for the 12 months ended June 30th, as a part of the Annual Filing.

Q: Could you provide an illustration of the operation of the modified PGA mechanism and the resulting monthly PGA rates?

A: Yes. Exhibit RJA-6 page 2, provides a comparative analysis of the monthly commodity costs related to the Company's proposal to modify its PGA mechanism. A graphical cost comparison of the monthly gas cost recovery method proposed by the Company is presented on Exhibit RJA-6, page 3 of the Exhibit. A series of three bar charts per customer class illustrates the differences between the Company’s current PGA cost recovery versus its proposed monthly PGA method and the results of the allocations of PGA related gas costs in the cost of service study. The Company’s monthly PGA approach represents a better matching of the gas costs as allocated by the cost of service study to the respective sales classes than the current periodic PGA recovery method. The fourth page of the Exhibit is a bar chart that illustrates the three primary cost components of the monthly PGA rates as they may tend to fluctuate throughout the year.

Q: Have the proposed modifications to the PGA been reflected in the Company's Rule No. 26, Purchased Gas Adjustment Mechanism?

A: Yes. Proposed revisions to Rule No. 26 are contained in Exhibit RJA-3, Sheet Nos. 40, 40-A, 40-B, and 40-C. Structural changes have also been made to the Supplemental Sheet Nos. 1101, and 1106 in order to accommodate the revised PGA rate components. Supplemental Schedule No. 102 (Sheet No. 1102) has been canceled.

Q: Has the Company contemplated the introduction of a supply option for customers who may want to be insulated from fluctuations in their energy bills due to volatility in the gas commodity markets?

A: Yes. As described in Mr. Gaines testimony, the Company plans to provide a hedged component to its gas supply portfolio in order to offer a "Fixed Gas Cost" rate option for the duration of the hedge for gas sales customers. The fixed-price option would be a subscription service available to customers through an annual solicitation and would be calculated as part of the annual PGA filing. The cost of the fixed-price option would include the estimated costs of related financial hedge transactions. Any difference between estimated and actual hedge-related costs are proposed to be rolled into the subsequent year's fixed price offering. No other costs for the Fixed Gas Cost option would be deferred.

Q: Please describe the Company's approach for this hedged rate supply option.

A: Similar to its proposal for recovery of electric commodity costs, the Company proposes as an alternative to the PGA rate an elective hedged rate which would natural gas cost volatility. A summary of these hedges follows:

Load/Temperature Uncertainty. To offset the effect on costs of load/temperature uncertainty, PSE would purchase a string of dual trigger "put" and "call" options. These options would hedge risks of (1) a surplus in gas supply due to lower than expected retail loads and low wholesale market prices and (2) a deficit in gas supply due to higher than expected retail loads and high wholesale market prices. The string of dual trigger "put" options provide benefit when the temperature rises above the temperature strike level and the price of natural gas drops below the price strike level. The string of dual trigger "call" options provide benefit when the temperature drops below the temperature strike level and the price of natural gas rises above the price strike level.

Market Prices. While the foregoing hedges are expected to provide a significant reduction in the volumetric related volatility in gas costs, they do not address volatility in gas costs for the expected volume of gas purchases market prices. This volatility will be offset by executing forward contracts at fixed rates or by executing "fixed for floating" price swaps for these expected volumes.

As described above, during an annual election period, the Company will provide a projection of the hedged rate for the upcoming annual hedge period reflecting a then current projection of the Company's natural gas costs based on then current projections of market prices for natural gas hedge costs and benefits and other factors. Customers that elect this hedged rate option during the annual election period will pay a rate which is based on this projection and which will not vary due to gas cost volatility during the upcoming annual hedge period. Any difference between the projected hedge cost and the actual hedge cost will be carried forward and included in the hedge cost for the subsequent year.

Q: What structural changes have been made to the PSE Gas Tariff to reflect these new programs?

A: PSE has revised its gas tariff to reflect an "unbundling" of its gas rates. The individual rate schedules now quote PSE's distribution charge and refer customers to the appropriate sheet in Supplemental Schedule No. 101 for the applicable gas cost rate. When gas cost rates change monthly for the Tracked Gas Cost ("Tracked") rate option and annually for the Fixed Gas Cost ("Fixed") rate option, a new Supplemental Schedule No. 101 will be issued. Supplemental Schedule No. 102 (Sheet No. 1102), which served only to provide increments to the total rate for changes in gas costs, is no longer needed under this structure and thus has been canceled. The Company has introduced a new Rule No. 29 (Original Sheet

Nos. 43 and 43-A) in Exhibit RJA-3 to govern the availability and annual selection of the Fixed and Tracked rate options.

For customers on the Tracked rate option, the estimated current gas cost rate will appear on Supplemental Schedule No. 101 (Sheet No. 1101) and the tracker rate on Supplemental Schedule No. 106 (Sheet No. 1106). For the Fixed rate option, the gas cost rate is on Sheet No. 1101-A. As an example, for a residential Schedule No. 24 customer on the Tracked rate option, the total volumetric rate is $0.35772 per therm for delivery service (from Sheet No 124 of Schedule No. 24), $0.48215 per therm for estimated gas costs (from Sheet No. 1101), and the deferred gas cost tracker rate (from Sheet No. 1106). The Gas Conservation Program Charge will continue to apply.

Q: Why has PSE modified the tariff format in this manner?

A: Previously, the gas cost component of a customer's rate and the total volumetric rates were not readily apparent. One had to add and subtract several components in the correct formula to obtain the particular total effective rate. With this change, the delivery service component and the gas cost rate will be separately stated and visible to the customer, with the added advantage of being stated in the same form in the tariff as they appear on the customer's bill.

Modifications to Propane Service Tariff, Rate Schedule No. 53

Q: Please describe the Company's Propane Service, Schedule No. 53 ("R-53").

A: Propane Service has been a tariff service available from Puget Sound Energy since April 1997. A PSE predecessor company, WNG had developed the service as suggested by the WUTC in Docket No. UG-920840, Fourth Supplemental Order, page 45:

> "The Commission believes that propane service may be worthwhile as a true bridging service to natural gas. Thus, the company should

> not be precluded from offering it at a compensatory rate. If the company wants to offer this service in the future, it must do so under a tariff that spells out the terms and conditions of the service"

The original Propane Service tariff proposed by WNG was approved by the Commission in May 1996. The tariff provides "interim" propane service to two or more residential premises, either new construction or energy conversions from another fuel source, served by a single propane source (one tank connected to underground distribution facilities and metering). The R-53 propane "bridging" service is available to qualifying customers who can be economically served by natural gas through a future line extension. Customers must agree to convert to natural gas when it becomes available, install equipment that is easily convertible to natural gas and install piping that is properly sized for natural gas.

Q: Please describe the pricing provisions of R-53.

A: R-53 charges customers the current cost of propane within a pre-established range plus the residential distribution margin and the residential monthly customer charge. Built in to the margin is revenue credit to be applied to the future costs of a natural gas line extension. The purpose of this provision is to create a fund to help extend a natural gas line extension sooner than otherwise would be possible without the use of the interim propane service. PSE reviews the propane service areas periodically to determine if sufficient funds have been collected or additional propane service users in the same general area can collectively justify a natural gas distribution main extension.

Q: What has been the Company's experience with Propane Service?

A: Two large residential developments have been served by a propane tank farm since the inception of the tariff service: Shadow Ridge, a development of about 50 homes in S.E. King County, and Swiftwater, a development of over 100 homes in Carnation. Natural gas has since been extended to these developments as well as several other smaller projects based on standard line extension cost effectiveness guidelines. Currently, there are very few customers served by R-53, largely due to the Company's efforts to extend natural gas service to areas served by propane.

Q: What are the future prospects for Propane Service?

A: The Company believes the Propane Service tariff continues to be a very valuable tool to meet the energy needs of the regions' consumers by offering options and more choice to prospective new customers. It is especially valuable where natural gas is in great demand by homebuilders or developers wishing to obtain gas service, but due to the location of existing natural gas facilities line extensions are economically unfeasible. Without the availability of R-53, these requests for service would go unmet.

Q: Is the Company proposing any changes to the R-53 tariff?

A: Yes. The Company is proposing minor changes to the R-53 tariff to update and clarify the terms and conditions of the tariff and eliminate other unnecessary language. In addition, the R-53 rates will be updated to match the pertinent rate components of the Company's residential service, Rate Schedule No. 24. Exhibit RJA-9 provides the cost analysis related to propane fuel costs, the propane equivalent cost of service components for the residential service class, and the development of the Propane Service rates. The proposed tariff revisions appear in Exhibit RJA-3, Sheet Nos. 153, 153-A and 153-B.

Revisions to Rule No. 7, Extension of Distribution Facilities and Schedule No. 7, Facilities Extension Standards

Q: Please explain the basis for the Company's proposed revisions to its line extension policy, Rule No. 7.

A: The Company established a set of objectives or principles to guide it in developing revisions to both its gas and electric line extension policies. Those guiding principles are listed below.

- Customer Choice – Customer choice and convenience must be provided.
- Low Cost / High Quality – Low administrative costs should be pursued and the policy should insure safety and reliability of the resulting facilities.
- All Costs Included – All actual costs related to the extension of distribution facilities should be reflected in the policy.
- Synergies – Synergies and economies of scale should be pursued.
- Consistency – Seek consistency between the gas and electric line extension policies.
- Regulatory Obligations – The tariff rule must reflect PSE's regulatory responsibilities.
- Extraordinary Costs – Extraordinary costs imposed by governmental agencies are to be passed through to the customer.

Q: How have the foregoing principles been reflected in the Company's proposed revisions to Rule No. 7 and the companion Schedule No. 7?

A: The approach to updating the gas line extension policy was to maintain the basic structure and key elements of the existing Rule No. 7, while seeking consistency where possible with the new electric line extension policy and pursuing improvements to the current rule to make it more user friendly. The key elements of that effort include the following:

- The Financial Investment Analysis ("FIA") tool for determining the economic viability of line extension requests and the required level of customer contributions was retained
- The customer choice features of the current policy were continued, including the New Customer Rate ("NCR").
- Least cost design principles were incorporated.
- The administrative tasks associated with tracking line extension information, used to determine refunds of customer advances, were reduced.
- The number of standard construction cost elements and customer load data inputs to the FIA were reduced in order to eliminate unnecessary complexity and simplify the estimating process.
- Extraordinary construction costs imposed by municipalities or other governmental agencies will be directly passed on to the customer.

The specific revisions to Rule No. 7 appear in Exhibit RJA-3, Sheet Nos. 18, 19, and 19-A through 19-F. The companion Schedule No. 7 revised sheets are also included in this Exhibit.

Q: Are there other changes to the application of Rule No. 7 the Company believes to be warranted?

A: Yes. The Company is concerned about the effect on natural gas conversions from the increases required in the standard construction costs contained in Schedule No. 7.

Q: Please define what you mean by natural gas conversions?

A: Natural gas conversions (typically residential homes or commercial businesses) are those buildings that did not receive gas service at the time they were originally constructed. These homes and businesses currently use other fuels for space heating such as electricity, oil, propane or wood and electricity or propane for water heating.

Q: Why was natural gas <u>not</u> installed at the time these homes and businesses were originally constructed?

A: There are a number of possible reasons. First, natural gas first became available in the northwest in the mid 1950's so most neighborhoods built prior to the 50's did not have underground gas distribution facilities installed. Most homes used oil for heating purposes at that time.

The energy picture in the northwest was different in the 1960's and 1970's with very inexpensive electric power rates that were comparable to or lower than natural gas prices. New homes were often built with electric space and water heating. As power rates began to increase over time, many northwest utilities countered higher power costs with effective conservation programs, which resulted in more efficient use of electricity but did not reduce the number of electrically heated structures.

Furthermore, home builders at times did not choose gas service when available due to the higher first cost of construction associated with the use of gas equipment.

Q: How many homes in PSE's service territory do not have gas service?

A: Based on a Company survey of several thousand customers in 1999, approximately 40% of those surveyed currently do not have gas service.

Q: Is gas service available in the neighborhoods of the people surveyed?

A: No. The majority of these existing homes are not located adjacent to a natural gas distribution main. A gas main would have to be extended to the neighborhood in order for these homes to receive gas service.

Most new homes built today have gas service. Why the difference in the availability of gas between new homes and homes in existing neighborhoods?

Today, and for nearly two decades, natural gas has been less expensive than other energy sources for home heating and water heating. Builders have responded to the resulting consumer preference by installing gas service and gas equipment at the time of home construction.

It is much less costly to extend gas service at the time of construction of new residential developments, where many homes are built at the same time and built at a much higher density per acre than many older neighborhoods. Homebuilders usually provide all trenching for electric power and other underground utilities and therefore natural gas can be installed at that time for a very low cost. New homes typically have multiple gas appliances and thus higher expected revenue compared to the older existing homes to cost justifying the extension of facilities, which allows PSE to extend facilities at little or no cost to the residential developer.

This is not the case with conversions. Construction is much more costly and unpredictable due to the presence of finished streets, sidewalks and landscaping requiring repair and restoration; the need for traffic control; more complex design and right-of-way issues; municipal permitting; and the involvement of multiple parties in the decision making process.

Q: Why does PSE want to extend gas service to these conversion customers?

A: First and foremost, the Company wants to extend service to these conversion customers because they request it. Notwithstanding the positive impact on customer satisfaction when gas service is made available to those requesting it, the Company believes it has a basic obligation to extend natural gas and/or electric utility service to customers and are required to do so if it is economically feasible under WAC 480-90-123.

Second, PSE's service territory is located in a high economic growth area. With increasing energy needs, it is important to offer gas service for home heating and water heating, which can be consumed directly at a higher level of efficiency as opposed to serving the same end use with electricity generated from a gas turbine at a higher cost and lower efficiency. This is consistent with the Washington State Energy Strategy.

Finally, new gas customer growth is beneficial to current gas customers if the new growth is cost effective, exceeds the current customer class rate of return, and helps lower average costs by spreading fixed distribution costs over a greater number of customers.

Q: What changes does the Company propose to make to the line extension policy that will continue to allow it to serve new conversion customers cost effectively and make it affordable?

A: In addition to updating the standard construction costs in Schedule No. 7 to more accurately reflect project costs, PSE wishes to provide more attainable customer payment options for those conversion projects requiring a customer contribution.

The new customer rate ("NCR") has been very well received by customers wanting gas service but unable to meet the target rate-of-return requirements by paying a large up-front customer advance payment. Because of this we want to continue to offer the prospective customer the option of the NCR.

However, the Company also wishes to establish an Infill Analysis for conversions, which in turn may lower the qualification payment levels that would permit more customers to select the NCR. By contrast, the lower cost of serving new construction developments and higher expected margins, as discussed above, enables most new residential developments to exceed the target rate of return ("ROR") without contribution.

Q: Is the NCR an effective way to meet the new facility extension requests of prospective conversion customers and contribute to the plant required to serve them?

A: Yes. It has provided customers with a way to make gas line extensions more affordable. To date, fifty-five percent of residential conversion customers have chosen the NCR option.

Q: How will the Infill Analysis for conversions benefit current customers?

A: With this analysis, PSE at it's discretion, may include a limited number of projected customers in the Facility Investment Analysis ("FIA") when an examination of potential customers on the route of a requested line extension show a probability of converting to gas in the near future.

Q: Is the Company able to estimate the likelihood of customers converting to gas in the future?

A: Yes. Through the review process outlined in Rule No. 7 PSE is able to monitor new customer conversions and develop guidelines to determine future growth.

Q: What are the benefits of offering this new element to Rule No. 7?

A: The Company may be able to offer natural gas service to prospective customers that would otherwise find it unaffordable. This also gives consumers and PSE more flexibility with regard to longer line extension requests, where there are many individual homeowner decision-makers. Frequently, the Company finds significant interest from residents along the proposed route of a line extension but are unable to make an immediate commitment. Once gas is available these interested homeowners become prime candidates for near-term conversions.

In addition, the use of an Infill Analysis in the FIA, which results in lower customer payment options, would enable the Company to refrain from reviewing the line extension project for possible refunds in the future, thus saving significant administrative costs.

The Company believes that offering ways such as the Infill Analysis for consumers who wish to convert to natural gas service will benefit all energy users by making natural gas line extensions more affordable. It is important to emphasize where natural gas is the most efficient and cost effective fuel for the job. Therefore, creating more options for consumers that encourage the direct use of natural gas for home heating and water heating best serves the region's growing energy needs in the most economic, efficient and environmentally beneficial manner.

Elimination of Canceled Rental Rates

Q: Please explain the proposed elimination of certain of the categories of rental equipment in the Company's rental rate schedules.

A: The Company's rental services, all of which have been previously closed to new accounts, include Residential Water Heater Rental Service (Schedule No. 71), Large Volume Water Heater Rental Service (Schedule No. 72), Gas Conversion Burner Rental Service (Schedule No. 74), and Residential Gas Circulating Heater Rental Service (Schedule No. 75). Programs have been initiated in recent years to encourage certain of the rental equipment customers to purchase their leased equipment from the company or, in some cases, the equipment has been conveyed to the customer at no cost. For example, letters were sent to about 900 customers with leases for gas circulating heaters (Schedule No. 75) during May and June of 2000 providing them with the option of retaining the equipment at no cost or having the equipment removed from the customer's premises. Schedule No. 75 had been closed to new accounts since January 1971. Most of the customers chose to retain the equipment. The Company then began canceling the leases in

June 2000 and completed the program in the following month. Since there are no customers remaining on Schedule No. 75, the Company proposes to cancel this rental service tariff.

In September 2000, PSE began a program to cancel certain boiler leases under its Schedule No. 72 (Large Volume Water Heater Rental Service). Customers with boiler equipment less than 10 years old were given the option of purchasing the leased equipment or having it removed. Similarly to the circulating heater program, the oldest equipment (10 years or older) was retired in place at no cost to the customer. While some of the canceled boiler equipment leases had been closed to new accounts in June 2000, the oldest equipment categories had been closed since October 1975. At this time, approximately 98% of the leased boiler equipment under Schedule No. 72 have been canceled. A letter campaign to customers leasing another class of aging equipment under Schedule No. 72, storage tanks for boilers, is scheduled to begin early next year and will be completed by the fall of 2002.

The canceled equipment types under Schedule No. 72 are shown in the legislative version of the gas tariff in Addendum D to the Company's filing. The revised rental service schedules are included in Exhibit RJA-3 as well as the canceled Schedule No. 75.

Q: Is the Company proposing any changes to the lease rates under the rental service schedules that remain?

A: Yes. Increases to the various lease rates for the remaining rental service equipment under Schedule Nos. 71, 72 and 74 are proposed. The increases have been established to address the COSS results for the rental service class, as discussed both by Mr. Feingold and my testimony above. Guidance as to the relative increases to the assorted rental equipment types was provided by their respective equipment lease values.

Q: Are the Company's proposed changes to miscellaneous customer charges consistent for both gas and electric service tariffs?

A: Yes.

Q: Please describe the Company's proposal regarding its Disconnection Visit Charge.

A: The Company proposes an increase to the disconnection visit charge. In 1998 the Company determined costs to be $12.50 to pick up a customer payment in lieu of disconnection. At that time, the Commission did not approve the Company request to increase this $9.00 charge. The Company has determined current costs to be $15.00. This increase in costs results solely from increases in wages. The Company proposes to increase the disconnection visit charge to $15.00 to appropriately cover costs.

Q: Please describe the Company's proposed change to its Connection / Reconnection Charge.

A: The Company proposes an increase to the connection or reconnection charge. In 1998 the Company determined costs to be $30.00 for the connection or reconnection of service when satisfactory arrangements are made during business hours (7:00 a.m. – 4:00 p.m.) and $50.00 when arrangements are made for the connection or reconnection of service outside of normal business hours. At that time, the Commission approved increased charges for each of the services to $20.00 and $40.00, respectively, to be consistent with the existing electric service charges. The Company has determined current costs for work performed between 7:00 a.m. to 7:00 p.m. to be $32.00. This increase in costs for work performed during normal business hours results solely from increases in wages. The decrease in costs for work performed between 4:00 p.m. and 7:00 p.m. results from the shift of work to lower wage personnel. The Company proposes to change the connection or reconnection charge to $32.00 when satisfactory arrangements are made between 7:00 a.m. and 7:00 p.m. to appropriately cover costs. If arrangements are made for connection service after these extended business hours due to an emergency or extenuating circumstances and the Company agrees that service can be connected or reconnected after 7 p.m., the charge shall be based upon a time and materials estimate of the Company's cost. While such costs would include the same categories used to derive the regular connection charge, the actual labor cost of after-hours work alone can vary significantly depending upon the day of the week and time of the job as well as the wage class of the employee performing the connection. The connection or reconnection charge would be based upon the applicable wages, vehicle cost and related overheads to make the after-hours connection or reconnection.

Q: Please describe the Company's proposed change to its Billing Initiation Charge.

A: The Company proposes an increase to the billing initiation charge. In 1998, the Company determined the cost to be $10.00 for each new service location established or a change of responsibility or restoration of seasonal service and $6.00 per each service for combined gas and electric service customers ($6.00 for each service type for a total of $12.00). At that time, the Commission approved increased charges at $5.50 and $3.50, respectively. The Company has determined current costs for each to be $10.00 and $6.25. The Company proposes to increase the billing initiation charge to $10.00 and $6.25, respectively, to appropriately cover costs.

Q: Please describe the Company's proposal for its Returned Check Charge.

A: The Company proposes an increase to the returned check charge. In 1998 the Company determined the cost to be $12.00 for each check returned for nonpayment. At that time, the Commission approved an increased charge of $10.00. The Company has determined current costs to be the same as in 1998. The Company proposes to increase the returned check charge to $12.00 to appropriately cover costs.

Q: Has the Company provided supporting analysis regarding the costs related to the miscellaneous service charges you've just described?

A: Yes, <u>Exhibit RJA-10</u> provides the cost analysis supporting each of the miscellaneous service charges described above.

<u>New Rule No. 28, Relocation of Company Owned Facilities</u>

Q: Please describe the Company's proposal for a new rule governing the relocation of Company-owned Facilities.

A: While the Company's tariff included some provisions in its Rule No. 7 regarding relocation of facilities when incremental load requirements were involved, the tariff does not cover other requests for facility relocations.

Q: Did the Company previously perform these relocations when requested?

A: Yes. The Company also charged the requesting party for the cost of the relocation except when performed under the provisions of a franchise agreement.

Q: Why has the Company included this new rule governing relocations?

A: The Company has included a rule for relocations so that charges would be consistent for all relocations. Furthermore, having the charges addressed in the tariff will thereby make them available to all interested parties.

<u>Miscellaneous Tariff Modifications</u>

Q: What is the purpose of the cancellation of Tariff Sheet Nos. S-1, S-2, S-3, S-4, S-5, S-6, and S-6.1 reflected on Seventh Revised Sheet No. 18?

A: The referenced tariff sheets are the Summary of Total Current Prices for the various gas service rate schedules. The Company is proposing to cancel these summary sheets to eliminate duplicative rate information in multiple locations in the gas service tariff. By consolidating this rate information, the Company can avoid updating multiple tariff sheets each time a particular rate component is subject to change in one or more of the tariff schedules. This should also require less audit review on the part of the Commission's Energy Staff. The "S" series tariff sheets of summary rate information have at times led to some confusion when comparisons are made with rate information contained elsewhere in the tariff, such as Schedule No. 102 (Purchased Gas Cost Adjustment) and Schedule No. 106 (Deferred Account Adjustment) as well as the various rate schedules. The Company's proposal to separate the distribution charges from the gas cost components of the sales rate schedules, along with the cancellation of Schedule No. 102, eliminates the need to use the summary sheets to net the same elements to obtain the total sales rates.

Q: Why has the Company not included a revised index of rate schedules with this filing?

A: The Company wishes to avoid substitutions of the index of rate schedules during the duration of the suspension period related to the tariff sheets included in this filing. At the conclusion of the instant proceeding, the Company plans to file a revised index to coincide with the effective date of the revised tariff schedules.

Q: Does this conclude your direct testimony?

A: Yes.

[BA013290025]

EXHIBIT NO. ______ (RJA-2)
DOCKET NO.____________
2001 PSE RATE CASE
WITNESS: RONALD J. AMEN

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

EXHIBIT TO DIRECT TESTIMONY OF RONALD J. AMEN
ON BEHALF OF PUGET SOUND ENERGY, INC.

RONALD J. AMEN

Mr. Amen is a Principal with Navigant Consulting, Inc., formerly Metzler & Associates (M&A). He has over twenty-three years of combined experience in utility management and consulting in the areas of pricing and regulatory affairs, distribution operations and customer service, marketing and sales, and systems administration. He joined M&A in 1997.

AREAS OF EXPERTISE

- Ratemaking and Regulatory Policy Analysis
- Market and Competitive Assessment
- Gas Supply Planning and Evaluation
- Business Process Redesign and Organizational Restructuring
- Benchmarking and Performance Measurement
- Mergers and Acquisitions
- Expert Testimony and Litigation Support

PRIOR EMPLOYMENT

- Director, Rates and Tariffs, Washington Natural Gas Company (now Puget Sound Energy), where responsibilities included regulatory policy, cost of service, rate design techniques and pricing strategy, tariff design and administration. Supervised Business Development group.
- Regional Director, Indiana Gas Company, with responsibility for sales, customer service, distribution system construction, operation and maintenance, community relations, and human resources for an operating region of the utility.
- Director of Rates for the same gas local distribution company. Responsible for cost of service, rate design and pricing, demand forecasting, and maintaining company rate tariffs. Prepared and presented rate filings to the Indiana Utility Regulatory Commission (IURC). Represented the company's interests in Federal Energy Regulatory Commission (FERC) interstate pipeline regulatory proceedings.
- Data Processing Manager, Ohio Valley Gas Corp. Responsible for supervision of computer system operations, including customer

billing, cash remittance processing, customer information, distributed data system, and system programming.

- Assistant District Manager, Ohio Valley Gas Corp. Responsibilities included gas distribution system construction, operation and maintenance; customer credit and collections; customer service; and appliance sales.

EDUCATION

- Bachelor of Science in Business Administration, University of Nebraska, College of Business Administration, Lincoln, Nebraska

  Areas of concentration - Finance, Accounting, Economics

PRESENTATION OF EXPERT TESTIMONY

- Connecticut Department of Public Utility Control
- Washington Utilities and Transportation Commission
- Indiana Utility Regulatory Commission
- Federal Energy Regulatory Commission
- British Columbia Utility Commission (Canada)

AFFILIATIONS

- Associate Member, American Gas Association
- Past Member, Marketing & Regulatory Committees of the Pacific Coast Gas Association
- Past Member, Rate Committee of the American Gas Association
- Past Member, Statistics and Load Forecasting Methods Committee of the American Gas Association
- Past Chairman, Rate Committee of the Indiana Gas Association