BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DOCKET NOs. UE-072300 and UG-072301

DIRECT TESTIMONY OF GLENN A. WATKINS (GAW-1T)

ON BEHALF OF

PUBLIC COUNSEL

REVISED (RED-LINED)

June 23, 2008

NON-CONFIDENTIAL

DIRECT TESTIMONY OF GLENN A. WATKINS (GAW-1T)
DOCKET NOs. UE-072300 AND UG-072301

TABLE OF CONTENTS

PAGE

I. INTRODUCTION 1

II. ELECTRIC OPERATIONS 2

A. ELECTRIC CLASS COST OF SERVICE 2
1. Income Taxes 6
2. Excise Taxes and WUTC Fees 8
3. Power Supply Costs 10

B. ELECTRIC CLASS REVENUE DISTRIBUTION 25

C. ELECTRIC RESIDENTIAL RATE DESIGN 29
1. Residential Rate Design Concepts 29
2. Electric Residential Rate Design 34

III. NATURAL GAS OPERATIONS 40

A. Natural Gas Class Cost Of Service 40
1. Separate Allocation of Mains to Large Customers 43
2. Peak and Average Classification 50
3. Treatment of Interruptible Volumes ..... ~~51~~52
4. Design Day versus Actual Peak Day 54

B. Natural Gas Class Revenue Distribution ..... ~~61~~62

C. Natural Gas Residential Rate Design 66

IV. PSE SUPPLEMENTAL FILING ..... ~~73~~74

DIRECT TESTIMONY OF GLENN A. WATKINS (WAW-1T)
DOCKET NOs. UE-072300 AND UG-072301

TABLES

		PAGE
Table 1.	Replication of PSE Electric CCOSS at Current Rates	6
Table 2.	Electric CCOSS (at Current Rates) ROR	8
Table 3.	Electric CCOSS (At Current Rates) Incorporating Income Taxes, Other Taxes and Fees Adjustments	9
Table 4.	SCCT Hours of Operation (Confidential)	13
Table 5.	Classification Percentages	18
Table 6.	Electric CCOSS (at Current Rates) Incorporating Income Taxes, Other Taxes and Fees, and Power Supply Cost Adjustments	22
Table 7.	Electric CCOSS (at Current Rates) Incorporating Table 6 and Salaries & Wages Adjustments	23
Table 8.	Electric CCOSS (at Current Rates) Incorporating All Public Counsel Adjustments	24
Table 9.	Electric CCOSS (at Current Rates) Comparison of Results	25
Table 10.	PSE-Proposed Electric Revenue Increase	26
Table 11.	Public Counsel Proposed Revenue Increase	27
Table 12.	Indexed Rate of Return -- Public Counsel CCOSS Results	29
Table 13.	PSE General Plant Investment	36
Table 14.	Gas CCOSS (at Current Rates) Incorporating Expense Oversight Adjustments	42
Table 15.	Gas CCOSS (at Current Rates) Incorporating Expense Oversight and Income Taxes Adjustments	43

TABLES (CONTINUED)

		PAGE
Table 16.	Gas CCOSS (at Current Rates) Incorporating Expense Oversight, Income Taxes, and Peak and Average Method Adjustments	50
Table 17.	Gas CCOSS (at Current Rates) Incorporating Table 16 and Interruptible Customer Usage Adjustments	54
Table 18.	Weather Normalized Monthly Usage	57
Table 19.	Comparison of System Design Day and Actual Peak Day Demands (Confidential)	58
Table 20.	Comparison of PSE Design Day and Public Counsel Actual Peak Day Demands (Confidential)	59
Table 21.	Comparison of PSE and Public Counsel Load Factors (Confidential)	60
Table 22.	Comparison of PSE and Public Counsel Class Contributions To Peak Day Demands (Confidential)	~~60~~61
Table 23.	Gas CCOSS (at Current Rates) Incorporating All Public Counsel Adjustments	~~61~~62
Table 24.	PSE Proposed Gas Revenue Increase	~~62~~63
Table 25.	Public Counsel Revenue Distribution at PSE Proposed Gas Revenue Increase	~~63~~64
Table 26.	Indexed ROR at PSE Proposed Gas Revenue Increase	~~65~~66

DIRECT TESTIMONY OF GLENN A. WATKINS (GAW-1T)
DOCKET NOs. UE-072300 AND UG-072301

EXHIBITS OF GLENN A. WATKINS (GAW-1T)

Exhibit No. ___ (GAW-2)	Background & Experience Profile
Exhibit No. ___ (GAW-3)	Electric Class Cost of Service Study (PSE Study Corrected for the Calculation of Income Taxes)
Exhibit No. ___ (GAW-4C)	PSE SCCT Hours of Dispatch Generating Units Time Period: 7/1/06 – 6/30/07 (Confidential)
Exhibit No. ___ (GAW-5)	Classification of Generation Plant
Exhibit No. ___ (GAW-6)	Public Counsel Electric Class Cost of Service Study
Exhibit No. ___ (GAW-7)	PSE and Public Counsel Revenue Distribution Proposals
Exhibit No. ___ (GAW-8)	Electric Residential Customer Costs (Cost of Equity @ PSE Proposed)
Exhibit No. ___ (GAW-9)	Example of Flow Analysis
Exhibit No. ___ (GAW-10)	Public Counsel Gas Class Cost of Service Study
Exhibit No. ___ (GAW-11)	PSE Natural Gas Operations PSE and Public Counsel Revenue Distribution Proposals
Exhibit No. ___ (GAW-12)	Natural Gas Residential Customer Costs (Cost of Equity @ PSE Proposed)
Exhibit No. ___ (GAW-13)	Natural Gas Residential Customer Costs (O&M + Depreciation Based)

1 **I. INTRODUCTION**

2 **Q: Please state your name and business address.**

3 A: My name is Glenn A. Watkins. My business address is James Center III, 1051 East Cary
4 Street, Suite 601, Richmond, VA 23219.

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

6 A: I am a Principal and Senior Economist with Technical Associates, Inc., which is an
7 economics and financial consulting firm with offices in Richmond, Virginia.

8 **Q: On whose behalf are you testifying?**

9 A: I am testifying on behalf of the Public Counsel Section of the Washington Attorney
10 General's Office (Public Counsel).

11 **Q: Please describe your professional qualifications.**

12 A: Except for a six month period during 1987 in which I was employed by Old Dominion
13 Electric Cooperative as its forecasting and rate economist, I have been employed by
14 Technical Associates continuously since 1980.

15 During my career at Technical Associates, I have conducted marginal and
16 embedded cost of service, rate design, cost of capital, and load forecasting studies
17 involving numerous electric, gas, water/wastewater, and telephone utilities, and have
18 provided expert testimony in Alabama, Arizona, Georgia, Maine, Maryland,
19 Massachusetts, Michigan, New Jersey, Illinois, Pennsylvania, Vermont, Virginia, South
20 Carolina, Washington, and West Virginia. I hold an M.B.A and B.S. in economics from
21 Virginia Commonwealth University. I am a member of several professional
22 organizations as well as a Certified Rate of Return Analyst. A more complete description
23 of my education and experience is provided in Exhibit No.___ (GAW-2).

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

2 A: Technical Associates has been retained by Public Counsel to evaluate the accuracy and
3 reasonableness of Puget Sound Energy's (PSE or Company) electric and natural gas class
4 cost of service studies (CCOSS), proposed distribution of revenues by class, and
5 residential rate designs. The purpose of my testimony, therefore, is to comment on PSE's
6 proposals on these issues and to present my findings and recommendations based on the
7 results of the studies I have undertaken on behalf of the Public Counsel.

8 **Q: Please explain how your direct testimony is structured.**

9 A: I have separated my direct testimony into three sections: Electric Operations; Natural
10 Gas Operations; and PSE Supplemental Filing. For each operational section, I have three
11 subsections entitled: Class Cost of Service; Class Revenue Distribution; and, Residential
12 Rate Design. My testimony concerning the first two sections (Electric Operations and
13 Natural Gas Operations) is based entirely on the Company's initial filing dated December
14 3, 2007. I discuss the rate design implications of PSE's April 11, 2008 supplemental
15 filing separately in the last section of my testimony.

16 **II. ELECTRIC OPERATIONS**

17 **A. ELECTRIC COST OF SERVICE**

18 **Q: Please explain the concept of a class cost of service study (CCOSS).**

19 A: There are two general types of cost of service studies used for public utility ratemaking:
20 marginal cost studies and embedded, fully allocated cost studies. PSE has utilized a
21 traditional embedded cost of service concept in this case for purposes of establishing its
22 overall retail revenue requirement, as well as for its CCOSS. However, as I will explain

later in my testimony certain aspects of the Company's electric CCOSS are premised on forward looking marginal cost principles.

Embedded cost of service studies are often referred to as fully allocated cost studies. This is because the vast majority of a public utility's plant investment serves all customers, and the majority of expenses are incurred in a joint manner such that these costs cannot be specifically attributed to any individual customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer (or group of customers), these costs are directly assigned in a CCOSS. However, the vast majority of PSE's Production, Transmission, and Distribution plant and expenses are incurred jointly to serve all (or most) customers. These joint costs are then allocated to rate classes.

It is generally recognized that to the extent possible, joint costs should be allocated to classes based on the concept of cost causation; i.e., costs are allocated based on specific factors that cause costs to be incurred by the utility. Although cost analysts generally strive to abide by the concept of cost causation to the greatest extent practical, some costs (particularly overhead costs), cannot be attributed to specific exogenous factors and must be subjectively assigned or allocated to rate classes. With regards to those costs that can be attributed to a specific factor, cost of service experts often disagree as to what is the most cost causative factor; e.g., peak demand, energy usage, number of customers, etc.

1 **Q: How should CCOSS results be used in the ratemaking process?**

2 A: Although there are certain principles used by all cost of service analysts, there are often
3 significant disagreements on the specific factors that drive costs. These disagreements
4 can and do arise as a result of the quality of data and the level of detail available from
5 financial records. Moreover, there are often fundamental differences in opinions
6 regarding cost causation factors that should be considered to properly allocate costs to
7 rate schedules or customer classes. Additionally, and as mentioned earlier, cost
8 causation factors cannot be realistically ascribed to some costs such that subjective
9 decisions are required.

10 In these regards, two different cost studies conducted for the same utility and time
11 period can, and often do, yield different results. As such, regulators should consider
12 CCOSS results as one of many tools in assigning revenue responsibility.

13 **Q: Please explain how you proceeded with your analysis of PSE's electric CCOSS.**

14 A: The process by which I conducted my analysis in this case was identical to how I
15 evaluate all CCOSSs. First, I reviewed the structure and organization of the Company's
16 CCOSS presented by PSE witness, David W. Hoff, in Exhibit No.___ (DWH-4C). Once
17 the basic structure was understood, I reviewed the accuracy and completeness of the
18 primary drivers (allocators) used to assign costs to rate schedules and classes. Next, I
19 reviewed PSE's selection of allocators used to allocate specific rate base, revenue and
20 expense accounts to customer rate classes. I then verified the accuracy of PSE's CCOSS
21 model by replicating the results using my own computer model. Finally, I adjusted
22 certain aspects of the Company's studies to better reflect cost causation and cost
23 incidence by rate schedule and customer class.

1 **Q: Did you find the Company's electric CCOSS to be mathematically accurate?**

2 A: Yes. Perhaps the most fundamental requirement of an embedded CCOSS is that the sum
3 of the parts (customer classes) must equal the whole (system). This is true with respect
4 to the allocation of financial accounts, as well as the various allocation factors.
5 Furthermore, certain costs previously allocated are carried forward for other purposes
6 such as for the development of composite or internal allocators and for the assignment of
7 income taxes. In all regards, I found Mr. Hoff's electric CCOSS to be mathematically
8 accurate and I was able to replicate his results.

9 **Q: How will you present the results of your CCOSS analyses?**

10 A: To understand the importance and impact of each adjustment I have made to Mr. Hoff's
11 CCOSS, I present a summary of each customer class's rate of return on rate base at
12 current rates after each adjustment. That is, I start with a replication of Mr. Hoff's
13 results, and subsequently present and discuss the resulting class rates of return at current
14 rates after each of my adjustments.

15 **Q: Please provide a summary of Mr. Hoff's CCOSS results at current rates.**

16 A: Mr. Hoff's CCOSS generates the following rates of return on rate base at current rates. It
17 should be noted that Mr. Hoff's electric CCOSS reflects all accounting and proforma
18 adjustments proposed by the Company in its initial filing on December 3, 2007.

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Table 1
Replication of PSE Electric CCOSS
at Current Rates

Rate Schedule	Class	Rate of Return	Indexed ROR
7	Residential	2.87%	54%
24	Secondary Voltage <50kw	5.77%	109%
25	Secondary Voltage >50kw and <350kw	12.62%	238%
26	Secondary Voltage >350	11.33%	213%
31/35/43	Primary Voltage	6.96%	131%
40	Campus	5.73%	108%
46/49	High Voltage	4.11%	77%
449/459	Transportation	6.06%	114%
50-59	Lighting	8.69%	164%
5	Firm Resale	2.34%	44%
Total Company		5.31%	100%

1. Income Taxes

Q: Please explain your disagreements with Mr. Hoff relating to the treatment of income taxes for purposes of PSE's CCOSS.

A: As is the case for virtually all investor owned public utilities, income taxes represent a significant expense for PSE's electric operations. Although Mr. Hoff has incorporated PSE's total company electric income taxes in his CCOSS, his analysis at current rates inappropriately assigns this expense to individual classes.

It is well understood that income tax expense is based on before tax profits. However, Mr. Hoff's CCOSS analysis at current rates ignores this concept and allocates PSE's total electric income taxes to customer classes based on allocated rate base (investment). In other words, Mr. Hoff's CCOSS analysis at current rates assigns income tax expense based on the level of plant investment rather than profit contributions by customer class. Mr. Hoff's determination of each class's income tax responsibility,

1 therefore, has nothing to do with the reality of tax incidence (revenues minus expenses),
2 but rather is based solely on investment. Mr. Hoff's approach unrealistically assigns the
3 same level of income tax responsibility to individual classes regardless of each class's
4 revenues and expenses.

5 This allocation, or assignment, of total Company income taxes based on rate base
6 investment significantly distorts individual class profitability at current rates and provides
7 inaccurate information as to the adequacy, or inadequacy, of current rates.

8 **Q: Are income taxes normally calculated or allocated for other types of financial or**
9 **profitability analysis?**

10 A: It is universally agreed that when the objective is to evaluate profitability, whether it be
11 for a firm, a specific business unit, or single project, income tax expenses are based on
12 the difference between revenue and deductible expenses. Allocating the total income
13 taxes based on investment (rate base) makes no sense.

14 **Q: Have you conducted a replication analysis of Mr. Hoff's CCOSS with a more proper**
15 **determination of class income tax responsibility?**

16 A: Yes.

17 **Q: Please explain how you calculated electric income taxes for each class.**

18 A: Income taxes were calculated for each class by first determining each class' earnings
19 before interest and income taxes (EBIT). Synchronized interest expense was then
20 determined for each class based on the allocated level of rate base. Subtracting interest
21 from EBIT results in each class's taxable income. This taxable income amount was then
22 multiplied by the system effective income tax rate to arrive at each class' income tax
23 responsibility.

Q: What individual class rates of return result when Mr. Hoff's study is adjusted for a proper calculation of income taxes?

A: A summary of this CCOSS scenario is provided in Exhibit No. ___ (GAW-3). A summary comparison of class rates of return (ROR) on rate base is provided below:

Table 2
Electric CCOSS (at Current Rates)
ROR

	PSE Study		Indexed ROR	
Class	Corrected For Income Taxes	As Filed By PSE	Corrected For Income Taxes	As Filed By PSE
Residential	4.09%	2.87%	77%	54%
Secondary Sch. 24	5.54%	5.77%	104%	109%
Secondary Sch. 25	8.97%	12.62%	169%	238%
Secondary Sch. 26	8.33%	11.33%	157%	213%
Primary Sch. 31/35/43	6.14%	6.96%	115%	131%
Campus Sch. 40	5.52%	5.73%	104%	108%
High Voltage Sch 46/49	4.71%	4.11%	89%	77%
Transportation Sch. 44	5.68%	6.06%	107%	114%
Lighting	7.01%	8.69%	132%	164%
Firm Resale	3.82%	2.34%	72%	44%
Total Electric	5.31%	5.31%	100%	100%

As can be seen above, the correction to income taxes produces significantly different results for several classes. Most notably, the Residential class ROR rises from 2.87 percent (54% of the system average) to 4.09 percent (77% of system average), the Firm Resale class rises from 2.34 percent (44% of system average) to 3.82 percent (72% of system average). Rate Schedule 25 decreases from 12.62 percent (238% of system average) to 8.97 percent (169% of system average), and Rate Schedule 26 decreases from 11.33 percent (213% of system average) to 8.33 percent (157% of system average).

2. Excise Taxes and WUTC Fees

Q: Please explain your next adjustments to Mr. Hoff's electric CCOSS.

A: The next adjustments I made to Mr. Hoff's CCOSS also reflect a more accurate assignment of expenses, specifically related to WUTC filing fees, and Washington State excise taxes. Whereas each of these expenses are incurred on revenue levels, Mr. Hoff allocates them to individual classes based on gross Production, Transmission, and Distribution plant (PTDP) investment.

I separated Account No. 928 into two components and allocated PSE's proforma WUTC fees ($3,628,231) based on retail rate revenues and the remainder ($2,075,607) on the basis of Mr. Hoff's PTDP allocator. With regards to proforma Washington Excise Tax expense booked under Account 236.21, I also allocated these revenue taxes based on retail rate revenue. These adjustments to revenue-related taxes and fees, coupled with my previous adjustment to properly reflect income tax responsibility, results in the following rates of return at current rates:

Table 3
Electric CCOSS (at Current Rates)
Incorporating Income Taxes, Other Taxes and Fees Adjustments

Class	ROR	Indexed ROR
Residential	4.22%	79%
Secondary Sch. 24	5.51%	104%
Secondary Sch. 25	8.69%	164%
Secondary Sch. 26	7.90%	149%
Primary Sch. 31/35/43	5.96%	112%
Campus Sch. 40	5.10%	96%
High Voltage Sch 46/49	4.21%	79%
Transportation Sch. 449	6.49%	122%
Lighting	7.26%	137%
Firm Resale	4.42%	83%
Total Electric	5.31%	100%

The details underlying these CCOSS results are provided in my filed workpapers.

1 **3. Power Supply Costs**

2 **Q: How has PSE assigned generation and other power supply costs to customer**
3 **classes?**

4 A: Mr. Hoff has utilized the Peak Credit method to classify power supply costs between
5 energy and demand. As noted on pages 10 and 11 of Mr. Hoff's direct testimony, the
6 Peak Credit method has a "long tradition in this region" and indeed has been used in
7 Washington State for many years by PSE, as well as other electric utilities.

8 **Q: Please explain the conceptual basis for the Peak Credit method.**

9 A: In general, electric utilities plan their power supply resources to meet the objective of
10 supplying the energy (kwh) needs of its customers at the lowest total costs, subject to the
11 constraint that enough capacity (kw) must also be available to meet peak load
12 requirements. Because there is typically a cost tradeoff between fixed capacity costs and
13 variable energy costs, an electric utility's power supply portfolio includes a mix of
14 expensive fixed capacity (kw)/cheaper variable (energy) cost resources to meet annual
15 energy requirements and less expensive fixed/more costly variable (energy) costs
16 resources to meet peak load demands. The Peak Credit method (and other peaker
17 methods) attempts to capture this energy/capacity tradeoff by recognizing that peak
18 demands require only peaking generation while more efficient base and intermediate
19 generation facilities are used to meet the annual energy requirements of customers.

20 As such, the Peak Credit method and other peaker methods have substantial
21 intuitive appeal in that base load units which operate with high capacity factors are
22 allocated on the basis of energy consumption, while peaking units, that are seldom used

1 and only called upon during peak load periods, are allocated on peak demand in
2 proportion to those classes contributing to the system peak load(s).

3 **Q: Please explain how Mr. Hoff applied the Peak Credit method in this case.**

4 A: As implied earlier, there are two components that result from the Peak Credit method: a
5 portion of power supply classified and allocated as demand-related (kw) and a portion
6 classified and allocated as energy-related (kwh). PSE has developed its demand/energy
7 relationship by calculating the ratio of the costs of a hypothetical peaker unit (demand) to
8 those of a hypothetical base load unit (energy).

9 **Q: What do you mean by the hypothetical costs of peaker and base load units?**

10 A: Instead of utilizing the actual costs of a particular generating unit actually in service, PSE
11 has estimated the forward-looking capital and operating costs of a natural gas-fired
12 simple cycle gas combustion turbine (SCCT) as a surrogate for a peaker unit and
13 forward-looking estimates of the capital and operating costs of a combined cycle
14 combustion turbine (CCCT) as a surrogate for a base load unit.

15 **Q: Please continue with your explanation of Mr. Hoff's application of the Peak Credit**
16 **method.**

17 A: Of critical importance is an understanding that Mr. Hoff's cost estimates for the
18 hypothetical SCCT and CCCT reflect estimates of both fixed capital costs and variable
19 operating costs. Specifically, Mr. Hoff assumes the SCCT unit will be used solely for
20 peaking purposes and operate only 75 hours per year.[1] Furthermore, Mr. Hoff assumes

[1] There are 8,760 hours in a year.

1 that the cost of natural gas used to run this SCCT will be purchased at a premium due to
2 the assumed peaking nature of the unit.[2]

3 **Q: Mr. Watkins, have you investigated the reasonableness of Mr. Hoff's assumption**
4 **that the hypothetical SCCT would be used solely for peaking purposes?**

5 A: Yes.

6 **Q: Please explain your investigation and the reasonableness of Mr. Hoff's assumption**
7 **that a SCCT will only operate for 75 hours during peak load conditions.**

8 A: To investigate the assumption that a PSE-owned SCCT would be used only to meet peak
9 loads, I evaluated the characteristics of PSE's dispatch of its generation, and specifically
10 the actual dispatch of its SCCTs. In Public Counsel Data Request No. 456, I requested
11 and was provided hourly PSE Area loads (retail plus wholesale) for the period October 1,
12 2005 through June 30, 2007. In addition, the hourly output of each PSE owned gas
13 generation unit was provided in response to Public Counsel Data Request No. 457. With
14 these two sets of data, I was able to evaluate the frequency of SCCT dispatch to serve
15 PSE's Area loads. In other words, I was able to examine not only the number of hours in
16 a year that PSE dispatches (utilizes) its SCCT's, but also examine each hourly SCCT
17 dispatch relative to the PSE Area load requirements.

18 The period October 1, 2005 through June 30, 2007 was separated into two annual
19 periods (October 1, 2005 through September 30, 2006, and July 1, 2006 through June 30,
20 2007) to enable an analysis of two complete winter seasons. PSE-owned, operated, and

[2] Because PSE's electric peak loads are in the winter and Mr. Hoff assumes this SCCT will only operate during the highest load periods of the winter, he further assumes that there will be a premium on the cost of gas for this unit because he assumes that fuel will be purchased during periods when natural gas is also in high demand.

dispatched four separate SCCTs during this study period. A summary of each unit's hours of dispatch during these two annual periods is provided below:

[Begin Confidential]

[redacted]

(End Confidential)

Q: **Please continue with your explanation of the operating characteristics of PSE's SCCT dispatch.**

A: Although PSE utilizes its SCCTs significantly more than the 75 hours assumed by Mr. Hoff **[Begin Confidential]** [redacted] **[End Confidential]**, this by itself tells us nothing of whether these units are used primarily to meet peak period demand. Therefore, I also compared each SCCT's hourly dispatch and its coincidence with the PSE area load. In this manner, I was able to determine the extent to which PSE utilizes its SCCTs for peaking purposes.

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3 **[Begin Confidential]** [redacted] **[End Confidential].**

1 To avoid disagreement as to what levels of load constitutes "peak" periods, I
2 evaluated the dispatch of PSE's SCCT's at various peak period definitions. Mr. Hoff
3 used the highest 75 hours of peak load to develop his coincident peak demand allocators
4 in his CCOSS, and indicated that 75 hours was selected because "[w]hile the data did not
5 suggest a clear cut-off point, the top 75 hours have peaks that were within 90 percent of
6 the system peak."[4]

7 Indeed, there are about 75 hours per year in which the PSE system load is at or
8 above 90 percent of the annual peak load. In addition to this 90 percent of annual peak
9 load standard, I also evaluated SCCT dispatch under more conservative definitions of
10 "peak" demand, including hours at or above 80 percent of annual peak, 70 percent of
11 annual peak, as well as PSE's previous standard of the highest 200 hours of peak load.

12 The detailed results of my analysis of PSE's utilization of its SCCTs is provided
13 in Exhibit No. ___ (GAW-4C).

14 **Q: Mr. Watkins, please explain what is shown in Exhibit No. ___ (GAW-4C) and your**
15 **conclusions based on the data therein.**

16 A: In Exhibit No.___(GAW-4C), I tabulate the number of hours of operation of each PSE
17 SCCT based on my analysis of the data provided by PSE in response to Public Counsel
18 Data Request No. 457. Specifically, this response provided the hourly generation of each
19 of PSE's generating facilities within the period October 1, 2005 through June 30, 2007.

20 In undertaking my analysis of the operations of PSE's SCCTs throughout this
21 period, I evaluated the operations of PSE's Fredonia, Frederickson and Whitehorn
22 generating facilities. These PSE generating facilities are identified in the Company's

[4] Hoff direct testimony at p. 13, ll. 9-11.

2007 Integrated Resource Plan (IRP) as SCCTs. My analysis, therefore, consists of tabulating the hours of operations of these generating facilities to meet Area loads that are within 90 percent, 80 percent, and 70 percent of the system peak load designated in PSE's response to Public Counsel Data Request No. 456.

[Begin Confidential]

[redacted]

[redacted]

[End Confidential]

Q: **How should PSE's actual dispatch of SCCTs during off-peak hours be reflected in the Peak Credit method?**

A: Given PSE's high levels of SCCT dispatch during off-peak periods, I recommend two adjustments to Mr. Hoff's Peak Credit assumptions and calculations. First, an annual utilization of [**Begin Confidential**] [redacted]**[End Confidential]** is clearly more appropriate than the 75 hours assumed by Mr. Hoff. This adjustment, by itself, increases the levelized cost of the SCCT unit relative to the CCCT baseload unit and increases the demand component from 26 percent to 28 percent. The second necessary adjustment is to recognize the magnitude of SCCT utilization during off-peak periods. In this regard, I recommend a 50 percent on-peak and a 50 percent off-peak SCCT utilization.

Q: **Why do you recommend a 50 percent on-peak and a 50 percent off-peak utilization when PSE actually dispatches its SCCTs in a more off-peak manner?**

A: **[Begin Confidential]** [redacted] **[End Confidential]**

Q: **What is the result of your two adjustments to Mr. Hoff's Peak Credit method?**

1 A: These two adjustments result in a classification of 14 percent demand and 86 percent
2 energy. For purposes of my CCOSS analysis, I have used a split of 15 percent demand
3 and 85 percent energy.

4 **Q: Do any other Washington State utilities recognize the off-peak utilization of SCCTs**
5 **in their applicatiou of the Peak Credit method?**

6 A: Yes. In its pending application before this Commission, PacifiCorp assigns 50 percent of
7 SCCT fixed costs to off-peak hours and 50 percent to on-peak hours.[5] This 50/50
8 assignment reduces the ratio of peak to base load costs in the same manner that I
9 recommend in this case.

10 **Q: Have you reviewed the Peak Credit demand/energy classification used by PSE in**
11 **previous cases?**

12 A: Yes.

13 **Q: What are these historical Peak Credit classifications?**

14 A: In response to WUTC Staff Data Request No. 100, PSE provided the allocation
15 (classification) percentages for demand and energy used in each rate case since 1982.
16 During the period 1982 through 1989, PSE made separate demand/energy classifications
17 for Thermal Hydro, and "Other" power supply resources. All power supply resources
18 have been combined since the 1992 case, and the following demand/energy percentages
19

[5] *See WUTC v. PacifiCorp d/b/a/ Pacific Power & Light Company*, Docket No. UE-080220.

have been utilized:

Table 5
Classification Percentages

Docket No.	Energy %	Demand %
UE-921262	87%	13%
UE-011570	84%	16%
UE-040641	86%	14%
UE-060266	80%	20%
UE-072300	74%	26%

As can be seen above, my recommended 85 percent energy and 15 percent demand split is consistent with PSE's classification prior to the 2006 rate case.

Q: **Earlier in your testimony you discussed PSE's use of hypothetical SCCT and CCCT generating units. How were costs developed for the hypothetical generating units?**

A: Mr. Hoff forecasted the future revenue requirements for each of these two units utilizing estimated construction costs, forecasts of natural gas prices, and forecasts of other operating costs.

Q: **Are these forecasted generating unit costs subject to uncertainty?**

A: **[Begin Confidential]** [redacted] **[End Confidential]** Of course, this involves a considerable amount of uncertainty. Furthermore, PSE's choice of which types of plants to use in their Peak Credit method is subject to uncertainty, let alone the estimated construction costs of the particular SCCT and CCCT selected for the hypothetical units. Finally, the future revenue requirement for each hypothetical unit is calculated and levelized to present value. Of critical importance to these calculations are

1 the assumed future costs of gas, costs of capital, and capital structure. For purposes of
2 PSE's analyses, Mr. Hoff has used the Company's proposed capital structure and
3 proposed costs of debt and equity. Each of these parameters represents multiple
4 uncertainties and requires assumptions that may or may not be reasonable.

5 **Q: Did you test the reasonableness of Mr. Hoff's forecasted fuel prices and operating**
6 **expenses incorporated in the calculations of generating unit costs?**

7 A: Yes I did.

8 **Q: Does the use of hypothetical investments, coupled with the uncertainties of future**
9 **assumed cost, cause you concern as to the reasonableness of either PSE's or your**
10 **own Peak Credit results?**

11 A: Yes, they do.

12 **Q: Were you able to test the reasonableness of the assumptions used by Mr. Hoff in his**
13 **Peak Credit analysis?**

14 A: Yes.

15 **Q: Please explain how you tested the reasonableness of Mr. Hoff's Peak Credit input**
16 **assumptions.**

17 A: In response to Public Council Data Request No. 454, I was provided PSE's confidential
18 computer model used to develop Mr. Hoff's proposed 26 percent demand and 74 percent
19 energy classification of electric supply resources. I undertook the calculations of
20 numerous scenarios with alternative future cost assumptions, including various future
21 inflation rates, costs of gas, costs of capital, capacity factors (utilization rates), and plant
22 investment costs. Not surprisingly, I found that the model is most sensitive to the

assigned capital construction costs of the selected plants and the estimation of future gas prices. PSE's model is relatively insensitive to the other model input assumptions.

Q: Did you conduct other analyses to test the reasonableness of your recommended 15 percent demand and 85 percent energy classification of electric supply resources?

A: Yes.

Q: Please discuss these additional analyses.

A: As is true for every cost allocation methodology, the Peak Credit method is subject to conceptual and practical criticism. To test the reasonableness of my recommended 15 percent demand and 85 percent energy classification of PSE's electric supply resources, I also conducted an analysis utilizing actual PSE booked (embedded) costs. Specifically, I evaluated PSE's actual investment in each generating facility and classified each unit as demand-related (peak) or energy-related (base load). I classified PSE's steam plant (Colstrip), hydro, wind, and CCCT generating unit investments as base load energy-related and its other generating units (SCCTs) as peaking units. The details of this analysis are provided on page 1 of Exhibit No. ___ (GAW-5) and produce the following results:

Base Load (Energy) related	94.46%
Peaker (Demand) related	5.54%

Recognizing that there are some peaking capabilities of PSE's hydro units and that its combined cycle (CCCT) units do not operate at 100 percent capacity factors, I also conducted sensitivity analyses whereby I reclassified each hydro unit as 25 percent demand-related and 75 percent energy-related and reclassified each CCCT unit as 15 percent demand-related and 85 percent energy-related. This analysis produced an overall

energy supply classification of 11.9 percent demand and 88.1 percent energy, as shown on page 2 of Exhibit No. ___ (GAW-5).

Based on these analyses, the diurnal and short-term peaking capabilities of certain hydro units, minimum water flow requirements, recognition of the fact that PSE meets a substantial portion of its peak load and energy requirements with purchased power (primarily hydro), and that Pacific Northwest regional wholesale market prices may dictate the dispatch of PSE's generating units at times that would otherwise be deemed inappropriate, I conclude that my adjustment to PSE's proposed 26 percent demand and 74 percent energy classification is conservatively reasonable such that a 15 percent demand and 85 percent energy is an appropriate classification of electric supply resources for CCOSS purposes.

Q: What are your CCOSS results after your adjustment to PSE's electric supply resource classification using your recommended 15 percent demand-related and 85 percent energy-related classification?

A: Building upon my earlier adjustments, the following class rates of return result from

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classifying electric supply resources as 15 percent demand and 85 percent energy:

Table 6
Electric CCOSS (at Current Rates)
Incorporating Income Taxes, Other Taxes and Fees,
and Power Supply Cost Adjustments

Class	ROR	Indexed ROR
Residential	4.67%	88%
Secondary Sch. 24	5.23%	98%
Secondary Sch. 25	8.11%	153%
Secondary Sch. 26	6.92%	130%
Primary Sch. 31/35/43	5.04%	95%
Campus Sch. 40	3.49%	66%
High Voltage Sch 46/49	2.62%	49%
Transportation Sch. 44	6.23%	117%
Lighting	7.08%	133%
Firm Resale	4.33%	82%
Total Electric	5.31%	100%

Q: Please explain your remaining adjustments to Mr. Hoff's CCOSS.

A: My last two adjustments to Mr. Hoff's electric CCOSS relate to: (1) the allocation of Salaries and Wages, which are then used to allocate certain rate base and expense accounts; and (2) the allocation of General Plant.

With regards to Salaries and Wages, Mr. Hoff grouped all labor costs into seven major categories and separately allocated each of these major categories.[6] In contrast, I have allocated Salaries and Wages associated with each individual FERC account based on the analysis of labor expenses by individual FERC account that was conducted by PSE witness, John Story and provided in his filed workpapers. As may be expected, this more detailed analysis did not produce significantly different results than those obtained by the

[6] Mr. Hoff's salaries and wages categories are: Production, Transmission, Distribution, Customer Accounts, Customer Service, and Information, General, and Sales.

more generic grouping of labor costs done by Mr. Hoff. The class rates of return obtained after a more specific allocation of Salaries and Wages (and building upon by previous CCOSS adjustments) is as follows:

Table 7
Electric CCOSS (at Current Rates)
Incorporating All Table 6 and Salaries & Wages Adjustments

Class	ROR	Indexed ROR
Residential	4.70%	88%
Secondary Sch. 24	5.24%	99%
Secondary Sch. 25	8.11%	153%
Secondary Sch. 26	6.90%	130%
Primary Sch. 31/35/43	4.86%	91%
Campus Sch. 40	3.42%	64%
High Voltage Sch 46/49	2.55%	48%
Transportation Sch. 44	6.11%	115%
Lighting	6.70%	126%
Firm Resale	4.22%	79%
Total Electric	5.31%	100%

Q: Mr. Watkins, please explain your final CCOSS adjustment which relates to the allocation of General plant.

A: Mr. Hoff allocated almost all of the Company's $282 million investment in General Plant based on Salaries and Wages.[7] Although I cannot say that Mr. Hoff's rationale and method to allocate General Plant is necessarily unreasonable since this approach is sometimes used in the industry, a more common, and in my opinion preferred, approach is to allocate General Plant based on the investment this "general" plant supports namely: Production, Transmission, and Distribution plant (PTD). As such, I have allocated all General Plant based on the composite investment in PTD plant.

[7] The exception is that Mr. Hoff allocated $1.076 million of General Plant associated with "Stores" equipment based on Production, Transmission, and Distribution Plant.

This adjustment, in conjunction with my earlier adjustment, produces my final recommended class rates of return at current rates and are summarized below:

Table 8
Electric CCOSS (at Current Rates)
Incorporating All Public Counsel Adjustments

Class	ROR	Indexed ROR
Residential	4.74%	89%
Secondary Sch. 24	5.30%	100%
Secondary Sch. 25	7.94%	149%
Secondary Sch. 26	6.71%	126%
Primary Sch. 31/35/43	4.83%	91%
Campus Sch. 40	3.34%	63%
High Voltage Sch 46/49	2.44%	46%
Transportation Sch. 44	5.83%	110%
Lighting	7.46%	140%
Firm Resale	4.06%	76%
Total Electric	5.31%	100%

The detailed output of my recommended CCOSS is provided in Exhibit No. ___ (GAW-6).

Q: Please provide a comparison of your CCOSS results to those obtained by PSE witness Hoff.

A: The following is a comparison of my recommended electric CCOSS rates of return at current rates:

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Table 9
Electric CCOSS (at Current Rates)
Comparison of Results

	ROR @ Current Rates	
Class	Public Counsel (Watkins)	PSE (Hoff)
Residential	4.74%	2.87%
Secondary Sch. 24	5.30%	5.77%
Secondary Sch. 25	7.94%	12.62%
Secondary Sch. 26	6.71%	11.33%
Primary Sch. 31/35/43	4.83%	6.96%
Campus Sch. 40	3.34%	5.73%
High Voltage Sch 46/49	2.44%	4.11%
Transportation Sch. 44	5.83%	6.06%
Lighting	7.46%	8.69%
Firm Resale	4.06%	2.34%
Total Electric	5.31%	5.31%

B. ELECTRIC CLASS REVENUE DISTRIBUTION

Q: How did Mr. Hoff determine his proposed distribution of the Company's requested electric revenue increase to individual classes?

A: Mr. Hoff sponsors PSE's proposed class distribution of the Company requested electric revenue increase of $174.8 million. Mr. Hoff states that his proposed revenue distribution to customer classes is influenced by two "rate spread policy factors": (1) the results of his cost of service study and relationships to system parity of the customer classes; and, (2) the impact on different classes of customers of the proposed revenue spread. Mr. Hoff goes on to describe his proposed rate spread as follows:

> Based upon the parity ratios shown in the Company's cost of service study and the desire to move towards parity in a gradual manner, the Company proposes to apply the average rate increase to retail classes within 5% of parity, apply a rate increase that is 125% of the average to the rate class

that is below 95% of parity (residential class), apply a rate increase that is 75% of the average to the one class that is more than 5%, but less than 10%, above parity (Lighting), and apply an increase that is 50% of the average to the two classes that are over 10% above parity (Medium Secondary Voltage and Large Secondary Voltage). As discussed below, rates in Schedule 40 (Large Demand General Service Greater than 3 aMW) are tied to rates in the high voltage schedules such that the rate increases for that schedule are not independently determined. The wholesale for resale is moved to full parity so that there is not a cross-jurisdictional subsidy.[8]

A summary of PSE's proposed revenue increase to the CCOSS customer rate classes is shown below:

Table 10
PSE-Proposed Electric Revenue Increase[9]

Class	Amount	Percent Increase
Residential (Schedule 7)	$115,972,986	11.78%
Secondary Voltage		
Schedule 24	21,259,081	9.43%
Schedules 25/29	12,298,629	4.71%
Schedule 26	7,498,336	4.71%
Primary Voltage		
Schedules 31/35	9,378,361	9.43%
Schedule 43	1,211,431	9.43%
Campus Rate (Schedule 40)	1,947,000	5.00%
High Voltage (Schedules 46/49)	3,007,097	9.43%
Schedules 449/459	817,118	9.43%
Lighting (Schedules 50-59)	1,092,472	7.07%
Firm Resale (Schedule 5)	336,605	29.47%
Total Company	$174,819,117	9.51%

Q: Are PSE's proposed customer class revenue increases reasonable for its electric operations?

[8] Hoff direct testimony at p. 19, l. 16 through p. 20, l. 7.
[9] Exhibit No. ___ (DWH-5), page 1.

A: No, they are not.

Q: Mr. Watkins, do you have an alternative electric revenue increase Distribution to that proposed by PSE?

A: Yes. Based on the results of my CCOSS presented in Exhibit No. ___ (GAW-6) as well as a recognition of gradualism and the general interest in moving customer class rates of return toward the system rate of return, I propose the following electric revenue increase Distribution at PSE's requested level:

Table 11
Public Counsel Proposed Revenue Increase

Class	Amount	Percent Increase
Residential (Schedule 7)	$101,002,871	10.26%
Secondary Voltage		
Schedule 24	21,444,363	9.51%
Schedules 25/29	18,602,204	7.13%
Schedule 26	12,852,702	8.08%
Primary Voltage		
Schedules 31/35	9,460,097	9.51%
Schedule 43	1,221,989	9.51%
Campus Rate (Schedule 40)	4,264,090	10.94%
High Voltage (Schedules 46/49)	3,792,429	11.89%
Schedules 449/459	824,240	9.51%
Lighting (Schedules 50-59)	1,101,607	7.13%
Firm Resale (Schedule 5)	252,526	22.11%
Total Company	$174,819,117	9.51%

In formulating my proposed electric revenue increase distribution to the various customer rate classes, I started with the results of my CCOSS, which are presented in Exhibit No. ___ (GAW-6). With the results of my CCOSS as a guide, I proceeded in a similar manner as Mr. Hoff. That is, I formulated increases consistent with the CCOSS

results as follows:

(1) I accepted PSE's proposal to bring Firm Resale (Schedule 5) to parity, an increase of $252,566;

(2) I increased Secondary Voltage Schedules 24, 31, 35, 43, and Transportation Schedules 449/459 at the system average increase because these customer rate classes have RORs close to the system average ROR at current rates; i.e., these classes were increased at 100% of the system average percentage increase;

(3) I increased Secondary Voltage Schedules 25/29 and Lighting Schedules 50-59 at 75% of the system average increase since each is considerably above parity;

(4) I increased Secondary Voltage Schedule 26 at 85% of the system average increase since it is also above parity, but somewhat less so than Schedules 25/29 and 50-59;

(5) I increased Campus Schedule 40 at 115% of the system average increase since it is somewhat below parity;

(6) I increased High Voltage Schedules 46/49 at 125% of the system average increase since this class was considerably below parity; and,

(7) Finally, I treated the residential customer class (Schedule 7) as the residual to "pick-up" the remainder of the revenue increase not assigned to the other customer rate classes.

My approach to the distribution of the $174.8 million overall revenue increase proposed by PSE produces an increase of 108 percent of the system average increase to the residential customer rate class. This relative increase (108% of system average) to the residential class is appropriate and reasonable since this class is currently earning slightly less than the system average rate of return (Indexed ROR of 89%).

Q: Does your proposed revenue Distribution move all classes towards rate of return parity?

A: Yes, it does. As shown below, and calculated on page 1 of Exhibit No. ___ (GAW-7), my proposed class electric revenue assignment moves all classes closer to rate of return parity:

Table 12
Indexed Rate of Return
Public Counsel CCOSS Results

Class	At Current Rates	At Public Counsel Proposed Rates
Residential (Schedule 7)	89%	93%
Secondary Voltage:		
Schedule 24	100%	100%
Schedules 25/29	149%	126%
Schedule 26	126%	118%
Primary Voltage:		
Schedules 31/35/43	91%	97%
Campus Rate (Schedule 40)	63%	91%
High Voltage (Schedules 46/49)	46%	86%
Transportation (Schedules 449/459)	110%	87%
Lighting (Schedules 50-59)	140%	117%
Firm Resale (Schedule 5)	76%	100%
Total Company	100%	100%

Q: Mr. Watkins, please provide your recommended scale back method to assign class electric revenue increases should the Commission authorize an overall revenue requirement increase less than that proposed by PSE.

A: I recommend that my customer class revenue increase distribution be scaled back in equal portions (i.e., equal percentages) should the Commission authorize an overall electric revenue increase different than that requested by PSE.

C. ELECTRIC RESIDENTIAL RATE DESIGN

1. Residential Rate Design Concepts

1 **Q: Mr. Watkins, have you identified a common objective in PSE's electric and gas**
2 **residential rate design proposals?**
3 A: Yes. It is clear from the testimony of witnesses, David W. Hoff and Janet K. Phelps, that
4 the primary objectives of PSE's gas and electric residential rate design proposals are to
5 increase revenue collection associated with fixed monthly customer charges with less
6 revenue reliance on volumetric charges.
7 **Q: Is there a fundamental reason why PSE desires more residential revenue**
8 **recognition from customer charges with less relative contributions from volumetric**
9 **charges?**
10 A: Yes. Fixed monthly customer charges represent guaranteed revenue to PSE. This
11 guarantee of revenue obviously reduces the risk of PSE's operations and provides more
12 assurances of net income available to shareholders.
13 **Q: What support do Mr. Hoff and Ms. Phelps offer to justify their proposed increased**
14 **reliance on fixed customer charge revenue?**
15 A: The underlying support provided by both Mr. Hoff and Ms. Phelps is the improper notion
16 that because many of PSE's costs are of a fixed nature, a large percentage of revenue
17 collection should also be fixed in nature.
18 **Q: Does PSE's proposal to increase revenue collection from fixed monthly charges**
19 **comport with the economic theory of competitive markets or the actual practices of**
20 **such competitive markets?**
21 A: No. The most basic tenant of competition is that prices ensure the most efficient
22 allocation of society's resources. Because public utilities are generally afforded
23 monopoly status under the belief that resources are better utilized without the duplication

1 of the fixed facilities required to serve consumers, a fundamental goal of regulatory
2 policy is that regulation should serve as a surrogate for competition to the greatest extent
3 practical. As such, the pricing policy for a regulated public utility should mirror those of
4 competitive firms to the greatest extent practical.

5 **Q: Please briefly discuss how prices are generally structured in competitive markets.**

6 A: Economic theory tells us that efficient price signals result when prices are equal to long-
7 run marginal costs. It is well known that, in the long-run, all costs are variable and
8 hence, efficient pricing results from the incremental variability of costs even though a
9 firm's short-run cost structure may include a high level of sunk or "fixed" costs. Indeed,
10 competitive market-based prices are generally structured based on usage, i.e. variable,
11 pricing.

12 **Q: Please explain how this theory and application of competitive pricing should be**
13 **transferred to that of a regulated public utility, such as PSE.**

14 A: Due to PSE's investment in system infrastructure, there is no debate that many of PSE's
15 short-run costs are fixed in nature. As discussed above, efficient competitive prices are
16 established based on long-run costs, which are entirely variable in nature.

17 However, marginal cost pricing only relates to efficiency. This pricing does not
18 attempt to always address fairness or equity. From a perspective of fair and equitable
19 pricing of a regulated monopoly's products and services, it is generally agreed that
20 payments for a good or service should be in accordance with the benefits received. Those
21 who receive more benefits should pay more in total than those who receive fewer
22 benefits. With respect to electric or natural gas usage, the volume of consumption is the

most direct, and perhaps best, indicator of benefits received, such that volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy is, and has been, the belief of economists, regulators, and the marketplace for many years. As an illustration, consider utility industry pricing in its infancy (1800s). In the beginning, customers paid a fixed monthly fee and consumed as much of the utility service/commodity as they desired (usually water). It soon became apparent that the fixed monthly fee rate schedule was inefficient and unfair. Utilities soon began metering their commodity and charging only for the amount actually consumed. In this way, consumers receiving more benefits from the utility than others paid more in total for the utility service because they used more of the commodity.

Furthermore, virtually every capital intensive industry is faced with a high percentage of fixed costs in the short-run. This includes the manufacturing and transportation industries. Prices for competitive products and services in these industries are invariably established on a volumetric basis, including those that were once regulated; e.g., airline travel and rail service.

Accordingly, Mr. Hoff and Ms. Phelps's positions, that most of PSE's fixed costs should be recovered through fixed monthly charges, in my view is incorrect since pricing should reflect long-run cost incidence wherein all costs are variable or volumetric in nature, and that users requiring more of PSE's products and services pay more than customers who use less of these products and services.

Q: Why do customer charges exist at all for public utilities?

A: The conventional wisdom in public utility pricing is that some revenues should be collected from fixed monthly charges. Although revenue stability clearly results from

1 such pricing mechanisms, this stability in and of itself simply reduces the risk to
2 shareholders at the expense of efficient price signals. From a practical standpoint, rates
3 charged by public utilities are usually separated into a few classes. Within these classes,
4 there are some customers who consume relatively small amounts of electricity or natural
5 gas, and others that require much greater quantities of the public utility's commodity or
6 service. Due to the incremental costs of connecting and maintaining a customer's
7 account, the general practice is to charge a fixed monthly fee, such that small usage
8 customers within a class provide revenue contributions to the utility to compensate for
9 the cost of connecting and maintaining the customer's account, as well as contribute
10 revenue based on the amount of electricity or natural gas actually used.

11 **Q: Do PSE's tariffs contain other provisions to recognize the costs to connect new**
12 **customers?**

13 A: Yes. PSE's electric and gas tariffs each contain line extension and new customer hook-
14 up fee schedules.[10]

15 **Q: How are PSE's line extension and new customer fees structured?**

16 A: For both electric and natural gas service, new customers are generally charged a
17 connection fee based on their expected level of consumption. That is, customers that are
18 expected to use less electricity or natural gas must pay a higher connection fee than
19 customers with expected higher levels of usage. This pricing mechanism eliminates
20 PSE's claim that customer charges should include the capital costs associated with
21 connecting a new customer. I will discuss PSE's specific electric and gas connection fees
22 later in my testimony with my explanation of residential "customer" costs and customer

[10] See Schedule 85 for PSE's electric tariff and Schedules 7 and Rule 7 for PSE's natural gas tariff.

1 charges for each type of new service. The purpose of this discussion is to bring to the
2 Commission's attention the fact that the claimed desire for higher customer charges due
3 to differences in intraclass consumption is largely already reflected in the upfront fees
4 that small volume residential customers pay in recognition of their expected lower
5 consumption. Therefore, higher monthly customer charges coupled with upfront
6 connection fees represent a clear, double counting of costs to connect such customers.

7 **2. Electric Residential Rate Design**

8 **Q: Please describe PSE's current and proposed residential electric rate structure.**

9 A: PSE's current residential electric rate structure consists of a fixed monthly customer
10 charge ($6.02) and an inverted, two-block energy rate. Mr. Hoff proposes to increase the
11 monthly customer charge by approximately 50 percent, from its current level of $6.02 to
12 a proposed rate of $9.00 per month. Base rate residential energy charges are proposed to
13 increase from 7.4314¢/kwh to 8.5225¢/kwh (14.7%) for the first 600 kwh of monthly
14 usage and from 9.2122¢/kwh to 10.3033¢/kwh (11.8%) for all additional energy
15 consumption.

16 **Q: Earlier you discussed the Company's objective to collect a higher proportion of**
17 **residential revenue from fixed monthly customer charges. Did Mr. Hoff conduct**
18 **any analysis of what he considered to be customer costs?**

19 A: Yes.

20 **Q: Do you agree with Mr. Hoff's customer cost analysis?**

21 A: No.

22 **Q: Please explain why you do not agree with Mr. Hoff's customer cost analysis.**

1 A: On page 15 of Exhibit No.___ (DWH-4C), Mr. Hoff presents a summary of the results of
2 his customer cost analysis. A closer examination of Mr. Hoff's customer cost analysis
3 reveals that he included provisions for various capital costs, including return and
4 depreciation, and operating and maintenance expenses. However, Mr. Hoff's analysis
5 inappropriately includes many costs that should not be deemed customer-related for
6 purposes of evaluating the reasonableness of residential customer charges.
7 **Q: Please identify those capital costs that Mr. Hoff included in his customer cost**
8 **analysis.**
9 A: Mr. Hoff's analysis includes the allocated residential gross plant investments in Meters
10 ($73.7 million), Services ($168.2 million), Distribution Line Transformers ($250.5
11 million), and an allocated portion of General plant ($56.9 million).
12 **Q: Are these rate base, or capital items, appropriately included in a customer cost**
13 **analysis?**
14 A: No. Investments in Meters and Services are often included in traditional customer cost
15 analyses. However, as mentioned earlier and as will be discussed in more detail later,
16 PSE's customer connection fees already contain a provision for service line investments.
17 Mr. Hoff's inclusion of Line Transformer costs is at odds with virtually every
18 accepted industry standard and practice. During my twenty-eight year career and practice
19 in the area of public utility ratemaking, I have never seen a customer cost analysis that
20 includes line transformers. Indeed, virtually every manual and text on the subject of
21 electric cost of service properly considers line transformers as demand-related. Mr.
22 Hoff's rationale for inclusion of transformers in this case is solely due to the fact that
23 every distribution customer is connected to a transformer and that, once installed,

transformers represent a fixed cost of providing service to the customer or group of customers connected to the transformer. Although such logic is meaningless since this notion could be extended to all distribution lines, substation equipment, and even transmission lines, the fundamental reason that transformers should not be considered customer-related is because they are sized and installed based on peak load requirements. Transformers are installed to reduce distribution voltage and are limited in capacity based on the maximum load going through each transformer. If customers were simply connected to a distribution system with no loads, there would not be a need for transformers.

Finally, Mr. Hoff has included $56.9 million in General plant in his customer cost analysis. This General plant represents the Company's investment in corporate overhead required to provide electricity sales to customers. This General overhead is needed to support PSE's electric operations which is that of selling electricity. In fact, the level of General plant included Mr. Hoff's residential customer costs includes the following gross plant amounts:

Table 13
PSE General Plant Investment
($ Millions)

Land and Land Rights	$1.6
Structure & Improvements	$23.7
Office Furniture	$14.7
Transportation Equipment	$0.6
Stores Equipment	$0.1
Tools, Shop and Garage Equipment	$0.7
Laboratory Equipment	$1.5
Power Equipment	$0.1
Communications Equipment	$13.9
Miscellaneous Equipment	$0.1

1 As can be seen above, the vast majority of the General plant Mr. Hoff assigns to
2 "customers" relates to corporate office buildings, furniture, and communications
3 equipment. Because General plant represents the overhead investment required to
4 conduct its public service obligations of selling electricity, such costs should not be
5 considered in a customer cost analysis for purposes of justifying fixed customer charges.

6 **Q: What Operations and Maintenance (O&M) expenses did Mr. Hoff include in his**
7 **customer cost analysis?**

8 A: Mr. Hoff's residential customer costs analysis includes allocations for Distribution
9 Supervision and Engineering ($0.3 million), Meters Operations Expenses ($0.9 million),
10 Customer Installation expenses ($1.7 million), Line Transformers Maintenance expenses
11 ($0.2 million), Meters Maintenance expenses ($0.1 million), Customer Accounting
12 Supervision ($0.1 million), Meter Reading ($11.5 million), Customer Records &
13 Collections expenses ($13.7 million), and a provision for Administrative and General
14 expenses ($11.9 million).

15 **Q: Are each of these O&M expenses properly included in a customer cost analysis?**

16 A: No. As can be observed from their descriptions, many of the O&M costs included by Mr.
17 Hoff represent costs that are more appropriately considered demand-related (e.g.,
18 transformer expenses) or are general overhead expenses required in order to sell
19 electricity. Meter Reading and Customer Records & Collections expenses are properly
20 included in Mr. Hoff's customer cost analysis.

21 **Q. What is your overall assessment of Mr. Hoff's residential customer costs analysis?**

22 A. Mr. Hoff's residential customer cost analysis greatly overstates those costs that should be
23 considered in establishing a reasonable fixed monthly customer charge. Because PSE is

in the business of selling electricity and not in the business of simply connecting customers, only those costs that can be directly attributed to connecting and servicing a customer's account should be included in such analysis.

Q: Please explain PSE's electric line extensions policy for residential customers.

A: Electric Tariff G, Schedule 85 contains PSE's policy regarding line extensions and connection fees for new customers. In general, customers are charged a connection fee based on the following formula:

+ Primary Voltage Lines Extension Costs
+ Secondary Voltage Lines Extension Costs
+ Exceptional Transmission & Substation Costs
- Margin Allowance
= Line Extension Cost
+ Service Line Costs
= Total Cost to Customer

These line extension costs include, at a minimum, the estimated cost to install conductors (excluding service lines) and transformers. It should be noted that the margin allowance does not include service lines meaning that customers are responsible for the costs of installing service lines to their meters. Customers are charged a non-refundable connection charge for all service line costs, as well as the line extension costs above the prescribed margin allowance. Estimated construction costs differ for underground and overhead service while the margin allowance is constant for both underground and overhead customer service.

Q: How do these new customer connection fees relate to customer charges?

A: As discussed earlier, Mr. Hoff has included the Company's allocated investment in Services and Line Transformers in his customer cost analysis. Although the Company's Schedule 85 margin allowance may be sufficient to cover the costs associated with

1 installing new transformers (or connecting to existing facilities), all new customers are
2 charged the costs of labor and materials to install a service line. As such, a higher
3 customer charge as proposed by Mr. Hoff represents a double cost to new customers.

4 **Q: Have you conducted an electric residential customer direct cost analysis applicable**
5 **to PSE?**

6 A: Yes. I have conducted a direct customer cost analysis which is provided in Exhibit
7 No. ___ (GAW-8) and results in a monthly customer cost of $3.30 at a 10.80 percent
8 return on equity and $3.25 at a 9.25 percent return on equity. It should be noted that my
9 direct customer analysis does not include Services investment for the reasons noted
10 earlier in my testimony.

11 **Q: Mr. Watkins, have you assessed the policy implications of Mr. Hoff's proposal to**
12 **increase the monthly customer charge?**

13 A: No. Public Counsel witness, Barbara Alexander, discusses various policy implications of
14 increasing PSE's monthly residential customer basic charge in her direct testimony.

15 **Q: Do you have any objections to the structures of PSE's residential rates?**

16 A: No, I do not have any objections to the general structure of PSE's residential rates. In
17 fact, PSE's inverted block rate structure sends efficient and proper pricing signals,
18 particularly during periods of peak demand.

19 **Q: What is your recommendation as to residential monthly customer charges for PSE**
20 **in this case?**

21 A: Given the results of my residential monthly direct customer cost studies indicating a
22 monthly customer cost range from $3.25 to $3.30, and in consideration of rate continuity,
23 I recommend that the current monthly customer charge of $6.02 be maintained.

1 Furthermore, I recommend the $6.02 residential monthly customer charge remain at the
2 current level regardless of the overall level in revenue requirement that may be
3 authorized by the Commission in this case.

4 **Q: What is your recommendation for the usage element of residential rates?**

5 A: As I stated earlier, I am not recommending any changes to the Company's energy usage
6 blocks; i.e., the first block is 600 kwh and the second block for all additional kwh. I do
7 recommend, however, that the ratio of the specific charges for these two blocks be
8 maintained, since the Company has not provided any evidence in support of changing this
9 ratio.

10 As such, any increase in residential revenue authorized by the Commission should
11 be reflected in energy charges, and these energy charges should be increased by an equal
12 percentage.

13 **III. NATURAL GAS OPERATIONS**

14 **A. NATURAL GAS CLASS COST OF SERVICE**

15 **Q: Mr. Watkins did PSE employ the same general procedures to conduct its natural**
16 **gas CCOSS as used for its electric study?**

17 A: Yes. PSE used the same general computer model to conduct its gas CCOSS as it did for
18 its electric CCOSS. PSE's natural gas CCOSS was conducted and sponsored by PSE
19 witness Janet Phelps.

20 **Q: Were you able to replicate Ms. Phelps's CCOSS results using your own**
21 **computerized model?**

22 A: Yes.

23 **Q: Did you find Ms. Phelps's CCOSS study to be mathematically accurate?**

1 A: Yes. However, I did discover what appears to be a slight oversight in Ms. Phelps's
2 calculation of class rates of return at present rates.
3 **Q: Please explain this slight oversight.**
4 A: Ms. Phelps's Exhibit No. ___ (JKP-5), page 1, presents a summary of PSE's gas CCOSS
5 excluding gas costs with Line 15 showing the resulting class rates of return at current
6 rates. In calculating these class rates of return, Ms. Phelps included certain revenue-
7 related expenses at proposed, not current, rates and conducted her allocations based on
8 these proforma expenses at PSE proposed rate levels.[11] In an attempt to correct for these
9 presumed oversights, Ms. Phelps then subtracted the expenses at proposed rate levels
10 after all allocations had been made; i.e., she backed the proposed expense levels out for
11 summary presentation purposes but not for allocating costs to individual classes.
12 Because Ms. Phelps's CCOSS includes numerous "internal" or composite allocators
13 based on previous account allocations, including those erroneous expense levels at
14 proposed rates, certain specific rate base and expense items are incorrectly allocated to
15 classes because the allocators for the accounts include a provision for expenses at
16 proposed rate levels.
17 **Q: Have you corrected for this apparent oversight?**
18 A: Yes. ~~A replication of Ms. Phelps's CCOSS, corrected to exclude those revenue~~
19 ~~dependent expenses at proposed rate levels, and is provided above:~~ This minor correction
20 results in an immaterial difference as shown below:
21

[11] These expenses, at proposed rate levels, reflect the additional amounts resulting from the Company's proposed revenue increase and include the incremental increases to: Federal Income Taxes ($19,012,582); "Other" Taxes ($2,181,139); WUTC Fees ($113,542); and, Uncollectibles ($154,417).

~~**Table 14**~~
~~**Gas CCOSS (at Current Rates) Incorporating Expense Oversight Adjustments**~~

~~Class~~	~~PSE CCOSS As Filed~~	~~PSE CCOSS Corrected For Expense Oversights~~
~~Residential (16, 23, 53)~~	~~6.18%~~	~~6.23%~~
~~Commercial & Industrial (31, 61)~~	~~4.08%~~	~~3.55%~~
~~Large Vol. (41)~~	~~15.96%~~	~~18.74%~~
~~Interruptible (85)~~	~~19.77%~~	~~23.61%~~
~~Limited Interruptible (86)~~	~~21.97%~~	~~26.42%~~
~~Non-Exclusive Interruptible (87)~~	~~4.97%~~	~~4.69%~~
~~Transport and Contracts~~	~~10.24%~~	~~11.42%~~
~~CNG~~	~~-14.23%~~	~~-19.86%~~
~~Rentals~~	~~-9.92%~~	~~-14.35%~~
~~Total Company~~	~~5.98%~~	~~5.98%~~

Table 14
Gas CCOSS (at Current Rates) Incorporating Expense Oversight Adjustments

	Operating Income		Rate Base	
Class	PSE As Filed	Corrected For Expenses	PSE As Filed	Corrected For Expenses
Residential (16, 23, 53)	$56,171,759	$56,171,790	$909,282,355	$909,282,284
Commercial & Industrial (31, 61)	12,724,166	12,726,426	311,614,874	311,609,632
Large Vol. (41)	6,374,954	6,374,278	39,932,031	39,933,599
Interruptible (85)	3,096,603	3,096,217	15,663,138	15,664,036
Limited Interruptible (86)	1,798,694	1,798,520	8,187,623	8,188,026
Non-Exclusive Interruptible (87)	1,429,584	1,429,108	28,757,555	28,758,660
Transport and Contracts	1,385,521	1,385,237	13,533,683	13,534,340
CNG	<62,500>	<62,512>	439,245	439,274
Rentals	<2,180,152>	<2,180,434>	21,984,537	21,985,190
Total Company	$80,738,630	$80,738,630	$1,349,395,041	$1,349,395,041

Q: ~~**Did Ms. Phelps also inappropriately allocate class income taxes at current rates based on rate base (investment) rather than calculate income taxes for each class?**~~ **Did Ms. Phelps allocate class income taxes at current rates in the same manner as Mr. Hoff did for PSE's Electric Operations?**

A: ~~Yes.~~ No. Whereas Mr. Hoff allocated income taxes based on total rate base. Ms. Phelps utilized a different approach to allocate income taxes at current rates. Ms. Phelps

allocated individual class income taxes based on each class' proportional relationship of revenues minus operating expenses (including depreciation) to total Company (gas) revenues minus operating expenses. While Ms. Phelps' method of allocating income taxes based on revenue minus operating expenses is far superior to Mr. Hoff's method, she did not reflect or consider a major income tax depreciation: interest expense. I have calculated each class's income tax responsibility consistent with the method used in my electric CCOSS.

Q: Please provide a summary of class rates of return after correcting for Ms. Phelps's improper allocation of income taxes at current rates.

A: Building upon my previous adjustment (to correct for expense levels at proposed rates) the following results are obtained:

Table 15
Gas CCOSS (at Current Rates)
Incorporating Expense Oversight
and Income Taxes Adjustments

Class	ROR
Residential (16, 23, 53)	6.13%
Commercial & Industrial (31, 61)	4.59%
Large Volume (41)	13.31%
Interruptible (85)	16.10%
Limited Interruptible (86)	17.71%
Non-Exclusive Interruptible (87)	5.24%
Transport and Contracts	9.10%
CNG	-8.85%
Rentals	-5.68%
Total Company	5.98%

1. Separate Allocation of Mains to Large Customers

1 **Q: What methodology does Ms. Phelps use to allocate distribution Mains to the various**
2 **customer classes?**
3 A: Ms. Phelps has employed two separate allocation methods to assign Mains cost
4 responsibility to the various customer classes. Under Ms. Phelps's approach, distribution
5 Mains investment is first allocated to the firm portion of PSE's largest customers taking
6 service under Rate Schedules 85, 87, 57 and Special Contracts, using one methodology,
7 while all other customers are then assigned cost responsibility for Mains based on the
8 Peak and Average method.
9 **Q: Mr. Watkins, on pages 31 through 33 of her direct testimony, Ms. Phelps refers to a**
10 **direct assignment of Mains plant to the largest customers who are served on**
11 **Schedules 85, 87, 57, and Special Contracts. Is Ms. Phelps's reference to this "direct**
12 **assignment" of Mains to PSE's largest customers the same as your reference to the**
13 **separate allocation method used for certain Rate Schedules 85, 87, 57, and Special**
14 **Contract customers?**
15 A: Yes. However, it should be clearly understood that the cost responsibility assigned to
16 these largest customers is anything but a direct assignment of Mains plant. Rather the
17 cost responsibility assigned to these customers is the result of a separate "special"
18 allocation procedure. Indeed, and as I will explain later in my testimony, this special
19 allocation for PSE's largest customers involves a much higher degree of uncertainty,
20 assumptions, and allocations than does the Peak and Average approach used to allocate
21 Mains costs to all other PSE customers.
22 **Q: Notwithstanding Ms. Phelps's characterization of a direct assignment of Mains**
23 **plant to PSE's largest customers, do you have any concerns or criticisms of the**

1 **overall approach Ms. Phelps used to allocate PSE's investment in distribution**
2 **Mains to all customer classes?**
3 A: Yes. I have three areas of concern and criticism regarding the Company's allocation of
4 distribution Mains. These are: (1) the special treatment (allocation) of PSE's largest
5 customers; (2) the use of minimum monthly usages for interruptible customers in
6 assigning the "average" portion of the Peak and Average allocation of Mains; and, (3) the
7 Company's biased and inaccurate allocation of peak day load to individual classes based
8 on an adjusted design day demand.
9 **Q: Please outline the basic approach used by Ms. Phelps to conduct her special**
10 **allocation of Mains to PSE's largest customers.**
11 A: Ms. Phelps has utilized a modified version of a natural gas computer model developed for
12 engineering analyses, known as "SynerGEE." The general concept behind PSE's special
13 allocation is that gas flowing from the City Gate to each large customer's meter is traced
14 given assumed load levels throughout the entire PSE distribution system. Each large
15 customer's load is estimated over the modeled path (from the City Gate to the customer's
16 meter) such that the customer in question is allocated costs in proportion to its estimated
17 load relative to the total load in each of the segments of the modeled path. To estimate
18 the customer's load contribution on various pipe segments, SynerGEE allows for the
19 segmentation of PSE's Distribution system. The basic concept of this system
20 segmentation can be seen schematically in my Exhibit No.___ (GAW-9) which is a
21 reproduction of a schematic provided by PSE in response to Public Counsel Data Request
22 No. 625. Using "Customer 6" as an example, various pipe segments are established from
23 this customer's meter to the PSE City Gate.

1 **Q: What concerns and criticisms do you have regarding this special allocation of**
2 **Distribution Mains for PSE's largest customers?**
3 A: I have three areas of concern regarding this approach being used for ratemaking purposes.
4 My first two concerns are conceptual in nature, while my third involves the practical
5 accuracy of this approach.
6 The first conceptual concern I have regarding PSE's special allocation method is
7 that as a matter of regulatory ratemaking policy, all analyses should be reasonably
8 transparent so that all assumptions, mechanics, and procedures can be explained and
9 verified. Such is not the case with this special allocation method. Indeed, this procedure
10 produces a black box output such that the Company has conducted analyses that require a
11 myriad of input assumptions and calculations that cannot be verified. I will discuss some
12 of these assumptions later under my third practical concern over this allocation approach.
13 My second concern is by far the most important from a ratemaking policy
14 perspective and that is the need and/or desire to afford special discriminatory treatment to
15 one group of customers at the expense of other customers absent any compelling reason
16 to do so.
17 PSE's special allocations to its large customers "skeletonizes" the PSE
18 Distribution system such that costs are assigned to a particular customer based on that
19 customer's physical geographic location relative to the PSE system as a whole. In other
20 words, the closer a customer happens to be to the City Gate, the fewer costs are assigned
21 to this customer because this customer is only assigned costs based on the pipes upstream
22 from its physical location. The classic analogy to this skeletonization approach is a
23 private lane through a neighborhood, with a homeowner closer to the public road arguing

1 that he or she should only be responsible for costs from the public road to his or her
2 driveway and that homeowners further down the private lane should bear more cost
3 responsibility for maintenance and upkeep of this private lane.

4 There are two fatal flaws with this reasoning as applied to public utility
5 ratemaking. The first is that under such thinking the customer must assume that the
6 distribution system was built and sited to specifically accommodate this one customer.
7 That is, the physical pipe locations were installed to connect this one customer to the City
8 Gate (source of supply). For example, consider Customers 4 and 6 in Exhibit
9 No. ___ GAW-9). Under this approach, Customer 6 would be allocated fewer costs than
10 Customer 4 (assuming they were the same size) simply because of the physical
11 configuration of PSE's routing of Distribution Mains. If PSE rerouted any upstream
12 Mains pipes, this customer's responsibility for costs could change dramatically.

13 The second fatal flaw with a skeletonization approach is that these customers
14 receive all of the benefits of PSE's economies of scale and scope and apply these
15 economies only to a self-serving portion of the system. Put succinctly, under this
16 approach, selected customers are allocated per unit (average) costs that are the result of
17 system economies but do not equitably share in all costs of the system that make these
18 per unit (average) costs possible. Indeed, the most basic concept of a regulated utility's
19 granted monopoly status is that societal costs and individual consumers' costs are lower
20 with a single company servicing the collective needs of all consumers.

21 The concept of skeletoniztion has been addressed extensively in economic
22 literature as well as in the Courts in the arena of anti-trust and undue price discrimination.
23 The economic standard applied in these situations is a customer's stand-alone cost. That

is, stand-alone costs are those costs that a customer would incur to design, construct, and operate a system to serve only itself, without enjoying any of the other benefits of an integrated system serving multiple customers.

Q: Please discuss your third concern which you referred to as practical in nature.

A: PSE's application of the modified SynerGEE model required a myriad of assumptions. Notwithstanding the inability to verify each of the assumptions which I discussed earlier, there are several assumptions required for this analysis that are clearly questionable as they relate to the allocation of cost responsibility.

Although Ms. Phelps claims on page 32 of her direct testimony that the SynerGEE model "was run to simulate the entire distribution system under design day conditions," the SynerGEE model itself is somewhat static in that it measures loads at particular points in time. This is of critical importance because, under a "design day" situation, loads vary throughout the day due to differences in customer demands for gas throughout the day. On such a design day, residential customer demands would increase in the morning and fall somewhat during the middle of the day as households are at work and the ambient temperature increases. Residential loads will then increase in the early evening hours and decline again later at night. Commercial loads tend to follow a similar, yet delayed diurnal pattern. As such, the PSE system load is not constant throughout the entire design day. However, the SynerGEE model requires assumed loads at all nodes. In the PSE application of the SynergGEE model, it is not known what point in time these loads are intended to represent. Nor is it known what loads are assumed to exist at each nodal end point. For example, the maximum diurnal load in a commercial/industrial area of PSE's system will peak at a different time than that for

1 residential areas of the system. The assumptions used for these various geographic areas
2 are critical to the ultimate costs allocated under this approach.
3 A second practical concern of this approach is the underlying assumption that the
4 PSE system contains no excess capacity for future expansion or growth. Indeed, much of
5 PSE's Distribution system was put into service many years ago when the total system
6 loads were smaller. PSE prudently planned for this growth such that the distribution
7 Mains particularly its trunk lines, now serve much higher demands. These demands will
8 continue to grow as new customers are added to the PSE system. Yet the same Mains
9 currently in service will continue to serve all customers in the future. Finally, as I will
10 discuss later in my testimony, PSE's estimation of class contributions to design day
11 demands are questionable at best.
12 To run the SynerGEE model, PSE's system must be "loaded" at a prescribed level
13 of demand. It has been represented by PSE that this level of loading is that for PSE's
14 design day. Because the demographics of the Company's service area vary significantly,
15 PSE's questionable assumptions as to design day loads for particular segments of the
16 distribution system are most suspect. In fact, Ms. Phelps developed class contributions to
17 design day demand independently. It is my understanding that Ms. Phelps had no input
18 as to the assumptions used to run SynerGEE for this application. Therefore, it is not
19 known what individual loads were used in the "Special" allocation of Mains to PSE's
20 larges gas customers, let alone whether or not they are reasonable.
21 **Q: What is your recommendation with regards to the special allocation used to assign**
22 **Mains to PSE's largest customers?**

A: This special allocation should be rejected and not considered by the Commission. There is no compelling reason, other than a desired end result, to treat PSE's largest customers any differently than all other retail customers.

Q: How does your rejection of PSE's special allocation for its largest customers affect your CCOSS analysis?

A: I have treated these large customers' firm loads in the same manner as all other firm customers and incorporated these contributions to peak load directly in my Peak and Average Mains allocator.

Q: What are the CCOSS results with this adjustment?

A: Building upon my previous adjustments to Ms. Phelps's CCOSS, incorporating the Peak and Average method used to allocate Mains to all customer classes produces the following results at current rates:

Table 16
Gas CCOSS (at Current Rates)
Incorporating Expense Oversight, Income Taxes, and Peak and Average Method Adjustments

Class	ROR
Residential	6.14%
Commercial & Industrial	4.16%
Large Volume	13.33%
Interruptible (85)	15.18%
Ltd. Interruptible (86)	17.72%
Non-Exclusive Interruptible (87)	4.80%
Transportation	9.03%
CNG	-8.85%
Rental	-5.68%
Total Company	5.98%

2. Peak and Average Classification

1 **Q: Before continuing with your next disagreement and adjustment to PSE's CCOSS,**
2 **please explain the Company's Peak and Average method further.**
3 A: As discussed previously, and but for Ms. Phelps's special allocation of Mains to the
4 largest customer' firm loads, the Company has utilized the Peak and Average method to
5 allocate distribution Mains investments. As the name implies, this method allocates
6 Mains costs partially on the basis of peak day demand and partially on the basis of
7 average day demand (usage). It is noted that average day use is the exact same as annual
8 throughput (usage) in relative terms. That is, class contributions to average daily use are
9 the same as class contributions to annual use. In the application of the Peak and Average
10 method, Ms. Phelps has elected to utilize PSE system load factors as a basis to classify
11 this allocator between peak (demand) and average demand (throughput).[12] Ms. Phelps's
12 load factor approach results in a distribution Mains classification of 67 percent peak day
13 and 33 percent average day.
14 **Q: Are there accepted ways to classify distribution Mains between Peak and Average**
15 **other than the load factor approach?**
16 A: Yes. Many utilities and cost analysts classify natural gas distribution Mains as 50 percent
17 peak-related and 50 percent average-related. The rationale behind this 50/50 split
18 between peak day demand and average usage (throughput) is that an equal weighting
19 strikes a reasonable balance between the fact that a local distribution company (LDC)
20 system is constructed and in place to serve usage requirements of customers throughout
21 the year, yet Mains are also physically sized to meet current and future peak load
22 requirements.

[12] Load factor is the ratio of average daily demand to peak day demand.

1 **Q: Are there a priori ramifications of using an equal weighting of 50 percent Peak day**
2 **and 50 percent Average day versus the load factor approach to classify Mains?**
3 A: Yes. The equal weighting method invariably allocates fewer costs to low volume, low
4 load factor customers, and more costs to large volume, high load factor customers than
5 does the load factor approach of classifying Mains utilized by PSE.

6 **3. Treatment of Interruptible Volumes**

7 **Q: Please explain your disagreement with Ms. Phelps as it relates to her treatment of**
8 **interruptible customers for the allocation of distribution Mains.**
9 A: Because of curtailment possibilities, there is no question that interruptible service is of a
10 lesser quality that firm service. As a result of this lower quality of service, questions
11 arise regarding what level of cost responsibility should be assigned interruptible
12 customers. At one extreme is the belief that interruptible customers should not be
13 assigned any Mains cost responsibility because the distribution system is claimed to be
14 designed only to meet firm loads, even though these customers may use these Mains
15 virtually every day of the year. At the other extreme is the thought that interruptible
16 service should be treated the same as firm customers so long as there are no curtailments
17 due to constraints of the local distribution system. That is, many natural gas LDCs have
18 sufficient distribution system capacity to meet all loads, firm and interruptible, each and
19 every day of the year.
20 To strike a balance between these two extremes, interruptible customers are
21 usually assigned some, but not a full share, of distribution Mains costs in order to
22 recognize the lesser quality of interruptible service. Although Ms. Phelps has assigned a

1 minimal level of Mains-related cost responsibility to interruptible customers, her
2 approach leans heavily towards the no cost responsibility view.
3 Remembering that Ms. Phelps has classified distribution Mains as 67 percent peak
4 day related and 33 percent average day (throughput) related, she then assigned zero peak
5 day responsibility to interruptible loads (i.e., 67% times 0% cost responsibility). With
6 respect to the average portion of this method, Ms. Phelps did not use the average or total
7 usage throughout the year for interruptible customers, but rather the minimum monthly
8 usage times 12 months, i.e., (33% times [minimum monthly usage times 12 months]). In
9 my opinion, Ms. Phelps's approach represents a clear bias with the objective to shift cost
10 responsibility away from interruptible customers.
11 Consider for example that Ms. Phelps assigns 67 percent of Mains investment
12 based on peak day demand, while interruptible loads are assumed to not have any cost
13 responsibility for this "peak" portion of Mains. Thus, for the remaining 33 percent, she
14 lowers interruptible customers' responsibility even more by not using annual usage, but
15 rather minimum monthly usage times 12.
16 **Q: What is your recommendation as to the assignment of distribution Mains cost**
17 **responsibility to interruptible customers in this case?**
18 A: Although it is common practice to utilize an equal weighting between Peak day and
19 Average day demands, I have accepted the Company's load factor approach in this case.
20 Furthermore, I assign no interruptible cost responsibility to the peak portion of the Peak
21 and Average method to recognize the lower quality of non-firm service. However, I have
22 incorporated interruptible customers' average daily usage (throughput) in the average
23 component of the Peak and Average allocation method. In my opinion, my treatment

strikes a balance between firm and interruptible customers that is more than fair to non-firm customers.

Q: Please provide a summary of class rates of return with your recommended allocation of Mains, incorporating your adjustments for interruptible customers' average, not minimum monthly usage.

A: Building upon my previous CCOSS adjustments, the following class rates of return are obtained at current rate levels:

Table 17
Gas CCOSS (at Current Rates)
Incorporating Table 16 and
Interruptible Customer Usage Adjustments

Class	ROR
Residential	6.27%
Commercial & Industrial	4.73%
Large Volume	13.97%
Interruptible (85)	11.20%
Ltd. Interruptible (86)	18.86%
Non-Exclusive Interruptible (87)	3.18%
Transportation	4.67%
CNG	-8.87%
Rental	-5.68%
Total Company	5.98%

4. Design Day versus Actual Peak Day

Q: What definition of peak day demand has PSE used for purposes of its proposed CCOSS?

A: As discussed on pages 28 through 30 of her direct testimony, Ms. Phelps has used a design day concept to measure peak day demand.

Q: Has the Commission rejected this design day concept in prior PSE rate cases?

A: Yes, that is my understanding. In previous cases, this issue has been explored in great detail. It is my understanding that this Commission has historically relied upon actual peak day volumes, rather than hypothetical design day volumes, for CCOSS purposes.

Q: Please explain how Ms. Phelps developed her design day demands for the PSE system as well as individual class contributions to this design day level.

A: Ms. Phelps started with a total PSE system design day demand and then used a top-down approach to estimate class contributions to this system design day demand.

Q: How did Ms. Phelps estimate her PSE system design day demand?

A: It is my understanding that Ms. Phelps was not responsible for the development and estimation of PSE's system design day demand. Rather, this total system estimate was provided to her by the Company's forecasting department.

Q: On pages 28 and 29 of her direct testimony, Ms. Phelps indicates that the system design day is based on 52 heating degree days, as explained in the Company's 2007 Integrated Resource Plan. Does the PSE system design day demand used by Ms. Phelps match the design day demand contained in the Company 2007 IRP?

A: No.

Q: Why not?

A: It is my understanding that the PSE system design day demand used by Ms. Phelps in this case was adjusted to reflect the test year proforma mix and level of customers.

Q: Please continue with your explanation of how Ms. Phelps developed class contributions to this adjusted system design day demand.

A: As indicated earlier, Ms. Phelps used a top-down approach, such that she started with the total system design day demand provided to her by the forecasting department, and then allocated this total system amount to individual customer classes.

Ms. Phelps's starting point was the large volume customer classes (Rate Schedules 85, 86, and 87). By utilizing their billed demand during the system peak month in 2007, Ms. Phelps assumed that these customers' demands would be the same under design day conditions as under actual, historical conditions. In other words, Ms. Phelps assumed no weather sensitivity for these customers. Next, Ms. Phelps estimated the design day demand for Commercial Schedule 50 customers (Compressed Natural Gas), incorporating a similar approach as used for Rate Schedules 85, 86, and 87 customers, except that actual average day usage during the 2007 peak month was used since there is no billing demand associated with Rate Schedule 50. After, the above classes' contributions to the design day demand were calculated, the residual (remaining) system design day load was allocated proportionally based on average daily usage in the peak month to the Residential (Rate Schedule 23) and Small Commercial/Industrial (Rate Schedule 31) classes.

Q: Does Ms. Phelps's allocation of adjusted system design day demand to individual classes produce realistic results?

A: In my opinion, no. Under Ms. Phelps's approach, she assumed that all usage above the actual 2007 amount is solely attributable to the Residential and Small Commercial/Industrial classes. While I would agree that these two customer classes tend to be the most weather sensitive, it is shortsighted to assume that other classes have

virtually no weather sensitivity, particularly at an extreme design day average temperature of 13 degrees Fahrenheit.[13]

Q: Is there any evidence to suggest that large volume commercial and industrial customers have some weather sensitive characteristics in their natural gas consumption patterns?

A: Yes. As part of her filed workpapers, Ms. Phelps provided test year weather normalized monthly usages by rate class. The following are the monthly usages for the large volume user classes. Please note that I have sorted these usages from the spring to the winter:

Table 18
Weather Normalized Monthly Usage

	Rate Schedule		
Month	85	86	87
April 2007	1,394	1,478	3,134
May 2007	1,149	1,083	2,656
June 2007	849	626	2,127
July 2007	764	450	878
August 2007	798	461	1,752
September 2007	932	670	1,884
October 2006	1,307	1,324	3,035
November 2006	1,502	2,127	3,599
December 2006	1,766	2,430	4,312
January 2007	1,779	2,337	4,047
February 2007	1,612	2,018	3,611
March 2007	1,657	1,957	3,654

It is clear from the above data that a significant portion of these large volume customers' loads are weather sensitive and therefore, would increase significantly under extreme design day temperatures.

[13] PSE's design day temperature is 52 heating degree days. Heating degree days are defined as a base of 65 degrees minus the average of high and low temperature for the day. Thus, 65-52=13 degrees average daily temperature.

Q: **In view of the shortcomings of Ms. Phelps's design day analysis, have you conducted an analysis of peak day demands by class?**

A: Yes. In accordance with what I understand to be prior Commission practice, I have estimated class contributions to actual system peak day loads. These system peak day loads represent the average of the five highest daily send outs occurring during the most recent three years which were provided in response to Public Counsel Data Request No. 657.

Q: **Please provide a comparison of the estimated system design day demand as used by Ms. Phelps to the average of the five highest actual system peak day demands during the last three years.**

A: **[Begin Confidential]**

[redacted]

[redacted]

1 [redacted]

2 [redacted][14]

3 [redacted]

4 [redacted]

5 [redacted]

6 [redacted]

7 [redacted]

8 [redacted]

9 [redacted]

10 [redacted]

11 [redacted]

12 [redacted]

13 [redacted]

14 [redacted]

15 [redacted]

16 [redacted]

17 [redacted]

18 **[End Confidential]**

19 **Q: Please explain how you calculated individual class contributions to this actual firm**

20 **peak day demand.**

---

[14] [Begin Confidential
[redacted] [End Confidential]]

A: Remembering that Ms. Phelps's assignments of design day demands to the large volume classes are based on actual test year experience, I accepted these levels since my system peak day amount is also based on actual experience. After these large volume contributions were determined, only Residential and Small Commercial/Industrial (Schedule 31) loads remained. I allocated this residual to these two classes in proportion to each class's average usage in the peak month. In other words, I used the same method as employed by Ms. Phelps to estimate class contribution to peak day demand.

Q: Please provide a comparison of Ms. Phelps's design day based on your actual peak day load factors.

A: **[Begin Confidential]** [redacted]

[redacted]

[End Confidential]

Q: Did you adjust Ms. Phelps's CCOSS to reflect actual system peak day demands?

A: Yes.

Q: Please provide a summary of CCOSS results incorporating actual system peak day loads.

A: Building upon my previous adjustments to Ms. Phelps's CCOSS, the following class rates of return results with the incorporation of actual system peak demands:

Table 23
Gas CCOSS (at Current Rates)
Incorporating All Public Counsel Adjustments

Class	ROR
Residential	6.62%
Commercial/Industrial (31)	5.01%
Large Volume (41)	10.64%
Interruptible (85)	7.44%
Limited Interruptible (86)	14.60%
Non-Exclusive Interruptible (87)	0.95%
Transportation & Contracts (57)	2.27%
CNG (50)	-8.78%
Rentals	-5.68%
Total System	5.98%

These class rates of return reflect my recommended CCOSS findings. The details of my CCOSS are provided in Exhibit No.___ (GAW-10).

B. NATURAL GAS CLASS REVENUE DISTRIBUTION

Q. How did Ms. Phelps determine her proposed distribution of PSE's requested gas revenue increase to individual customer classes?

A. Ms. Phelps discusses her proposed class distribution of the overall gas revenue increase of $56.77 million to individual customer classes beginning on page 43 of her direct testimony. Ms. Phelps states that the results of her cost of service study is the "Company's best indicator of what it costs to serve each class of customer." Accordingly, she uses these results to formulate her rate spread to customer classes. While she states the Company's long-term goal is to move customer class rates of return toward cost of service levels, Ms. Phelps indicates that moving all the way to cost-based rates in a single step would cause unreasonably large impacts on certain customers. In

this regard, Ms. Phelps proposes to allocate a "relatively larger portion of the revenue increase to those classes with current parity ratios below 100 percent."

A summary of PSE's proposed revenue increase for each customer class is shown below:

Table 24
PSE Proposed Gas Revenue Increase[15]

Class	Income Amount	Percent Margin Increase
Residential	$38,682,592	17.06%
Commercial & Industrial	16,178,327	24.74%
Large Volume	127	0.00%
Interruptible	-146	0.00%
United Interruptible	-302,266	-8.53%
Non-Exclusive Interruptible	1,242,877	21.42%
Transportation & Contracts	558,839	14.27%
Compressed Natural Gas	5,074	17.54%
Rentals	404,902	5.20%
Total Company	$56,770,327	17.02%

Q. Are PSE's proposed customer class revenue increases reasonable for its gas operations?

A. No, they are not.

Q. Mr. Watkins, do you have an alternative gas revenue increase distribution to that proposed by Ms. Phelps?

A. Yes. Based on the results of my CCOSS, presented in Exhibit No.___ (GAW-10), and considering the principle of gradualism, I propose the following gas revenue increase distribution at PSE's requested overall revenue level:

[15] *See* Ms. Phelps direct testimony, Exhibit No. ___(JKP-10), page 1, columns M and N. Note that Ms. Phelps's total increase of $56,770,327 is not exactly the same as the level proposed for overall revenue requirement purposes of $56,770,922 due to Ms. Phelps' application of her proposed rates multiplied by billing determinants. This difference is attributable to Ms. Phelps's ultimate rounding of proposed distribution rates.

Table 25
Public Counsel Revenue Distribution
at PSE Proposed Gas Revenue Increase

Class	Amount	Percent Margin Increase
Residential	$36,493,752	16.10%
Commercial & Industrial	13,914,794	21.28%
Large Volume	1,168,693	8.51%
Interruptible	948,869	14.47%
Limited Interruptible	0	0.00%
Non-Exclusive Interruptible	1,383,297	23.83%
Transportation & Contracts	865,122	22.13%
Compressed Natural Gas	7,388	25.54%
Rentals	1,989,015	25.54%
Total Company	$56,770,930	17.02%

In formulating my proposed gas revenue increase distribution to the various customer classes, I began with the results of my CCOSS, which is presented in Exhibit No. ___ (GAW-10). With the results of my CCOSS as a guide, I proceeded in a similar manner as I did for PSE's electric operations. That is, I formulated increases consistent with my CCOSS results that provides for the movement to equal rates of return (parity) for all classes. My specific methodology is discussed narratively below with the actual calculation provided in Exhibit No.___ (GAW-11):

(1) I propose no increase to Limited Interruptible (Schedule 86) since this customer class exhibits the highest rate of return (14.60%) compared to the system average rate of return of 5.98% and is currently providing a ROR exceeding PSE's proposed overall ROR on rate base of 8.60%;

(2) I increased Large Volume (Schedule 41) at 50% of the system average percentage increase because this customer class has the next highest ROR (10.64%) at almost twice the system average rate of return (5.98%);

(3) I increased Interruptible (Schedule 85) at 85% of the system average percentage increase as this class's rate of return at current rates of 7.44% is also in excess of the system average rate of return of 5.98%, but below that of the 8.60% overall ROR requested by PSE;

(4) I increased Commercial & Industrial (Schedules 31 and 61) at 125% of the system average increase because this class's rate of return of 5.01% is less than the system average ROR at current rates;

(5) I increased Transportation & Contracts (Schedule 57 and Special Contracts) at 130% of the system average percentage because this class is only producing a current ROR of 2.27% and is the second lowest class rate of return compared to the system average rate of return of 5.98%;

(6) I increased Non-Exclusive Interruptible (Schedule 87) at 140% of the system average because their rate of return is even lower than for the Transportation & Contracts class;

(7) I increased both Compressed Natural Gas and Rentals at 150% of system average percentage increase since these classes are achieving the lowest rates of return at current rates of -8.78% and -5.68%, respectively; and,

(8) Finally, I treated the Residential class (Schedules 16, 23 and 53) as the residual to recover the remainder of the required revenue increase.

My recommended distribution results in an increase to the Residential class of 94.6 percent of the system average percentage increase. This relative percentage increase of 94.6 percent of system average is appropriate and reasonable since this class is currently earning somewhat in excess of the system rate of return; i.e., 6.62 percent compared to 5.98 percent.

Q. Does your proposed revenue distribution move all classes towards rate of return parity?

A. Yes. As shown below, and calculated on page 1 of Exhibit No.___ (GAW-11), my proposed class revenue assignment moves all classes closer to rate of return parity.

Table 26
Indexed ROR
at PSE Proposed Gas Revenue Increase

Class	At Current Rates	At Public Counsel Proposed Rates
Residential	111%	107%
Commercial & Industrial	84%	92%
Large Volume	178%	142%
Interruptible	124%	113%
Limited Interruptible	244%	170%
Non-Exclusive Interruptible	16%	32%
Transportation & Contracts	38%	51%
Compressed Natural Gas	-147%	-90%
Rentals	-95%	-1%
Total Company	100%	100%

Q: Mr. Watkins, please provide your recommended scale back method to assign class natural gas revenue increases should the Commission authorize an overall revenue requirement increase less than that proposed by PSE.

A: I recommend that my customer class revenue increase distribution be scaled back in equal portions (i.e., equal percentages) should the Commission authorize an overall electric revenue increase different than that requested by PSE.

C. NATURAL GAS RESIDENTIAL RATE DESIGN

Q: Please describe PSE's current and proposed residential natural gas rate structure.

A: Currently, PSE's residential natural gas base rates include a fixed monthly customer charge of $8.25, a flat delivery (distribution charge) of $0.30039/therm and a "new" customer delivery charge applicable to certain new customers ranging from $0.11/therm to $0.17/therm. Ms. Phelps proposes to increase the fixed monthly customer charge to

1 $18.00 (118% increase) and decrease the flat distribution charge to $0.22510 (25%
2 decrease).

3 **Q: Did Ms. Phelps conduct a residential customer cost analysis similar to that**
4 **performed by Mr. Hoff?**

5 A: Yes.

6 **Q: Please comment on Ms. Phelps's residential customer cost analysis.**

7 A: Ms. Phelps conducted an analysis that portrays the monthly residential customer cost to
8 be $18.39. The results of Ms. Phelps's customer cost analysis is summarized on page 4
9 of her Exhibit No.___ (JKP-5). A closer examination of Ms. Phelps's study revealed that
10 many costs included in her determination of the monthly $18.39 amount cannot be
11 deemed directly customer-related. To illustrate, of the $75.2 million of Intangible plant
12 that Ms. Phelps assigned to the residential class, $56.2 million is deemed customer-
13 related and included in her customer cost analysis. Similarly, of the $79.2 million in total
14 General plant assigned to the residential class, Ms. Phelps's customer cost study portrays
15 $51.7 million to be customer-related and included in this analysis. Examples of Ms.
16 Phelps's improper assignment of expenses to residential customer costs include all of
17 Informational and Instructional Advertising ($0.4 million), $59.9 million in
18 Administrative and General expenses (out of a total $80.0 million allocated to the
19 residential class), and $0.7 million in increased Excise Tax associated with the
20 Company's proposed rate increase. Overall, of the $909.3 million of total Rate Base
21 allocated to the residential class, Ms. Phelps included $410.3 million as part of
22 Residential customer costs. With respect to expenses, Ms. Phelps' CCOSS allocates

1 $161.1 million in total expenses (excluding income taxes) to the residential class. Of this
2 $161.1 million, Ms. Phelps includes $98.3 million in her customer cost analysis.
3 In summary, Ms. Phelps has greatly overstated customer costs by including costs
4 not required to connect customers or maintain customer accounts, but are rather general
5 overhead costs.
6 **Q: Please explain PSE's natural gas line extension and new customer connection policy.**
7 A: PSE's Natural Gas Schedule 7 (Facilities Extension Standards), coupled with its Natural
8 Gas Rule No. 7 (Extension of Distribution Facilities-Other than the Kittitas County), and
9 sets forth the terms and pricing structure for new customer connections.
10 PSE's connection pricing methodology is based on a philosophy that small
11 volume customers will utilize the Company's system less than similar, yet larger, usage
12 customers. The Company's connection pricing method recognizes that the volume of
13 natural gas used by small customers may not be sufficient to recover the investment
14 required to add these customers to the system. In other words, PSE must install a service
15 line, meter (and base) and regulator for every new customer. If a prospective customer is
16 only planning to use natural gas, example as a decorative fireplace, this customer will not
17 generate enough base rate (non-gas or margin) future revenue over time to justify the
18 Company's investment. Conversely, a prospective customer who will use natural gas for
19 space heating, hot water heating, and cooking will use substantially more gas and provide
20 significantly more base rate revenue to PSE, thereby justifying PSE's investment to add
21 this customer.
22 PSE's Rule 7 provides the formulaic cost/benefit method used to evaluate whether
23 each new customer will or will not provide enough future revenue to recover the

1 investment required to connect the perspective customer. If a new customer is not
2 expected to consume enough gas (and hence, generate revenue) to justify the incremental
3 costs to add this customer, this customer will be required to make an upfront cash
4 contribution to PSE. Furthermore, depending on the specific differences between the
5 expected connection costs and future revenues (i.e. benefits), the customer may pay an
6 upfront cash contribution and agree to pay a "new customer" surcharge on gas used for a
7 period of up to five years.

8 **Q: What criteria are used to evaluate whether a potential customer will or will not use**
9 **enough natural gas to justify the costs of connecting this customer?**

10 A: The cost/benefit method outlined in Natural Gas Schedule 7 provides various usage
11 allowances based on the number and type of natural gas appliances installed in a
12 customers house. For customers who use natural gas for space heating, an allowance is
13 given based on the square footage of the customer's home. Specific usage allowances are
14 also given for water heaters, cooking ranges, clothes dryers, hot tubs, and fireplaces.
15 These allowances represent the "benefits" portion of this method. Natural Gas Schedule
16 7 also provides a schedule of specific incremental costs considered in PSE's cost/benefit
17 method. These costs include a flat cost per foot to extend any Mains ($40.79), a fixed
18 cost to run a Service line ($3,026), a fixed cost for a new meter ($132), and a provision
19 for annual Operating and Maintenance expenses ($48.00).

20 **Q: You mentioned a surcharge imposed on certain new customers. What is the current**
21 **structure and level of this surcharge?**

22 A: Depending on the expected level of revenue shortfall from PSE's cost/benefit analysis, as
23 well as the upfront cash contribution made by the customer, the monthly "new customer"

1 residential surcharge imposed is either $0.115/therm or $0.17/therm for all gas consumed
2 each month. This surcharge is in addition to the base rate distribution usage charge of
3 $0.30039/therm and in addition to the monthly fixed customer charge of $8.25.

4 **Q: What are the ratemaking implications of PSE's connection polices?**

5 A: First, it is obvious that PSE recognizes customers do not connect to its gas distribution
6 system simply for the sake of being connected. Rather, customers join the Company's
7 system in order to consume gas. More importantly, PSE's cost/benefit methodology
8 recognizes that expected revenue is a function of a customer's usage rather than of a
9 customer simply being connected to the system. This realistic understanding—that
10 revenue contributions are, and should be, a function of usage—dovetails with my earlier
11 discussion that prices should reflect variability in usage rather than fixed per customer
12 amounts. Such a pricing structure is not only the most efficient but also the fairest to all
13 customers in that customers pay in relation to the level of gas consumed.

14 **Q: If a customer is charged an up front connection fee and/or a new customer**
15 **surcharge, will this customer be overcharged if fixed monthly customer charges are**
16 **increased?**

17 A: Yes. Connection fees and new customer surcharges represent a payment to PSE to
18 compensate the Company for the costs of installing services lines and costs associated
19 with metering and regulating equipment. If customer charges are increased or designed
20 to also recover the costs of Services, Meters and other expenses, the customer will be
21 double-charged: once for the connection and/or "new customer" surcharge and again for
22 the ongoing monthly customer charge that must be paid.

1 **Q: Is the proper solution to this double payment problem the abandonment of**
2 **connection fees?**
3 A: No. Although PSE's line extension and customer polices (Schedule 7 and Rule 7) are
4 admittedly complicated and even perhaps self-serving to the Company, they do provide
5 pricing and costing signals that are in the best interest of PSE and all of its customers. As
6 I explained earlier, there is no doubt that there are circumstances in which it is neither
7 beneficial to PSE nor its existing customers to extend service to a customer that will have
8 little or no gas consumption.
9 The more appropriate solution is to maintain a pricing policy for PSE's recurring
10 revenues that is volumetrically based and with a minimum level of customer charges.
11 **Q: Mr. Watkins, your discussion thus far has been limited to new customers on the**
12 **PSE system. Do these circumstances and concepts apply to existing customers as**
13 **well?**
14 A: Yes. First, it is well recognized that pricing should be forward looking. Therefore,
15 recognition of how new customers affect costs and revenue collection is an important
16 point to consider in establishing pricing policies for all customers.
17 Second, PSE is a relatively young and rapidly growing gas distribution company.
18 This growth has occurred for several years and will undoubtedly continue in the
19 foreseeable future.
20 Third, existing customers, like new customers, are not connected to the PSE
21 system simply for the sake of being connected, but rather because they desire to use gas
22 throughout the year. PSE's service lines and meters were not installed simply to enable
23 this connection, but rather to serve as the means of enabling customers the ability to

1 purchase or transport gas. As such, service lines are merely an extension of PSE's
2 Distribution Mains with the primary difference being one of accounting nomenclature
3 because service lines are typically located on customer owned property.

4 **Q: What ramifications do these factors have on determining a reasonable fixed**
5 **monthly customer charge for PSE's residential rates?**

6 A: Given PSE's new customer connection policies and pricing methodology, the relatively
7 young age of the PSE system, its level of growth, recognition that service lines represent
8 an extension of distribution Mains, and most importantly, that efficient and fair pricing
9 dictates volumetric based rates, PSE's natural gas fixed monthly customer charges should
10 remain at their current levels regardless of any increase in overall revenue requirement
11 authorized by this Commission.

12 **Q: Have you conducted an analysis to determine if PSE's current residential customer**
13 **charges are reasonable?**

14 A: Yes. Similar to the direct customer cost analysis I conducted for PSE's electric
15 operations, I have also conducted an analysis of the Company's residential gas customer
16 costs that should be considered in evaluating the reasonableness of fixed monthly
17 customer charges.

18 **Q: Mr. Watkins, does your analysis include the policy implications of increasing PSE's**
19 **natural gas fixed monthly customer charges?**

20 A: No. In her direct testimony, Public Counsel witness, Barbara Alexander, discusses
21 various potential policy implications of increasing PSE's monthly basic charge for
22 residential gas customer.

23 **Q: Please explain your natural gas Residential customer cost analysis.**

1 A: Exhibit No. ___ (GAW-12) presents the results of my residential natural gas customer
2 cost analysis.

3 **Q: Please explain your residential natural gas customer cost analysis.**

4 A: The direct customer costs provided on page 1 of Exhibit No.___ (GAW-12) include those
5 rate base and expense items required for each customer connection as well as those
6 required to maintain a customer's account. In recognition of PSE's connection fees and
7 new customer surcharges and the concepts enumerated earlier, I have excluded Services
8 investment from my analysis shown on page 1, and excluded all rate base items on page
9 2. The results of these analyses indicate a monthly customer cost in the range of $4.25 to
10 $7.48 using PSE's requested return on equity, and $4.25 to $7.24 at a 9.25 percent cost of
11 equity.

12 **Q: Mr. Watkins, are there other reasonable ways to evaluate customer costs while at**
13 **the same time recognize PSE's customer connection policies?**

14 A: Yes. Considering that PSE recognizes a customer's desired use of facilities in order to
15 consume natural gas, another reasonable method is to include the costs required to
16 maintain a customer's account plus a provision for depreciation on the assets employed to
17 render service. In this manner, depreciation expense represents a return of the investment
18 to connect the customer and thus, provides for the replacement of such facilities. Profit
19 (return) on the assets is then recovered from volumetric usage charges, which recognizes
20 the utilization of these assets.

21 **Q: Have you conducted an analysis such as you just described?**

22 A: Yes. Exhibit No.___ (GAW-13) presents this analysis in which a depreciation allowance
23 is provided for all investments required to connect a customer but excludes profit (return)

1 for the reasons discussed. This analysis also includes all direct Operating and
2 Maintenance expenses required to maintain a customer's account. This customer cost
3 analysis results in a monthly customer cost of $7.23.

4 **Q: Should the Commission authorize higher or lower revenue than that proposed by**
5 **you or the Company, how should PSE's residential rates be established?**

6 A: I recommend that PSE's current residential monthly customer charge of $8.25 be
7 maintained regardless of the change in revenue authorized by the Commission. As such,
8 any required change in residential revenue should be derived from the volumetric
9 distribution charge.

10 **IV. PSE SUPPLEMENTAL FILING**

11 **Q: Does PSE offer revised class revenue distribution proposals that incorporate the**
12 **Company's supplemental request for an overall revenue requirement increase**
13 **above those contained in its original December 31, 2007 filing?**

14 A: Yes. Revised class revenue distribution proposals appear in David Hoff's prefiled
15 supplemental testimony relating to PSE's electric operations, identified as Exhibit No.___
16 (DWH-8T), and in Janet Phelps's prefiled supplemental testimony concerning the
17 Company's natural gas operations, identified as Exhibit No.___ (JKP-14T).

18 **Q: Please explain Mr. Hoff's and Ms. Phelps's modified class revenue distribution**
19 **proposals that incorporate PSE's proposed additional overall increases in**
20 **requirement provided in the Supplemental testimonies of John Story.**[16]

21 A: Mr. Hoff and Ms. Phelps both utilized the same methodologies employed in their initial
22 filings to distribute the Company's latest proposed revenue requirement for its electric

[16] Exhibit No.___(JHS-9T) and Karl Karzmar, Exhibit No.___(KRK-7T).

1 and natural gas operations. I discussed Mr. Hoff's and Ms. Phelps's class revenue
2 distribution methodologies earlier in my testimony.

3 **Q: Do Mr. Hoff's and Ms. Phelps's supplemental testimonies effect your class revenue**
4 **distribution proposals in any way?**

5 A: No. As discussed earlier, my proposals (for purposes of the dollar amounts provided and
6 discussed in revenue distribution) are based on the amounts PSE requested in its initial
7 filing and provide an "apples to apples" comparison of the Company's and my proposals.
8 Recognizing that the Commission may ultimately authorize an overall revenue
9 requirement different than that proposed by PSE, I have provided a method by which my
10 revenue distribution proposals should be applied to a different overall change in
11 revenues.

12 **Q: Does this complete your direct testimony?**

13 A: Yes.

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

VICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jul. 1995-Present	Vice President/Senior Economist, Technical Associates, Inc.
Mar. 1993-1995	Vice President/Senior Economist, C. W. Amos of Virginia
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

GLENN A. WATKINS

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

Puget Sound Energy
Electric Class Cost of Service Study
(PSE Study Corrected for the Calculation of Income Taxes)

Description		Alloc	Total Company	Residential Sch 7	Sec. Voltage Sch 24	Sec. Voltage Sch 25	Sec. Voltage Sch 26	Prim. Voltage Sch 31/35/43	Campus Sch 40	High Voltage Sch 46/49	Transportation Sch 449/459	Street & Area Lighting	Firm Resale
Revenue			$1,881,488,606	$1,013,357,511	$229,990,175	$263,974,312	$160,751,386	$114,224,930	$39,448,308	$33,291,306	$9,695,709	$15,695,457	$1,159,713
Total O&M Expenses			$1,304,026,881	$716,133,883	$158,301,772	$169,034,912	$109,597,498	$80,106,945	$29,760,423	$26,326,966	$4,744,919	$9,310,044	$709,522
Total Depreciation Expenses			$233,507,011	$141,726,506	$28,326,097	$26,011,496	$14,566,604	$12,187,967	$3,637,374	$2,856,248	$1,585,392	$2,410,079	$197,249
Total Taxes Other than Income			$116,380,829	$69,167,509	$13,964,517	$13,406,825	$7,708,271	$6,291,588	$1,939,216	$1,563,324	$1,133,733	$1,083,486	$122,360
Total Expenses Before Interest & Income Taxes			$1,653,914,721	$927,027,898	$200,592,385	$208,453,233	$131,874,371	$98,586,500	$35,337,013	$30,746,539	$7,464,043	$12,803,609	$1,029,132
Earnings Before Interest and Taxes			$227,574,085	$86,329,613	$29,397,790	$55,521,079	$28,877,015	$15,638,430	$4,111,295	$2,544,767	$2,231,667	$2,791,848	$130,581
Interest		75	$123,453,265	$72,663,406	$14,962,888	$14,608,259	$8,356,622	$6,849,917	$2,104,335	$1,672,604	$1,092,771	$1,015,708	$124,756
Earnings Beore Income Taxes			$104,120,820	$13,666,207	$14,434,902	$40,912,819	$20,518,393	$8,788,513	$2,006,961	$872,163	$1,138,896	$1,776,140	$5,826
Income Taxes @	49.92%		$51,973,585	$6,821,707	$7,205,414	$20,422,293	$10,242,087	$4,386,928	$1,001,607	$435,354	$568,498	$886,589	$2,908
Operating Income			$175,600,500	$79,507,906	$22,192,376	$35,098,786	$18,634,928	$11,251,502	$3,109,488	$2,109,413	$1,663,169	$1,905,259	$127,673
Rate Base			$3,305,098,647	$1,945,349,323	$400,587,392	$391,093,248	$223,777,550	$183,386,407	$56,337,377	$44,779,062	$29,255,735	$27,192,589	$3,339,963
RoR			5.31%	4.09%	5.54%	8.97%	8.33%	6.14%	5.52%	4.71%	5.68%	7.01%	3.82%
Indexed RoR			100.00%	76.93%	104.27%	168.92%	156.74%	115.46%	103.88%	88.66%	107.00%	131.67%	71.95%

Dockets UE-072300 & UG-072301
Exhibit No.___(GAW-3)
Page 1 of 1

Docket Nos. UE-072300 and UG-072301
Exhibit No. __ (GAW-4C)
NON-CONFIDENTIAL

BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DOCKET NOs. UE-072300 and UG-072301

DIRECT TESTIMONY OF GLENN A. WATKINS (GAW-1TC)

ON BEHALF OF

PUBLIC COUNSEL

May 30, 2008

Re: EXHIBIT NO. ___ (GAW-4C) IS CONFIDENTIAL IN ITS ENTIRETY

Puget Sound Energy
Classification of Generation Plant
Scenario A

	Generating Unit	Gross Plant	Classification		Classified Amount	
			Base Load	Peak Load	Base Load	Peak Load
Steam	Colstrip	$711,063,674	100%		$711,063,674	$0
CCCT	Frederickson 1	$73,647,607	100%		$73,647,607	$0
SCCT	Frederickson	$34,005,912		100%	$0	$34,005,912
CCCT	Encogen	$155,434,396	100%		$155,434,396	$0
Hydro	Lower Baker	$30,455,274	100%		$30,455,274	$0
Hydro	Upper Baker	$66,173,289	100%		$66,173,289	$0
Hydro	Electron	$55,695,000	100%		$55,695,000	$0
Hydro	Snoqualmie	$13,970,582	100%		$13,970,582	$0
Diesel	Crystal Mountain	$771,671		100%	$0	$771,671
SCCT	Fredonia	$51,393,071		100%	$0	$51,393,071
Wind	Hopkins Ridge	$179,696,732	100%		$179,696,732	$0
SCCT	Whitehorn 2 & 3	$33,269,424		100%	$0	$33,269,424
Wind	Wild Horse	$344,895,360	100%		$344,895,360	$0
CCCT	Goldendale	$306,756,121	100%		$306,756,121	$0
CCCT	Sumas	$99,273,738	100%		$99,273,738	$0
	Total	$2,156,501,851			$2,037,061,773	$119,440,078
	Percent				94.46%	5.54%

Puget Sound Energy
Classification of Generation Plant
Scenario B

Generating Unit		Net Plant	Classification		Classified Amount	
			Base Load	Peak Load	Base Load	Peak Load
Steam	Colstrip	$711,063,674	100%		$711,063,674	$0
CCCT	Frederickson 1	$73,647,607	85%	15%	$62,600,466	$11,047,141
SCCT	Frederickson	$34,005,912		100%	$0	$34,005,912
CCCT	Encogen	$155,434,396	85%	15%	$132,119,237	$23,315,159
Hydro	Lower Baker	$30,455,274	75%	25%	$22,841,456	$7,613,819
Hydro	Upper Baker	$66,173,289	75%	25%	$49,629,967	$16,543,322
Hydro	Electron	$55,695,000	75%	25%	$41,771,250	$13,923,750
Hydro	Snoqualmie	$13,970,582	75%	25%	$10,477,937	$3,492,646
Diesel	Crystal Mountain	$771,671		100%	$0	$771,671
SCCT	Fredonia	$51,393,071		100%	$0	$51,393,071
Wind	Hopkins Ridge	$179,696,732	100%		$179,696,732	$0
SCCT	Whitehorn 2 & 3	$33,269,424		100%	$0	$33,269,424
Wind	Wild Horse	$344,895,360	100%		$344,895,360	$0
CCCT	Goldendale	$306,756,121	85%	15%	$260,742,703	$46,013,418
CCCT	Sumas	$99,273,738	85%	15%	$84,382,677	$14,891,061
	Total	$2,156,501,851			$1,900,221,457	$256,280,394
	Percent				88.12%	11.88%

Puget Sound Energy
Public Counsel Electric Class Cost of Service Study
(Summary)

Account Description	Allocator	Alloc	Total	Residential Sch 7	Sec. Voltage Sch 24	Sec. Voltage Sch 25	Sec. Voltage Sch 26	Prim. Voltage Sch 31/35/43	Campus Sch 40	High Voltage Sch 46/49	Transportation Sch 449/459	Street & Area Lighting	Firm Resale
			4	5	6	7	8	9	10	11	12	13	14
Revenue			$1,881,488,806	$1,013,251,566	$230,003,864	$263,999,672	$160,776,687	$114,245,340	$39,459,664	$33,300,440	$9,695,869	$15,596,001	$1,159,704
TOTAL O & M EXPENSES			$1,304,026,881	$599,833,574	$160,132,154	$173,055,178	$113,688,247	$83,326,513	$31,528,577	$27,799,793	$4,634,310	$9,329,466	$699,068
TOTAL DEPRECIATION EXPENSES			$233,507,011	$138,779,184	$28,146,635	$27,094,992	$15,448,375	$12,834,951	$3,882,467	$3,081,883	$1,763,804	$2,263,176	$211,543
TOTAL TAXES OTHER THAN INCOME			$116,380,829	$64,624,096	$14,203,973	$15,317,915	$9,199,824	$6,869,477	$2,299,040	$1,872,212	$857,521	$1,039,288	$97,483
Total Expense Before Income Taxes			$1,653,914,721	$903,236,854	$202,482,763	$215,468,086	$138,336,446	$103,030,942	$37,710,085	$32,753,887	$7,255,635	$12,631,930	$1,008,094
Earnings Before Interest & Taxes			$227,574,085	$110,014,712	$27,521,101	$48,531,586	$22,440,241	$11,214,399	$1,749,579	$546,553	$2,440,234	$2,964,070	$151,610
Interest		75	$123,453,265	$71,521,352	$15,000,011	$14,946,203	$8,658,987	$7,080,627	$2,211,312	$1,763,962	$1,150,821	$990,854	$129,134
Earnings Before Taxes			$104,120,820	$38,493,360	$12,521,090	$33,585,383	$13,781,253	$4,133,771	-$461,732	-$1,217,410	$1,289,413	$1,973,217	$22,475
Income Taxes @	49.92%		$51,973,585	$19,214,581	$6,250,104	$18,764,685	$6,879,135	$2,063,439	-$230,481	-$607,690	$643,631	$984,963	$11,219
Operating Income			$175,600,500	$90,800,131	$21,270,997	$31,766,901	$15,561,106	$9,150,960	$1,980,060	$1,154,242	$1,796,603	$1,979,107	$140,391
Rate Base			$3,305,098,647	$1,914,774,187	$401,581,260	$400,140,700	$231,818,958	$189,563,006	$59,201,375	$47,224,915	$30,809,860	$26,527,195	$3,457,191
ROR			5.31%	4.74%	5.30%	7.94%	6.71%	4.83%	3.34%	2.44%	5.83%	7.46%	4.06%
Indexed ROR			100.00%	89.25%	99.69%	149.42%	126.34%	90.86%	62.95%	46.00%	109.75%	140.42%	76.43%
Required Income @ 8.60%			$284,238,484	$164,670,560	$34,535,988	$34,412,100	$19,936,430	$16,302,419	$5,091,318	$4,061,343	$2,649,648	$2,281,339	$297,318
Income Deficiency			$108,637,984	$73,870,449	$13,264,991	$2,645,199	$4,375,324	$7,151,458	$3,111,258	$2,907,100	$853,045	$302,231	$156,928
Conversion Factor			0.6214308	0.6214308	0.6214308	0.6214308	0.6214308	0.6214308	0.6214308	0.6214308	0.6214308	0.6214308	0.6214308
Additional Reveunue Required			$174,819,118	$118,871,560	$21,345,886	$4,256,627	$7,040,727	$11,508,053	$5,006,604	$4,678,076	$1,372,711	$486,347	$252,526
PC Proposed Increase			$174,819,118	$101,002,871	$21,444,363	$18,602,204	$12,852,702	$10,682,086	$4,284,090	$3,792,429	$824,240	$1,101,607	$252,526
Difference from Required Rev. Increase @ 8.60% ROR			$0	-$17,868,689	$98,477	$14,345,577	$5,811,975	-$825,967	-$742,514	-$885,647	-$548,471	$615,260	$0
Conversion Factor			0.6214308	0.6214308	0.6214308	0.6214308	0.6214308	0.6214308	0.6214308	0.6214308	0.6214308	0.6214308	0.6214308
Income Difference from Required			$0	-$11,104,154	$61,197	$8,914,763	$3,611,740	-$513,281	-$461,421	-$550,368	-$340,837	$382,341	$0
Operating Income @ PC Proposed Rates			$284,238,484	$153,566,426	$34,597,185	$43,326,864	$23,548,171	$15,789,137	$4,629,897	$3,510,975	$2,308,811	$2,663,680	$297,318
ROR @ PC Proposed Rates			8.60%	8.02%	8.62%	10.83%	10.16%	8.33%	7.82%	7.43%	7.49%	10.04%	8.60%
Indexed ROR				93%	100%	128%	118%	97%	91%	86%	87%	117%	100%

Puget Sound Energy
Public Counsel Electric Class Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential Sch 7	Sec. Voltage Sch 24	Sec. Voltage Sch 25	Sec. Voltage Sch 26	Prim. Voltage Sch 31/35/43	Campus Sch 40	High Voltage Sch 46/49	Transportation Sch 449/459	Street & Area Lighting	Firm Resale
				4	5	6	7	8	9	10	11	12	13	14
RATE BASE														
Plant-In-Service														
	Intangible Plant													
300	Production Plant	PP.T	63	49,116,606	26,673,323	5,949,423	6,910,775	4,847,847	3,291,576	1,289,853	1,156,563	0	179,860	17,385
300.01	Distribution Plant	DP.T	66	12,327,993	6,113,660	1,490,115	1,186,355	528,107	558,254	107,216	57,294	92,948	182,388	11,455
300.01	General Plant	GP.T	71	168,572,155	98,928,289	20,278,179	19,862,456	11,529,050	9,413,902	2,932,568	2,366,212	1,546,072	1,544,222	171,205
	Sub-total			230,016,754	132,715,472	27,717,717	27,959,586	16,705,004	13,263,733	4,329,639	3,580,069	1,639,019	1,906,490	200,025
	Production Plant													
310	Thermal Baseload Generation	PC3	59	829,109,314	433,378,880	100,426,805	116,856,835	78,457,648	55,563,213	21,773,270	19,523,282	0	3,036,453	293,128
330	Hydro Baseload Generation	PC3	59	160,755,038	84,026,899	19,472,024	22,516,458	15,212,082	10,773,088	4,221,594	3,785,346	0	588,734	56,834
340	Other Production Generation	PC3	59	1,169,304,950	611,197,448	141,636,207	164,522,835	110,649,965	78,361,609	30,707,160	27,533,969	0	4,282,354	413,403
	Sub-total			2,159,169,302	1,128,601,027	261,537,035	303,798,128	204,319,675	144,697,906	56,702,025	50,842,597	0	7,907,542	763,365
	Transmission Plant													
350	Transmission Plant - Integrated Generation	PC3	59	217,184,510	113,522,689	26,307,244	30,558,163	20,551,917	14,554,738	5,703,490	5,114,108	0	795,396	76,785
350.01	Bulk Transmission Plant (>230 kV)	PC4	60	117,203,204	55,670,616	12,926,148	15,012,446	10,092,513	7,146,208	2,798,670	2,509,967	9,737,130	390,816	716,470
350.02	Sub Transmission Plant (<230 kV)	PC4	60	238,988,945	112,972,728	26,141,163	30,355,687	20,407,411	14,449,861	5,859,008	5,075,281	19,688,815	790,243	1,448,728
	Sub-total			571,376,659	282,366,213	65,376,554	75,926,297	51,051,841	36,150,828	14,161,168	12,699,376	29,425,945	1,976,456	2,241,982
	Distribution Plant													
360.01	Land & Land Rights - Assigned	DIR360.01	33	1,012,984	0	0	0	0	0	522,558	469,441	0	0	20,965
360.02	Land & Land Rights - Allocated	NCP_360	30	14,644,605	6,390,341	1,958,336	2,658,914	2,196,559	1,155,113	0	0	137,828	144,847	668
360.03	Land & Land Rights - Transm Related	PC4	60	10,716,471	5,109,500	1,182,305	1,372,919	922,981	853,535	255,944	229,543	890,480	35,741	65,523
361.01	Structures & Improve - Assigned	DIR361.01	34	518,444	0	0	0	0	0	91,698	211,704	198,439	0	14,602
361.02	Structures & Improve - Allocated	NCP_361	31	4,659,632	2,311,555	609,421	697,743	572,966	410,596	0	0	19,994	37,283	74
361.03	Structures & Improve - Transm Related	PC4	60	1,043,991	497,871	115,158	133,724	89,899	83,655	24,929	22,358	86,734	3,481	6,382
362.01	Station Equipment - Assigned	DIR362.01	35	22,590,134	0	0	0	0	465,179	4,746,514	7,375,038	9,780,010	0	223,393
362.02	Station Equipment - Allocated	NCP_362	32	267,547,095	155,544,382	41,139,546	40,703,861	26,844,767	21,027,004	0	0	683,343	1,533,770	70,389
362.03	Station Equipment - Transm Related	PC4	60	95,790,096	45,663,179	10,556,166	12,269,662	8,248,604	5,840,591	2,287,351	2,051,411	7,958,150	319,414	585,571
364	Poles Towers & Fixtures	OH_NCP	39	230,067,210	156,698,935	27,727,723	21,923,445	8,077,829	12,413,637	0	0	25,905	1,067,057	132,678
364.01	OH Lines Direct Assignment	DIR364.01	36	957,728	0	0	0	0	0	783,835	0	0	0	173,891
365	OVHD Cond & Devices	OH_NCP	39	239,765,816	165,386,973	28,898,600	22,847,639	8,418,354	12,936,840	0	0	26,997	1,112,040	138,271
366	UNGD Conduit	UG_NCP	40	501,935,042	343,599,440	58,725,987	51,342,606	23,737,604	23,650,174	0	0	62,064	2,686,023	131,144
366.01	UG Lines Direct Assignment	DIR366.01	37	14,663,077	0	0	0	0	0	12,557,576	1,548,219	0	0	557,282
367	UNGDCond & Devices	UG_NCP	40	537,940,287	368,246,816	60,785,105	55,025,569	25,440,370	25,346,669	0	0	66,516	2,878,700	140,551
368.OH	Line Transf OVHD	TFR	16	125,492,624	104,824,822	17,580,509	2,933,246	31,675	0	0	0	0	122,373	0
368.UG	Line Transf UNGD	TFR	17	228,268,921	145,719,631	40,524,327	32,968,315	9,027,161	0	0	0	0	29,487	0
368.03	Line Transf Assigned	TFR	Dir	2,244,856					1,049,213	1,176,246				19,397
369.OH	Services - OVHD	OH_SVC	23	42,092,559	36,463,376	5,396,070	230,667	2,426	0	0	0	0	0	0
369.UG	Services - UNGD	RESID	Dir	131,754,580	131,754,580									
370	Meters	METER	6	129,474,364	73,742,332	27,780,476	10,186,263	1,064,815	15,053,218	632,405	540,443	306,345	0	188,046
372	Leased Prop Assigned - Water Htrs	DIR372.00	8	1,051,383	1,042,190	8,797	398	0	0	0	0	0	0	0
373	Str & Area Lighting Sys	DIR373.00	Dir	29,598,724									29,598,724	
374	Asset Retirement Obligation	LINE.T	61	6,729,326	4,570,263	786,281	686,784	289,736	328,000	58,659	6,830	801	34,164	5,620
375	Easements	LINE.T	81	24,814,955	16,853,186	2,833,100	2,458,823	1,068,426	1,209,528	217,048	25,167	2,952	125,981	20,723
	Sub-total			2,685,374,886	1,767,421,166	324,587,910	258,420,636	115,038,173	121,603,055	23,354,961	12,480,175	20,246,558	39,729,084	2,495,168
	General Plant													
389	Land & Land Rights	PTDP.T	62	7,669,895	4,512,893	925,048	906,082	525,930	429,442	133,777	107,941	70,528	70,444	7,810
390	Structures & Improvements	PTDP.T	62	112,994,773	66,312,135	13,592,566	13,313,905	7,727,981	6,310,167	1,965,715	1,586,084	1,036,340	1,035,100	114,760
391	Office Furniture & Equip	PTDP.T	62	70,060,037	41,115,448	8,427,786	8,255,007	4,791,572	3,912,499	1,218,801	983,416	642,561	641,792	71,154
392	Transportation Equip	PTDP.T	62	2,692,595	1,580,177	323,902	317,262	184,153	150,368	46,842	37,795	24,695	24,666	2,735
393	Stores Equip	PTDP.T	62	1,076,322	631,651	129,475	126,820	73,612	60,107	18,724	15,108	9,872	9,860	1,093
394	Tools & Shop & Garage Equip	PTDP.T	62	6,279,098	3,684,953	755,336	739,851	429,442	350,656	109,234	88,138	57,589	57,520	6,377
395	Lab Equip	PTDP.T	62	13,388,039	7,856,907	1,610,498	1,577,461	915,640	747,654	232,905	187,925	122,789	122,642	13,597
396	Power Operated Equip	PTDP.T	62	1,252,830	735,236	150,706	147,616	85,684	69,964	21,795	17,586	11,490	11,477	1,272
397	Communication Equip	PTDP.T	62	68,310,039	38,914,723	7,976,684	7,813,154	4,535,101	3,703,080	1,153,564	930,780	608,187	607,440	67,348
398	Miscellaneous Equip	PTDP.T	62	713,533	418,744	85,834	84,074	48,800	39,847	12,413	10,016	6,544	6,536	725
39	Other Tangible Property	PTDP.T	62	23,898	14,025	2,875	2,816	1,634	1,335	416	335	219	219	24
	Sub-total			282,481,059	165,776,892	33,980,710	33,264,071	19,319,560	15,775,139	4,914,186	3,965,128	2,590,795	2,587,696	286,893
	TOTAL PLANT-IN-SERVICE			**5,928,418,660**	**3,476,880,770**	**713,199,926**	**699,388,718**	**406,432,243**	**331,490,662**	**103,461,978**	**83,567,345**	**53,902,318**	**54,107,267**	**5,987,433**

Accumulated Reserve for Depreciation

	Intangible Plant													
111	Accum Amortization	GP.T	71	-116,972,014	-88,646,220	-14,071,004	-13,782,534	-7,999,994	-8,532,295	-2,034,908	-1,641,912	-1,072,817	-1,071,534	-118,799
	Sub-total			-116,972,014	-88,646,220	-14,071,004	-13,782,534	-7,999,994	-8,532,295	-2,034,908	-1,641,912	-1,072,817	-1,071,534	-118,799
	Production Plant													
108.01	Accum Depreciation Thermal Baseload Generati	PP.T	63	-477,221,768	-249,444,533	-67,805,178	-67,145,767	-45,158,940	-31,981,277	-12,532,336	-11,237,282	0	-1,747,733	-168,720
108.02	Accum Depreciation Hydro Baseload Generatio	PP.T	63	-117,167,011	-61,243,372	-14,192,270	-16,485,582	-11,087,378	-7,852,011	-3,076,927	-2,758,966	0	-429,102	-41,424
108.03	Accum Depreciation Other Production Generatio	PP.T	63	-405,325,557	-211,864,275	-49,096,495	-57,029,870	-38,355,485	-27,163,113	-10,644,269	-9,544,321	0	-1,484,427	-143,301
	Sub-total			-999,714,336	-522,552,180	-121,093,943	-140,661,200	-94,601,803	-66,996,401	-26,253,535	-23,540,569	0	-3,661,261	-353,445
	Transmisson Plant													
108.04	Accum Depreciation Transmisson Plant	TP.T	64	-217,102,108	-107,288,772	-24,840,685	-28,849,199	-19,397,821	-13,735,985	-5,380,723	-4,825,296	-11,180,776	-750,980	-851,871
	Sub-total			-217,102,108	-107,288,772	-24,840,685	-28,849,199	-19,397,821	-13,735,985	-5,380,723	-4,825,296	-11,180,776	-750,980	-851,871
	Distribution Plant													
108.05_36	Structures & Improve	D361.T	Acct 361	-2,303,899	-1,040,531	-268,382	-307,974	-245,524	-175,662	-43,198	-86,696	-113,039	-15,099	-7,800
108.05_36	Station Equipment	D362.T	Acct 362	-162,134,404	-80,765,202	-20,652,158	-21,158,554	-13,617,483	-10,917,183	-2,809,447	-3,785,087	-7,357,867	-740,194	-351,229
108.10_36	Poles Towers & Fixtures	D364.T	Acct 364, 365	-82,807,813	-57,004,117	-9,959,704	-7,874,827	-2,901,529	-4,458,936	-137,869	0	-9,305	-383,283	-78,243
108.10_36	OVHD Cond & Devices	D364.T	Acct 364, 365	-113,912,790	-76,416,489	-13,700,853	-10,832,836	-3,991,426	-8,133,840	-189,657	0	-12,800	-627,256	-107,634
108.10_36	UNGD Conduit	D366.T	Acct 366, 367	-149,888,187	-101,179,193	-16,704,013	-15,118,777	-6,989,975	-8,964,230	-1,784,887	-220,058	-18,276	-790,949	-117,628
108.10_36	UNGDCond & Devices	D366.T		-192,090,860	-129,667,311	-21,407,212	-19,376,638	-8,958,080	-8,925,086	-2,287,442	-282,018	-23,422	-1,013,850	-151,003
108.10_36	Line Transformers	D368.T		-127,635,539	-89,825,285	-20,831,786	-12,671,440	-3,247,777	-376,164	-421,708	0	0	-54,445	-6,954
108.10_36	Services	D369.T		-93,218,644	-90,200,218	-2,893,429	-123,697	-1,301	0	0	0	0	0	0
108.10_37	Meters	D370.T		-47,633,433	-27,129,698	-10,213,039	-3,747,519	-391,744	-5,536,057	-232,861	-198,828	-112,704	0	-69,182
108.10_37	Leased Prop Assigned - Water Htrs	DIR372.00	8	-1,056,248	-1,047,013	-8,637	-398	0	0	0	0	0	0	0
108.10_37	Str & Area Lighting Sys	DIR373.00	Dir	-15,811,486									-15,811,486	
108.10_37	Easements	LINE.T	61	-11,696,597	-7,943,797	-1,335,390	-1,158,973	-503,606	-570,114	-102,305	-11,872	-1,392	-59,382	-9,768
	Sub-total			-1,000,189,901	-664,218,853	-117,974,783	-92,570,631	-40,848,443	-44,059,273	-8,009,176	-4,564,559	-7,648,799	-19,395,742	-899,641
	General Plant													
108.06	Accum Depreciation General Plant	GP.T	71	-106,290,251	-62,377,518	-12,786,054	-12,523,927	-7,269,443	-5,935,773	-1,849,080	-1,491,974	-974,849	-973,682	-107,950
108.07	RWIP	PTDGP.T	72	-12,883,306	-7,560,700	-1,549,781	-1,518,009	-881,120	-719,467	-224,125	-180,840	-118,160	-118,019	-13,085
	Sub-total			-119,173,557	-69,938,218	-14,335,836	-14,041,937	-8,150,563	-6,655,240	-2,073,205	-1,672,814	-1,093,009	-1,091,701	-121,035
	TOTAL ACCUMULATED RESERVE FOR DEPRECIATION			**-2,453,151,916**	**-1,432,644,242**	**-292,316,250**	**-289,905,501**	**-170,998,624**	**-137,979,194**	**-43,751,544**	**-35,245,149**	**-20,995,401**	**-25,971,219**	**-2,344,790**

Rate Base Adjustments and Working Capital

	Working Capital Assets													
WC	Working Capital	EPIS.T	74	95,493,209	56,004,584	11,488,013	11,265,546	6,546,690	5,339,553	1,666,535	1,346,078	868,243	871,544	96,444
	Sub-total			95,493,208	56,004,584	11,488,013	11,265,546	6,546,690	5,339,553	1,666,535	1,346,078	868,243	871,544	96,444
	Other Items													
BEP	Bonneville Exchange Power, Tenaska & Cabot	PC3	59	206,861,228	108,126,874	25,056,800	29,105,663	19,576,037	13,862,918	5,432,390	4,871,022	0	757,589	73,135
186.01	Misc Def Debits - Conservation Related	PC3	59	577	302	70	81	55	39	15	14	0	2	0
186.02	Misc Def Debits - WUTC AFUDC Non Project	PTDGP.T	72	32,402,291	19,015,615	3,897,794	3,817,885	2,216,070	1,809,504	563,687	454,824	297,180	296,824	32,908
186.03	Misc Def Debits - Colstrip FERC Adj. - General	GP.T	71	12,307,614	7,222,849	1,480,529	1,450,177	841,747	687,318	214,110	172,759	112,880	112,745	12,500
282	Accum Deferred Income Tax - Prod	PP.T	63	-37,168,678	-19,438,578	-4,604,610	-5,232,499	-3,519,121	-2,492,220	-976,613	-875,693	0	-136,196	-13,148
282.01	Accum Deferred Income Tax - Trans/Dist	TDP.T	65	57,676,154	36,301,158	6,908,161	5,921,190	2,941,372	2,793,777	664,400	445,923	879,686	738,593	83,894
282.02	Accum Deferred Income Tax - Other	PTDGP.T	72	-463,936,503	-272,267,044	-55,808,908	-54,664,769	-31,729,856	-25,908,619	-8,070,914	-6,512,208	-4,256,045	-4,249,955	-471,185
235	Customer Deposits	CUS	14	-13,420,963	-10,908,880	-1,493,272	-535,719	-442,381	-40,731	0	0	0	0	0
252	Customer Advances	CUST_4	3	-60,361,006	-63,519,000	-8,324,991	-470,072	-44,274	0	-2,669	0	0	0	0
	Sub-total			-265,661,306	-165,466,905	-30,790,429	-20,608,063	-10,161,352	-9,268,014	-2,175,594	-1,443,358	-2,965,299	-2,480,397	-281,896
	TOTAL OTHER RATE BASE			-170,168,097	-129,462,341	-19,302,416	-9,342,517	-3,614,662	-3,948,461	-509,059	-97,280	-2,097,056	-1,608,853	-185,452
TOTAL RATE BASE				**3,305,098,647**	**1,914,774,187**	**401,581,260**	**400,140,700**	**231,818,958**	**189,563,006**	**59,201,375**	**47,224,915**	**30,809,860**	**26,527,195**	**3,457,191**

Puget Sound Energy
Public Counsel Electric Class Cost of Service Study
(Expense)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential Sch 7	Sec. Voltage Sch 24	Sec. Voltage Sch 25	Sec. Voltage Sch 26	Prim. Voltage Sch 31/35/43	Campus Sch 40	High Voltage Sch 46/49	Transportation Sch 449/459	Street & Area Lighting	Firm Resale
				4	5	6	7	8	9	10	11	12	13	14
O & M Expenses														
	Production - O&M - Fuel													
FUEL.ST	Steam Prod O&M - Fuel	PP.T	63	60,795,254	31,777,770	7,364,041	8,553,977	5,752,964	4,074,227	1,596,546	1,431,564	0	222,651	21,494
FUEL.OT	Other Prod O&M - Fuel	PP.T	63	126,387,410	66,062,888	15,309,123	17,782,885	11,959,893	8,469,921	3,319,064	2,976,082	0	462,870	44,664
	Sub-total			187,182,664	97,840,659	22,673,164	26,336,862	17,712,877	12,544,146	4,915,611	4,407,645	0	685,521	66,178
	Production - O&M - Purchase Power													
555	Purch Pwr - Other	PC3	59	728,285,381	380,676,859	88,216,148	102,470,788	68,916,797	48,806,442	19,125,529	17,149,151	0	2,667,205	257,482
555.01	Purch Pwr - Res Exchange	BPAX	55	0	0	0	0	0	0	0	0	0	0	0
555.02	Purch Pwr - Transp Ancillary	ANCIL	49	695,897	0	0	0	0	0	0	0	694,664	0	1,233
555.03	Purch Pwr - Transp Imbalance	ANCIL	49	691,750	0	0	0	0	0	0	0	690,524	0	1,226
557	Regulation & Frequency Response	ENERGY_1	53	15,104,630	6,915,268	1,690,277	1,965,115	1,354,013	964,624	385,709	343,444	1,316,043	51,405	96,933
	Sub-total			744,777,857	387,591,127	89,906,426	104,455,882	70,270,810	49,771,068	19,511,238	17,492,595	2,703,231	2,718,610	356,873
	Production - O&M - Wheeling													
565	Wheeling by Others - Wheeling	PP.T	63	69,765,605	36,488,586	8,450,606	9,616,118	6,601,838	4,675,380	1,832,117	1,642,791	0	255,503	24,685
	Sub-total			69,765,605	36,466,586	8,450,606	9,616,118	6,601,838	4,675,380	1,832,117	1,642,791	0	255,503	24,685
	Production - O&M - Other													
500	Steam Prod O&M	PP.T	63	35,655,505	18,637,186	4,318,699	5,016,779	3,374,039	2,389,473	936,351	839,591	0	130,581	12,606
535	Hydro Prod O&M - O&M	PP.T	63	15,167,314	7,927,976	1,837,195	2,134,062	1,435,265	1,016,446	398,309	357,149	0	55,547	5,362
545	Other Prod O&M - O&M	PP.T	63	45,748,396	23,912,755	5,541,437	6,436,863	4,329,117	3,065,654	1,201,400	1,077,251	0	167,545	16,174
556	System Control & Load Dispatch	ENERGY_1	53	841,961	365,465	94,216	110,653	75,474	53,769	21,500	19,144	73,469	2,865	5,403
	Sub-total			97,413,176	50,863,384	11,791,749	13,698,357	9,213,896	6,525,542	2,557,560	2,293,135	73,469	356,539	39,545
	Transmission - O&M													
565.01	Transmission O&M	TP.T	64	10,232,042	5,056,530	1,170,744	1,359,665	914,221	647,378	253,594	227,417	526,951	35,394	40,149
565.02	Transmission O&M - Direct Assigned	DIR565.02	50	115,688	0	0	0	0	0	0	0	109,261	0	6,427
	Sub-total			10,347,730	5,056,530	1,170,744	1,359,665	914,221	647,378	253,594	227,417	636,212	35,394	46,576
	Distribution Expense - Operating													
581	Dist O&M - Load Dispatch	DEM_12NCI	47	5,026,360	2,979,526	599,514	670,091	396,044	355,174	0	0	0	33,986	2,026
582	Dist O&M - Station	D362.T	Acct 362	1,713,652	853,634	218,279	223,832	143,926	115,367	29,694	39,794	77,768	7,823	3,712
583	Dist O&M - OVHD Lines	D364.T	Acct 364	1,918,424	1,319,248	230,498	182,247	67,150	103,193	3,191	0	215	8,670	1,811
584	Dist O&M - UNGD Lines	D366.T	Acct 366	2,670,432	1,802,825	297,801	269,359	124,535	124,076	31,800	3,921	326	14,082	2,099
585	Dist O&M - Street Lighting	DIR373.00	Acct 373	1,258,852									1,258,852	
586	Dist O&M - Meter	D370.T	Acct 370	1,677,243	898,321	338,175	124,088	12,971	183,377	7,704	6,584	3,732	0	2,291
587	Dist O&M - Cust Installations - Meters	D370.T	Acct 370	3,056,150	1,740,635	655,266	240,440	25,134	355,320	14,927	12,757	7,231	0	4,439
589	Dist O&M - Rents	DEM_12NCI	47	436,263	256,608	51,167	58,161	34,375	30,827	0	0	0	2,950	176
580	Dist O&M - Supr & Eng	DES1.T	Acct 581 to 589	2,035,205	1,135,748	274,410	203,806	92,696	146,093	10,055	7,269	10,291	152,919	1,908
588	Dist O&M - Miscellaneous	DES1.T	Acct 581 to 589	1,485,164	828,808	200,250	148,727	67,645	106,611	7,345	5,304	7,510	111,592	1,392
	Sub-total			21,175,765	11,617,153	2,855,160	2,120,550	964,477	1,520,059	104,726	75,828	107,072	1,591,085	19,854
	Customer Accounts Expense													
901	CAE - Suprv	CAES1.T	Accts 902-905	222,285	164,013	39,089	7,830	2,815	3,022	2,446	1,392	908	680	90
902	CAE - Meter Reading	CUST_6	5	16,085,014	11,461,990	4,051,903	406,346	42,860	36,085	4,038	31,452	28,307	0	2,052
903	CAE - Records & Collections		4	16,729,057	13,681,729	2,068,353	229,013	21,569	143,736	316,611	125,068	73,588	61,877	7,311
904	CAE - Uncollect Accts	PTDP.T	62	6,301,611	3,698,165	758,045	742,504	430,082	351,913	109,626	88,454	57,796	57,727	6,400
905	CAE - Miscellaneous	CUST_1	2	-2,437	-2,153	-254	-19	-2	-2	0	0	0	-7	0

	Sub-total			39,335,530	29,023,744	6,017,135	1,385,675	498,225	534,734	432,622	246,366	160,599	120,276	15,853
	Customer Service & Information Expense													
908.01	Cust Svc Exp - Cust Assistance	DIR908.01	26	662,257	589,860	64,695	4,608	453	401	41	11	11	1,871	5
908.02	Cust Svc Exp - Weatherization	PC3	59	5,111	2,872	619	719	484	343	134	120	0	19	2
909	Cust Svc Exp - Info & Instruct	CUST_1	2	989,686	874,229	103,318	7,679	723	641	65	18	17	2,988	9
911	Cust Svc Exp - Demonstration	DIR373.00 Dir		1,368									1,368	
912	Cust Svc Exp - Demonstration & Selling	CUST_1	2	254,738	225,020	26,593	1,976	186	165	17	5	4	769	2
913	Cust Svc Exp - Advertising	CUST_1	2	66,097	58,386	6,900	513	48	43	4	1	1	200	1
916	Cust Svc Exp - Misc Selling	CUST_1	2	105,999	93,633	11,066	822	77	69	7	2	2	320	1
	Sub-total			2,085,256	1,843,899	213,192	16,517	1,972	1,661	269	158	35	7,534	19
	General Expenses													
920	A&G Exp - Salaries	ADJPTDCE.	73	17,982,689	10,474,904	2,322,557	1,936,813	1,150,041	974,247	309,116	256,271	193,912	342,235	20,493
920.01	A&G Exp - Salaries - Dir Assign	DIR920.01	27	259,892	0	0	0	0	0	142,447	39,225	73,989	0	4,231
921	A&G Exp - Office Supplies	ADJPTDCE.	73	12,777,189	7,442,733	1,650,246	1,377,585	617,139	692,232	219,636	182,088	137,780	243,168	14,561
922	A&G Exp - Transf (credit)	ADJPTDCE.	73	-101,798	-59,298	-13,148	-10,976	-6,510	-5,515	-1,750	-1,451	-1,098	-1,937	-116
923	A&G Exp - Outside Svcs	ADJPTDCE.	73	7,527,593	4,384,842	972,233	811,596	481,412	407,824	129,397	107,276	81,172	143,281	8,579
924	A&G Exp - Prop Insurance - Other	PTDGP.T	72	3,697,809	2,170,097	444,823	435,704	252,902	206,504	84,329	51,905	33,915	33,874	3,756
925	A&G Exp - Injuries & Damages - Other	SW.T	78	6,030,236	3,705,309	767,764	595,774	337,355	320,780	95,759	73,738	40,951	87,780	5,046
926	A&G Exp - Pensions & Benefits	SW.T	78	17,124,886	10,522,474	2,180,324	1,691,900	958,034	910,907	271,940	209,403	116,293	249,281	14,330
928	A&G Exp - Reg Comm Exp - WUTC Fees	RETAIL RAT	80	3,628,231	1,942,595	445,123	515,018	314,000	221,729	78,941	62,963	17,109	30,499	2,255
928	A&G Exp - Reg Comm Exp - Non WUTC Fees	PTDP.T	62	2,075,607	1,218,091	249,663	244,564	141,956	115,912	36,108	29,135	19,037	19,014	2,108
930	A&G Exp - Miscellaneous	ADJPTDCE.	73	3,040,720	1,771,227	392,727	327,839	194,463	164,738	52,269	43,333	32,789	57,869	3,465
931	A&G Exp - Rents	ADJPTDCE.	73	4,402,309	2,564,358	568,564	474,640	281,541	238,505	75,674	62,738	47,472	83,782	5,017
	Sub-total			78,445,241	46,137,330	9,960,816	8,402,457	4,922,334	4,247,842	1,471,866	1,116,624	783,320	1,288,827	83,725
	TOTAL OPERATING EXPENSES			1,250,528,624	666,840,411	153,959,090	167,592,083	111,100,551	80,467,810	31,079,904	27,502,360	4,473,938	7,059,269	653,289
	Distribution Expense - Maintenance													
591	Dist O&M - Structure	D361.T	Acct 361	179	81	21	24	19	14	3	7	9	1	1
592	Dist O&M - Station Eqpt	D362.T	Acct 362	4,405,173	2,194,361	561,117	574,875	369,985	296,819	76,332	102,297	189,912	20,111	9,543
593	Dist O&M - OVHD Lines	D364.T	Acct 364	28,941,806	18,923,266	3,480,974	2,752,287	1,014,101	1,558,424	48,186	0	3,252	133,960	27,347
594	Dist O&M - UNGD Lines	D366.T	Acct 366	10,457,286	7,085,744	1,166,507	1,055,804	488,138	486,340	124,646	15,389	1,276	55,235	8,228
595	Dist O&M - Lines Transformers	D368.T	Acct 368	324,038	228,048	52,867	32,678	8,245	955	1,071	0	0	138	18
596	Dist O&M - Street Lighting	DIR373.00	Dir	2,039,684									2,039,684	
597	Dist O&M - Meters	D370.T	Acct 370	217,074	123,635	46,543	17,078	1,785	25,238	1,080	906	514	0	315
590	Dist O&M - Supr & Eng	DES2.T	Acct 591 to 597	39,755	25,306	4,548	3,798	1,613	2,029	216	102	176	1,927	39
	Sub-total			46,434,875	29,560,481	5,312,597	4,436,555	1,883,887	2,369,817	251,514	118,679	205,139	2,251,036	45,490
	General Expense - Maintenance & Other													
935	A&G Exp - Maint of Gen Plant	GP.T	71	3,399,565	1,995,069	408,846	400,663	232,604	189,849	59,141	47,719	31,179	31,142	3,453
411.01	Regulatory Debit	PP.T	63	17,719,489	9,262,003	2,146,336	2,493,157	1,676,775	1,187,481	465,332	417,246	0	84,894	6,265
411.02	Gain / Loss on Disposition of Plant	TDP.T	85	-2,762,428	-1,757,644	-334,366	-286,678	-142,408	-135,263	-32,167	-21,590	-42,591	-35,759	-4,062
411.03	Gain From Disposition - Production	PP.T	63	-420,047	-219,559	-50,880	-59,101	-39,749	-28,150	-11,031	-9,891	0	-1,538	-149
411.04	Other Utility Operating Income - FAS133	POWER.T	77	0	0	0	0	0	0	0	0	0	0	0
411.05	Loss on FV of OPT - FAS133	POWER.T	77	-10,843,497	-5,647,268	-1,309,569	-1,521,400	-1,023,412	-724,632	-284,115	-254,731	-33,356	-39,598	-5,217
	Sub-total			7,083,082	3,632,702	860,468	1,026,540	703,710	489,085	197,160	178,754	-44,767	18,141	290
	TOTAL MAINTENANCE EXPENSES			53,498,057	33,193,153	6,173,065	5,463,095	2,587,597	2,858,703	448,674	297,433	160,372	2,270,177	45,780
	TOTAL O & M EXPENSES			1,304,026,681	699,833,574	160,132,154	173,055,178	113,688,247	83,326,513	31,528,577	27,799,793	4,634,310	9,329,466	699,068
Depreciation Expense														
403.01	Depr Exp - Production Steam Baseload	PP.T	63	28,694,254	14,898,529	3,476,693	4,037,321	2,715,304	1,922,961	753,541	675,672	0	105,087	10,145
403.02	Depr Exp - Production Hydro	PP.T	63	4,854,139	2,537,266	587,975	682,984	459,342	325,303	127,475	114,302	0	17,777	1,716
403.03	Depr Exp - Production Other	PP.T	63	30,491,286	15,937,841	3,693,365	4,290,166	2,885,355	2,043,390	800,733	717,987	0	111,668	10,780
403.04	Depr Exp - Transmission	TP.T	64	6,688,117	3,305,172	765,250	886,738	597,575	423,155	165,760	148,650	344,439	23,135	26,243

403.05	Depr Exp - Distribution	DP.T	66	80,211,030	52,792,135	9,695,306	7,718,917	3,436,083	3,632,233	697,803	372,778	604,756	1,166,691	74,530
403.06	Depr Exp - General	GP.T	71	19,713,263	11,568,930	2,371,383	2,322,767	1,348,237	1,100,886	342,942	276,711	180,802	180,585	20,021
403.07	Depr Exp - FAS 143	PP.T	63	426,601	222,985	51,674	60,023	40,369	26,589	11,203	10,045	0	1,562	151
403.08	Depr Exp - VROW	DP.T	66	4,430,220	2,915,818	535,492	426,332	189,782	200,816	38,530	20,589	33,402	65,543	4,116
404	Amort Exp - Limited Term Plant - Hydro Prod	PP.T	63	979,509	511,991	118,647	137,616	92,890	65,642	25,723	23,065	0	3,587	346
404.01	Amort Exp - Limited Term Plant - Other Prod	PP.T	63	22,699	11,969	2,774	3,222	2,167	1,535	601	539	0	84	8
404.02	Amort Exp - Limited Term Plant - General	GP.T	71	24,914,335	14,621,232	2,997,039	2,935,597	1,703,951	1,391,340	433,423	349,717	228,504	228,230	25,303
404.03	Amort Exp - FAS 143	PP.T	63	660,096	345,033	79,956	92,876	62,464	44,237	17,335	15,543	0	2,417	233
405	Amort Exp - WUTC AFUDC - Non Project	PTDP.T	62	1,409,935	827,435	169,606	166,129	96,429	76,736	24,526	19,791	12,931	12,916	1,432
405	Amort Exp - Acq Adjustment - Transmission	PC4	80	25,600	12,299	2,846	3,305	2,222	1,573	616	553	2,143	86	158
406.01	Amort Exp - Acq Adjustment - Distribution	DP.T	66	11,200	7,371	1,354	1,078	460	507	97	52	84	166	10
406.02	Amort Exp - FERC Colstrip - Production	PP.T	63	715,263	373,879	86,641	100,641	67,686	47,935	18,784	16,843	0	2,620	253
406.03	Amort Exp - Acq Adjustment - Encogen	PP.T	63	4,332,173	2,264,439	524,760	609,543	409,948	290,323	113,767	102,011	0	15,866	1,532
407	Amort Exp - Property Losses	PP.T	63	1,537,229	803,512	186,202	216,290	145,486	103,018	40,369	36,198	0	5,630	543
407.01	Amort Exp - Storm T&D	TDP.T	65	23,369,642	14,721,354	2,800,683	2,401,244	1,192,826	1,132,972	269,437	180,837	356,743	299,525	34,022
	TOTAL DEPRECIATION EXPENSES			**233,507,011**	**138,779,184**	**28,146,635**	**27,094,992**	**15,446,375**	**12,634,951**	**3,882,467**	**3,061,883**	**1,763,804**	**2,263,176**	**211,543**
Taxes (other than Income)														
236	Property Taxes	PTDGP.T	72	36,842,385	21,621,330	4,431,909	4,341,051	2,519,738	2,057,461	640,929	517,149	337,903	337,498	37,418
236.11	Payroll Taxes	SW.T	78	6,739,597	4,141,180	858,078	665,857	377,040	358,493	107,023	82,412	45,768	98,106	5,640
236.21	Other Taxes - Wash Excise - Allocated	RETAIL RAT	80	70,768,716	37,889,277	8,681,864	10,045,145	6,124,412	4,324,709	1,500,688	1,228,053	333,699	594,885	43,984
236.24	Other Taxes - MT Corp Lic	REVFAC1.T	78	451,680	246,754	55,245	56,157	36,961	27,884	10,042	8,664	2,243	3,440	299
236.25	Other Taxes - MT Elec Energy Lic	ENERGY_1	53	1,590,441	723,555	176,856	207,706	141,672	100,930	40,357	35,935	137,909	5,379	10,142
	TOTAL TAXES OTHER THAN INCOME			**116,380,829**	**64,624,096**	**14,203,973**	**15,317,915**	**9,199,824**	**6,869,477**	**2,299,040**	**1,872,212**	**857,521**	**1,039,288**	**97,483**

INCOME TAXES

409.10	Current Federal Income Tax @ Rate	RB.T	75	-40,382,647	Class Income Taxes are Calculated and Not Allocated
410.10	Provision for Def Inc Tax	RB.T	75	155,001,217	Class Income Taxes are Calculated and Not Allocated
411.10	Prov for Def Income Tax (Credit)	RB.T	75	-62,644,985	Class Income Taxes are Calculated and Not Allocated
	TOTAL FIT			51,973,585	Class Income Taxes are Calculated and Not Allocated

Puget Sound Energy
Public Counsel Electric Class Cost of Service Study
(Revenue)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential Sch 7	Sec. Voltage Sch 24	Sec. Voltage Sch 25	Sec. Voltage Sch 26	Prim. Voltage Sch 31/35/43	Campus Sch 40	High Voltage Sch 46/49	Transportation Sch 449/459	Street & Area Lighting	Firm Resale
				4	5	6	7	8	9	10	11	12	13	14
REVENUE														
447	Sales of Electricity - Firm Revenue	PROFORMA_RETAIL		1,821,740,023	980,874,299	224,604,546	259,853,388	158,401,794	111,882,634	38,799,981	31,773,067	0	15,450,314	0
447.01	Sales of Electricity - Transportation Revenue - R	DIR_449		6,435,623	0	0	0	0	0	0	0	6,435,623	0	0
447.02	Sales of Electricity - Small Firm Resale	DIR_RESALE_SMALL		355,704	0	0	0	0	0	0	0	0	0	355,704
447.03	Sales of Electricity - Unbilled Revenue	UNBILLED		6,354,482	3,116,081	668,234	1,047,085	666,299	442,141	177,079	122,890	-105,327	0	0
447.04	Other Elect Revenue - OATT - Sch 449	DIR_449_OATT		2,336,798	0	0	0	0	0	0	0	2,336,798	0	0
447.05	Other Elect Revenue - Firm Resale	DIR_RESALE_LARGE		786,676	0	0	0	0	0	0	0	0	0	786,676
	SALES REVENUE			1,838,009,306	984,090,360	225,492,780	260,900,473	159,068,093	112,324,775	38,977,060	31,895,957	8,667,094	15,450,314	1,142,380
NON FIRM REVENUE														
447.07	Sales of Electricity - Non Firm Revenue			6,086,572	3,260,843	727,003	837,401	657,027	392,619	151,342	136,487	0	21,683	2,167
	TOTAL NON FIRM REVENUE			6,086,572	3,260,843	727,003	837,401	657,027	392,619	151,342	136,487	0	21,683	2,167
OTHER OPERATING REVENUE														
450.01	Late Payment Revenue - Interest	DIR450.01	1	2,866,365	2,306,882	315,956	156,743	52,837	38,998	3,469	8,181	2,555	2,745	0
450.02	Late Payment Revenue - Field Call	DIR450.02	26	335,677	299,962	33,687	1,644	0	27	0	0	0	458	0
451.01	Misc Service Revenue - Temporary Service	CUST_4	3	1,054,095	934,812	110,454	8,209	773	0	47	0	0	0	0
451.02	Misc Service Revenue - Seas Svc Charge	DIR451.02	11	299	26	26	247	0	0	0	0	0	0	0
451.03	Misc Service Revenue - Reconnection Charge	DIR451.03	22	1,091,204	1,067,434	22,626	1,030	0	38	0	0	0	76	0
451.04	Misc Service Revenue - Modified Service Charg	CUST_4	3	803,586	712,500	84,205	6,258	589	0	36	0	0	0	0
451.05	Misc Service Revenue - Water Heater Rental	DIR451.05	13	7,628	6,227	1,341	60	0	0	0	0	0	0	0
451.06	Misc Service Revenue - Billing Initiation Charge	DIR451.06	16	1,240,167	1,141,099	95,159	3,480	365	57	7	0	0	0	0
451.07	Misc Service Revenue - NSF Handling Chg	DIR451.07	21	190,792	180,834	9,334	402	28	42	0	0	28	125	0
451.08	Misc Service Revenue - Deferred FIT CIAC	CUST_4	3	9,868,651	8,767,936	1,036,214	77,011	7,253	0	437	0	0	0	0
454.04	Rental Revenue - Transf & Equip	DIR454.04	12	2,624,783	0	0	0	0	458,655	73,798	1,069,030	1,019,808	0	3,493
454.01	Rental Revenue - Steam Plant	PP.T	63	38,300	20,019	4,639	6,389	3,624	2,567	1,006	902	0	140	14
454.03	Rental Revenue - Distribution Pole Contacts	D364.T		4,858,526	3,344,563	584,359	462,034	170,239	261,616	8,099	0	646	22,488	4,591
454.05	Rental Revenue - Personal Cell Site	D364.T		3,050,165	2,099,705	366,858	290,063	106,876	164,242	5,078	0	343	14,118	2,882
454.07	Rental Revenue - Pole Rental	DIR373.00	Dir	47,934									47,934	
454.08	Rental Revenue - Land & Bldg	PTDP.T	82	609,645	357,776	73,336	71,833	41,695	34,046	10,606	8,557	5,591	5,585	619
454.08	Rental Revenue - Reserve of Power Capacity	DIR_40	Dir	22,372						22,372				
456.13	Other Elect Revenue - CLX Reconciliation Adjus	CUST_5	4	-733	-599	-91	-10	-1	-5	-14	-5	-3	-3	0
456.01	Other Elect Revenue - Wheeling	PC3	59	6,835,150	3,672,743	827,932	961,715	646,802	458,061	179,498	160,949	0	25,032	2,417
456.05	Other Elect Revenue - Dist O&M	LINE.T	61	72,853	49,478	8,318	7,219	3,137	3,551	637	74	9	370	61
456.08	Other Elect Revenue - PCS	D364.T		790,443	544,133	95,070	75,169	27,697	42,563	1,316	0	89	3,659	747
456.09	Other Elect Revenue - Non-Core Gas Sales	PP.T	63	947,407	495,211	114,758	133,301	89,652	63,491	24,880	22,309	0	3,470	335
456.14	Other Elect Revenue -Green Energy Option	PC3	59	0	0	0	0	0	0	0	0	0	0	0
456.16	Other Elect Revenue - Intollight	DIR373.00	Dir	-2,393									-2,393	
456.17	Other Elect Revenue - AG Settlement	DIR_449	20	-190	0	0	0	0	0	0	0	-190	0	0
	TOTAL OTHER OPERATING INCOME			37,392,928	25,900,543	3,784,061	2,261,798	1,151,567	1,527,946	331,262	1,267,996	1,028,775	123,804	15,157
	TOTAL REVENUE			1,881,488,806	1,013,251,566	230,003,864	263,999,672	160,776,687	114,245,340	39,459,664	33,300,440	9,695,869	15,596,801	1,159,704

Puget Sound Energy
Public Counsel Electric Class Cost of Service Study
(Allocator Amounts)

	Acct. No.	Account Description	Alloc	Total	Residential Sch 7	Sec. Voltage Sch 24	Sec. Voltage Sch 25	Sec. Voltage Sch 26	Prim. Voltage Sch 31/35/43	Campus Sch 40	High Voltage Sch 46/49	Transportation Sch 449/459	Street & Area Lighting	Firm Resale	Transp HV 449	Lighting 50-59	Firm Resale Large	Firm Resale Small
				4	5	6	7	8	9	10	11	12	13	14				
1	DIR450.01	Late Payment Interest Rev		2768118.39	2212375.56	303012.05	150321.51	50871.96	35510.11	1.02	1889.25	3328.96	5927.37	0	2449.88	2832.72	0	0
2	CUST_1	Ave. No. Cust.		1044131	922322	109002	8101	763	493	1	182	69	19	3	15	3152	1	8
3	CUST_4	Ave. No. Cust Incl. RES & SEC Only		1040234	922322	109002	8101	763	0	0	0	46	0	0	0	0	0	0
4	CUST_5	Wtd. Ave. No. Cust. CAE - NO HV		15304958	12517041	1892260	209518	19733	95902	195	35403	289842	114421	8224	59100	56610	3940	2749
5	CUST_6	Wtd. Ave. No. Sch. Mtr Reading		16075226	11475003	4049437	406099	42834	25589	58	10396	4036	31433	4715	23575	0	1572	479
6	METER	Meter Investment		101649191	57894460	21794507	7997182	835977	8756854	17602	3043684	496496	424297	35204	205305	0	18403.667	131229.33
7	DIR368.03C	Line Transformers - Customer Related		2244856	0	0	0	0	989588	0	59625	1176246	0	0	0	0	0	19397
8	DIR372.00	Leased Wtr. Htrs.		732314	725911	6127	276	0	0	0	0	0	0	0	0	0	0	0
9	UNBILLED	Direct Assignment of Unbilled Revenue		6354482	3118061	888234	1047085	668299	407135	2180	32826	177079	122890	-5659	-99668	0	0	0
10	PROFORMA	Proforma Revenue		1829318043	980974300	224604546	259853388	158401794	98820701	245245	12816688	38799981	31773067	855758	5580880	15450314	786677	355704
11	DIR451.02	Seasonal Svc. Chgs.		57	5	5	47	0	0	0	0	0	0	0	0	0	0	0
12	DIR454.04	Equip. (Transf.) Rentals		2572298	0	0	0	0	433723	0	15778	72325	1047694	0	998455	0	0	3423
13	DIR451.05	Water Htr. Rentals		10218.94	8342.07	1795.87	81	0	0	0	0	0	0	0	0	0	0	0
14	DIR235.00	Customer Deposits		10354938	8416729	1152132	413333	341318	31426	0	0	0	0	0	0	0	0	0
15	PROFORMA_RETAIL	Proforma Retail Revenue - No Transportation		1821740024	980974300	224604546	259853388	158401794	98820701	245245	12816688	38799981	31773067	0	0	15450314	0	0
16	OH_TFMRC	Allocate Overhead Transformers		302025535	252283935	42311352	7059499	76232	0	0	0	0	0	0	0	294517	0	0
17	UG_TFMRC	Allocate Underground Transformers		334740770	213687878	59426156	48345761	13237715	0	0	0	0	0	0	0	43240	0	0
18	DIR451.06	Acct. Svc. Chgs. Rev.		1248756.66	1149004.64	95817.76	3503.66	367.8	57.5	0	0	7.5	0	0	0	0	0	0
19	DIR_RESALE	Firm Resale Allocation Only Excise Tax		39792.42	0	0	0	0	0	0	0	0	0	0	0	0	27351.6	12440.82
20	DIR_449	Schedule 449 / 459 Allocation Only		6436638	0	0	0	0	0	0	0	0	0	855758	5580880	0	0	0
21	DIR451.07	NSF Check Charge Revenue		220096	208608	10768	464	32	48	0	0	0	0	0	32	144	0	0
22	DIR451.03	Connect/Reconnect Revenue		1063335.7	1040368.7	22052	1004	0	37	0	0	0	0	0	0	74	0	0
23	OH_SVC	Dist OH Services		418388	360703	53379	2282	24	0	0	0	0	0	0	0	0	0	0
24	DIR_449_OATT	Transportation OATT Revenue		2335798.16	0	0	0	0	0	0	0	0	0	-6286.1	2343084.3	0	0	0
25	PROFORMA_RETAIL_TA	Proforma State Revenue		1828178662	980974300	224604546	259853388	158401794	98820701	245245	12816688	38799981	31773067	855758	5580880	15450314	0	0
26	DIR908.01	Direct Assign A/C 908		866796	772170	84676	6293	593	363	1	141	54	15	2	12	2449	1	8
27	DIR920.01	Direct Assign A/C 920.01		259682	0	0	0	0	0	0	0	142447	39225	10526	63463	0	4231	0
28	DIR450.02	Direct Assign Disconnect Call - A/C 450.02		323908	289445	32409	1586	0	26	0	0	0	0	0	0	442	0	0
29	DEM_1	Annual Kw - Top 200 Hours		4170502	2388268	422689	451855	274115	186975	5	37448	60605	65280	14519	238832	11240	17197	1474
30	NCP_360	Allocate Substation Land - 12 NCP		12599969	5496141	1884919	2287884	1891603	875177	637	118026	0	0	118585	0	124624	0	573
31	NCP_361	Allocate Substation Structures - 12 NCP		4038630	2003488	528202	604753	496605	299587	0	56288	0	0	17329	0	32314	0	64
32	NCP_362	Allocate Substation Equipment - 12 NCP		572847657	311865723	81957684	81069773	51487815	35088781	251204	8549745	0	0	1361347	0	3055557	0	140228
33	DIR360.01	Direct Assign Substation Land		1012963	0	0	0	0	0	0	0	522557	469441	0	0	0	20333	632
34	DIR361.01	Direct Assign Substation Structures		518714.01	0.01	0	0	0	0	0	0	91746	211615	0	196543	0	14521	89
35	DIR362.01	Direct Assign Substation Equipment		22590134.01	0.01	0	0	0	465179	0	0	4746514	7375036	0	9780010	0	162281	61132
36	DIR364.01	Direct Assign OH Dist Lines		957726	0	0	0	0	0	0	0	783835	0	0	0	0	173891	0
37	DIR366.01	Direct Assign OH Dist Lines		14563077	0	0	0	0	0	0	0	12557576	1546219	0	0	0	557282	0
38	DIR368.03	Line Transformers		2244856	0	0	0	0	989588	0	59625	1176246	0	0	0	0	0	19397
39	OH_NCP	Allocate Overhead Lines - 12 NCP		10213.4	7045.14	1230.92	973.25	358.6	398.89	12.63	139.56	0	0	1.15	0	47.37	0	5.89
40	UG_NCP	Allocate Underground Lines - 12 NCP		9300.48	6366.64	1051.09	851.34	439.64	298.24	3.65	136.13	0	0	1.15	0	49.77	0	2.43
41	OH_TFMR	Allocate Overhead Transformers		302025535	252283935	42311352	7059499	76232	0	0	0	0	0	0	0	294517	0	0
42	UG_TFMR	Allocate Underground Transformers		334740770	213687878	59426156	48345761	13237715	0	0	0	0	0	0	0	43240	0	0
43	DIR106.09	Dist Accum Depr - Subs & Lines		-17269940.78	0	0	0	0	-100001.98	0	0	-8536059.8	-3575622.182	0	-4723210	0	-326057.7	-28989.305
44	DEM_1A	200 CP Demand Excl. Interruptible		4126524	2388268	422689	451855	274115	186975	5	0	60605	58750	14519	238832	11240	17197	1474
45	DEM_12CP	12 Monthly CP Demand		3772628	1916008	412716	489384	299371	204805	535	32355	84728	68203	14727	242349	7951	18465	1031
46	DEM_12NCP2	Dist 12 NCP Dem, Excl Dir Assn Transf (No HV, PRI & FR)		4328974	2762443	546563	821269	367189	0	0	0	0	0	0	0	31510	0	0
47	DEM_12NCP1	12 NCP Distribution Demand (No HV, LFR, Trans)		4660149	2762443	546563	821269	367189	253690	1958	73649	0	0	0	0	31510	0	1678
48	DEM_2A	200 CP Demand - NO RETAIL WHEELING & INTERRUPT		3855976	2388268	422689	451855	274115	186975	5	0	60605	58750	0	0	11240	0	1474
49	ANCIL	Transportation Ancillary Exp		1388659.072	0	0	0	0	0	0	0	0	0	-60950.4703	1447149.4	0	2450.19	0
50	DIR565.02	Direct Assign A/C 565.02		115688.01	0.01	0	0	0	0	0	0	0	0	12854	96407	0	6427	0
51	DEM_3B	Top 75 CP - No Interruptibles		4277389	2498708	433094	467088	282773	190771	5	0	61983	59567	14590	239439	12698	17278	1495
52	DEM_3A	Top 75 CP - No Interruptibles or Transportation		4006082	2498708	433094	467088	282773	190771	5	0	61983	59567	0	0	12598	0	1495
53	ENERGY_1	Annual kWhs		25203044595	11538414973	2820298304	3312247709	2259228104	1430742880	5063752	173706788	643571762	573051540	123721455	2.075E+09	85771201	153736746	7999367
54	DIR_449_ENERGY	Schedule 449 / 459 Energy Allocation		2199209489	0	0	0	0	0	0	0	0	0	123721455	2.075E+09	0	0	0
55	BPAX	BPA Residential Exchange kWh		1128124215	10744798449	287626642	189481705	24396882	27948701	4620400	0	0	0	0	0	2170456	0	0
56	ENERGY_2	Energy - NO RETAIL WHEELING		22850098360	11538414973	2820298304	3312247709	2259228104	1430742880	5063752	173706788	643571762	573051540	0	0	85771201	0	7999367
57	DEM_12NCP_P	12 NCP Distribution Demand (No HV)		4701071	2762443	546563	821269	367189	253690	1958	73649	0	0	16669	0	31510	24233	1678
58	DEM_12NCP_S	Dist 12 NCP Dem, Excl Dir Assn Transf (No HV, PRI & FR)		4328974	2762443	546563	821269	367189	0	0	0	0	0	0	0	31510	0	0
59	PC3			100.000000%	52.270150%	12.112854%	14.070139%	9.482883%	6.036521%	0.016855%	0.646179%	2.628104%	2.354730%	0.000000%	0.000000%	0.386231%	0.000000%	0.035355%
60	PC4			100.000000%	47.570041%	11.030541%	12.808904%	8.611124%	5.494334%	0.017096%	0.585852%	2.387876%	2.141569%	0.486428%	7.839476%	0.333451%	0.579085%	0.032221%
61	Line.T	Dist. Poles, lines, conductors		1,525,329,156	1,035,834,184	174,145,415	151,139,250	65,674,156	74,347,421	Included in Svc 31	Included in Svc 31	13,341,411	1,546,219	181,482	Included in PV 449 7,743,820	1,273,818	Included in Lg Resale	

62 PTDP.T	Prod Trans Dist Plant	5,415,920,847	3,178,388,406	651,501,500	638,145,061	370,407,689	302,451,791	Included in Svc 31	Included in Svc 31	94,218,153	76,022,148	49,672,503	Included in PV 449	49,613,081	5,500,515	Included in Lg Resale
63 PP.T	Prod Plant	2,158,169,302	1,128,601,027	261,537,035	303,798,128	204,319,675	144,897,908	Included in Svc 31	Included in Svc 31	56,702,025	50,842,597	0	Included in PV 449	7,907,542	763,365	Included in Lg Resale
64 TP.T	Trans Plant	671,276,659	282,368,213	85,376,554	75,926,297	51,051,841	36,150,628	Included in Svc 31	Included in Svc 31	14,161,168	12,899,376	29,425,945	Included in PV 449	1,976,456	2,241,862	Included in Lg Resale
65 TDP.T	Trans & Dist Plant	3,256,751,545	2,049,787,279	389,964,464	334,346,933	186,088,013	157,753,883	Included in Svc 31	Included in Svc 31	37,516,129	25,179,531	49,672,503	Included in PV 449	41,705,539	4,737,150	Included in Lg Resale
66 DP.T	Dist Plant	2,885,374,886	1,787,421,166	324,567,910	258,420,636	115,036,173	121,803,055	Included in Svc 31	Included in Svc 31	23,354,961	12,480,175	20,248,558	Included in PV 449	39,729,084	2,495,168	Included in Lg Resale
67	Customer Accts Expenses excluding Uncollect	-4,216,355	-1,854,265	-544,853	-725,068	-429,010	-350,252	Included in Svc 31	Included in Svc 31	-109,357	-88,297	-57,781	Included in PV 449	-50,193	-6,381	Included in Lg Resale
68	Customer Service Expenses	2,085,256	1,843,899	213,192	16,517	1,972	1,681	Included in Svc 31	Included in Svc 31	269	158	35	Included in PV 449	7,534	19	Included in Lg Resale
69 SW.T	Total Salaries & Wages	66,490,363	41,599,450	8,545,518	6,589,858	3,636,339	3,071,807	Included in Svc 31	Included in Svc 31	969,189	754,733	400,788	Included in PV 449	851,142	49,745	Included in Lg Resale
70 SWPTD.T	Salaries & Wages P,T,D related	34,492,559	20,771,145	4,168,849	3,942,925	2,206,155	1,866,751	Included in Svc 31	Included in Svc 31	547,250	426,532	184,014	Included in PV 449	352,910	26,030	Included in Lg Resale
71 GP.T	General Plant	282,481,059	165,776,882	33,980,710	33,284,071	19,319,550	15,775,139	Included in Svc 31	Included in Svc 31	4,914,186	3,985,128	2,590,795	Included in PV 449	2,567,698	268,893	Included in Lg Resale
72 PTDGP.T	Prod/Trans/Dist/Gen'l Plant	6,698,401,906	3,344,165,297	688,482,209	671,429,132	389,727,239	318,226,929	Included in Svc 31	Included in Svc 31	99,132,339	79,987,276	52,263,298	Included in PV 449	52,200,777	5,787,408	Included in Lg Resale
73 adjptdce.t	Adj Total Prod Trans Dist & Cust Exp	231,892,151	135,077,767	29,950,234	25,001,715	14,830,207	12,583,273	Included in Svc 31	Included in Svc 31	3,986,160	3,304,707	2,500,568	Included in PV 449	4,413,251	264,269	Included in Lg Resale
74 EPIS.t	Elect Plant In Service	5,928,416,660	3,476,860,770	713,199,926	699,388,718	408,432,243	331,490,882	Included in Svc 31	Included in Svc 31	103,461,978	83,567,345	53,902,316	Included in PV 449	54,107,267	5,987,433	Included in Lg Resale
75 RB.T	Rate base	3,305,098,647	1,914,774,167	401,581,260	400,140,700	231,618,958	189,563,008	Included in Svc 31	Included in Svc 31	59,201,375	47,224,915	30,809,880	Included in PV 449	26,527,195	3,457,191	Included in Lg Resale
76 Revfact1.T		1,621,772,376	1,003,283,338	222,814,778	234,562,271	149,073,053	112,463,883	Included in Svc 31	Included in Svc 31	40,502,363	34,843,018	9,047,781	Included in PV 449	13,873,961	1,207,930	Included in Lg Resale
77 Power.T		1,109,487,032	577,818,285	133,992,688	155,666,884	104,713,643	74,163,514	Included in Svc 31	Included in Svc 31	29,070,120	26,063,584	3,412,912	Included in PV 449	4,051,566	533,837	Included in Lg Resale
78 SW.T alt	Total Salarys and Wages alt	66,490,363	40,855,344	8,465,489	6,569,099	3,719,735	3,536,755	Included in Svc 31	Included in Svc 31	1,055,854	613,045	451,527	Included in PV 449	967,677	55,639	Included in Lg Resale
79 SWPTD.T alt	Salaries & Wages P,T,D related alt	34,492,558	19,580,573	4,413,734	4,131,278	2,341,628	2,306,402	Included in Svc 31	Included in Svc 31	493,189	430,993	196,001	Included in PV 449	568,264	28,488	Included in Lg Resale
80 Retail RATE REV	Retail Rate Revenue	1,838,009,206	984,060,380	225,492,780	260,900,473	159,068,093	112,324,775			36,977,060	31,895,957	8,667,094		15,450,314	1,142,380	

Puget Sound Energy
Public Counsel Electric Class Cost of Service Study
(Allocator Percentage)

Acct. No.	Account Description	Total	Residential Sch 7	Sec. Voltage Sch 24	Sec. Voltage Sch 25	Sec. Voltage Sch 26	Prim. Voltage Sch 31/15/43	Campus Sch 40	High Voltage Sch 46/49	Transportation Sch 449/459	Street & Area Lighting	Firm Resale
		4	5	6	7	8	9	10	11	12	13	14
DIR450.01	Late Payment Interest Rev	100.0000%	79.9234%	10.9465%	5.4305%	1.8306%	1.3511%	0.1202%	0.2141%	0.0885%	0.0951%	0.0000%
CUST_1	Ave. No. Cust.	100.0000%	86.3339%	10.4395%	0.7759%	0.0731%	0.0647%	0.0068%	0.0018%	0.0017%	0.3019%	0.0009%
CUST_4	Ave. No. Cust Incl. RES & SEC Only	100.0000%	88.6649%	10.4786%	0.7788%	0.0733%	0.0000%	0.0044%	0.0000%	0.0000%	0.0000%	0.0000%
CUST_5	Wtd. Ave. No. Cust. CAE - NO HV	100.0000%	81.7842%	12.3638%	1.3690%	0.1289%	0.8592%	1.8938%	0.7476%	0.4399%	0.3699%	0.0437%
CUST_6	Wtd. Ave. No. Sch. Mtr Reading	100.0000%	71.3832%	25.1905%	2.5262%	0.2665%	0.2242%	0.0251%	0.1955%	0.1760%	0.0000%	0.0128%
METER	Meter Investment	100.0000%	56.9552%	21.4409%	7.8674%	0.8224%	11.6264%	0.4884%	0.4174%	0.2366%	0.0000%	0.1452%
DIR368.03C	Line Transformers - Customer Related	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	46.7385%	52.3974%	0.0000%	0.0000%	0.0000%	0.8641%
DIR372.00	Leased Wtr. Htrs.	100.0000%	99.1256%	0.8367%	0.0377%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
UNBILLED	Direct Assignment of Unbilled Revenue	100.0000%	49.0375%	13.9781%	16.4779%	10.4855%	8.9579%	2.7867%	1.9339%	-1.6575%	0.0000%	0.0000%
PROFORMA	Proforma Revenue	100.0000%	53.6251%	12.2780%	14.2049%	8.8591%	6.1161%	2.1210%	1.7369%	0.3519%	0.8446%	0.0624%
DIR451.02	Seasonal Svc. Chgs.	100.0000%	8.7719%	8.7719%	82.4561%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DIR454.04	Equip. (Transf.) Rentals	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	17.4740%	2.8116%	40.7283%	38.8530%	0.0000%	0.1331%
DIR451.05	Water Htr. Rentals	100.0000%	81.6334%	17.5739%	0.7926%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DIR235.00	Customer Deposits	100.0000%	61.2823%	11.1264%	3.9917%	3.2962%	0.3035%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PROFORMA_RETAIL	Proforma Retail Revenue - No Transportation	100.0000%	53.8462%	12.3291%	14.2640%	8.6951%	6.1415%	2.1298%	1.7441%	0.0000%	0.8481%	0.0000%
OH_TFMRC	Allocate Overhead Transformers	100.0000%	83.5307%	14.0092%	2.3374%	0.0252%	0.0000%	0.0000%	0.0000%	0.0000%	0.0975%	0.0000%
UG_TFMRC	Allocate Underground Transformers	100.0000%	63.8368%	17.7529%	14.4428%	3.9546%	0.0000%	0.0000%	0.0000%	0.0000%	0.0129%	0.0000%
DIR451.06	Acct. Svc. Chgs. Rev.	100.0000%	92.0117%	7.6730%	0.2806%	0.0295%	0.0046%	0.0006%	0.0000%	0.0000%	0.0000%	0.0000%
DIR_RESALE	Firm Resale Allocation Only Excise Tax	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DIR_449	Schedule 449 / 459 Allocation Only	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
DIR451.07	NSF Check Charge Revenue	100.0000%	94.7805%	4.8924%	0.2108%	0.0145%	0.0218%	0.0000%	0.0000%	0.0145%	0.0654%	0.0000%
DIR451.03	Connect/Reconnect Revenue	100.0000%	97.8217%	2.0735%	0.0944%	0.0000%	0.0035%	0.0000%	0.0000%	0.0000%	0.0070%	0.0000%
OH_SVC	Dist OH Services	100.0000%	86.8267%	12.8195%	0.5480%	0.0058%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DIR_449_OATT	Transportation OATT Revenue	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
PROFORMA_RETAIL_TA	Proforma State Revenue	100.0000%	53.6586%	12.2857%	14.2138%	8.6645%	6.1199%	2.1223%	1.7380%	0.3521%	0.8451%	0.0000%
DIR908.01	Direct Assign A/C 908	100.0000%	89.0832%	9.7688%	0.7280%	0.0684%	0.0606%	0.0062%	0.0017%	0.0016%	0.2825%	0.0008%
DIR920.01	Direct Assign A/C 920.01	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	54.8101%	15.0928%	28.4691%	0.0000%	1.6280%
DIR450.02	Direct Assign Disconnect Call - A/C 450.02	100.0000%	89.3603%	10.0056%	0.4896%	0.0000%	0.0080%	0.0000%	0.0000%	0.0000%	0.1365%	0.0000%
DEM_1	Annual Kw - Top 200 Hours	100.0000%	57.2657%	10.1352%	10.8345%	6.5727%	5.3613%	1.4532%	1.5653%	6.0748%	0.2695%	0.4477%
NCP_360	Allocate Substation Land - 12 NCP	100.0000%	43.6361%	13.3724%	18.1563%	15.0128%	7.8876%	0.0000%	0.0000%	0.9412%	0.9891%	0.0045%
NCP_361	Allocate Substation Structures - 12 NCP	100.0000%	49.6081%	13.0787%	14.9742%	12.2964%	8.6118%	0.0000%	0.0000%	0.4291%	0.8001%	0.0016%
NCP_362	Allocate Substation Equipment - 12 NCP	100.0000%	54.4413%	14.3071%	14.1556%	8.9880%	7.3125%	0.0000%	0.0000%	0.2376%	0.5334%	0.0245%
DIR360.01	Direct Assign Substation Land	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	51.5870%	46.3434%	0.0000%	0.0000%	2.0697%
DIR361.01	Direct Assign Substation Structures	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	17.7557%	40.9927%	38.4242%	0.0000%	2.8275%
DIR362.01	Direct Assign Substation Equipment	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	2.0592%	21.0114%	32.6472%	43.2933%	0.0000%	0.9889%
DIR364.01	Direct Assign OH Dist Lines	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	81.8433%	0.0000%	0.0000%	0.0000%	18.1567%
DIR366.01	Direct Assign OH Dist Lines	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	85.6408%	10.5588%	0.0000%	0.0000%	3.8006%
DIR368.03	Line Transformers	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	46.7385%	52.3974%	0.0000%	0.0000%	0.0000%	0.8641%
OH_NCP	Allocate Overhead Lines - 12 NCP	100.0000%	66.9794%	12.0520%	9.5291%	3.5111%	5.3957%	0.0000%	0.0000%	0.0113%	0.4638%	0.0577%
UG_NCP	Allocate Underground Lines - 12 NCP	100.0000%	68.4550%	11.3015%	10.2289%	4.7292%	4.7118%	0.0000%	0.0000%	0.0124%	0.5351%	0.0261%
OH_TFMR	Allocate Overhead Transformers	100.0000%	83.5307%	14.0092%	2.3374%	0.0252%	0.0000%	0.0000%	0.0000%	0.0000%	0.0975%	0.0000%
UG_TFMR	Allocate Underground Transformers	100.0000%	63.6368%	17.7529%	14.4428%	3.9646%	0.0000%	0.0000%	0.0000%	0.0000%	0.0129%	0.0000%
DIR106.09	Dist Accum Depr - Subs & Lines	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.5784%	49.3701%	20.6804%	27.3177%	0.0000%	2.0535%
DEM_1A	200 CP Demand Excl. Interruptible	100.0000%	57.8760%	10.2432%	10.9500%	6.6426%	4.5312%	1.4687%	1.4237%	6.1396%	0.2724%	0.4525%
DEM_12CP	12 Monthly CP Demand	100.0000%	50.7871%	10.9398%	12.9720%	7.9353%	6.3005%	1.7157%	1.8078%	6.8142%	0.2108%	0.5168%
DEM_12NCP2	Dist 12 NCP Dem, Excl Dir Assn Transf (No HV, PR	100.0000%	63.8129%	12.6257%	14.3514%	8.4821%	0.0000%	0.0000%	0.0000%	0.0000%	0.7279%	0.0000%
DEM_12NCP1	12 NCP Distribution Demand (No HV, LFR, Trans)	100.0000%	59.2780%	11.7284%	13.3315%	7.8793%	7.0662%	0.0000%	0.0000%	0.0000%	0.6762%	0.0403%
DEM_2A	200 CP Demand - NO RETAIL WHEELING & INTEI	100.0000%	61.9366%	10.9619%	11.7183%	7.1088%	4.6491%	1.5717%	1.5236%	0.0000%	0.2915%	0.0382%
ANCIL	Transportation Ancillary Exp	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	99.6228%	0.0000%	0.1772%
DIR565.02	Direct Assign A/C 565.02	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	94.4445%	0.0000%	5.5555%
DEM_3B	Top 75 CP - No Interruptibles	100.0000%	58.3699%	10.1252%	10.9199%	6.6109%	4.4601%	1.4491%	1.3926%	5.9389%	0.2945%	0.4389%
DEM_3A	Top 75 CP - No Interruptibles or Transportation	100.0000%	62.3229%	10.8109%	11.6595%	7.0586%	4.7622%	1.5472%	1.4869%	0.0000%	0.3145%	0.0373%
ENERGY_1	Annual kWhs	100.0000%	45.7618%	11.1903%	13.1423%	6.9641%	6.3862%	2.5535%	2.2737%	8.7260%	0.3403%	0.6417%
DIR_449_ENERGY	Schedule 449 / 459 Energy Allocation	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%

BPAX	BPA Residential Exchange kWh	100.0000%	95.2446%	2.5496%	1.6796%	0.2163%	0.2905%	0.0000%	0.0000%	0.0000%	0.0192%	0.0000%
ENERGY_2	Energy - NO RETAIL WHEELING	100.0000%	50.4961%	12.3426%	14.4956%	9.8872%	7.0438%	2.8165%	2.5079%	0.0000%	0.3754%	0.0350%
DEM_12NCP_P	12 NCP Distribution Demand (No HV)	100.0000%	58.7620%	11.6264%	13.2155%	7.8108%	7.0047%	0.0000%	0.0000%	0.3550%	0.6703%	0.5554%
DEM_12NCP_S	Dist 12 NCP Dem, Excl Dir Assn Transf (No HV, PR	100.0000%	63.6129%	12.6257%	14.3514%	8.4821%	0.0000%	0.0000%	0.0000%	0.0000%	0.7279%	0.0000%
PC3	Peak Credit 3	100.0000%	52.2701%	12.1129%	14.0701%	9.4629%	6.7016%	2.6261%	2.3547%	0.0000%	0.3662%	0.0354%
PC4	Peak Credit 4	100.0000%	47.6700%	11.0305%	12.8089%	8.6111%	6.0973%	2.3879%	2.1416%	8.3079%	0.3335%	0.6113%
Line.T	Dist. Poles, lines, conductors	100.0000%	67.9155%	11.4169%	9.9086%	4.3056%	4.8742%	0.8747%	0.1015%	0.0119%	0.5077%	0.0835%
PTDP.T	Prod Trans Dist Plant	100.0000%	58.6860%	12.0294%	11.7828%	6.8392%	5.5845%	1.7397%	1.4037%	0.9172%	0.9161%	0.1016%
PP.T	Prod Plant	100.0000%	52.2701%	12.1129%	14.0701%	9.4629%	6.7016%	2.6261%	2.3547%	0.0000%	0.3662%	0.0354%
TP.T	Trans Plant	100.0000%	49.4186%	11.4419%	13.2883%	8.9349%	6.3270%	2.4784%	2.2226%	5.1500%	0.3459%	0.3924%
TDP.T	Trans & Dist Plant	100.0000%	62.9398%	11.9740%	10.2663%	5.0998%	4.8439%	1.1519%	0.7731%	1.5252%	1.2808%	0.1455%
DP.T	Dist Plant	100.0000%	65.8166%	12.0872%	9.6233%	4.2838%	4.5283%	0.8697%	0.4647%	0.7540%	1.4795%	0.0929%
	Customer Accts Expenses excluding Uncollect	100.0000%	43.9779%	12.9224%	17.2183%	10.1749%	8.3070%	2.5936%	2.0942%	1.3699%	1.1904%	0.1513%
	Customer Service Expenses	100.0000%	88.4256%	10.2238%	0.7921%	0.0946%	0.0796%	0.0129%	0.0076%	0.0017%	0.3613%	0.0009%
SW.T	Total Salaries & Wages	100.0000%	62.5646%	12.8523%	9.9107%	5.4720%	4.6199%	1.4877%	1.1351%	0.6028%	1.2601%	0.0748%
SWPTD.T	Salaries & Wages P,T,D related	100.0000%	60.2192%	12.0862%	11.4312%	6.3960%	5.4120%	1.5868%	1.2366%	0.5335%	1.0231%	0.0755%
GP.T	General Plant	100.0000%	58.6660%	12.0294%	11.7828%	6.8392%	5.5845%	1.7397%	1.4037%	0.9172%	0.9161%	0.1016%
PTDGP.T	Prod/Trans/Dist/Gen'l Plant	100.0000%	58.6860%	12.0294%	11.7828%	6.8392%	5.5845%	1.7397%	1.4037%	0.9172%	0.9161%	0.1016%
adjptdce.t	Adj Total Prod Trans Dist & Cust Exp	100.0000%	58.2503%	12.9156%	10.7815%	6.3953%	5.4177%	1.7190%	1.4251%	1.0783%	1.9031%	0.1140%
EPIS.t	Elect Plant in Service	100.0000%	58.6477%	12.0302%	11.7972%	6.6557%	5.5916%	1.7452%	1.4096%	0.9092%	0.9127%	0.1010%
RB.T	Rate base	100.0000%	57.9339%	12.1504%	12.1068%	7.0140%	5.7355%	1.7912%	1.4289%	0.9322%	0.8026%	0.1048%
Revfac1.T	Revenue Factor 1	100.0000%	55.0718%	12.2307%	12.8755%	8.1828%	6.1733%	2.2232%	1.9181%	0.4966%	0.7616%	0.0663%
Power.T	Power Allocator	100.0000%	52.0798%	12.0770%	14.0305%	9.4380%	6.6845%	2.6201%	2.3492%	0.3076%	0.3652%	0.0481%
SW.T alt	Total Salarys and Wages alt	100.0000%	61.4455%	12.7319%	9.8798%	5.5944%	5.3192%	1.5880%	1.2228%	0.6791%	1.4557%	0.0837%
SWPTD.T alt	Salaries & Wages P,T,D related alt	100.0000%	56.7675%	12.7962%	11.9773%	6.7888%	6.6925%	1.4299%	1.2495%	0.5682%	1.6475%	0.0826%
Retail RATE REV	Retail Rate Revenue	100.0000%	53.5411%	12.2683%	14.1947%	8.6544%	6.1112%	2.1206%	1.7354%	0.4715%	0.8406%	0.0622%

Puget Sound Energy
Public Counsel Electric Class Cost of Service Study
(Peak Credit)

Classification			Total	Residential Sch 7	Sec. Voltage Sch 24	Sec. Voltage Sch 25	Sec. Voltage Sch 26	Prim. Voltage Sch 31/35/43	Campus Sch 40	High Voltage Sch 46/49	Transportation Sch 449/459	Street & Area Lighting	Firm Resale	Transp HV 449	Lighting 50-59	Firm Resale Large	Firm Resale Small
Demand	0.15																
Energy	0.85																
PC4																	
Demand																	
	Dem_3B	amt	4277389	2496708	433094	467068	282773	190771	5	0	61983	59567	14590	239439	12598	17278	1495
	Dem_3B	pct	100.0000%	58.3699%	10.1252%	10.9199%	6.6109%	4.4600%	0.0001%	0.0000%	1.4491%	1.3926%	0.3411%	5.5978%	0.2945%	0.4039%	0.0350%
	Weighted		0.15	8.755488%	1.518779%	1.637990%	0.991632%	0.668998%	0.000018%	0.000000%	0.217363%	0.208890%	0.051184%	0.839668%	0.044179%	0.060591%	########
Energy																	
	Energy_1	amt	25,203,044,595	11,538,414,973	2,820,298,304	3,312,247,709	2,259,228,104	1,430,742,880	5,083,762	173,708,768	643,571,762	573,051,540	#########	2,075,488,034	85,771,201	153,736,746	7,999,367
	Energy_1	pct	100.0000%	45.7616%	11.1903%	13.1423%	8.9641%	5.6769%	0.0201%	0.6892%	2.5535%	2.2737%	0.4908%	8.2351%	0.3403%	0.6100%	0.0317%
	Weighted		85.000000%	38.914555%	9.511762%	11.170914%	7.619492%	4.825335%	0.017078%	0.585852%	2.170516%	1.932678%	0.417264%	6.999808%	0.289273%	0.518494%	########
Total			100.000000%	47.670041%	11.030541%	12.808904%	8.611124%	6.494334%	0.017096%	0.585852%	2.387878%	2.141569%	0.468428%	7.839476%	0.333451%	0.579085%	########
PC3																	
Demand																	
	Dem_3a	amt	4006082	2496708	433094	467068	282773	190771	5	0	61983	59567	0	0	12598	0	1495
	Dem_3a	pct	100.0000%	62.3229%	10.8109%	11.6595%	7.0586%	4.7620%	0.0001%	0.0000%	1.5472%	1.4869%	0.0000%	0.0000%	0.3145%	0.0000%	0.0373%
	Weighted		0.15	9.348441%	1.621637%	1.748921%	1.058789%	0.714305%	0.000019%	0.000000%	0.232083%	0.223037%	0.000000%	0.000000%	0.047171%	0.000000%	########
Energy																	
	Energy_2	amt	22,850,098,360	11,538,414,973	2,820,298,304	3,312,247,709	2,259,228,104	1,430,742,880	5,083,752	173,708,768	643,571,762	573,051,540	0	0	85,771,201	0	7,999,367
	Energy_2	pct	100.0000%	50.4981%	12.3426%	14.4956%	9.8872%	6.2614%	0.0222%	0.7602%	2.8165%	2.5079%	0.0000%	0.0000%	0.3754%	0.0000%	0.0350%
	Weighted		85.000000%	42.921709%	10.491218%	12.321219%	8.404095%	5.322215%	0.018837%	0.646179%	2.394020%	2.131692%	0.000000%	0.000000%	0.319060%	0.000000%	########
Total			100.000000%	52.270150%	12.112854%	14.070139%	9.462683%	6.036521%	0.016855%	0.646179%	2.626104%	2.354730%	0.000000%	0.000000%	0.366231%	0.000000%	########

Puget Sound Energy
Public Counsel Electric Class Cost of Service Study
(Salaries and Wages)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential Sch 7	Sec. Voltage Sch 24	Sec. Voltage Sch 25	Sec. Voltage Sch 26	Prim. Voltage Sch 31/35/43	Campus Sch 40	High Voltage Sch 46/49	Transportation Sch 449/459	Street & Area Lighting	Firm Resale
			4	5	6	7	8	9	10	11	12	13	14	
	Labor O & M Expenses													
	Production Labor Exp													
S100	Salary & Wages - Prod Related													
			63	13,536,024	7,075,300	1,639,598	1,904,537	1,280,898	907,124	355,470	318,737	0	49,573	4,786
	Transmission Labor Exp													
S101	Salary & Wages - Trans Related													
			64	591,683	292,401	67,700	78,625	52,866	37,436	14,664	13,151	30,472	2,047	2,322
	Distribution Labor Expense - Operating													
S102	Salary & Wages - Dist Related													
			68	20,384,852	13,403,443	2,461,550	1,959,763	872,390	922,191	177,115	94,645	153,542	301,290	16,922
	Customer Accounts Labor Expense													
S103	Salary & Wages - Customer Accts Related													
				10,847,059	8,015,548	1,905,984	379,354	134,618	145,217	118,130	66,932	43,829	33,108	4,340
	Customer Service & Information Labor Expense													
S104	Salary & Wages - Cust Svc Related													
				1,460,361	1,289,994	152,454	11,330	1,067	945	97	27	25	4,409	13
-	TOTAL LABOR OPERATING EXPENSES													
				46,799,979	30,076,687	6,227,287	4,333,609	2,341,840	2,012,913	665,477	493,491	227,868	390,427	30,383
-	General Labor Expense - Maintenance			-	-	-		-	-	-	-	-	-	-
S105	Salary & Wages - Admin & Gen Related													
				19,406,793	11,522,783	2,318,231	2,256,047	1,296,499	1,058,894	323,712	261,242	172,918	177,124	19,362
S108	Salary & Wages - Sales													
				283,591	-	-		-	-	-	-	-	283,591	-
-														
-	**TOTAL LABOR MAINTENANCE EXPENSES**			19,690,384	11,522,783	2,318,231	2,256,047	1,296,499	1,058,894	323,712	261,242	172,918	460,715	19,362
-	**TOTAL LABOR O & M EXPENSES**													
				66,490,363	41,599,450	8,545,518	6,589,656	3,638,339	3,071,807	989,189	754,733	400,786	851,142	49,745
	Labor O&M P/T/D			34,492,559	20,771,145	4,168,849	3,942,925	2,206,155	1,866,751	547,250	428,532	184,014	352,910	26,030
500	Operation supervision and engineering		63	14,578	7,619	1,766	2,051	1,379	977	383	343	0	53	5
502	Steam expenses (major only)		63	533,017	278,609	64,564	74,998	50,439	35,720	13,998	12,551	0	1,952	188
506	Miscellaneous steam power expenses (major only)		63	43,947	22,971	5,323	6,183	4,159	2,945	1,154	1,035	0	161	16
507	Rents		63	4,775	2,496	578	672	452	320	125	112	0	17	2
510	Maintenance supervision and engineering (major only)		63	76,101	39,778	9,218	10,707	7,201	5,100	1,998	1,792	0	279	27
511	Maintenance of structures (major only)		63	1,315	668	159	185	124	88	35	31	0	5	0
512	Maintenance of boiler plant (major only)		63	35,258	18,429	4,271	4,961	3,336	2,363	926	830	0	129	12
513	Maintenance of electric plant (major only)		63	30,040	15,702	3,639	4,227	2,843	2,013	789	707	0	110	11
514	Maintenance of miscellaneous steam plant (major only)		63	7,640	3,993	925	1,075	723	512	201	180	0	28	3
535	Operation supervision and engineering		63	638,937	281,703	85,281	75,829	50,999	36,117	14,163	12,691	0	1,974	191
537	Hydraulic expenses (major only)		63	857,331	448,128	103,847	120,628	81,128	57,454	22,514	20,188	0	3,140	303
538	Electric expenses (major only)		63	929,839	486,028	112,630	130,830	87,980	62,314	24,419	21,895	0	3,405	329
539	Miscellaneous hydraulic power generation expenses (major on		63	831,772	434,766	100,751	117,031	78,710	55,742	21,843	19,586	0	3,046	294
540	Rents		63	1,789	935	217	252	169	120	47	42	0	7	1
541	Maintenance supervision and engineering (major only)		63	262,791	137,361	31,831	36,975	24,868	17,611	6,901	6,188	0	962	93

Acct. No.	Account Description	Allocator	Alloc	Total	Residential Sch 7	Sec. Voltage Sch 24	Sec. Voltage Sch 25	Sec. Voltage Sch 26	Prim. Voltage Sch 31/35/43	Campus Sch 40	High Voltage Sch 46/49	Transportation Sch 449/459	Street & Area Lighting	Firm Resale
542	Maintenance of structures (major only)		63	301,825	167,764	36,560	42,487	26,561	20,227	7,926	7,107	0	1,105	107
543	Maintenance of reservoirs, dams, and waterways (major only)		63	323,889	189,297	39,232	45,572	30,649	21,706	8,508	7,627	0	1,186	115
544	Maintenance of electric plant (major only)		63	550,533	287,764	86,685	77,461	52,098	38,894	14,456	12,964	0	2,016	195
545	Maintenance of miscellaneous hydraulic plant (major only)		63	517,474	270,484	62,681	72,809	48,968	34,679	13,589	12,185	0	1,895	183
546	Operation supervision and engineering		83	466,345	244,805	56,730	65,897	44,319	31,386	12,299	11,028	0	1,715	166
548	Generation expenses (major only)		83	1,532,538	801,059	185,634	215,630	145,022	102,704	40,246	38,087	0	5,613	542
549	Miscellaneous other power generation expenses (major only)		63	421,049	220,083	51,001	59,242	39,843	28,217	11,057	9,915	0	1,542	149
550	Rents		63	4,095	2,141	498	576	388	274	108	96	0	15	1
551	Maintenance supervision and engineering (major only)		63	171,801	89,801	20,810	24,173	16,257	11,513	4,512	4,045	0	629	61
552	Maintenance of structures (major only)		83	110,425	57,719	13,376	15,537	10,449	7,400	2,900	2,600	0	404	39
553	Maintenance of generating and electric equipment (major only)		63	844,944	337,113	78,121	90,745	61,030	43,221	16,937	15,187	0	2,362	228
554	Maintenance of miscellaneous other power generation plant (m		63	587,247	306,955	71,132	82,626	55,570	39,355	15,422	13,828	0	2,151	208
556	System control and load dispatching (major only)		63	748,152	390,015	90,380	104,985	70,607	50,004	19,595	17,570	0	2,733	264
557	Other expenses		63	2,986,683	1,651,091	361,760	420,218	282,617	200,147	78,431	70,326	0	10,938	1,056
560	Operation supervision and engineering		64	456,411	226,540	52,451	60,915	40,958	29,004	11,361	10,189	23,608	1,586	1,799
561.1	Load Dispatching (major only)		64	53,527	26,452	6,125	7,113	4,783	3,387	1,327	1,190	2,757	185	210
561.2	Load Dispatching (major only)		64	139,128	68,755	15,919	16,488	12,431	8,803	3,446	3,092	7,165	481	546
561.3	Load Dispatching (major only)		64	32,926	16,271	3,767	4,375	2,942	2,083	616	732	1,696	114	129
561.6	Load Dispatching (major only)		84	28,197	13,935	3,226	3,747	2,519	1,784	699	627	1,452	98	111
561.8	Load Dispatching (major only)		64	57,807	28,567	6,614	7,682	5,165	3,657	1,433	1,285	2,977	200	227
562	Station expenses (major only)		64	60,794	30,044	6,958	8,079	5,432	3,846	1,507	1,351	3,131	210	239
563	Overhead line expenses (major only)		64	56,975	29,145	6,746	7,837	5,269	3,731	1,462	1,311	3,037	204	231
566	Miscellaneous transmission expenses (major only)		64	298,520	147,524	34,156	39,668	26,672	18,887	7,399	6,635	15,374	1,033	1,171
569.2	Maintenance of structures (major only)		64	-17,130	-8,466	-1,960	-2,276	-1,531	-1,084	-425	-381	-882	-59	-67
570	Maintenance of station equipment (major only)		64	187,426	92,623	21,445	24,906	16,746	11,856	4,645	4,166	9,652	648	735
571	Maintenance of overhead lines (major only)		64	-766,887	-378,990	-87,748	-101,908	-68,521	-48,521	-19,007	-17,045	-39,495	-2,653	-3,009
560	Operation supervision and engineering		68	1,066,133	701,692	128,866	102,597	45,671	48,278	9,272	4,955	8,038	15,773	991
581	Load dispatching (major only)		47	4,602,917	2,728,517	539,851	613,639	362,680	325,253	0	0	0	31,123	1,855
562	Station expenses (major only)	D362.T	Acct 362	740,841	369,090	94,379	96,693	62,231	49,891	12,839	17,206	33,625	3,383	1,605
563	Overhead line expenses (major only)	D364.T	Acct 364	-1,056,182	-727,066	-127,032	-100,440	-37,008	-56,872	-1,758	0	-119	-4,889	-998
584	Underground line expenses (major only)	D366.T	Acct 366	291,898	197,040	32,530	29,443	13,613	13,562	3,476	429	36	1,540	229
585	Street lighting and signal system expenses	DIR373.00	Acct 373	153,514									153,514	
586	Meter expenses	D370.T	Acct 370	1,049,781	597,905	225,083	82,591	8,634	122,052	5,128	4,382	2,484	0	1,525
587	Customer installations expenses	D370.T	Acct 370	2,130,864	1,213,837	456,877	167,644	17,525	247,743	10,408	8,895	5,042	0	3,095
588	Miscellaneous distribution expenses		66	747,200	491,781	90,316	71,905	32,009	33,836	6,498	3,473	5,634	11,055	694
590	Maintenance supervision and engineering (major	DES2.T	Acct 591 to 597	33,626	20,611	3,972	4,239	2,397	2,219	21	-2	-26	285	12
591	Maintenance of structures (major only)	D361.T	Acct 361	133	60	16	18	14	10	2	5	7	1	0
592	Maintenance of station equipment (major only)	D362.T	Acct 362	2,414,674	1,202,840	307,573	315,115	202,806	162,590	41,641	56,074	109,581	11,024	5,231
593	Maintenance of overhead lines (major only)	D364.T	Acct 364	5,580,386	3,841,471	671,178	530,680	195,532	300,485	9,291	0	827	25,829	5,273
594	Maintenance of underground lines (major only)	D366.T	Acct 366	2,097,099	1,415,607	233,707	211,528	97,797	97,437	24,973	3,079	256	11,066	1,649
595	Maintenance of line transformers	D368.T	Acct 368	108,444	78,319	17,699	10,936	2,759	320	358	0	0	46	8
596	Maintenance of street lighting and signal systems	DIR373.00	Dir	256,893									256,893	
597	Maintenance of meters	D370.T	Acct 370	146,548	83,487	31,421	11,530	1,205	17,038	716	612	347	0	213
901C	Supervision (major only)	CAES1.T	Accts 902-905	215,014	112,388	26,044	30,253	20,347	14,409	5,646	5,063	0	787	76
902C	Meter reading expenses		5	160,508	114,575	40,433	4,055	428	360	40	314	282	0	20
902E	Meter reading expenses		5	2,847	1,889	667	67	7	6	1	5	5	0	0
903C	Customer records and collection expenses		4	8,663,139	7,085,081	1,071,096	118,594	11,170	74,434	164,061	64,766	38,108	32,043	3,786
903E	Customer records and collection expenses		4	1,750,101	1,431,307	216,360	23,958	2,256	15,037	33,143	13,084	7,698	6,473	765
905C	Miscellaneous customer accounts expenses (major only)		2	55,550	49,158	5,810	432	41	36	4	1	1	168	0
908C	Customer assistance expenses (major only)		59	697,301	364,480	84,463	98,111	65,985	46,730	18,312	16,420	0	2,554	247
908E	Customer assistance expenses (major only)		59	390,963	204,357	47,357	55,009	36,998	26,201	10,267	9,206	0	1,432	138
909C	Informational and instructional advertising expenses (major or		2	372,098	328,688	38,845	2,887	272	241	25	7	6	1,123	3
912C	Demonstrating and selling expenses (major only)		2	36	31	4	0	0	0	0	0	0	0	0
912E	Demonstrating and selling expenses (major only)		2	165,400	146,104	17,267	1,283	121	107	11	9	3	499	1
913E	Advertising expenses (major only)		2	10,349	9,142	1,080	80	8	7	1	0	0	31	0
916E	Miscellaneous sales expenses (major only)		2	107,806	95,230	11,254	836	79	70	7	2	2	325	1
920C	Administrative and general salaries		73	13,331,883	7,765,856	1,721,891	1,437,392	852,614	722,284	229,171	189,993	143,762	253,725	15,193
920E	Administrative and general salaries		73	4,326,139	2,521,152	559,005	466,843	276,798	234,487	74,399	61,681	46,672	82,371	4,932
924C	Property insurance		72	240,038	140,869	28,875	26,283	16,417	13,405	4,176	3,389	2,202	2,199	244
924E	Property insurance		72	261,692	153,694	31,504	30,858	17,911	14,625	4,556	3,676	2,402	2,399	266
925C	Injuries and damages		65	238,234	149,944	28,526	24,458	12,149	11,540	2,744	1,842	3,634	3,051	347
925E	Injuries and damages		65	240,607	151,437	28,810	24,701	12,271	11,655	2,772	1,860	3,670	3,081	350
930.2C	Miscellaneous general expenses		73	33,685	19,622	4,351	3,632	2,154	1,825	579	480	363	641	38
935C	Maintenance of general plant		71	697,612	409,401	83,918	82,198	47,711	38,958	12,136	9,792	6,398	6,391	709
935E	Maintenance of general plant		71	34,701	20,365	4,174	4,089	2,373	1,938	604	487	318	318	35

Acct. No.	Account Description	Allocator	Alloc	Total	Residential Sch 7	Sec. Voltage Sch 24	Sec. Voltage Sch 25	Sec. Voltage Sch 26	Prim. Voltage Sch 31/35/43	Campus Sch 40	High Voltage Sch 46/49	Transportation Sch 449/459	Street & Area Lighting	Firm Resale
Total Salarys and Wages alt				66,490,363	40,855,344	8,465,469	6,569,099	3,719,735	3,536,755	1,055,864	813,045	451,527	967,877	55,639
Salaries & Wages P,T,D related alt				34,492,558	19,580,573	4,413,734	4,131,278	2,341,628	2,308,402	493,199	430,993	196,001	568,264	28,486

Exhibit No.__(GAW-7)

PUGET SOUND ENERGY ELECTRIC OPERATIONS
PSE AND PUBLIC COUNSEL REVENUE DISTRIBUTION PROPOSALS

Customer Class	(1) Current Revenue	(2) Rate of Return PSE	(3) Rate of Return Public Counsel	(4) Proposed Revenue Increase PSE	(5) Proposed Revenue Increase Public Counsel	(6) Proposed Revenue Increase (%) PSE	(7) Proposed Revenue Increase (%) Public Counsel	(8) Public Counsel Pct of Sys Avg Pct
Residential - Sch. 7	$984,090,383	2.87%	4.74%	$115,972,986	$101,002,871	11.78%	10.26%	108%
Secondary Voltage:								
Demand <= 50 kW - Sch. 24	225,492,780	5.77%	5.30%	21,259,081	21,444,363	9.43%	9.51%	100%
Demand > 50 kW but <= 350 kW - Sch. 25/29	260,900,473	12.62%	7.94%	12,298,629	18,602,204	4.71%	7.13%	75%
Demand > 350 kW - Sch. 26	159,068,092	11.33%	6.72%	7,498,336	12,852,702	4.71%	8.08%	85%
Primary Voltage:								
General Service/Irrigation - Sch. 31/35	99,475,260	6.96%	4.83%	9,378,361	9,460,097	9.43%	9.51%	100%
Interruptible Total Elec. Schools - Sch. 43	12,849,516	6.96%	4.83%	1,211,431	1,221,989	9.43%	9.51%	100%
Campus Rate - Sch. 40	38,977,016	5.73%	3.35%	1,947,000	4,264,090	5.00%	10.94%	115%
Total High Voltage - Sch. 46/49	31,895,958	4.11%	2.45%	3,007,097	3,792,429	9.43%	11.89%	125%
Schedule 449 - 459	8,667,087	6.06%	5.82%	817,118	824,240	9.43%	9.51%	100%
Lighting - Sch. 50-59	15,450,314	8.69%	7.46%	1,092,472	1,101,607	7.07%	7.13%	75%
Firm Resale - Sch. 005	1,142,381	2.34%	4.05%	336,605	252,526	29.47%	22.11%	
Total	$1,838,009,260	5.31%	5.31%	$174,819,116	$174,819,118	9.51%	9.51%	100%

Puget Sound Energy
Electric Residential Customer Costs
(Cost of Equity @ PSE Proposed)

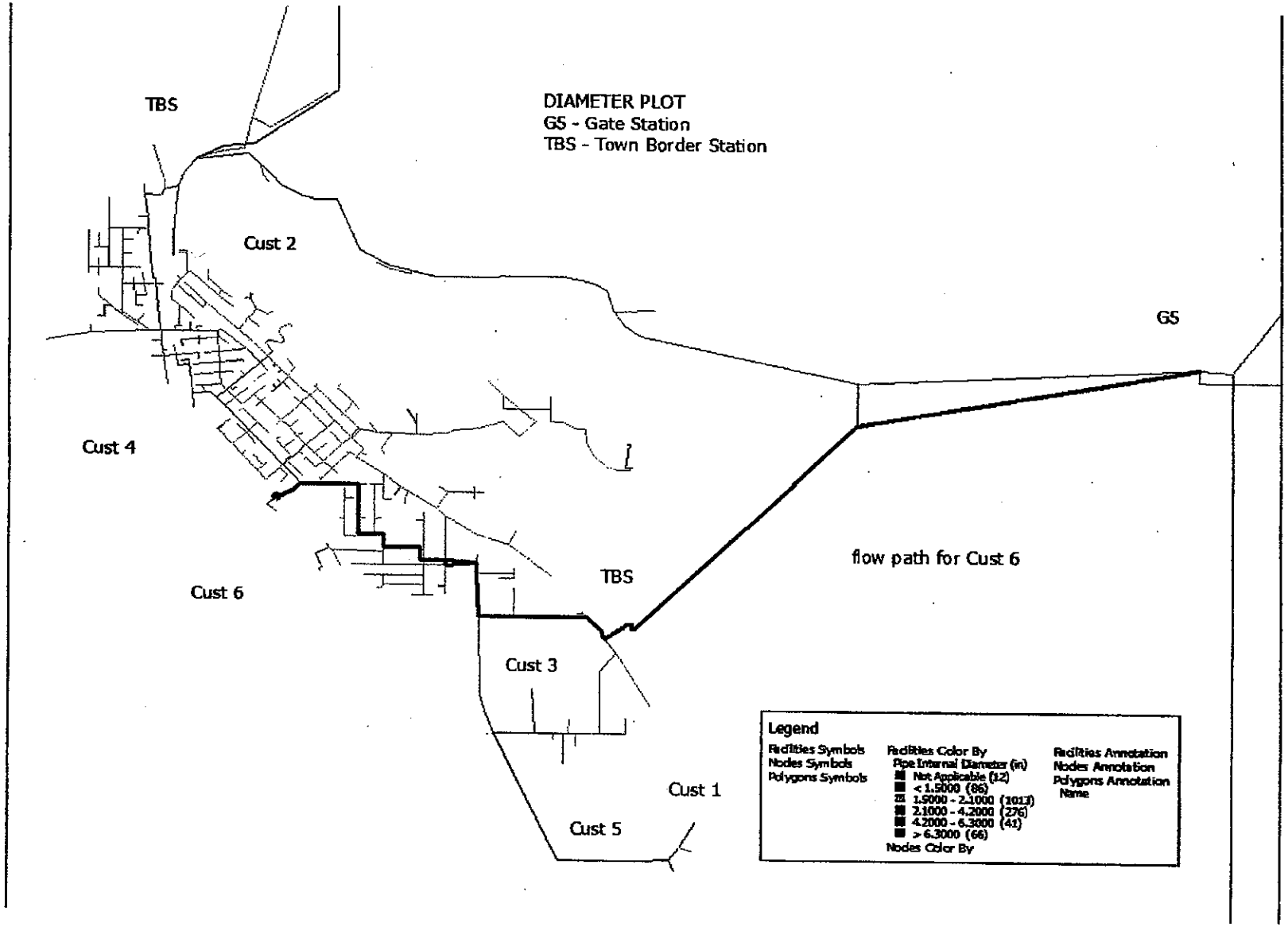
	Residential				
Gross Plant					
Meters	$73,742,332				
Total Gross Plant	$73,742,332				
Depreciation Reserve					
Meters	-$27,129,698				
Total Depreciation Reserve	-$27,129,698				
Total Net Plant	$46,612,634				
Total Rate Base	$46,612,634				
Operation & Maintenance Expenses					
Dist Oper - Meters	$898,321				
Dist Oper - Cust Installations - Meters	$1,740,635				
Meter Reading	$11,481,990				
Records & Collections	$13,681,729				
Dist Maint - Meters	$123,635				
Total O & M Expenses	$27,926,311				
Depreciation Expense					
Meters	$1,710,822	Rate Per PSB Depreciation Study		2.32%	
Total Depreciation Expense	$1,710,822				
Revenue Requirement			Cost of Capital		
			PCT	Cost	WGHT Cost
Interest	$1,742,362	Debt	54.97%	6.80%	3.74%
Equity return	$2,266,578	Preferred	0.03%	8.61%	0.00%
Income Tax	$1,220,465	Common	45.00%	10.80%	4.86%
Revenue For Return	5,229,405	Total	100.00%		8.60%
O & M Expenses	$27,926,311				
Depreciation Expense	$1,710,822				
Total Customer Revenue Requirement Before Gross up	$34,866,537				
Gross Up for Uncollect., WUTC Fee, and Excise Tax	0.956050	Per Witness Story			
Total Customer Revenue Requirement	$36,469,366				
Number of Bills	11,067,864				
Monthly Cost	$3.30				

Puget Sound Energy
Electric Residential Customer Costs
(Cost of Equity @ Public Counsel Proposed)

	Residential				
Gross Plant					
Meters	$73,742,332				
Total Gross Plant	$73,742,332				
Depreciation Reserve					
Meters	-$27,129,698				
Total Depreciation Reserve	-$27,129,698				
Total Net Plant	$46,612,634				
Total Rate Base	$46,612,634				
Operation & Maintenance Expenses					
Dist Oper - Meters	$898,321				
Dist Oper - Cust Installations - Meters	$1,740,635				
Meter Reading	$11,481,990				
Records & Collections	$13,681,729				
Dist Maint - Meters	$123,635				
Total O & M Expenses	$27,926,311				
Depreciation Expense					
Meters	$1,710,822	Rate Per PSE Depreciation Study		2.32%	
Total Depreciation Expense	$1,710,822				
Revenue Requirement			Cost of Capital		
			PCT	Cost	WGHT Cost
Interest	$1,742,362	Debt	54.97%	6.80%	3.74%
Equity return	$1,941,455	Preferred	0.03%	8.61%	0.00%
Income Tax	$1,045,399	Common	45.00%	9.25%	4.16%
Revenue For Return	4,729,215	Total	100.00%		7.90%
O & M Expenses	$27,926,311				
Depreciation Expense	$1,710,822				
Total Customer Revenue Requirement Before Gross up	$34,366,348				
Gross Up for Uncollect., WUTC Fee, and Excise Tax	0.956050	Per Witness Story			
Total Customer Revenue Requirement	$35,846,183				
Number of Bills	11,067,864				
Monthly Cost	$3.25				

Example of Flow Analysis
Map 2

Exhibit No. __(GAW-9)



Source: PSE response to PC No. 625

Puget Sound Energy
Public Counsel Gas Class Cost of Service Study
(Summary)

Account Description		Total	Residential (16,23,53)	Comm. & Indust (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transport & Contracts	CNG Service (50)	Rentals
Revenue @ Current Rates		$339,752,293	$231,328,530	$66,832,859	$13,774,048	$6,672,319	$3,575,636	$5,819,417	$3,931,144	$29,651	$7,788,789
TOTAL O & M EXPENSES		$108,932,397	$78,480,123	$21,008,107	$2,467,477	$1,727,756	$632,048	$2,231,025	$1,397,902	$53,849	$934,109
TOTAL DEPRECIATION EXPENSES		$99,429,849	$58,771,377	$21,371,757	$3,017,365	$1,719,684	$605,064	$3,150,320	$1,699,605	$51,452	$9,043,226
TOTAL TAXES OTHER THAN INCOME		$28,153,873	$17,685,595	$6,655,591	$954,979	$548,733	$195,152	$977,936	$530,963	$5,467	$599,457
Total Expense Before Income Taxes		$236,516,118	$154,937,095	$49,035,455	$6,439,821	$3,996,172	$1,432,265	$6,359,281	$3,628,470	$110,767	$10,576,793
Earnings Before Interest & Taxes		$103,236,175	$76,391,436	$17,797,405	$7,334,226	$2,676,147	$2,143,271	-$539,864	$302,675	-$81,116	-$2,788,004
Interest @ Weighted Cost of Debt	3.74%	$50,439,847	$32,581,144	$11,177,452	$1,739,511	$982,517	$353,476	$1,805,972	$961,198	$16,779	$821,798
Earnings Before Tax		$52,796,328	$43,810,291	$6,619,953	$5,594,715	$1,693,630	$1,789,795	-$2,345,836	-$658,523	-$97,895	-$3,609,802
Income Taxes @ efective Income Tax Rate	42.61%	$22,497,545	$18,668,420	$2,820,891	$2,384,017	$721,689	$762,667	-$999,607	-$280,609	-$41,715	-$1,538,207
Operating Income @ Current Rates		$80,738,630	$57,723,016	$14,976,513	$4,950,209	$1,954,459	$1,380,604	$459,743	$583,284	-$39,401	-$1,249,797
Rate Base		$1,349,395,041	$871,629,028	$299,025,444	$46,536,370	$26,284,857	$9,456,389	$48,314,384	$25,714,496	$448,881	$21,985,190
RoR		**5.98%**	**6.62%**	**5.01%**	**10.64%**	**7.44%**	**14.60%**	**0.95%**	**2.27%**	**-8.78%**	**-5.68%**
Indexed RoR		**100%**	**111%**	**84%**	**178%**	**124%**	**244%**	**16%**	**38%**	**-147%**	**-95%**
Required Income @ 8.60%		$116,047,974	$74,960,096	$25,716,188	$4,002,128	$2,260,498	$813,249	$4,155,037	$2,211,447	$38,604	$1,890,726
Income Deficiency		$35,309,344	$17,237,081	$10,739,675	-$948,081	$306,039	-$567,355	$3,695,294	$1,628,163	$78,005	$3,140,524
Conversion Factor		0.6219617	0.6219617	0.6219617	0.6219617	0.6219617	0.6219617	0.6219617	0.6219617	0.6219617	0.6219617
Additional Revenue Required		$56,770,930	$27,714,055	$17,267,421	-$1,524,340	$492,055	-$912,202	$5,941,354	$2,617,786	$125,418	$5,049,384
PC Proposed Revenue Increase		$56,770,930	$36,493,148	$13,914,794	$1,168,693	$948,869	$0	$1,383,297	$865,122	$7,388	$1,989,015
Difference from Required Rev. Increase @ 8.60% ROR		$0	$8,779,093	-$3,352,627	$2,693,033	$456,814	$912,202	-$4,558,057	-$1,752,664	-$118,030	-$3,060,369
Conversion Factor		0.6219617	0.6219617	0.6219617	0.6219617	0.6219617	0.6219617	0.6219617	0.6219617	0.6219617	0.6219617
Income Difference from Required		$0	$5,460,260	-$2,085,206	$1,674,963	$284,121	$567,355	-$2,834,937	-$1,090,090	-$73,410	-$1,903,432
Operating Income @ PC Proposed Rates		$116,047,974	$80,420,356	$23,630,982	$5,677,091	$2,544,619	$1,380,604	$1,320,100	$1,121,357	-$34,806	-$12,706
ROR @ PC Proposed Rates		**8.60%**	**9.23%**	**7.90%**	**12.20%**	**9.68%**	**14.60%**	**2.73%**	**4.36%**	**-7.75%**	**-0.06%**
Indexed ROR @ PC Proposed Rates		**100%**	**107%**	**92%**	**142%**	**113%**	**170%**	**32%**	**51%**	**-90%**	**-1%**
Indexed ROR @ Current Rates		**100%**	**111%**	**84%**	**178%**	**124%**	**244%**	**16%**	**38%**	**-147%**	**-95%**

Puget Sound Energy
Public Counsel Gas Class Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential (16,23,53)	Comm. & Indust (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible	Transport & Contracts	CNG Service (60)	Rentals
Plant-In-Service													
	Intangible Plant												
301	Organization	PLT	63	$158,692	$100,411	$37,250	$5,317	$2,943	$1,059	$5,480	$2,914	$6	$3,311
302	Franchise and Consents	PLT	63	$93,331	$59,054	$21,906	$3,127	$1,731	$623	$3,223	$1,714	$3	$1,947
303	Misc. Intangible	OML	66	$103,398,316	$73,823,688	$20,126,296	$2,505,119	$1,687,399	$672,497	$2,213,282	$1,332,924	$65,479	$971,631
	Sub-total			$103,650,338	$73,983,153	$20,185,454	$2,513,564	$1,692,074	$674,179	$2,221,984	$1,337,552	$65,488	$976,889
	Production and Gathering Plant												
304	Land and Land Rights	PRODPT	52	$153,211	$107,494	$38,524	$6,565	$212	$302	$110	$0	$4	$0
305	Structures and Improvements	PRODPT	52	$470,201	$329,896	$118,229	$20,148	$652	$926	$338	$0	$13	$0
311	Liquefied Petroleum Gas Equipment	PDAYXT	45	$6,218,505	$4,362,938	$1,563,598	$266,459	$8,622	$12,243	$4,474	$0	$173	$0
320	Other Equipment	PDAYXT	45	$68,857	$48,310	$17,313	$2,950	$95	$136	$50	$0	$2	$0
	Sub-total			$6,910,774	$4,848,637	$1,737,663	$296,122	$9,582	$13,606	$4,972	$0	$192	$0
	Natural Gas Underground Storage												
	JP Storage Balancing - DIR	COM1	34	$5,371,157	$2,639,317	$1,010,374	$338,861	$311,879	$84,028	$674,223	$311,876	$599	$0
350	Land and Land Rights	SEAS3_DEM	47	$365,517	$253,259	$81,286	$12,720	$3,396	$0,886	$7,968	$0	$0	$0
351	Structures and Improvements	SEAS3_DEM	47	$569,201	$394,387	$126,586	$19,808	$5,288	$10,723	$12,408	$0	$0	$0
352	Wells	SEAS3_DEM	47	$9,428,691	$6,532,944	$2,096,678	$328,109	$87,590	$177,631	$205,539	$0	$0	$0
353	Lines	SEAS3_DEM	47	$1,290,979	$894,493	$287,105	$44,925	$11,993	$24,321	$28,142	$0	$0	$0
354	Compressor Equipment	SEAS3_DEM	47	$5,952,236	$4,124,181	$1,323,738	$207,132	$55,295	$112,137	$129,755	$0	$0	$0
355	Measuring and Regulating Equipment	SEAS3_DEM	47	$268,488	$186,029	$59,710	$9,343	$2,494	$5,056	$5,853	$0	$0	$0
356	Purification Equipment	SEAS3_DEM	47	$788,118	$546,071	$175,272	$27,426	$7,321	$14,848	$17,180	$0	$0	$0
357	Other Equipment	SEAS3_DEM	47	$379,985	$263,270	$84,502	$13,222	$3,530	$7,156	$8,283	$0	$0	$0
	Sub-total			$24,414,352	$15,833,951	$5,246,453	$1,001,545	$488,785	$442,791	$1,089,352	$311,876	$599	$0
	Natural Gas Local Storage												
360	Land & Land Rights	SEAS3_DEM	47	$1,704,569	$1,181,061	$379,085	$59,317	$15,835	$32,113	$37,158	$0	$0	$0
361	Structures & Improvement	SEAS3_DEM	47	$3,973,839	$2,753,390	$883,755	$138,285	$36,916	$74,865	$86,627	$0	$0	$0
362	Gas Holders	SEAS3_DEM	47	$3,334,728	$2,310,564	$741,621	$116,045	$30,979	$62,824	$72,695	$0	$0	$0
363	Purification Equipment	SEAS3_DEM	47	$3,967,556	$2,749,037	$882,358	$138,067	$36,857	$74,747	$86,490	$0	$0	$0
364	Terminating & Processing	SEAS3_DEM	47	$1,089,858	$755,140	$242,377	$37,926	$10,124	$20,532	$23,758	$0	$0	$0
	Sub-total			$14,070,550	$9,749,192	$3,129,196	$489,640	$130,711	$265,081	$306,729	$0	$0	$0
	Transmission Plant												
365	Land and Land Rights	PAVG	42	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
366	Structures and Improvements	PAVG	42	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
367	Mains	PAVG	42	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
369	M&R Station Equipment	PAVG	42	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
372	Easements	PAVG	42	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Distribution Plant												
373	Easements	DISTPT	53	$7,334,283	$4,732,461	$1,760,106	$250,700	$140,568	$48,645	$261,184	$140,340	$277	$0
374	Land and Land Rights	DISTPT	53	$3,326,019	$2,146,121	$798,189	$113,690	$63,746	$22,060	$118,444	$63,643	$126	$0
375	Structures and Improvements	DISTPT	53	$8,067,108	$5,218,223	$1,940,771	$276,434	$154,997	$53,638	$287,993	$154,745	$306	$0
376	Mains	PA_MAINS	43	$1,034,641,312	$615,131,677	$226,170,982	$53,632,285	$32,035,772	$8,520,893	$64,940,319	$34,041,189	$68,194	$0
378	Meas. & Reg. Station Equip.- Gen.	PAVG	42	$56,506,957	$33,598,600	$12,353,443	$2,929,423	$1,749,914	$465,299	$3,547,131	$1,859,461	$3,686	$0
380	Services	SERV	7	$565,691,244	$388,991,269	$171,589,143	$3,862,161	$0	$1,146,909	$0	$0	$1,761	$0
380	Services - DIR	DIR380	8	$2,463,353	$0	$0	$0	$1,250,387	$21,395	$409,673	$801,896	$0	$0
381	Meters	MTRS_CUS	4	$54,327,287	$41,601,625	$12,184,869	$398,388	$42,249	$98,763	$0	$1,372	$0	$0
382	Meter Installations	MTRS_INST	5	$153,230,540	$141,416,119	$11,602,752	$156,724	$16,859	$37,464	$0	$623	$0	$0
383	House Regulators	MTRS_CUS	4	$12,454,845	$9,537,413	$2,763,456	$91,333	$9,686	$22,642	$0	$314	$0	$0
384	House Regulators Installations	MTRS_CUS	4	$33,548,468	$25,690,051	$7,524,476	$246,015	$26,090	$60,989	$0	$847	$0	$0
385	Indust. Meas. & Reg. Station Equip.	MTRS_386	6	$34,078,629	$185,909	$22,971,615	$5,227,911	$2,180,546	$2,537,711	$429,780	$545,258	$0	$0
386	Rental Property on Customers Premise	DIR386	10	$43,013,666	$0	$0	$0	$0	$0	$0	$0	$0	$43,013,666
387	Other Equipment	DISTPT	53	$6,729,480	$4,342,211	$1,614,963	$230,027	$128,977	$44,634	$239,646	$128,767	$255	$0

Puget Sound Energy
Public Counsel Gas Class Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential (16,23,53)	Comm. & Indust (31,35,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible	Transport & Contracts	CNG Service (50)	Rentals
388	ARO	DISTPT	53	$6,365,682	$4,120,375	$1,532,458	$216,275	$122,387	$42,354	$227,403	$122,189	$242	$0
	Sub-total			$2,021,638,873	$1,276,712,056	$474,837,143	$57,633,356	$37,922,178	$13,123,397	$70,461,574	$37,860,647	$74,847	$43,013,666
	General Plant												
389	Land and Land Rights	PLTXR	76	$674,480	$435,590	$161,603	$23,134	$12,847	$4,614	$23,947	$12,721	$25	$0
390	Structures and Improvements	PLTXR	76	$32,963,934	$21,301,532	$7,902,654	$1,131,296	$628,241	$225,619	$1,171,091	$622,069	$1,233	$0
391	Office Furniture and Equipment	OML	66	$46,058,871	$32,884,827	$8,965,276	$1,115,907	$751,654	$299,565	$985,908	$593,752	$29,168	$432,814
392	Transportation Equipment	OML	66	$625,235	$446,401	$121,701	$15,146	$10,203	$4,066	$13,369	$8,050	$396	$5,875
392	CNG Equipment - DIR	DIRCNG	49	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
392	CNG Equipment - Other	SEAS3_DEM	47	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
393	Stores Equipment	PLTXR	76	$257,624	$166,378	$61,726	$8,836	$4,907	$1,762	$9,147	$4,859	$10	$0
394	Tools, Shop, and Garage Equipment	OML	66	$6,872,321	$4,906,657	$1,337,685	$166,502	$112,152	$44,697	$147,105	$88,592	$4,352	$64,579
394	CNG Equipment - DIR	DIRCNG	27	$354,005	$0	$0	$0	$0	$0	$0	$0	$354,005	$0
394	CNG Equipment - Other	SEAS3_DEM	47	$744,365	$515,755	$165,542	$25,903	$6,915	$14,023	$16,227	$0	$0	$0
395	Laboratory Equipment	PLTXR	76	$1,478,578	$954,886	$354,263	$50,713	$26,162	$10,114	$52,497	$27,886	$55	$0
396	Power Operated Equipment	PLTXR	76	$611,269	$394,767	$146,458	$20,966	$11,643	$4,181	$21,703	$11,528	$23	$0
397	Communication Equipment	OML	66	$20,923,231	$14,936,639	$4,072,669	$506,925	$341,455	$135,084	$447,870	$269,725	$13,250	$196,615
398	Misc. Equipment	OML	66	$469,642	$335,312	$91,415	$11,376	$7,654	$3,055	$10,053	$6,054	$297	$4,413
399	Other Intangible Property	OML	66	$4,216	$3,010	$821	$102	$69	$27	$90	$54	$3	$40
	Sub-total			$112,057,771	$77,283,756	$23,382,013	$3,076,810	$1,915,911	$747,808	$2,899,021	$1,945,300	$402,816	$704,336
	Other Assets												
114	Plant Acquisition Adjustment	DISTPT	53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PLANT-IN-SERVICE				$2,282,742,658	$1,458,410,745	$528,516,924	$75,011,046	$42,159,241	$15,266,862	$76,983,632	$41,155,375	$543,943	$44,694,890
Accumulated Reserve													
	Intangible Plant												
301	Organization	PLT	63	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
302	Franchise and Consents	PLT	63	-$14,692	-$9,296	-$3,449	-$492	-$273	-$96	-$507	-$270	-$1	-$307
303	Misc. Intangible	OML	66	-$57,103,016	-$47,909,795	-$13,061,482	-$1,625,762	-$1,095,082	-$436,485	-$1,436,367	-$865,036	-$42,494	-$630,365
	Sub-total			-$57,117,709	-$47,919,092	-$13,064,930	-$1,626,254	-$1,095,354	-$436,533	-$1,436,874	-$865,305	-$42,495	-$630,671
	Production and Gathering Plant												
304	Land and Land Rights	PRODPT	52	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
305	Structures and Improvements	PRODPT	52	-$413,934	-$290,418	-$104,081	-$17,737	-$574	-$815	-$298	$0	-$12	$0
311	Liquefied Petroleum Gas Equipment	PDAYXT	45	-$4,658,331	-$3,408,632	-$1,221,592	-$208,176	-$6,735	-$9,565	-$3,495	$0	-$135	$0
320	Other Equipment	PDAYXT	45	-$67,561	-$47,401	-$16,988	-$2,895	-$94	-$133	-$49	$0	-$2	$0
	Sub-total			-$5,339,826	-$3,746,452	-$1,342,660	-$228,808	-$7,404	-$10,513	-$3,841	$0	-$148	$0
	Storage												
	JP Storage Balancing - DIR	COM1	34	-$3,014,074	-$1,481,077	-$566,981	-$190,155	-$175,014	-$47,153	-$378,347	-$175,012	-$336	$0
350	Land and Land Rights	SEAS3_DEM	47	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
351	Structures and Improvements	SEAS3_DEM	47	-$448,765	-$310,940	-$99,802	-$15,617	-$4,169	-$8,454	-$9,783	$0	$0	$0
352	Wells	SEAS3_DEM	47	-$6,206,253	-$4,300,154	-$1,380,229	-$215,971	-$57,654	-$116,922	-$135,292	$0	$0	$0
353	Lines	SEAS3_DEM	47	-$675,677	-$468,163	-$150,266	-$23,513	-$6,277	-$12,729	-$14,729	$0	$0	$0
354	Compressor Equipment	SEAS3_DEM	47	-$2,569,612	-$1,780,431	-$571,465	-$89,420	-$23,871	-$48,410	-$56,016	$0	$0	$0
355	Measuring and Regulating Equipment	SEAS3_DEM	47	-$45,153	-$31,286	-$10,042	-$1,571	-$419	-$851	-$984	$0	$0	$0
356	Purification Equipment	SEAS3_DEM	47	-$449,667	-$311,565	-$100,003	-$15,648	-$4,177	-$8,471	-$9,802	$0	$0	$0
357	Other Equipment	SEAS3_DEM	47	-$291,134	-$201,721	-$64,746	-$10,131	-$2,705	-$5,485	-$6,347	$0	$0	$0
	Sub-total			-$13,700,336	-$8,885,366	-$2,943,534	-$562,026	-$274,286	-$248,476	-$611,300	-$175,012	-$336	$0
	Natural Gas Local Storage												
360	Land & Land Rights	SEAS3_DEM	47	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
361	Structures & Improvement	SEAS3_DEM	47	-$330,001	-$228,651	-$73,390	-$11,484	-$3,066	-$6,217	-$7,194	$0	$0	$0
362	Gas Holders	SEAS3_DEM	47	-$168,661	-$116,862	-$37,509	-$5,869	-$1,567	-$3,177	-$3,677	$0	$0	$0
363	Purification Equipment	SEAS3_DEM	47	-$446,009	-$309,030	-$99,189	-$15,521	-$4,143	-$8,403	-$9,723	$0	$0	$0
364	Terminating & Processing	SEAS3_DEM	47	-$215,142	-$149,067	-$47,846	-$7,487	-$1,999	-$4,053	-$4,690	$0	$0	$0

Puget Sound Energy
Public Counsel Gas Class Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential (16,23,53)	Comm. & Indust (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible	Transport & Contracts	CNG Service (50)	Rentals
	Sub-total			-$1,159,813	-$603,610	-$257,935	-$40,360	-$10,774	-$21,850	-$25,263	$0	$0	$0
	Transmission Plant												
365	Land and Land Rights	TRANPT		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
366	Structures and Improvements	PAVG	42	-$62	-$37	-$14	-$3	-$2	-$1	-$4	-$2	$0	$0
367	Mains	PAVG	42	-$3,715	-$2,209	-$812	-$193	-$115	-$31	-$233	-$122	$0	$0
369	M&R Station Equipment	PAVG	42	-$23,470	-$13,955	-$5,131	-$1,217	-$727	-$193	-$1,473	-$772	-$2	$0
372	Easements	PAVG	42	-$989	-$588	-$216	-$51	-$31	-$8	-$62	-$33	$0	$0
	Sub-total			-$28,237	-$16,789	-$6,173	-$1,464	-$874	-$233	-$1,773	-$929	-$2	$0
	Distribution Plant												
373	Easements	DISTPT	53	-$251,447	-$162,247	-$60,343	-$8,595	-$4,819	-$1,668	-$8,954	-$4,811	-$10	$0
374	Land and Land Rights	DISTPT	53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
375	Structures and Improvements	DISTPT	53	-$2,949,557	-$1,903,208	-$707,845	-$100,822	-$56,531	-$19,563	-$105,038	-$56,439	-$112	$0
376	Mains	PA_MAINS	43	-$290,807,115	-$172,912,059	-$63,576,128	-$15,075,908	-$9,005,180	-$2,395,203	-$18,254,570	-$9,568,898	-$19,169	$0
376	Mains - DIR			$0									
376	Mains - Small Diameter			$0									
376	Mains - Small Diameter - DIR			$0									
378	Meas. & Reg. Station Equip.- Gen.	PAVG	42	-$13,107,844	-$7,793,523	-$2,865,612	-$679,534	-$405,925	-$107,985	-$822,823	-$431,337	-$855	$0
380	Services	SERV	7	-$247,712,363	-$170,366,757	-$75,151,006	-$1,691,513	$0	-$502,313	$0	$0	-$771	$0
380	Services - DIR	DIR380	8	-$1,070,966	$0	$0	$0	-$539,240	-$9,227	-$176,675	-$345,825	$0	$0
381	Meters	MTRS_CUS	4	-$18,109,596	-$13,867,592	-$4,061,742	-$132,800	-$14,084	-$32,922	$0	-$457	$0	$0
382	Meter Installations	MTRS_INST	5	-$21,761,039	-$20,083,214	-$1,647,765	-$22,257	-$2,394	-$5,320	$0	-$88	$0	$0
383	House Regulators	MTRS_CUS	4	-$4,663,100	-$3,570,812	-$1,045,871	-$34,195	-$3,626	-$8,477	$0	-$118	$0	$0
384	House Regulators Installations	MTRS_CUS	4	-$5,922,336	-$4,535,084	-$1,328,301	-$43,429	-$4,606	-$10,766	$0	-$150	$0	$0
385	Indust. Meas. & Reg. Station Equip.	MTRS_385	6	-$9,695,849	-$52,894	-$6,535,719	-$1,487,414	-$620,396	-$722,014	-$122,276	-$155,133	$0	$0
386	Rental Property on Customers Premise	DIR386	10	-$18,950,642	$0	$0	$0	$0	$0	$0	$0	$0	-$18,950,642
387	Other Equipment	DISTPT	53	-$2,738,695	-$1,765,839	-$656,754	-$93,545	-$52,451	-$16,151	-$97,456	-$52,366	-$104	$0
388	ARO	DISTPT	53	-$2,943,270	-$1,899,151	-$706,336	-$100,507	-$56,410	-$19,521	-$104,814	-$56,319	-$111	$0
	Sub-total			-$640,681,790	-$398,912,679	-$158,343,424	-$19,470,620	-$10,765,662	-$3,853,081	-$19,692,609	-$10,671,941	-$21,132	-$18,950,642
	General Plant												
389	Land and Land Rights	PLTXR	76	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
390	Structures and Improvements	PLTXR	76	-$7,148,650	-$4,616,708	-$1,712,796	-$245,187	-$136,159	-$48,899	-$253,812	-$134,822	-$267	$0
391	Office Furniture and Equipment	OML	66	-$21,788,666	-$15,556,537	-$4,241,125	-$527,893	-$355,578	-$141,712	-$466,395	-$280,881	-$13,798	-$204,747
392	Transportation Equipment	OML	66	-$327,660	-$233,941	-$63,778	-$7,938	-$5,347	-$2,131	-$7,014	-$4,224	-$207	-$3,079
392	CNG Equipment - DIR	DIRCNG	49	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
392	CNG Equipment - Other	SEAS3_DEM	47	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
393	Stores Equipment	PLTXR	76	-$238,559	-$154,065	-$57,158	-$8,182	-$4,544	-$1,632	-$8,470	-$4,499	-$9	$0
394	Tools, Shop, and Garage Equipment	OML	66	-$3,868,002	-$2,761,652	-$752,900	-$93,713	-$63,124	-$25,157	-$82,795	-$49,853	-$2,449	-$36,347
394	CNG Equipment - DIR	DIRCNG	49	-$16,070	$0	$0	$0	$0	$0	$0	$0	-$16,070	$0
394	CNG Equipment - Other	SEAS3_DEM	47	-$33,790	-$23,412	-$7,515	-$1,176	-$314	-$637	-$737	$0	$0	$0
395	Laboratory Equipment	PLTXR	76	-$81,362	-$52,545	-$19,494	-$2,791	-$1,550	-$557	-$2,869	-$1,534	-$3	$0
396	Power Operated Equipment	PLTXR	76	-$651,993	-$421,087	-$156,216	-$22,362	-$12,418	-$4,460	-$23,149	-$12,296	-$24	$0
397	Communication Equipment	OML	66	-$7,192,811	-$5,135,336	-$1,400,029	-$174,261	-$117,379	-$46,780	-$153,961	-$92,721	-$4,555	-$67,589
398	Misc. Equipment	OML	66	-$242,734	-$173,306	-$47,248	-$5,881	-$3,961	-$1,579	-$5,196	-$3,129	-$154	-$2,281
399	Other Intangible Plant	OML	66	-$4,033	-$2,879	-$785	-$98	-$66	-$26	-$86	-$52	-$3	-$38
	Sub-total			-$41,594,130	-$29,131,448	-$8,459,042	-$1,089,483	-$700,440	-$273,570	-$1,004,504	-$584,022	-$37,540	-$314,081
	Other Assets												
108	Retirement Work in Progress	DISTPT	53	$8,047,672	$5,192,777	$1,931,307	$275,086	$154,241	$53,377	$286,589	$153,991	$304	$0
230	Asset Retirment Obligations	DISTPT	53	-$7,144,135	-$4,609,766	-$1,714,474	-$244,201	-$136,924	-$47,364	-$254,412	-$136,702	-$270	$0
253	Landlord Incentives	DISTPT	53	-$4,504,983	-$2,906,850	-$1,081,121	-$153,989	-$86,342	-$29,880	-$160,429	-$86,202	-$170	$0
101	Plant in Service	DISTPT	53	-$4,216	-$2,720	-$1,012	-$144	-$81	-$28	-$150	-$81	$0	$0
	Sub-total			-$3,605,662	-$2,326,561	-$865,299	-$123,249	-$69,106	-$23,915	-$128,403	-$68,994	-$136	$0
	TOTAL ACCUMULATED RESERVE			-$773,227,502	-$491,741,996	-$185,282,997	-$23,142,263	-$12,923,901	-$4,868,170	-$22,904,587	-$12,366,204	-$101,789	-$19,895,695

Puget Sound Energy
Public Counsel Gas Class Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential (16,23,53)	Comm. & Indust (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible	Transport & Contracts	CNG Service (50)	Rentals
Rate Base Adjustments and Working Capital													
	Other Rate Base												
n/a	Customer Advances for Construction	DIR252	9	-$24,086,431	-$11,763,813	-$12,322,618	$0	$0	$0	$0	$0	$0	$0
n/a	Gas Stored Underground - Non current	SEA53_DEM	47	$5,771,153	$3,998,712	$1,283,466	$200,830	$53,612	$108,725	$125,807	$0	$0	$0
n/a	CIAC - Accum. Def. FIT.	DIR252	9	$2,848,376	$1,293,456	$1,354,909	$0	$0	$0	$0	$0	$0	$0
n/a	Liberalized Depr.Tot. Accum. Def. FIT	NETPLT	77	-$181,534,908	-$115,562,838	-$41,590,839	-$6,332,620	-$3,537,593	-$1,251,020	-$6,625,304	-$3,515,917	-$6,952	-$3,111,825
n/a	Allowance for Working Capital	OM	78	$37,081,696	$26,994,752	$7,066,600	$789,377	$533,497	$199,992	$734,836	$441,243	$13,679	$297,720
	Total Other Rate Base			-$160,120,115	-$95,039,720	-$44,208,462	-$5,332,413	-$2,950,484	-$942,303	-$5,784,661	-$3,074,674	$6,728	-$2,814,105
TOTAL RATE BASE				$1,349,395,041	$871,629,028	$299,025,444	$46,536,370	$26,284,857	$9,456,389	$48,314,384	$25,714,496	$448,881	$21,995,180

Puget Sound Energy
Public Counsel Gas Class Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential (16,23,53)	Comm. & Indust (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transport & Contracts	CNG Service (50)	Rentals
O & M Expenses													
	Production Expense												
710	Oper.Supervision and Engineering	PROD_OML		$0									
717	LPG Expenses	PDAYXT	45	$344	$241	$86	$15	$0	$1	$0	$0	$0	$0
735	Misc.Production Expenses	PDAYXT	45	$13,007	$9,126	$3,271	$557	$18	$28	$9	$0	$0	$0
741	Main.Structures and Improvements	PDAYXT	45	$97,123	$68,142	$24,421	$4,162	$135	$191	$70	$0	$3	$0
742	Maintenance of Production Equipment	PDAYXT	45	$102,018	$71,576	$25,652	$4,371	$141	$201	$73	$0	$3	$0
	Sub-total			$212,492	$149,085	$53,429	$9,105	$295	$418	$153	$0	$6	$0
	Other Gas Supply Expenses												
804	Natural Gas Purchases - City Gate	GAS		$0									
805	Other Gas Purchases	GAS		$0									
805	Purchased Gas Cost Adjustment	GAS		$0									
807	Oper.of Purch.Gas Measuring Sta.	COM1	34	$398,282	$195,710	$74,921	$25,127	$23,128	$6,231	$49,995	$23,126	$44	$0
807	Purch.Gas Calculation Exp.	COM1XT_CO	35	$406,923	$248,332	$95,066	$31,698	$7,230	$7,906	$18,636	$0	$56	$0
808	Gas Withdrawn From Storage	GAS		$0									
808	Gas Delivered to Storage	GAS		$0									
812	Gas Used for Other Utility Operations	COM1	34	-$205,569	-$101,014	-$38,670	-$12,969	-$11,936	-$3,218	-$25,804	-$11,936	-$23	$0
813	Other Gas Supply Expenses	COM1XT_CO	35	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total			$599,636	$343,029	$131,317	$43,855	$18,420	$10,921	$40,827	$11,190	$78	$0
	Underground Storage Expenses												
	JP Storage Balancing - DIR	COM1	34	$137,069	$67,354	$25,784	$8,648	$7,959	$2,144	$17,206	$7,959	$15	$0
814	Operation Supv & Eng	STOR_OML	79	$69,461	$48,128	$15,448	$2,417	$645	$1,309	$1,514	$0	$0	$0
815	Oper Map & Records	STORPT	54	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
816	Oper Wells Expense	STORPT	54	$8,756	$6,067	$1,947	$305	$81	$165	$191	$0	$0	$0
817	Oper Lines Expense	STORPT	54	$638	$442	$142	$22	$8	$12	$14	$0	$0	$0
818	Oper Compressor Sta Exp	STORPT	54	$103,125	$71,453	$22,934	$3,589	$958	$1,943	$2,248	$0	$0	$0
819	Oper Compressor Sta Fuel	STORPT	54	$15,110	$10,469	$3,360	$526	$140	$285	$329	$0	$0	$0
820	Oper Meas & Reg Sta Exp	STORPT	54	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
821	Oper Purification Exp	STORPT	54	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
823	Storage Gas Losses	STORPT	54	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
824	Oper Other Expenses	STORPT	54	$13,632	$9,445	$3,032	$474	$127	$257	$297	$0	$0	$0
825	Oper Storage Well Royalty	STORPT	54	$30,455	$21,102	$6,773	$1,060	$283	$574	$664	$0	$0	$0
826	Oper Other Storage Rents	STORPT	54	-$2,442	-$1,692	-$543	-$85	-$23	-$46	-$53	$0	$0	$0
830	Maint Supv & Engineering	STORPT	54	$65,249	$45,210	$14,511	$2,271	$606	$1,229	$1,422	$0	$0	$0
831	Maint Structures	STORPT	54	$1,968	$1,364	$438	$69	$18	$37	$43	$0	$0	$0
832	Maint Reservoirs & Wells	STORPT	54	$3,400	$2,356	$756	$118	$32	$64	$74	$0	$0	$0
833	Maint Of Lines	STORPT	54	$6,448	$4,468	$1,434	$224	$60	$121	$141	$0	$0	$0
834	Maint Compressor Sta Equip	STORPT	54	$159,505	$110,518	$35,473	$5,551	$1,482	-$3,005	$3,477	$0	$0	$0
835	Maint M&R Sta Equip	STORPT	54	$2,588	$1,793	$576	$90	$24	$49	$56	$0	$0	$0
836	Maint Purification Equip	STORPT	54	$545	$377	$121	$19	$5	$10	$12	$0	$0	$0
837	Maint Other Equipment	STORPT	54	$7,535	$5,221	$1,676	$262	$70	$142	$164	$0	$0	$0
	Sub-total			$623,042	$404,075	$133,861	$25,559	$12,474	$11,300	$27,800	$7,959	$15	$0
	Natural Gas Local Storage Expenses												
641	Operating Labor & Expenses	LNGPLT	55	$216,007	$149,667	$48,038	$7,517	$2,007	$4,069	$4,709	$0	$0	$0
643	Maint Struc & Impro	LNGPLT	55	$27,012	$18,716	$6,007	$940	$251	$509	$589	$0	$0	$0
643	Maintenance of Gas Holders	LNGPLT	55	$30,361	$21,038	$6,752	$1,057	$282	$572	$662	$0	$0	$0
644	Maintenance of Vaporizing Equipment	LNGPLT	55	$18,319	$12,693	$4,074	$637	$170	$345	$399	$0	$0	$0
644	Maint Measur & Reg	LNGPLT	55	$14,164	$9,814	$3,150	$493	$132	$267	$309	$0	$0	$0
844	Other Gas Maintenance	LNGPLT	55	$24,463	$16,950	$5,440	$851	$227	$461	$533	$0	$0	$0
	Sub-total			$330,327	$228,877	$73,462	$11,495	$3,069	$6,223	$7,201	$0	$0	$0
	Transmission												
850	Oper Supervision & Engineering	PAVG	42	$6,661	$3,861	$1,456	$345	$206	$55	$418	$219	$0	$0

Puget Sound Energy
Public Counsel Gas Class Cost of Service Study
(Expenses)

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856	Oper Mains Expenses	PAVG	42	$203,391	$120,935	$44,465	$10,544	$6,299	$1,675	$12,768	$6,693	$13	$0
857	Oper Meas & Reg Sta Exp	PAVG	42	$98,459	$58,543	$21,525	$5,104	$3,049	$811	$6,181	$3,240	$6	$0
862	Maint Structures & Improvements	PAVG	42	$107,447	$63,887	$23,490	$5,570	$3,327	$885	$6,745	$3,536	$7	$0
863	Maint Mains	PAVG	42	$119,464	$71,032	$26,117	$6,193	$3,700	$984	$7,499	$3,931	$8	$0
864	Maint Supv & Eng	PAVG	42	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
865	Maint Structures	PAVG	42	$11,353	$6,750	$2,482	$589	$352	$93	$713	$374	$1	$0
867	Maint Other Equipment	PAVG	42	$46,851	$27,857	$10,242	$2,429	$1,451	$386	$2,941	$1,542	$3	$0
	Sub-total			$593,625	$352,985	$129,777	$30,775	$18,383	$4,888	$37,264	$19,534	$39	$0
	Distribution												
870	Oper Supv & Engineering	OIST_OML	70	$1,094,596	$738,382	$257,498	$32,166	$18,188	$8,521	$26,418	$15,370	$55	$0
871	Oper Load Dispatching	COM1	34	$164,312	$80,741	$30,809	$10,386	$9,541	$2,571	$20,628	$9,541	$18	$0
874	Oper Mains & Services Exp	DMAINS_SEF	58	$13,788,211	$8,639,038	$3,422,155	$494,657	$286,380	$63,362	$562,243	$299,775	$602	$0
875	Oper Meas & Reg Sta Gen	PAVG	42	$1,929,304	$1,147,149	$421,781	$100,019	$59,747	$15,887	$121,109	$63,487	$126	$0
876	Oper Meas & Reg Sta Indus	INDUSMR	57	$135,356	$738	$91,240	$20,765	$8,661	$10,079	$1,707	$2,166	$0	$0
878	Oper Meter & House Reg	MRHREG	58	$6,006,899	$4,599,839	$1,347,268	$44,049	$4,671	$10,920	$0	$152	$0	$0
879	Oper Customer Install Exp	CUSINSTL	59	$5,069,031	$4,535,126	$519,097	$10,930	$1,166	$2,872	$0	$40	$0	$0
880	Oper Other Expense	DISTOM	69	$2,293,002	$1,608,271	$493,624	$57,618	$31,329	$10,621	$59,725	$31,751	$63	$0
881	Oper Rents Expense	DIR386	10	$198,260	$0	$0	$0	$0	$0	$0	$0	$0	$198,260
887	Maint Mains	DMAINS	60	$4,099,979	$2,437,821	$896,336	$212,549	$126,961	$33,769	$257,364	$134,908	$270	$0
889	Maint Meas & Reg Sta Gen	PAVG	42	$77,538	$46,103	$16,951	$4,020	$2,401	$636	$4,867	$2,552	$5	$0
890	Maint Meas & Reg Sta Ind	INDUSMR	57	$201,941	$1,102	$136,123	$30,979	$12,921	$15,038	$2,547	$3,231	$0	$0
892	Maint Services	DSERV	61	$4,884,020	$3,344,352	$1,475,237	$33,205	$10,750	$10,044	$3,522	$6,894	$15	$0
893	Maint Meters & House Reg	MRHREG	58	$503,721	$365,729	$112,978	$3,694	$392	$918	$0	$13	$0	$0
894	Maint Other Equipment	DMAINT	62	$741,427	$471,788	$200,222	$21,592	$11,646	$4,585	$20,367	$11,204	$22	$0
	Direct Assign to Sales		11	$1,217,081	$18,987	$900,667	$151,511	$51,158	$80,867	$13,178	$0	$713	$0
	Direct Assignment to Transport		12	$115,162	$0	$0	$1,427	$57,146	$0	$10,877	$45,713	$0	$0
	Sub-total			$42,519,841	$28,053,167	$10,322,085	$1,229,546	$693,057	$290,490	$1,104,650	$626,797	$1,890	$198,260
	Customer Accounts Expense												
901	Supervision - Customer Accounting	CUSTACC	71	$150,341	$131,393	$13,599	$1,029	$1,716	$333	$1,134	$1,109	$28	$0
902	Meter Reading Expense SALES		18	$11,427,635	$10,208,788	$1,095,527	$66,201	$22,907	$27,790	$6,088	$0	$337	$0
902	Meter Reading Expense TRANSPORT		19	$54,048	$0	$0	$675	$26,640	$0	$5,058	$21,672	$0	$0
903	Cust. Records & Collection Exp.	OTH903	20	$10,600,566	$9,792,521	$782,024	$19,889	$148	$5,940	$0	$0	$44	$0
904	Uncollectible Accounts	DIR904	21	$938,024	$695,043	$242,981	$0	$0	$0	$0	$0	$0	$0
904	Uncollectible Accounts - Gas Cost Rel	GASREV		$0									
904	Uncollectible Accounts - Rate Inc Rel	DIR904	21		$0	$0	$0	$0	$0	$0	$0	$0	$0
905	Misc. Customer Accounts Expense	CUSTACC	71	-$2,360	-$2,063	-$213	-$16	-$27	-$5	-$18	-$17	$0	$0
903	Direct Assign to Sales		13	$426,745	$2,650	$192,909	$69,134	$47,995	$16,924	$93,301	$0	$3,832	$0
903	Direct Assignment to Transport		14	$379,731	$0	$0	$786	$163,600	$0	$68,213	$147,133	$0	$0
	Sub-total			$23,974,729	$20,828,333	$2,326,827	$157,697	$262,979	$50,981	$173,774	$169,896	$4,241	$0
	Customer Service & Information Expenses												
908	Customer Assistance Expense - DIR Sales		15	$536,937	$0	$152,225	$4,445	$1,576	$3,106	$129	$0	$9,819	$365,637
908	Customer Assistance Expenses - DIR Transport		16	$662	$0	$0	$13	$186	$0	$103	$360	$0	$0
908	Customer Assistance Expenses	OTH908	22	$106,624	$98,679	$7,884	$201	$0	$60	$0	$0	$0	$0
909	Information, Instructional Advertising	CUSTXT	2	$429,138	$396,390	$31,669	$809	$19	$240	$10	$0	$2	$0
910	Misc. Cust. Serv. & Infor. Expenses	CSI		$0									
908	Conservation Amortization	CUSTXT	2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total			$1,073,561	$495,069	$191,778	$5,468	$1,781	$3,406	$242	$360	$9,821	$365,637
	Sales Expense												
912	Demonstrating and Selling -DIR	DIR_CNG	27	$9,819	$0	$0	$0	$0	$0	$0	$0	$9,819	$0

Puget Sound Energy
Public Counsel Gas Class Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential (16,23,53)	Comm. & Indust (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transport & Contracts	CNG Service (50)	Rentals
912	Demonstrating and Selling	CUSTXT	2	$262,281	$242,266	$19,356	$494	$11	$147	$6	$0	$1	$0
913	Advertising Expenses	CUSTXT	2	$35,235	$32,546	$2,600	$66	$2	$20	$1	$0	$0	$0
	Sub-total			$307,335	$274,812	$21,956	$561	$13	$167	$7	$0	$9,820	$0
	Administrative & General Expenses												
920	A & G Salaries - DIR Sales		23	$474,177	$6,790	$323,744	$61,185	$27,767	$27,140	$24,990	$0	$2,561	$0
920	A & G Salaries - DIR Transport		24	$237,169	$0	$0	$2,089	$112,191	$0	$29,468	$93,421	$0	$0
921	A & G Salaries - DIR Sales Admin		2	$708,260	$654,212	$52,268	$1,335	$31	$397	$16	$0	$3	$0
921	A & G Salaries - DIR Rental	DIR386	10	$53,386	$0	$0	$0	$0	$0	$0	$0	$0	$53,386
920	A & G Salaries	OM	78	$7,554,934	$5,499,845	$1,439,732	$162,863	$108,693	$40,746	$149,714	$89,898	$2,787	$60,657
921	Office Supplies and Expenses	OM	78	$6,378,540	$4,841,997	$1,215,167	$137,460	$81,740	$34,390	$126,362	$75,876	$2,352	$51,196
922	Admin Expenses Transferred	OM	78	-$54,454	-$39,841	-$10,377	-$1,174	-$783	-$294	-$1,079	-$648	-$20	-$437
923	Outside Services Employed	OM	78	$2,900,270	$2,111,340	$552,700	$62,522	$41,726	$15,642	$57,474	$34,511	$1,070	$23,286
924	Property Insurance	PLT	63	$1,209,483	$765,293	$283,905	$40,627	$22,433	$8,073	$41,763	$22,211	$44	$25,234
925	Injuries & Damages	OML	66	$2,235,728	$1,598,251	$435,180	$54,167	$36,486	$14,541	$47,857	$28,821	$1,416	$21,009
926	Emp Pension & Benefits	OML	66	$9,841,983	$7,098,315	$1,935,189	$240,873	$162,247	$64,662	$212,812	$128,164	$6,296	$93,424
928	Regulatory Commission Expense	STREV	33	$1,317,613	$917,247	$284,544	$55,547	$26,529	$14,334	$23,481	$15,815	$117	$0
928	Regulatory Commission Expense - Gas Cost R	GASREV	30	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
928	Reg. Comm. Expense - Rate Inc Rel	STREV	33		$0	$0	$0	$0	$0	$0	$0	$0	$0
930	Gen Advertising Exp	OM	78	$4,066	$2,960	$775	$88	$59	$22	$81	$48	$2	$33
930	Misc. General Expenses	OM	78	$1,378,123	$1,003,247	$262,627	$29,708	$19,827	$7,433	$27,310	$16,399	$508	$11,065
931	Rents	OM	78	$2,276,797	$1,657,464	$433,886	$49,081	$32,756	$12,279	$45,119	$27,092	$840	$18,280
932	Maint Of General Plant- DIR	DIR_CNG	27	$2,482	$0	$0	$0	$0	$0	$0	$0	$2,482	$0
932	Maint Of General Plant- Gas	GENPLT	64	$2,081,251	$1,435,392	$434,275	$57,148	$35,584	$13,889	$53,844	$30,558	$7,482	$13,082
	Sub-total			$38,697,809	$27,350,711	$7,623,613	$953,417	$717,286	$253,254	$839,209	$562,165	$27,939	$370,213
	TOTAL O & M EXPENSES			$108,932,397	$78,480,123	$21,008,107	$2,467,477	$1,727,756	$632,048	$2,231,025	$1,397,902	$53,849	$934,109
	Depreciation Expense												
403	Production Depreciation Expense	PRODPT	52	$61,340	$43,036	$15,423	$2,628	$85	$121	$44	$0	$2	$0
403	JP Balancing Depreciation Expense	COM1	34	$197,623	$97,109	$37,175	$12,468	$11,475	$3,092	$24,807	$11,475	$22	$0
403	Storage Depreciation Expense	STORPT	54	$675,402	$467,972	$150,205	$23,503	$6,274	$12,724	$14,723	$0	$0	$0
403	Transmission Depreciation Expense	PAVG	42	-$170,306	-$101,263	-$37,232	-$8,829	-$5,274	-$1,402	-$10,691	-$5,604	-$11	$0
403	Distribution Depreciation Expense	DISTPT	53	$68,425,986	$42,851,506	$15,941,132	$2,270,573	$1,273,115	$440,576	$2,365,521	$1,271,050	$2,513	$0
403	Rental Depreciation Expense	DIR386	10	$8,694,520	$0	$0	$0	$0	$0	$0	$0	$0	$8,694,520
403	General Depreciation Expense	GENPLT	64	$10,009,688	$6,903,444	$2,088,620	$274,839	$171,141	$66,789	$258,958	$146,968	$35,982	$62,915
403	CNG Equipment - DIR	DIRCNG	49	$13,518	$0	$0	$0	$0	$0	$0	$0	$13,518	$0
403	CNG Equipment - Other	SEAS3_DEM	47	$28,420	$19,692	$6,320	$989	$264	$535	$620	$0	$0	$0
403	Depr. Expense - FAS 143	DMAINS	60	$614,403	$365,320	$134,321	$31,852	$19,026	$5,060	$38,567	$20,217	$40	$0
404	Amort. Ltd - Term Plant	PLT	63	$13,783,889	$8,721,669	$3,235,525	$461,868	$255,661	$82,002	$475,952	$253,129	$502	$287,581
407	Amortization of Property Losses	PLT	63	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
407	Regulatory Debits	SGTREV	32	$1,015,556	$650,196	$227,303	$68,476	$18,275	$16,543	$32,857	$3,785	$121	$0
407	Regulatory Credits	SGTREV	32	-$1,939,081	-$1,241,471	-$434,007	-$126,927	-$34,895	-$31,587	-$62,736	-$7,227	-$231	$0
411	Accretion Exp - FAS143	DMAINS	60	$303,738	$180,601	$66,403	$15,746	$9,406	$2,502	$19,066	$9,994	$20	$0
414	Gains/Losses Property Sales	GENPLT	64	-$284,823	-$198,436	-$59,431	-$7,820	-$4,870	-$1,901	-$7,369	-$4,162	-$1,024	-$1,790
	TOTAL DEPRECIATION EXPENSES			$99,429,849	$58,771,377	$21,371,757	$3,017,365	$1,719,684	$605,064	$3,150,320	$1,699,605	$51,452	$9,043,226
	Taxes (other than income)												
408	Taxes other than Income Taxes - DIR Sales		25	$161,089	$2,257	$107,555	$20,323	$9,221	$9,027	$8,254	$0	$4,452	$0
408	Taxes other than Income Taxes - DIR Transport		26	$48,562	$0	$0	$318	$22,365	$0	$6,938	$18,941	$0	$0
408	Other Taxes - DIR Sales Procurement		2	$44,807	$41,388	$3,307	$84	$2	$25	$1	$0	$0	$0
408	Other Taxes - DIR Rental	DIR386	10	$17,746	$0	$0	$0	$0	$0	$0	$0	$0	$17,746
408	Taxes Other than Income Taxes	PLT	63	$27,881,669	$17,841,950	$6,544,729	$934,253	$517,144	$188,100	$862,743	$512,022	$1,015	$581,711
408	Other Taxes - Rate Inc Rel	PLT	63		$0	$0	$0	$0	$0	$0	$0	$0	$0

Puget Sound Energy
Public Counsel Gas Class Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential (16,23,53)	Comm. & Indust (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transport & Contracts	CNG Service (50)	Rentals
408	Other Taxes - Gas Cost Rel	GASREV	30	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL TAXES OTHER THAN INCOME			$28,153,873	$17,685,595	$6,655,591	$954,979	$548,733	$195,152	$977,936	$530,963	$5,467	$599,457
TOTAL EXPENSES				$236,518,118	$154,937,095	$49,035,455	$6,439,821	$3,996,172	$1,432,265	$6,359,281	$3,628,470	$110,767	$10,576,793
INCOME TAXES & ITC													
	DIT, utility operating income	BASE	65	$45,507,283		Class Tax Amounts calculated and Not Allocated							
	Provision for DIT - credit	BASE	65	-$40,948,243		Class Tax Amounts calculated and Not Allocated							
	ITC adjustments	BASE	65	-$450,709		Class Tax Amounts calculated and Not Allocated							
	FIT Current	BASE	65	$18,389,214		Class Tax Amounts calculated and Not Allocated							
	FIT Current - Rate Incr. Rel.	BASE	65										
	TOTAL INCOME TAXES & ITC			$22,497,545									

Puget Sound Energy
Public Counsel Electric Class Cost of Service Study
(Revenue)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential (16,23,53)	Comm. & Indust (31,35,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transport & Contracts	CNG Service (50)	Rentals
412	Lease Inc Everett Delta to NWP - Gas	PA_MAINS	43	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
480,481	Gas Revenues	GASREV	30	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
480,481	Res., Comm. & Indus. Sales	SALESREV	29	$313,114,919	$226,714,023	$65,386,783	$13,626,378	$1,791,780	$3,542,875	$2,024,148	$0	$28,932	$0
489	Rev From Transp. of Gas To Others	TRANSREV	31	$12,556,941	$0	$0	$103,087	$4,765,304	$0	$3,779,628	$3,908,922	$0	$0
	Other Operating Revenue	OTHREV	28	$8,291,644	$4,614,507	$1,446,076	$44,583	$115,235	$32,661	$15,641	$22,222	$719	$0
	Rental Revenue	DIR388	10	$7,788,789	$0	$0	$0	$0	$0	$0	$0	$0	$7,788,789
TOTAL REVENUE				$339,752,293	$231,328,530	$66,832,859	$13,774,048	$6,672,319	$3,575,536	$5,819,417	$3,931,144	$29,651	$7,788,789

Puget Sound Energy
Public Counsel Gas Class Cost of Service Study
(Allocator Amounts)

	Name	Description	Total	Residential (16,23,53)	Comm. & Indust (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transport & Contracts	CNG Service (50)	Rentals
1	CUST	Average Customers	717,603	662,728	52,948	1,354	107	402	27	34	3	
2	CUSTXT	Customers (excl. transport)	717,480	662,728	52,948	1,352	31	402	16	0	3	
3	DIR_CUSTXT	Customers (excl. transport)	717,480	662,728	52,948	1,352	31	402	16	0	3	0
4	MTRS_CUS	Customer Meters - Acc 381	125,159,053	95,841,709	28,071,513	917,806	97,334	227,531	0	3,160	0	0
5	MTRS_INST	Meters Installation - Acc 382	29,036,398	26,797,626	2,198,662	29,698	3,195	7,099	0	118	0	0
6	MTRS_385	Regulators - Acc 385	39,281,466	214,292	26,478,612	6,026,064	2,513,453	2,925,147	495,395	628,503	0	0
7	SERV	Services	963,603	662,728	292,338	6,580	1,954	0	0	0	3	0
8	DIR380	Distr. Plant - Services	2,483,352	0	0	0	1,250,386	21,395	409,673	601,898	0	0
9	DIR252	Cust. Advances in Aid of Construction	1	0.4884	0.5116							
10	DIR386	Rental Property	1									1
11	DIR_DSALES	Direct Distr. Assignment to Sales	1,217,082	18,987	900,668	151,511	51,158	80,867	13,178	0	713	0
12	DIR_DTRNSP	Direct Distr. Assignment to Transport	115,182	0	0	1,427	57,146	0	10,877	45,713	0	0
13	DIR_CASALES	Direct Cust. Acct. Assignment to Sales	426,745	2,650	192,909	69,134	47,995	16,924	93,301		3,832	0
14	DIR_CATRNSP	Direct Cust. Acct. Assignment to Transport	379,732	0	0	786	163,600	0	68,213	147,133		
15	DIR_CSISALES	Direct Cust. Service Assignment to Sales	536,939	0	152,226	4,445	1,676	3,106	129	0	9,819	365,638
16	DIR_CSITRNSP	Direct Cust. Service Assignment to Transport	662	0	0	13	186	0	103	360	0	0
17	TRANSCUS	Transport Customers	123	0	0	2	76	0	11	34	0	0
18	SALES_902	Sales Meter Reading Costs	11,259,543	10,068,624	1,079,413	65,227	22,570	27,381	5,996	0	332	0
19	TRANS_902	Transport Meter Reading Costs	53,252	0	0	665	26,249	0	4,984	21,354	0	0
20	OTH903	Customer Allocator for 903 Net of Direct	717,414	662,728	52,925	1,346	10	402	0	0	3	0
21	DIR904	Uncollectibles	910,815,776	674,882,702	235,933,074							
22	OTH908	Other Customer Assistance Expense	717,433	662,728	52,948	1,352	0	402	0	0	3	0
23	DIR920_SALES	Acct. 920 Direct Assignment to Sales	474,177	6,790	323,744	61,185	27,767	27,140	24,990	0	2,561	0
24	DIR920_TRNSPT	Acct. 920 Direct Assignment to Transport	237,169	0	0	2,089	112,191	0	29,468	93,421		
25	DIR408_SALES	Acct. 408 Direct Assignment to Sales	161,067	2,257	107,540	20,320	9,220	9,026	8,253	0	4,451	0
26	DIR408_TRNSPT	Acct. 408 Direct Assignment to Transport	48,562	0	0	318	22,365	0	6,938	18,941	0	0
27	DIR_CNG	Direct Assignment to CNG	1	0	0	0	0	0	0	0	1	0
28	OTHREV	Other Operating Revenue	8,040,088	5,896,876	1,847,940	56,972	147,259	41,737	19,987	28,398	919	0
29	SALESREV	Sales Margin	313,114,919	226,714,023	65,386,783	13,626,378	1,791,780	3,542,875	2,024,148	0	28,932	0
30	GASREV	Gas Cost Recovery Revenue	728,442,505	448,168,679	170,546,291	66,270,173	12,412,192	13,626,513	28,300,674	19,677	96,406	
31	TRANSREV	Revenue from Transportation for Others	12,556,941	0	0	103,087	4,765,304	0	3,779,628	3,908,922	0	
32	SGTREV	Sales, Gas & Transportation Revenue	1,054,114,365	674,882,702	235,933,074	68,999,638	18,969,276	17,171,388	34,104,450	3,928,499	125,338	0
33	STREV	Sales & Transportation Revenue	925,671,860	226,714,023	65,386,783	13,729,465	6,557,084	3,542,875	5,803,776	3,908,922	28,932	0
34	COM1	Weather Normalized Volumes	1,084,208,166	532,765,816	203,951,509	68,401,688	62,955,045	16,961,705	136,096,989	62,954,572	120,864	0
35	COM1XT_COM	Weather Normalized Volumes (excl. Transportation)	873,001,720	532,765,816	203,951,609	68,000,772	15,510,556	16,961,705	35,690,498	0	120,864	0
36	SEAS3_COM	Seasonal 3	1.0000	0.6929	0.2224	0.0348	0.0093	0.0188	0.0218	0.0000	0.0000	0.0000
37	COM1GS	Weather Normalized Volumes	1,084,208,168	532,765,816	203,951,509	68,401,688	62,955,045	16,961,705	136,096,989	62,954,572	120,864	0
38	PDAYXT_COM	Peak Day (excl. transport)	6,277,490	4,404,322	1,578,429	268,986	8,704	12,359	4,516	0	174	0
39	TF1_COM	TF-1 Allocator (Annual, Winter & Peak Day Sales)	1.0000	0.6478	0.2369	0.0618	0.0120	0.0145	0.0270	0.0000	0.0001	0.0000
40	SEAS2_COM	Seasonal 2	565,646,449	362,090,858	129,849,293	35,258,164	8,316,124	10,870,291	19,223,944	0	37,777	0
41	JPTF2_COM	TF-2 Allocator (Seasonal Sales & Peak Day x Transport)	1.0000	0.6944	0.2489	0.0451	0.0030	0.0040	0.0046	0.0000	0.0000	0.0000
42	PAVG	Peak and Average	1.0000	0.6946	0.2186	0.0518	0.0310	0.0082	0.0628	0.0329	0.0001	0.0000
43	PA_MAINS	Peak and Average for Mains	1,033,284,953	614,384,654	225,896,317	53,567,153	31,996,668	8,510,545	64,861,455	33,999,849	68,112	0
44	PDAY	Peak Day (Design Day)	6,451,760	4,404,322	1,578,429	272,553	60,606	12,359	59,530	73,766	174	0
45	PDAYXT	Peak Day (excl. transport)	6,277,490	4,404,322	1,578,429	268,986	8,704	12,359	4,516	0	174	0
46	SEAS2_DEM	Seasonal 2	565,646,449	362,090,856	129,849,293	36,258,164	8,316,124	10,870,291	19,223,944	0	37,777	0
47	SEAS3_DEM	Seasonal 3	1.0000	0.6929	0.2224	0.0348	0.0093	0.0188	0.0218	0.0000	0.0000	0.0000
48	JPTF2_DEM	TF-2 Allocator (Seas.Sales & Peak Day x Transport)	1.0000	0.6944	0.2489	0.0451	0.0030	0.0040	0.0046	0.0000	0.0000	0.0000
49	DIRCNG	Direct Rate 50 (CNG)	1								1	
50	COM1XT_DEM	Weather Normalized Volumes x Transport	873,001,720	532,765,816	203,951,509	68,000,772	15,510,556	16,961,705	35,690,498	0	120,864	0
51	TF1_DEM	TF-1 Allocator (Annual, Winter & Peak Day Sales)	1	0.6478	0.2369	0.0618	0.0120	0.0145	0.0270	0.0000	0.0001	0.0000
52	PRODPT	Plant Accounts 311 and 320	6,287,362	4,411,248	1,580,911	269,409	8,718	12,378	4,523	0	175	0
53	DISTPT	Plant Accounts 376 - 385	1,946,762,635	1,266,152,665	467,190,656	86,544,240	37,311,502	12,912,066	69,326,904	37,250,952	73,642	0
54	STORPT	Storage Plant	19,043,195	13,194,634	4,235,079	662,883	176,906	358,763	415,129	0	0	0
55	LNGPLT	LNG Plant	14,070,550	9,749,192	3,129,196	489,640	130,711	265,081	306,729	0	0	0
56	DMAINS_SERV	Distribution Mains & Services Plant (Accounts 376 & 380)	1,602,615,909	1,004,122,946	397,760,125	57,494,446	33,286,159	9,689,198	65,349,993	34,843,087	69,955	0

Puget Sound Energy
Public Counsel Gas Class Cost of Service Study
(Allocator Amounts)

	Name	Description	Total	Residential (16,23,53)	Comm. & Indust (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transport & Contracts	GNG Service (50)	Rentals
57	INDUSMR	Industrial Measurement & Regulation (Acct. 385)	34,078,629	185,909	22,971,515	5,227,911	2,180,548	2,537,711	429,780	545,258	0	0
58	MRHREG	Meters & House Regulators (Accts. 381 & 383)	66,782,132	51,139,039	14,978,345	489,721	51,936	121,405	0	1,686	0	0
59	CUSINSTL	Customer Installation (Accts. 382 & 384)	166,779,008	167,106,171	19,127,227	402,739	42,949	98,453	0	1,470	0	0
60	DMAINS	Mains Plant (Account 376)	1,034,541,312	615,131,677	226,170,982	53,632,285	32,035,772	8,520,893	64,940,319	34,041,189	68,194	0
61	DSERV	Distribution Service Plant (Account 380)	668,074,597	388,991,269	171,589,143	3,862,161	1,250,387	1,168,304	409,673	801,898	1,761	0
62	DMAINT	Distr. O&M Maintenance (Accounts 887 - 893)	9,767,199	6,216,107	2,637,625	284,447	153,425	60,406	268,300	147,598	290	0
63	PLT	Plant - Prod., Stor.(x JP Bal.), Trans., Distr.	2,061,663,392	1,304,504,519	483,939,082	69,081,811	38,239,377	13,760,847	71,188,404	37,860,647	75,039	43,013,666
64	GENPLT	General Plant	112,057,771	77,283,756	23,382,013	3,076,810	1,915,911	747,808	2,899,021	1,845,300	402,816	704,336
65	BASE	Rate Base	1,349,395,041	871,629,028	299,025,444	46,536,370	26,284,857	9,456,389	48,314,384	25,714,496	448,881	21,985,190
66	OML	O&M Labor Expense (excluding JP Balancing Exp.)	26,985,527	19,266,959	5,252,684	653,801	440,388	175,512	577,636	347,875	17,089	253,582
67	PROD_OML	Production O&M Labor Exp. (Accounts 717 - 742)	93,229	65,410	23,442	3,995	129	184	67	0	3	0
68	STOR_OML	Underground Storage O&M Labor (Excluding JP Bal.)	305,642	211,773	67,973	10,636	2,839	5,758	6,663	0	0	0
69	DISTOM	Distribution O&M Operating Exp. (Accounts 871 - 879)	27,093,114	19,002,631	5,832,450	680,786	370,165	125,490	705,684	375,160	746	0
70	DIST_OML	Distribution O&M Labor Exp. (Accounts 871 - 894)	17,509,271	11,779,245	4,118,928	514,525	290,938	136,295	422,590	246,867	882	0
71	CUSTACC	Customer Account Expense (Accounts 902 - 904)	23,039,064	20,135,352	2,084,060	157,713	263,006	50,986	173,792	169,914	4,241	0
72	MR_EXP	Meter Reading Expenses	11,481,681	10,208,788	1,095,527	66,676	49,547	27,790	11,144	21,672	337	0
73	EXP903	Customer Collection & Record Expenses (Account 903)	11,407,042	9,795,171	974,933	89,809	211,742	22,864	161,514	147,133	3,876	0
74	CSI	Customer Service & Information Expense (Accounts 908 & 909)	1,073,561	495,068	191,778	5,468	1,781	3,406	242	360	9,821	365,637
75	EXP912	Demonstrating & Selling Expenses (Account 912)	272,100	242,266	19,356	494	11	147	6	0	9,820	0
76	PLTXR	Plant excluding Rentals	2,024,020,883	1,307,143,836	484,949,456	69,420,673	38,551,256	13,844,875	71,862,627	38,172,523	75,638	0
77	NETPLT	Net Plant - Prod., Stor. (x JP Bal.), Trans., Distr.	1,403,767,464	893,620,699	321,612,337	48,968,689	27,355,391	9,673,847	51,231,943	27,187,776	53,757	24,063,024
78	OM	O&M Expenses Excluding Gas & A&G	70,234,588	51,129,412	13,384,494	1,514,061	1,010,470	378,794	1,391,816	835,736	25,910	563,896
79	STOR_OML	Underground Storage O&M Labor (Excluding JP Bal.)	305,642	211,773	67,973	10,636	2,839	5,758	6,663	0	0	0

Puget Sound Energy
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	Name	Description	Total	Residential (16,23,53)	Comm. & Indust (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transport & Contracts	CNG Service (50)	Rentals
1	CUST	Average Customers	100.0000%	92.3530%	7.3785%	0.1887%	0.0149%	0.0560%	0.0038%	0.0047%	0.0004%	0.0000%
2	CUSTXT	Customers (excl. transport)	100.0000%	92.3688%	7.3797%	0.1884%	0.0043%	0.0560%	0.0022%	0.0000%	0.0004%	0.0000%
3	DIR_CUSTXT	Customers (excl. transport)	100.0000%	92.3688%	7.3797%	0.1884%	0.0043%	0.0560%	0.0022%	0.0000%	0.0004%	0.0000%
4	MTRS_CUS	Customer Meters - Acc 381	100.0000%	76.5759%	22.4287%	0.7333%	0.0778%	0.1818%	0.0000%	0.0025%	0.0000%	0.0000%
5	MTRS_INST	Meters Installation - Acc 382	100.0000%	92.2898%	7.5721%	0.1023%	0.0110%	0.0244%	0.0000%	0.0004%	0.0000%	0.0000%
6	MTRS_385	Regulators - Acc 385	100.0000%	0.5455%	87.4074%	15.3407%	6.3986%	7.4466%	1.2611%	1.6000%	0.0000%	0.0000%
7	SERV	Services	100.0000%	68.7760%	30.3380%	0.6829%	0.0000%	0.2028%	0.0000%	0.0000%	0.0003%	0.0000%
8	DIR380	Distr. Plant - Services	100.0000%	0.0000%	0.0000%	0.0000%	50.3507%	0.8615%	16.4966%	32.2910%	0.0000%	0.0000%
9	DIR252	Cust. Advances in Aid of Construction	100.0000%	48.6400%	51.1600%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
10	DIR386	Rental Property	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
11	DIR_DSALES	Direct Distr. Assignment to Sales	100.0000%	1.5800%	74.0022%	12.4487%	4.2033%	6.6443%	1.0828%	0.0000%	0.0586%	0.0000%
12	DIR_DTRNSP	Direct Distr. Assignment to Transport	100.0000%	0.0000%	0.0000%	1.2387%	49.8220%	0.0000%	9.4448%	39.6945%	0.0000%	0.0000%
13	DIR_CASALES	Direct Cust. Acct. Assignment to Sales	100.0000%	0.6210%	45.2047%	16.2003%	11.2468%	3.9658%	21.8634%	0.0000%	0.8980%	0.0000%
14	DIR_CATRNSP	Direct Cust. Acct. Assignment to Transport	100.0000%	0.0000%	0.0000%	0.2070%	43.0830%	0.0000%	17.9635%	38.7465%	0.0000%	0.0000%
15	DIR_CSISALES	Direct Cust. Service Assignment to Sales	100.0000%	0.0000%	28.3507%	0.8278%	0.2935%	0.5785%	0.0240%	0.0000%	1.8287%	68.0967%
16	DIR_CSITRNSP	Direct Cust. Service Assignment to Transport	100.0000%	0.0000%	0.0000%	1.9637%	28.0967%	0.0000%	15.5589%	54.3807%	0.0000%	0.0000%
17	TRANSCUS	Transport Customers	100.0000%	0.0000%	0.0000%	1.6260%	81.7886%	0.0000%	8.8431%	27.6423%	0.0000%	0.0000%
18	SALES_902	Sales Meter Reading Costs	100.0000%	89.3342%	9.5867%	0.5783%	0.2005%	0.2432%	0.0533%	0.0000%	0.0029%	0.0000%
19	TRANS_902	Transport Meter Reading Costs	100.0000%	0.0000%	0.0000%	1.2488%	49.2920%	0.0000%	9.3593%	40.0998%	0.0000%	0.0000%
20	OTH903	Customer Allocator for 903 Net of Direct	100.0000%	92.3773%	7.3772%	0.1878%	0.0014%	0.0560%	0.0000%	0.0000%	0.0004%	0.0000%
21	DIR904	Uncollectibles	100.0000%	74.0965%	25.9035%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
22	OTH908	Other Customer Assistance Expense	100.0000%	92.3749%	7.3602%	0.1664%	0.0000%	0.0560%	0.0000%	0.0000%	0.0004%	0.0000%
23	DIR920_SALES	Acct. 920 Direct Assignment to Sales	100.0000%	1.4320%	68.2749%	12.9034%	5.8558%	5.7238%	5.2702%	0.0000%	0.5401%	0.0000%
24	DIR920_TRNSPT	Acct. 920 Direct Assignment to Transport	100.0000%	0.0000%	0.0000%	0.8808%	47.3042%	0.0000%	12.4249%	39.3901%	0.0000%	0.0000%
25	DIR408_SALES	Acct. 408 Direct Assignment to Sales	100.0000%	1.4013%	66.7872%	12.6159%	5.7243%	5.6039%	5.1240%	0.0000%	2.7634%	0.0000%
26	DIR408_TRNSPT	Acct. 408 Direct Assignment to Transport	100.0000%	0.0000%	0.0000%	0.6546%	46.0545%	0.0000%	14.2869%	39.0037%	0.0000%	0.0000%
27	DIR_CNG	Direct Assignment to CNG	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%
28	OTHREV	Other Operating Revenue	100.0000%	73.3434%	22.9841%	0.7086%	1.8316%	0.5191%	0.2486%	0.3532%	0.0114%	0.0000%
29	SALESREV	Sales Margin	100.0000%	72.4060%	20.8827%	4.3519%	0.5722%	1.1315%	0.6465%	0.0000%	0.0082%	0.0000%
30	GASREV	Gas Cost Recovery Revenue	100.0000%	61.5242%	23.4125%	7.5874%	1.7039%	1.8709%	3.8851%	0.0027%	0.0132%	0.0000%
31	TRANSREV	Revenue from Transportation for Others	100.0000%	0.0000%	0.0000%	0.8210%	37.9496%	0.0000%	30.0999%	31.1296%	0.0000%	0.0000%
32	SGTREV	Sales, Gas & Transportation Revenue	100.0000%	64.0237%	22.3821%	6.5457%	1.7995%	1.6290%	3.2354%	0.3727%	0.0119%	0.0000%
33	STREV	Sales & Transportation Revenue	100.0000%	69.6143%	20.0775%	4.2157%	2.0134%	1.0879%	1.7821%	1.2003%	0.0089%	0.0000%
34	COM1	Weather Normalized Volumes	100.0000%	49.1387%	18.8111%	8.3089%	5.8065%	1.5644%	12.5527%	5.8065%	0.0111%	0.0000%
35	COM1XT_COM	Weather Normalized Volumes (excl. Transportation)	100.0000%	61.0269%	23.3621%	7.7893%	1.7767%	1.9429%	4.0883%	0.0000%	0.0138%	0.0000%
36	SEAS3_COM	Seasonal 3	100.0000%	69.2878%	22.2393%	3.4799%	0.9290%	1.8839%	2.1799%	0.0000%	0.0000%	0.0000%
37	COM1GS	Weather Normalized Volumes	100.0000%	49.1387%	18.8111%	8.3089%	5.8065%	1.5644%	12.5527%	5.8065%	0.0111%	0.0000%
38	PDAYXT_COM	Peak Day (excl. transport)	100.0000%	70.1606%	25.1443%	4.2849%	0.1387%	0.1969%	0.0719%	0.0000%	0.0028%	0.0000%
39	TF1_COM	TF-1 Allocator (Annual, Winter & Peak Day Sales)	100.0000%	64.7788%	23.6849%	6.1809%	1.1989%	1.4534%	2.6972%	0.0000%	0.0080%	0.0000%
40	SEAS2_COM	Seasonal 2	100.0000%	84.0136%	22.9559%	6.2333%	1.4702%	1.9217%	3.3986%	0.0000%	0.0067%	0.0000%
41	JPTF2_COM	TF-2 Allocator (Seasonal Sales & Peak Day x Transport)	100.0000%	69.4352%	24.8860%	4.5148%	0.2958%	0.4004%	0.4645%	0.0000%	0.0033%	0.0000%
42	PAVG	Peak and Average	100.0000%	59.4592%	21.8618%	5.1642%	3.0968%	0.8234%	6.2773%	3.2907%	0.0065%	0.0000%
43	PA_MAINS	Peak and Average for Mains	100.0000%	59.4594%	21.8620%	5.1842%	3.0966%	0.8236%	6.2772%	3.2905%	0.0066%	0.0000%

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44	PDAY	Peak Day (Design Day)	100.0000%	68.2654%	24.4651%	4.2245%	0.7844%	0.1916%	0.8227%	1.1437%	0.0027%	0.0000%
45	PDAYXT	Peak Day (excl. transport)	100.0000%	70.1608%	25.1443%	4.2849%	0.1387%	0.1969%	0.0719%	0.0000%	0.0028%	0.0000%
46	SEAS2_DEM	Seasonal 2	100.0000%	64.0136%	22.9559%	6.2333%	1.4702%	1.9217%	3.3986%	0.0000%	0.0067%	0.0000%
47	SEAS3_DEM	Seasonal 3	100.0000%	69.2879%	22.2393%	3.4799%	0.9290%	1.8839%	2.1799%	0.0000%	0.0000%	0.0000%
48	JPTF2_DEM	TF-2 Allocator (Seas.Sales & Peak Day x Transport)	100.0000%	89.4352%	24.8860%	4.5148%	0.2958%	0.4004%	0.4645%	0.0000%	0.0033%	0.0000%
49	DIRCNG	Direct Rate 50 (CNG)	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%
50	COM1XT_DEM	Weather Normalized Volumes x Transport	100.0000%	61.0269%	23.3521%	7.7893%	1.7767%	1.8429%	4.0883%	0.0000%	0.0138%	0.0000%
51	TF1_DEM	TF-1 Allocator (Annual, Winter & Peak Day Sales)	100.0000%	64.7766%	23.6849%	6.1809%	1.1989%	1.4534%	2.6972%	0.0000%	0.0080%	0.0000%
52	PRODPT	Plant Accounts 311 and 320	100.0000%	70.1608%	25.1443%	4.2849%	0.1387%	0.1969%	0.0719%	0.0000%	0.0028%	0.0000%
53	DISTPT	Plant Accounts 376 - 385	100.0000%	64.5252%	23.9983%	3.4182%	1.9166%	0.6633%	3.5611%	1.9135%	0.0038%	0.0000%
54	STORPT	Storage Plant	100.0000%	69.2879%	22.2393%	3.4799%	0.9290%	1.8839%	2.1799%	0.0000%	0.0000%	0.0000%
55	LNGPLT	LNG Plant	100.0000%	69.2879%	22.2393%	3.4799%	0.9290%	1.8839%	2.1799%	0.0000%	0.0000%	0.0000%
56	DMAINS_SERV	Distribution Mains & Services Plant (Accounts 376 & 38	100.0000%	62.6552%	24.8194%	3.5875%	2.0770%	0.6046%	4.0777%	2.1741%	0.0044%	0.0000%
57	INDUSMR	Industrial Measurement & Regulation (Acct. 385)	100.0000%	0.5455%	67.4074%	15.3407%	6.3986%	7.4466%	1.2611%	1.6000%	0.0000%	0.0000%
58	MRHREG	Meters & House Regulators (Accts. 381 & 383)	100.0000%	76.5759%	22.4287%	0.7333%	0.0776%	0.1818%	0.0000%	0.0025%	0.0000%	0.0000%
59	CUSINSTL	Customer Installation (Accts. 382 & 384)	100.0000%	89.4873%	10.2406%	0.2156%	0.0230%	0.0527%	0.0000%	0.0008%	0.0000%	0.0000%
60	DMAINS	Mains Plant (Account 376)	100.0000%	59.4594%	21.8620%	5.1842%	3.0966%	0.8236%	6.2772%	3.2905%	0.0066%	0.0000%
61	DSERV	Distribution Service Plant (Account 380)	100.0000%	68.4754%	30.2054%	0.6799%	0.2201%	0.2057%	0.0721%	0.1412%	0.0003%	0.0000%
62	DMAINT	Distr. O&M Maintenance (Accounts 887 - 893)	100.0000%	63.6324%	27.0049%	2.9123%	1.5708%	0.8185%	2.7470%	1.5112%	0.0030%	0.0000%
63	PLT	Plant - Prod., Stor.(x JP Bal.), Trans., Distr.	100.0000%	63.2744%	23.4732%	3.3508%	1.8548%	0.6675%	3.4530%	1.8364%	0.0036%	2.0864%
64	GENPLT	General Plant	100.0000%	68.9678%	20.8660%	2.7457%	1.7098%	0.8673%	2.5871%	1.4683%	0.3595%	0.6285%
65	BASE	Rate Base	100.0000%	64.5941%	22.1600%	3.4487%	1.9479%	0.7008%	3.5804%	1.8056%	0.0333%	1.6293%
66	OML	O&M Labor Expense (excluding JP Balancing Exp.)	100.0000%	71.3974%	19.4848%	2.4228%	1.6319%	0.6504%	2.1405%	1.2891%	0.0633%	0.9397%
67	PROD_OML	Production O&M Labor Exp. (Accounts 717 - 742)	100.0000%	70.1608%	25.1443%	4.2849%	0.1387%	0.1969%	0.0719%	0.0000%	0.0028%	0.0000%
68	STOR_OML	Undergroung Storage O&M Labor (Excluding JP Bal.)	100.0000%	69.2879%	22.2393%	3.4799%	0.9290%	1.8839%	2.1799%	0.0000%	0.0000%	0.0000%
69	DISTOM	Distribution O&M Operating Exp. (Accounts 871 - 879)	100.0000%	70.1382%	21.5274%	2.5128%	1.3683%	0.4632%	2.6047%	1.3847%	0.0028%	0.0000%
70	DIST_OML	Distribution O&M Labor Exp. (Accounts 871 - 894)	100.0000%	67.2743%	23.5243%	2.9386%	1.6516%	0.7784%	2.4135%	1.4042%	0.0050%	0.0000%
71	CUSTACC	Customer Account Expense (Accounts 902 - 904)	100.0000%	87.3966%	9.0458%	0.6845%	1.1416%	0.2213%	0.7543%	0.7375%	0.0184%	0.0000%
72	MR_EXP	Meter Reading Expenses	100.0000%	88.9137%	9.5415%	0.5826%	0.4315%	0.2420%	0.0971%	0.1888%	0.0029%	0.0000%
73	EXP903	Customer Collection & Record Expenses (Account 903)	100.0000%	85.8895%	8.5468%	0.7873%	1.8562%	0.2004%	1.4159%	1.2898%	0.0340%	0.0000%
74	CSI	Customer Service & Information Expense (Accounts 90	100.0000%	46.1148%	17.8638%	0.5093%	0.1659%	0.3173%	0.0225%	0.0335%	0.8148%	34.0583%
75	EXP912	Demonstrating & Selling Expenses (Account 912)	100.0000%	89.0356%	7.1134%	0.1816%	0.0042%	0.0540%	0.0021%	0.0000%	3.6090%	0.0000%
76	PLTXR	Plant excluding Rentals	100.0000%	64.5815%	23.9597%	3.4298%	1.9047%	0.6840%	3.5505%	1.8860%	0.0037%	0.0000%
77	NETPLT	Net Plant - Prod., Stor. (x JP Bal.), Trans., Distr.	100.0000%	63.6587%	22.9107%	3.4884%	1.9487%	0.6891%	3.6496%	1.9368%	0.0038%	1.7142%
78	OM	O&M Expenses Excluding Gas & A&G	100.0000%	72.7981%	19.0588%	2.1557%	1.4387%	0.5393%	1.9817%	1.1899%	0.0369%	0.8029%
79	STOR_OML	Undergroung Storage O&M Labor (Excluding JP Bal.)	100.0000%	69.2879%	22.2393%	3.4799%	0.9290%	1.8839%	2.1799%	0.0000%	0.0000%	0.0000%

Puget Sound Energy
Public Counsel Gas Class Cost of Service Study
(Salaries & Wages)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential (16,23,53)	Comm. & Indust (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transport & Contracts	CNG Service (50)	Rentals
Labor O & M Expenses													
	Production Expense - Labor												
710	Oper. Supervision and Engineering	PROD_OML	67	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
717	LPG Expenses	PDAYXT	45	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
735	Misc. Production Expenses	PDAYXT	45	$1,959	$1,374	$493	$84	$3	$4	$1	$0	$0	$0
741	Maint. Structures and Improvements	PDAYXT	45	$35,554	$24,952	$8,942	$1,524	$49	$70	$26	$0	$1	$0
742	Maint. Production Equipment	PDAYXT	45	$55,706	$39,084	$14,007	$2,387	$77	$110	$40	$0	$2	$0
	Sub-total			$93,229	$65,410	$23,442	$3,995	$129	$184	$67	$0	$3	$0
0	Other Gas Supply Expenses												
807	Purchased Gas Expense	COM1	34	$131,374	$64,555	$24,713	$8,288	$7,628	$2,065	$16,491	$7,628	$15	$0
807	Purchased Gas Expense	COM1XT_COI	35	$372,009	$227,026	$86,909	$28,977	$6,609	$7,228	$15,209	$0	$52	$0
	Sub-total			$503,383	$291,581	$111,622	$37,265	$14,238	$9,283	$31,700	$7,628	$66	$0
	Natural Gas Underground Storage - Labor												
0	JP Storage Balancing - DIR	COM1	34	$100,054	$49,165	$18,821	$6,312	$5,810	$1,565	$12,559	$5,810	$11	$0
814	Operation Supv & Eng	STOR_OML	68	$49,095	$34,017	$10,918	$1,708	$456	$925	$1,070	$0	$0	$0
818	Oper Compressor Sta Exp	STORPT	54	$75,385	$52,233	$16,765	$2,623	$700	$1,420	$1,643	$0	$0	$0
841	Operating Labor & Expenses	STORPT	54	$89,705	$62,155	$19,950	$3,122	$833	$1,690	$1,956	$0	$0	$0
830	Maint Supv & Engineering	STORPT	54	$49,535	$34,322	$11,016	$1,724	$460	$933	$1,080	$0	$0	$0
834	Maint Compressor Sta Equip	STORPT	54	$88,886	$61,587	$19,768	$3,093	$826	$1,675	$1,938	$0	$0	$0
835	Maint M&R Sta Equip	STORPT	54	$2,132	$1,477	$474	$74	$20	$40	$46	$0	$0	$0
	Sub-total			$454,791	$294,955	$97,712	$18,657	$9,105	$8,248	$20,292	$5,810	$11	$0
	Natural Gas Local Storage - Labor												
843	Maint Struc & Impro	LNGPLT	55	$8,929	$6,187	$1,986	$311	$83	$168	$195	$0	$0	$0
843	Maintenance of Gas Holders	LNGPLT	55	$8,929	$6,187	$1,986	$311	$83	$168	$195	$0	$0	$0
844	Maintenance of Vaporizing Equipment	LNGPLT	55	$8,929	$6,187	$1,986	$311	$83	$168	$195	$0	$0	$0
844	Maint Measur & Reg	LNGPLT	55	$8,929	$6,187	$1,986	$311	$83	$168	$195	$0	$0	$0
844	Other Gas Maintenance	LNGPLT	55	$8,929	$6,187	$1,986	$311	$83	$168	$195	$0	$0	$0
	Sub-total			$44,645	$30,934	$9,929	$1,554	$415	$841	$973	$0	$0	$0
	Transmission - Labor												
856	Oper Mains Expenses	PAVG	42	$91,073	$54,151	$19,910	$4,721	$2,820	$750	$5,717	$2,997	$6	$0
857	Oper Meas & Reg Sta Exp	PAVG	42	$67,854	$40,345	$14,834	$3,518	$2,101	$559	$4,259	$2,233	$4	$0
862	Maint Structures & Improvements	PAVG	42	$33,804	$20,100	$7,390	$1,752	$1,047	$278	$2,122	$1,112	$2	$0
863	Maint Supv & Eng	PAVG	42	$34,265	$20,374	$7,491	$1,776	$1,061	$282	$2,151	$1,128	$2	$0
865	Maint Structures	PAVG	42	$7,865	$4,676	$1,719	$408	$244	$65	$494	$259	$1	$0
867	Maint Other Equipment	PAVG	42	$25,309	$15,049	$5,533	$1,312	$784	$208	$1,589	$833	$2	$0
	Sub-total			$260,170	$154,695	$56,878	$13,488	$8,057	$2,142	$16,332	$8,561	$17	$0
	Distribution - Labor												
870	Oper Supv & Engineering	DIST_OML	70	$542,210	$364,768	$127,651	$15,933	$9,009	$4,221	$13,086	$7,614	$27	$0
871	Oper Load Dispatching	COM1	34	$140,260	$68,922	$26,384	$8,849	$8,144	$2,194	$17,606	$8,144	$16	$0
874	Oper Mains & Services Exp	DMAINS_SER	56	$4,903,063	$3,072,026	$1,216,912	$175,899	$101,836	$29,643	$199,933	$106,599	$214	$0
875	Oper Meas & Reg Sta Gen	PAVG	42	$1,164,132	$692,164	$254,500	$60,351	$36,051	$9,586	$73,076	$38,308	$76	$0
876	Oper Meas & Reg Sta Indus	INDUSMR	57	$82,668	$451	$55,724	$12,662	$5,290	$6,156	$1,043	$1,323	$0	$0
878	Oper Meter & House Reg	MRHREG	58	$3,358,910	$2,572,117	$753,359	$24,631	$2,612	$6,106	$0	$85	$0	$0
879	Oper Customer Install Exp	CUSINSTL	59	$3,658,765	$3,273,399	$374,678	$7,889	$841	$1,929	$0	$29	$0	$0
880	Oper Other Expense	OISTOM	69	$485,905	$340,806	$104,603	$12,210	$6,639	$2,251	$12,556	$6,728	$13	$0
887	Maint Mains	DMAINS	60	$1,376,023	$818,175	$300,828	$71,335	$42,610	$11,333	$86,376	$45,278	$91	$0
889	Maint Meas & Reg Sta Gen	PAVG	42	$19,736	$11,735	$4,315	$1,023	$611	$163	$1,239	$649	$1	$0
890	Maint Meas & Reg Sta Ind	INDUSMR	57	$143,352	$782	$96,630	$21,991	$9,172	$10,675	$1,808	$2,294	$0	$0

Puget Sound Energy
Public Counsel Gas Class Cost of Service Study
(Salaries & Wages)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential (16,23,53)	Comm. & Indust (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transport & Contracts	CNG Service (50)	Rentals
892	Maint Services	DSERV	61	$463,573	$317,433	$140,024	$3,152	$1,020	$953	$334	$654	$1	$0
893	Maint Meters & House Reg	MRHREG	58	$378,685	$269,982	$64,934	$2,777	$294	$688	$0	$10	$0	$0
894	Maint Other Equipment	DMAINT	62	$485,785	$309,117	$131,186	$14,147	$7,631	$3,004	$13,344	$7,341	$14	$0
	Direct Assign to Sales		11	$776,804	$12,118	$574,852	$96,702	$32,652	$51,613	$8,411	$0	$465	$0
	Direct Assignment to Transport		12	$71,610	$0	$0	$887	$35,534	$0	$6,763	$28,425	$0	$0
	Sub-total			$18,051,481	$12,144,014	$4,246,479	$530,459	$299,948	$140,516	$435,676	$253,480	$909	$0
	Customer Accounts Expense - Labor												
901	Supervision - Customer Accounting	CUSTACC	71	$114,258	$99,858	$10,336	$782	$1,304	$253	$862	$843	$21	$0
902	Meter Reading Expenses	MR_EXP	72	$469,260	$417,236	$44,775	$2,733	$2,025	$1,136	$455	$886	$14	$0
903	Cust. Records & Coll. Exp.	EXP903	73	$5,892,897	$5,060,202	$503,652	$46,395	$109,386	$11,812	$83,438	$76,009	$2,003	$0
905	Misc. Customer Accounts Expense	CUSTACC	71	$29,527	$25,806	$2,671	$202	$337	$86	$223	$218	$5	$0
	Sub-total			$6,505,942	$5,603,102	$561,433	$50,113	$113,053	$13,266	$84,978	$77,955	$2,043	$0
	Customer Service & Information Expenses - Labor												
906	Customer Assistance Expenses	CSI	74	$744,553	$343,348	$133,005	$3,792	$1,235	$2,362	$168	$250	$6,811	$253,582
909	Information, Instructional Advertising	CUSTXT	2	$226,801	$209,493	$16,737	$427	$10	$127	$5	$0	$1	$0
	Sub-total			$971,354	$552,841	$149,742	$4,220	$1,245	$2,489	$173	$250	$6,812	$253,582
	Sales Expense - Labor												
912	Demonstrating and Selling	EXP912	75	$200,586	$178,593	$14,269	$364	$8	$108	$4	$0	$7,239	$0
	Sub-total			$200,586	$178,593	$14,269	$364	$8	$108	$4	$0	$7,239	$0
	TOTAL LABOR O & M EXPENSES			$27,085,581	$19,316,124	$5,271,506	$660,114	$446,198	$177,078	$590,195	$353,684	$17,100	$253,582

Exhibit No.__(GAW-11)

PUGET SOUND ENERGY NATURAL GAS OPERATIONS
PSE AND PUBLIC COUNSEL REVENUE DISTRIBUTION PROPOSALS

Customer Class	(1) Current Revenue	(2) Rate of Return PSE	(3) Rate of Return Public Counsel	(4) Proposed Revenue Increase PSE	(5) Proposed Revenue Increase Public Counsel	(6) Proposed Revenue Increase (%) PSE	(7) Proposed Revenue Increase (%) Public Counsel	(8) Public Counsel Pct of Sys Avg Pct
Residential	226,714,023	6.18%	6.56%	38,682,592	$36,493,752	17.06%	16.10%	95%
Comm & Ind (31, 36, 51, 61)	65,386,783	4.08%	4.96%	16,178,327	13,914,794	24.74%	21.28%	125%
Large Volume (41)	13,729,465	15.96%	11.09%	127	1,168,693	0.00%	8.51%	50%
Interuptible (85)	6,557,084	19.77%	7.97%	-146	948,869	0.00%	14.47%	85%
Limited Interupt (86)	3,542,875	21.97%	15.22%	-302,266	0	-8.53%	0.00%	0%
Non-Exclusive Interuptible (87)	5,803,776	4.97%	1.26%	1,242,877	1,383,297	21.41%	23.83%	140%
Transportation 1/	2,319,556	10.24%	2.60%	558,839	513,364	24.09%	22.13%	130%
Special Contracts 1/	1,589,366			0	351,758	0.00%	22.13%	130%
CNG	28,932	-14.23%	-8.79%	5,074	7,388	17.54%	25.54%	150%
Rentals	7,788,789	-9.92%	-5.68%	404,902	1,989,015	5.20%	25.54%	150%
Total Company	333,460,649	5.98%	5.98%	56,770,326 2/	$56,770,930	17.02%	17.02%	100%

1/ Transportation and Sepecial Contracts are combined for CCOSS purposes.
2/ PSE's total increase does do exactly equal the requested overall increase due to the application of billing units and proposed rates which require rounding.

Puget Sound Energy
Natural Gas Residential Customer Costs
(Cost of Equity @ PSE Proposed)

	Residential
Gross Plant	
Meters	$41,601,625
Meter Installations	$141,416,119
House Regulators	$9,537,413
House Regulator Installations	$25,690,051
Total Gross Plant	$218,245,210
Depreciation Reserve	
Meters	-$13,867,592
Meter Installations	-$20,083,214
House Regulators	-$3,570,812
House Regulator Installations	-$4,535,084
Total Depreciation Reserve	-$42,056,701
Total Net Plant	$176,188,508
Total Rate Base	$176,188,508
Operation & Maintenance Expenses	
Oper Meter & House Reg	$4,599,839
Oper Customer Install Exp	$4,535,126
Maint Services	$3,344,352
Maint Meters & House Reg	$385,729
Meter Reading Expense	$10,208,788
Cust. Records & Collection Exp.	$9,792,521
Total O & M Expenses	$32,866,355
Depreciation Expense	
Meters	$1,135,724
Meter Installations	$3,153,579
House Regulators	$229,852
House Regulator Installations	$716,752
Total Depreciation Expense	$5,235,908

Rate Per PSC Depreciation Study	2.73%
Rate Per PSC Depreciation Study	2.23%
Rate Per PSC Depreciation Study	2.41%
Rate Per PSC Depreciation Study	2.79%

Revenue Requirement

Interest	$6,585,856
Equity return	$8,567,312
Income Tax	$4,613,168
Revenue For Return	$19,766,337
O & M Expenses	$32,866,355
Depreciation Expense	$5,235,908
Total Customer Revenue Requirement Before Gross Up	$57,868,600
Gross Up for Uncollectibles, WUTC Fees, and Excise Te	0.95686
Total Customer Revenue Requirement	$60,477,603
Number of Bills	8,081,247
Monthly Cost	$7.48

Per Witness Karzmar

Cost of Capital			
	PCT	Cost	WGHT Cost
Debt	54.97%	6.80%	3.74%
Preferred	0.03%	8.61%	0.00%
Common	45.00%	10.80%	4.86%
Total	100.00%		8.60%

Puget Sound Energy
Natural Gas Residential Customer Costs
(Cost of Equity @ Public Counsel Proposed)

	Residential			
Gross Plant				
Meters	$41,601,625			
Meter Installations	$141,416,119			
House Regulators	$9,537,413			
House Regulator Installations	$25,690,051			
Total Gross Plant	$218,245,210			
Depreciation Reserve				
Meters	-$13,867,592			
Meter Installations	-$20,083,214			
House Regulators	-$3,570,812			
House Regulator Installations	-$4,535,084			
Total Depreciation Reserve	-$42,056,701			
Total Net Plant	$176,188,508			
Total Rate Base	$176,188,508			
Operation & Maintenance Expenses				
Oper Meter & House Reg	$4,599,839			
Oper Customer Install Exp	$4,535,126			
Maint Services	$3,344,352			
Maint Meters & House Reg	$385,729			
Meter Reading Expense	$10,208,788			
Cust. Records & Collection Exp.	$9,792,521			
Total O & M Expenses	$32,866,355			
Depreciation Expense				
Meters	$1,135,724	Rate Per PSC Depreciation Study	2.73%	
Meter Installations	$3,153,579	Rate Per PSC Depreciation Study	2.23%	
House Regulators	$229,852	Rate Per PSC Depreciation Study	2.41%	
House Regulator Installations	$716,752	Rate Per PSC Depreciation Study	2.79%	
Total Depreciation Expense	$5,235,908			

Revenue Requirement

		Cost of Capital			
			PCT	Cost	WGHT Cost
Interest	$6,585,856	Debt	54.97%	6.80%	3.74%
Equity return	$7,338,398	Preferred	0.03%	8.61%	0.00%
Income Tax	$3,951,445	Common	45.00%	9.25%	4.16%
Revenue For Return	$17,875,698	Total	100.00%		7.90%
O & M Expenses	$32,866,355				
Depreciation Expense	$5,235,908				
Total Customer Revenue Requirement Before Gross Up	$55,977,961				
Gross Up for Uncollectibles, WUTC Fees, and Excise T	0.95686	Per Witness Karzmar			
Total Customer Revenue Requirement	$58,501,726				
Number of Bills	8,081,247				
Monthly Cost	$7.24				

Puget Sound Energy
Natural Gas Residential Customer Costs
(No Rate Base)

	Residential	
Operation & Maintenance Expenses		
Oper Meter & House Reg	$4,599,839	
Oper Customer Install Exp	$4,535,126	
Maint Services	$3,344,352	
Maint Meters & House Reg	$385,729	
Meter Reading Expense	$10,208,788	
Cust. Records & Collection Exp.	$9,792,521	
Total O & M Expenses	$32,866,355	
Total Customer Revenue Requirement Before Gross Up	$32,866,355	
Gross Up for Uncollectibles, WUTC Fees, and Excise Ta	0.95686	Per Witness Karzmar
Total Customer Revenue Requirement	$34,348,133	
Number of Bills	8,081,247	
Monthly Cost	$4.25	

Puget Sound Energy
Natural Gas Residential Customer Costs
(O&M + Depreciation Based)

	Residential		
Operation & Maintenance Expenses			
Oper Meter & House Reg	$4,599,839		
Oper Customer Install Exp	$4,535,126		
Maint Services	$3,344,352		
Maint Meters & House Reg	$385,729		
Meter Reading Expense	$10,208,788		
Cust. Records & Collection Exp.	$9,792,521		
Total O & M Expenses	$32,866,355		
Depreciation Expense			
Services	$17,815,800	Rate Per Depreciation Study	4.58%
Meters	$1,135,724	Rate Per PSC Depreciation Study	2.73%
Meter Installations	$3,153,579	Rate Per PSC Depreciation Study	2.23%
House Regulators	$229,852	Rate Per PSC Depreciation Study	2.41%
House Regulator Installations	$716,752	Rate Per PSC Depreciation Study	2.79%
Total Depreciation Expense	$23,051,708		
Revenue Requirement			
O & M Expenses	$32,866,355		
Depreciation Expense	$23,051,708		
Total Customer Revenue Requirement Before Gross Up	$55,918,063		
Gross Up for Uncollectibles, WUTC Fees, and Excise Tax	0.95686	Per Witness Karzmar	
Total Customer Revenue Requirement	$58,439,127		
Number of Bills	8,081,247		
Monthly Cost	$7.23		