Exhibit No.___(DWS-1T)
Docket Nos. UE-111048/UG-111049
Witness: Donald W. Schoenbeck

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENRGY, INC., Respondent. ______________________________	)	Docket Nos. UE-111048/UG-111049 *(Consolidated)*

RESPONSIVE TESTIMONY OF DONALD W. SCHOENBECK

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

December 7, 2011

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald W. Schoenbeck, and my business address is 900 Washington Street, Suite 780, Vancouver, Washington 98660. I am employed by Regulatory and Cogeneration Services, Inc. ("RCS"), a utility rate and consulting firm.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I have been involved in the electric utility industry for over 35 years. For the majority of this time, I have provided consulting services for large industrial customers addressing regulatory and contractual matters. I have appeared before the Washington Utilities and Transportation Commission (the "Commission") on many occasions since 1982. A further description of my educational background and work experience can be found in Exhibit No. ___ (DWS-2) attached to this testimony.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including Puget Sound Energy ("PSE" or the "Company").

Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?

A. This testimony will address certain power supply matters, the Company's proposed Conservation Savings Adjustment ("CSA") mechanism, the spreading of any increase in electric revenues allowed by the Commission to the various customer classes and the design of Schedule 448 and 449 demand charges. In addition, my associate Michael C.

Deen will also present additional power supply adjustments on behalf of ICNU, along with recommendations regarding the Company's electric class cost of service study.

Q. PLEASE BRIEFLY SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING.

A. The combined power supply-related adjustments addressed by ICNU will reduce PSE's costs by $53.2 million or the proposed revenue requirement by $54.5 million as indicated by the following table. The conversion of a "cost" or "expense" amount shown under the column heading "Power Supply Cost" to a revenue requirement amount reflects the Company's production factor adjustment (97.901%) and revenue sensitive item adjustment (4.5%).

ICNU Power Supply Adjustments
($ in Millions)

Number	Issue	Power Supply Cost	Revenue Requirement	ICNU Witness
1	Market Price Update	-26.7	-27.4	Schoenbeck
2	Hedging Costs	-4.4	-4.5	Schoenbeck
3	Production O&M Expense	-8.4	-8.6	Schoenbeck
4	Peaking Resource Costs	-1.1	-1.1	Schoenbeck
5	Transmission Reassignment	-1.1	-1.1	Deen
6	Wind Integration Costs	-2.5	-2.6	Deen
7	OATT Revenues	-2.4	-2.5	Deen
8	Mid-C Hydro Contracts	-2.8	-2.9	Deen
9	Interstate Pipeline Increases	-1.6	-1.6	Deen
10	FERC 557 Account/A&G	-1.8	-1.8	Deen
11	CCCT Operating Constraints	-0.4	-0.4	Deen
	Total:	-53.2	-54.5	

My testimony addresses the following four power supply issues: forward gas prices used in the AURORA simulation including the mark-to-market adjustment, the Company's gas financial hedges, production related operations and maintenance

("O&M") expense and peaking market purchase costs. Below is a brief summary of each issue.

- **Forward Gas Price Update** The Company's original filing was based on a forward Sumas gas price of $[redacted] per MMBTU for May 2012, through April 2013. PSE's supplemental filing had a Sumas gas price of $[redacted] per MMBTU. As of November 16, 2011, the Sumas forward gas price is only $[redacted] per MMBTU. ICNU recommends the Commission require PSE to update its power supply cost to take into account current forward gas prices and short term purchases and sales. This should result in a substantial reduction in PSE's projected power costs as indicated by the above table.

- **Gas Financial Hedges** The Company has executed a number of financial gas hedges based upon its modeling of the Company's expected gas need for the rate year. However, the AURORA model is projecting far less gas need. ICNU recommends limiting the amount of hedges included in base power costs to the projected AURORA need. However, ICNU recommends that all gas hedges be allowed to flow through the power cost adjustment mechanism.

- **O&M Expenses** During the historic test period, PSE incurred substantial O&M expense at several Company owned gas-fired plants. As these plants are only overhauled every three or four years, ICNU recommends normalizing the O&M expense based on the actual average O&M expense incurred at these facilities for the most recent four-year period.

- **Peaking Market Purchases** PSE's power supply cost includes $[redacted] associated with peaking market purchases based on an incredible weather event occurring during the rate year. ICNU recommends [redacted] of this expense from the base power supply determination based on the expected occurrence of normal weather conditions.

PSE's CSA mechanism would allow for the automatic recovery of lost margin revenue due to Company sponsored conservation programs. ICNU recommends the Commission reject this one-sided and singularly focused proposal that offers no symmetrical ratepayer benefit.

The Company's rate spread proposal gives most customer classes the same percentage increase. The few exceptions are Schedules 25, 29, 448 and 449. For Schedules 25 and 29, the Company is proposing an increase of 75% of the average value.

For Schedules 448 and 449, the Company is proposing an increase of 125% of the average value. Based on the cost-of-service analysis conducted by Mr. Deen, I recommend that Schedules 448 and 449 should receive the average system increase as the revenue to cost ratio under the recommended ICNU cost of service study is comparable to those of most other classes.

In Docket No. UE-111701, the Company is proposing to re-classify numerous facilities from distribution to transmission service ("wholesale distribution facilities"). The Company is also seeking the approval of the Federal Energy Regulatory Commission ("FERC") to include the associated cost of these wholesale distribution facilities in its Open Access Transmission Tariff ("OATT") charges. As Schedule 448 and 449 customers are required to pay the OATT charges, upon FERC approval, Schedule 448 and 449 customers would be paying for the wholesale distribution facilities twice: once through the Schedule 448/449 charges and once through the OATT charges. ICNU and PSE are attempting to achieve a settlement on how to best address this issue. Absent a successful resolution, ICNU recommends that when FERC approves the proposed re-classification, the increase in the OATT charges be offset by a corresponding dollar for dollar credit to the customers' retail bill to eliminate the double charge for these facilities.

Q. HAVE YOU PREPARED AN EXHIBIT THAT SUMMARIZES ALL OF ICNU'S PROPOSED ADJUSTMENTS IN THIS CASE?

A. Yes. Attached as Exhibit No.__(DWS-7) is a calculation of ICNU's revenue requirement recommendation, which includes ICNU's proposed adjustments related to power supply, cost of capital and consolidated tax adjustment. Taken together, the ICNU adjustments reduce PSE's claimed increase by $112.9 million, resulting in an increase of $39.4 million or just 2.0%.

II. POWER SUPPLY ADJUSTMENTS

Q. HAVE YOU REVIEWED THE COMPANY'S TESTIMONY, EXHIBITS, AND WORKPAPERS REGARDING POWER COSTS IN THIS PROCEEDING?

A. Yes. I have reviewed both the power cost testimony and supporting evidence provided by the Company in its initial filing as well, as the supplemental filing. As a result of this analysis, I recommend that the Commission order several changes to the power cost determination. While most of the ICNU power cost adjustments are "outside" the AURORA model simulation, two of the adjustments address changing model input variables.

Q. WHAT ARE THE ICNU ADJUSTMENTS RELATED TO THE AURORA INPUT VARIABLES?

A. The two adjustments are the gas prices to be used in the model simulation and certain gas-fired generating unit operating parameters. I will address the updating adjustment related to PSE's gas prices (and short-term transactions), and Mr. Deen will address the proper representation of certain gas-fired resources within the AURORA simulation.

Q. PLEASE DESCRIBE THE REASONING BEHIND ICNU'S NATURAL GAS PRICE UPDATE RECOMMENDATION.

A. ICNU recommends the Company provide another update of the natural gas prices used in its AURORA simulation as part of its rebuttal filing due to the significant change in gas prices since the Company made its supplemental filing. This update should include more current natural gas prices, but it also should reflect additional short-term sales or purchase transactions the Company has executed since its supplemental filing. The Company's original filing reflected forward gas prices as of April 12, 2011. At that time, the three month average of daily forward prices for the rate year at Sumas was $[redacted] per MMBTU. The Company's supplemental filing of September 1, 2011 is based on forward gas prices as of July 26, 2011 Exh. No.__(DEM-8T) at 5. At that time, the three month average Sumas price was $[redacted] per MMBTU. ICNU has performed a comparative analysis of the gas prices in the Company's supplemental filing with more current market prices at many of the gas market hubs used in the AURORA simulation. A summary of this analysis is provided in the following table for some of these hubs.

Confidential Gas Price Comparison – May 2012 to April 2013 ($ Per MMBTU)				
Gas Market	**PSE Through 7/26/11**	**ICNU Through 11/16/11**	**Delta**	**ICNU Average Days**
Henry Hub	[redacted]	[redacted]	[redacted]	5 days
Sumas	[redacted]	[redacted]	[redacted]	3 months
AECO	[redacted]	[redacted]	[redacted]	5 days
Stanfield	[redacted]	[redacted]	[redacted]	3 days
Rockies	[redacted]	[redacted]	[redacted]	5 days

As is indicated by the column heading "ICNU Average Days," the ICNU analysis only used a three-month average period (ended November 16, 2011) for the Sumas hub, as we have the daily Kiodex future prices readily available for this location. For the remaining hubs, we relied upon available IntercontinentalExchange, Inc. ("ICE") futures prices for the period from November 10 through November 16, 2011. This was done for two reasons. First, as we do not track gas prices at these other hubs, it would be a time consuming effort to obtain and then derive the 60 day average values for all the hubs used within AURORA for a PSE simulation. Second, it is likely that this mid-November period will be near the middle of any PSE rebuttal update filing as the gas prices should reflect the October through December period. As such, mid-November prices should be relatively close to a three-month average value given today's relatively stable gas price environment.

Q. WHAT IS THE OVERALL EFFECT OF THIS UPDATE ON PSE'S FORECAST POWER COSTS?

A. To approximate the effect of using updated gas prices on PSE's power supply costs, we performed two average water year AURORA simulations. The first simulation used PSE's gas prices and a single average water year. The second average water simulation, which used the lower ICNU gas prices, reduced PSE's AURORA dispatch cost by $32.0 million. However, it is also necessary to update PSE's "out-of-AURORA" mark-to-market adjustment. The mark to market adjustment is a necessary step to reflect the difference between the AURORA dispatch costs based on current forward market gas prices and the actual fixed gas hedges the Company has executed for the rate year. With the lower more current gas prices, the mark-to-market adjustment is increased by $5.3 million, for a net power supply cost reduction of $26.7 million. A comparative summary of the two average water year simulations is attached to this testimony as Exhibit No.___ (DWS-3C). As this analysis produced a substantial adjustment in PSE's power cost, the Commission should require PSE to perform an additional update to its power supply costs based on forward gas prices from the three-month period of October through December.

Q. WHAT ARE THE ICNU ADJUSTMENTS TO POWER COSTS THAT ARE OUTSIDE OF THE AURORA MODEL?

A. ICNU's "Not-In-Model" cost adjustments fall into the following categories:

i. Hedging costs beyond the stated need,

ii. Production O&M Expenses,

iii. Peaking resource costs,

iv. Transmission capacity reassignment revenues,

v. Wind integration opportunity costs,

vi. Anticipated wind integration OATT revenues,

vii. Mid-Columbia hydro contract costs,

viii. Interstate gas pipeline cost increases, and

ix. FERC 557 costs (including reassigned legal costs).

I will address the first three issues, and Mr. Deen will address the remaining matters.

Hedging Costs

Q. PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENT REGARDING THE LEVEL OF HEDGING COSTS INCLUDED IN RATES.

A. As described in its testimony and exhibits, the Company engages in a variety of hedging strategies to attempt to manage the risk and volatility associated with its power and gas supply portfolios. As part of this program, the Company engages in hedging transactions for its natural gas for power needs. As the company uses the AURORA model to project variable power cost based on current market prices, actual gas for power contracts that have been executed for the rate year are included as a mark-to-market cost in the "Not-in-Models" cost calculation.

In terms of gas for power contracts, however, there is a disconnect between the volume of transactions the company has included in its "Not-in-Models" calculation and the volume of gas used for generation in the AURORA model during the rate year. This occurs because the Company uses a probabilistic risk assessment to determine its gas needs based on current market conditions as opposed to the regulatory requirements imposed under the Commission standards. Examples of two such regulatory standards are: 1) the use of average water conditions; and 2) a three months average gas price, instead of the instant market prices at the time of the gas hedging analysis. As a result of this discrepancy, the Company is proposing to include mark-to-market costs for gas in excess of the AURORA generation need in six of the twelve months of the rate year, as shown by confidential Exhibit No. ___(DWS-4C). Customers power supply costs should be based on a uniform set of assumptions pursuant to Commission guidelines. PSE should not be allowed to impose an exogenous cost above and beyond these regulatory guidelines. Removing the mark-to-market costs of natural gas hedges beyond 100% of the projected AURORA need for natural gas during the rate year reduces power costs by approximately $4.4 million.

Q. ARE YOU PROPOSING THAT THESE HEDGING COSTS BE REMOVED WHEN DETERMINING THE ACTUAL COSTS THAT WILL FLOW THROUGH PSE'S POWER COST ADJUSTMENT CLAUSE AS WELL?

A. No. ICNU proposes to exclude hedging costs in excess of need from PSE's base power cost determination. The base power cost determination should be based on the gas need reflected for serving the projected load based on the regulatory standards imposed by the Commission. To the extent these loads and gas needs do change from the expected projection due to day-to-day actual conditions, these costs can and should flow through the power cost adjustment mechanism.

Q. HAS ICNU RECOMMENDED A SIMILAR ADJUSTMENT IN A PRIOR PSE PROCEEDING?

A. Yes. ICNU made a similar recommendation in PSE's 2009 general rate case, which was rejected by the Commission. However, at that time, ICNU proposed a disallowance of the above AURORA hedge volumes. After further consideration, ICNU continues to believe the above AURORA need volumes should not be used to derive the base power supply, but they should be allowed to flow through the power cost adjustment mechanism like all other costs that deviate from normalized rate making standards (examples would be load deviations, resource forced outage rate deviations, hydro deviations, and forward market prices). Therefore, using the power cost adjustment mechanism to account for hedging costs in excess of AURORA need is a superior method compared to making a not-in-model adjustment to the AURORA results.

<u>Production O&M Expenses</u>

Q. PLEASE DESCRIBE THE COMPANY'S PRODUCTION O&M EXPENSE INCREASE FOR THE RATE YEAR.

A. The Company is proposing a $25.4 million increase to its production O&M expenses in this proceeding relative to the 2009 general rate case ($112.2 million for the rate year of April 2010 to March 2011, as compared to $137.6 million for the period of May 2012 to April 2013). Roughly one-half of this increase is due to wind resources ($12.9 million). The remaining amount is primarily attributable to a substantial increase in O&M expense at the Company's gas-fired facilities ($13.6 million). As compared to the test year amount (January 2010 to December 2010), the production O&M increase is $28.3 million ($109.3 million to $137.6 million). Once again, this amount reflects a large increase in wind resources ($14.4 million), but the remainder is primarily related to coal cost increases ($14.5 million).

Q. HAS THE COMPANY USED THE SAME METHOD TO PROJECT THE RATE YEAR O&M EXPENSE AMOUNT FOR ALL PLANTS?

A. No. The Company's treatment of production O&M expenses is inconsistent between resources. For some resources, such as Colstrip, the Company uses projected budgets for the rate year. For most resources, however, the Company has simply used the test year value without any adjustment. Given that the maintenance costs of generating facilities can and do vary significantly year to year due to major maintenance overhaul schedules, using unadjusted test year costs is not appropriate for the rate year, as it does not provide an accurate picture of the likely costs during the rate year. This is demonstrated by Exhibit No.___ (DWS-5), which contains a series of PSE responses to data requests ("DR"). The first several pages of this exhibit is PSE's response to Public Counsel DR 26, showing actual O&M expense by FERC account for four years (2007 – 2010). The cyclical nature of gas-fired maintenance expense is apparent by observing the costs at plants such as Whitehorn or Frederickson, where a major overhaul has occurred within the four-year window. The remaining pages of this exhibit are PSE's responses to ICNU DRs regarding production O&M expense. Attachment A of the response to ICNU DR 5.06 indicates the Company performed $8.2 million of non-contract major maintenance expense at Encogen, Fredonia, Frederickson, Mint Farm and Sumas during the test period. Exh. No. __(DWS-5) at 11. Attachment B of the Company's response to ICNU DR 5.06 shows the 2012 and 2013 budget amounts for most of these same plants. Id. at 12. It shows that the Company is expecting to incur $8.3 million less in non-contract major maintenance expense at these facilities in the rate year as compared to the unadjusted test period results the Company has included in the claimed revenue requirement in its filing. The following table presents this comparison showing the 2010 test period non-contract major maintenance the Company is using for the rate year along with the budgeted amounts for 2012 and 2013.

Non-Contract Major Maintenance Expense (Dollars in Thousands)					
Plant	**2010**	**2012**	**2013**	**Rate Year**	**RY - 2010**
Frederickson	$5,605	$0	$0	$0	-$5,605
Fredonia	$1,794	$320	$0	$213	-$1,581
Mint Farm	$848	$0	$0	$0	-$848
Sumas	$346	$0	$330	$110	-$236
Total:	$8,593	$320	$330	$323	-$8,270

Q. HOW SHOULD THE GAS-FIRED O&M EXPENSE AMOUNT BE DETERMINED BY THE COMMISSION FOR THE RATE YEAR?

A. There are at least two methods that are superior to the "unadjusted approach" used by the Company. One method would be to simply use the rate year budget amounts for these plants as the Company is doing with regard to its new resources and the Colstrip units. Another approach would be to normalize the values for production O&M by using the average values from the previous four years. A comparison between these two methods and PSE's "unadjusted" approach is provided in the following table for the plants where there was substantial maintenance expense during the test period. The table indicates the difference between using an historic four-year average or rate year budgets as compared to the test period values PSE has proposed. (For Sumas and Mint Farm, only two complete years of historical data is available at this time.) Adoption of either method results in a substantial reduction in O&M costs for the rate year as compared to PSE's proposal.

O&M Comparison (Dollars in Thousands)		
	Test Period v. 4-Year Avg	**Test Period v. Budget**
Frederickson	-$4,032	-$5,553
Fredonia	-$1,131	-$771
Sumas	-$717	-$445
Mint Farm	-$1,221	-$1,454
Undistributed	-$1,265	-$805
Total	-$8,367	-$9,028

Q. WHICH METHOD DOES ICNU RECOMMEND THE COMMISSION ADOPT?

A. ICNU recommends using the average of the last four years of actual production O&M expenses to derive the allowable production O&M expenses for these cost categories. These historical values have the advantage of being known and audited while still providing a normalized maintenance cycle for the plants. It also does not allow for budget gaming that could easily arise under the alternate approach of using Company budget projections for Company owned facilities. The effect of this recommendation as shown by the above table is to lower the Company's rate year production O&M expense by $8.4 million for the rate year.

<u>Peaking Resource Costs</u>

Q. PLEASE DESCRIBE ICNU'S PROPOSED ADJUSTMENT REGARDING PEAKING RESOURCE COSTS.

A. The Company's workpapers contain an estimated premium for Westside delivered power during winter peaking months (November through February) in excess of the Mid-Columbia ("Mid-C") market price. The cost for this Westside delivered power is assumed to be a [redacted] MWh premium above the Mid-C price. The Company assumes this premium is incurred for Westside delivered power during peak hours in each of four months at various monthly megawatt levels.

While acknowledging that there can be constraints to the availability of Mid-C transmission capacity or due to insufficient resources to meet the peak load, the crux of the issue is really the number of hours this is likely to occur. [redacted] This is simply not realistic. An examination of the actual hourly loads for the past four years shows PSE has relatively sharp and short monthly peaks. In addition, the use of a planning reserve margin of the amount proposed by PSE is inappropriate as well. For near term circumstances, the adjustment should reflect the expected forced outage rate of the generating units and not a long-term planning reserve value. ICNU has estimated the number of hours in each of the four months where the hourly load is likely to be above the monthly resource capability using PSE's planning reserve value. This analysis started with actual hourly load data from four years (2007-2010) for the four winter months. The historic winter month with the highest actual peak load was used to achieve the PSE projected peak for the rate year. This historic month selection process is presented in the following table.

Winter Monthly Peak Comparison (MW)						
Month	2007	2008	2009	2010	Max Historic Peak	PSE Rate Year Value
January	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
February	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
November	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
December	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

For each chosen month, the historic hourly load was adjusted by the same percentage for all hours to achieve the PSE projected rate year peak for that month. The intent of the adjustment was to derive an hourly load for each hour of the four months for the rate year. A comparative analysis showed the manufactured hourly loads resulted in a greater retail energy level than is used in AURORA for each of the four months. The hourly loads were further adjusted—increased—using PSE's assumed planning reserve margin. These hourly values were then compared to the PSE monthly resource capability to identify the number of hours and associated energy where PSE was resource deficient. As shown by the following table, the number of expected hours of load in excess of the resource capability is far fewer hours than PSE has assumed in its analysis.

Comparison of Hours Above Resource Capability			
Month	PSE	ICNU	Difference
November	[redacted]	[redacted]	[redacted]
December	[redacted]	[redacted]	[redacted]
January	[redacted]	[redacted]	[redacted]
February	[redacted]	[redacted]	[redacted]
Total:	[redacted]	[redacted]	[redacted]

There is also a substantial difference in the associated amount of energy as well. Since PSE had assumed the maximum peak monthly load for each and every hour, the [redacted]/MWh value was applied to [redacted] MWhs [redacted] Under the ICNU analysis, there is only [redacted] MWhs [redacted] or just [redacted] of PSE's amount. ICNU proposes that if this cost item is to be included in PSE base power supply cost, it should be based on the expected hours where loads actually exceed PSE's resource capacity. Using this methodology, ICNU recommends reducing the PSE proposed cost premium for Westside power by nearly $1.1 million [redacted].

III. PROPOSED CSA MECHANISM

Q. PLEASE BRIEFLY DESCRIBE THE PROPOSED CONSERVATION SAVINGS ADJUSTMENT MECHANISM.

A. The CSA rate proposal seeks recovery of the Company's claimed revenue loss ("unrecovered costs") from implementing the Company's conservation programs that are not already reflected in deriving the rate schedule charges. The Company is proposing to collect 75% of the unrecovered costs in the subsequent year (beginning May 1 of each year) and the remaining 25% in the following year. Also under the Company's proposal, there is an earnings test so that the Company will not earn beyond its authorized rate of return, because of the CSA charges and the conservation savings is subject to third party verification. As shown by Exhibit No. __ (JAP-17), the Company is proposing to collect from customers $9.8 million associated with unrecovered fixed electric costs from 2011. The Company's proposed CSA rate charges would collect $7.4 million from May 1, 2012 through April 30, 2012, and the remaining $2.4 million would be collected in the following year.

Q. IS THE PROPOSED CSA COST RECOVERY IN ADDITION TO THE GENERAL RATE INCREASE BEING SOUGHT BY THE COMPANY?

A. Yes. The Company's claimed $153.0 million electric revenue deficiency does not include the amount the Company is seeking under the CSA mechanism. Taken together, the Company's total instant proposal in this proceeding is an increase in electric revenue of $160.4 million ($153.0 million + $7.4 million = $160.4 million) with additional amounts from unrecovered costs due to conservation programs in 2011 ($2.4 million) and other subsequent years to follow.

Q. DOES THE COMPANY CLAIM THERE ARE CUSTOMER BENEFITS FROM THE CSA MECHANISM?

A. Yes. The Company claims there are three benefits from the CSA. These are: 1) more stable and predictable rates; 2) maintaining or improving the Company's credit rating which will reduce borrowing costs; 3) and greater customer scrutiny of conservation program expenditures.

Q. DOES ICNU AGREE WITH THE COMPANY'S CLAIMED BENEFITS?

A. No. ICNU views the CSA proposal as yet another attempt by the Company to impose automatic rate increases on its customers with no corresponding tangible benefit. The implementation of the CSA will not result in more stable or predictable rates because the Company has proposed no "stay out" period as part of its proposal. PSE customers have been barraged with rate filings for many years, and it is highly likely that this will continue. Accordingly, the implementation of the CSA will only "pancake" on top of the otherwise applicable rate changes that are occurring virtually every year.

Regarding the second claimed benefit, PSE has acknowledged in response to Public Counsel DR 255 that it is not possible to quantify the impact of the CSA on the Company's cost of capital. Exhibit No.__(DWS-5) at 7. ICNU witness Michael Gorman addresses this issue in his testimony and recommends a conservative 200 basis point adjustment to PSE's return on equity if the CSA is adopted.

Similarly, the Company's third claimed benefit is impossible to quantify because it is based on a rather unique perspective that greater customer involvement will occur if the mechanism is adopted. PSE has had the Conservation Resource Advisory Group ("CRAG") in place for many years. The singular focus of this group is to review PSE's conservation program. PSE's third claimed benefit is in essence suggesting the unsupported proposition that the CRAG will do a better job than they are currently doing.

Q. DOES ICNU HAVE ANY OTHER CONCERNS WITH THE CSA PROPOSAL?

A. Yes. ICNU believes the CSA proposal is similar to the mechanism that was proposed by PSE in 2009 and rejected by the Commission. In rejecting the 2009 proposal, the Commission noted that a proper mechanism must conform to the matching principle, taking into account both changes in expenses and revenues.[1/] The Company's proposal does not do this as it only focuses on lost margins due to conservation measures. The Company has stated that it is "not appropriate to offset the effects of energy efficiency with the growth in the number of customers and use per customer." (See Exhibit No. __ (TAD-1T) at 13:16-19. Further, the Company has noted that at least for some classes, retail sales will be relatively flat during the 2010 to 2012 period. Id. at 17:1-3. This is the precise situation that calls into serious question the equity of the Company's proposal. To the extent the lost revenues are truly fixed costs, the offsetting increase in sales from the growth in customers during a flat load period will allow PSE the same fixed cost recovery even with the conservation savings. ICNU recommends that the Commission should reject PSE's CSA proposal. Finally, I am not making an alternative proposal or addressing the issue of full decoupling. If the Commission wishes to consider full

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1/ WUTC v. Puget Sound Energy, Docket No. UE-090704, Order No. 11 ¶¶ 42-47 (Apr. 2, 2010).

decoupling with respect to PSE I recommend that it be reviewed in a bifurcated proceeding similar to the Avista case.

IV. RATE SPREAD

Q. HOW HAS THE COMPANY PROPOSED TO SPREAD THE CLAIMED INCREASE IN ELECTRIC REVENUE AMONG THE VARIOUS CUSTOMER CLASSES?

A. The Company is using the results of it cost-of-service study as a guide to allocate the proposed revenue increase based on the class parity ratio (or revenue to cost ratio) produced by the cost study. For parity ratios within the range of 95% to 105%, the Company is proposing to give these classes the same percentage increase. These classes are the residential class (Schedule 7), small general service (Schedule 24), large general service (Schedule 26), primary general service (Schedule 31), irrigation and pumping service (Schedule 35), primary electric school service (Schedule 43), high voltage service (Schedules 46 and 49), and the lighting schedules (Schedules 50-59). The medium general service class (Schedule 24) is the only class with a parity ratio above this range (106%). For this class, the Company has proposed an increase of just 75% of the average value. The retail wheeling class (Schedules 448 and 449) is the only class with a parity ratio below the PSE range (88%). For this class, PSE has proposed an increase of 125% of the average value.

Q. DO YOU AGREE WITH THE COMPANY'S RATE SPREAD PROPOSAL?

A. ICNU certainly supports using the results of a cost study as the primary guide for spreading any allowed revenue increase. Given the Commission precedent, ICNU also supports giving the same percentage increase to classes that fall within a reasonable parity ratio range, giving classes with a parity ratio above the range a below average increase and giving classes with a parity ratio below the range an above average increase. ICNU does have, however, both minor and substantive issues with PSE's rate spread implementation.

Q. WHAT IS THE MINOR ISSUE WITH PSE'S IMPLEMENTATION?

A. PSE has derived class parity ratios based upon its proposed rate of return. ICNU, on the other hand, prefers to calculate parity ratios at the current earned rate of return, because it is highly unlikely that the Company will receive its entire requested rate increase, including its proposed return on common equity. As there are differences in the amount of investment needed to serve the various classes of customers, using the proposed rate of return as compared to the current earned rate of return can result in a different parity ratio for a given customer class. The following table illustrates the difference in the resulting class parity ratio between the two approaches using the PSE cost-of-service study for the major customer classes. This in turn can affect the proposed rate spread assignment.

Comparison of Parity Ratio Calculation
(Current versus Proposed Rate of Return)

Class	Current	Proposed	Difference
Residential Sch 7	96%	98%	-2%
Sch 24 (kW< 50)	105%	103%	2%
Sch 25 (kW > 50 & < 350)	111%	106%	5%
Sch 26 (kW > 350)	106%	104%	2%
Primary Sch 31/35/43	105%	103%	2%
High Voltage Sch 46/49	98%	99%	-1%
Wheeling Sch 448/449	96%	88%	8%
Lighting 50-59	93%	95%	-2%
Total:	100%	100%	0%

The above table shows that different approaches produce the same rate spread results under PSE's proposal for five of the classes shown in the table (Schedules 7, 24, 25, Primary, and High Voltage) but different results for the other three classes. For the three different classes, Schedule 26 goes from an average percentage increase to a below average increase, the wheeling schedules go from an above average increase to an average increase, and the lighting schedules goes from an average increase to an above average increase.

Q. WHAT SUBSTANTIVE ISSUES DOES ICNU HAVE WITH PSE'S RATE SPREAD PROPOSAL?

A. The major issues ICNU has with the PSE rate spread proposal is the cost study that should be used and adjustments for classes that fall outside the reasonable range. As testified to by Mr. Deen, ICNU believes the PSE study contains major flaws in deriving the cost of service of each customer class. When these flaws are corrected, the revenue to cost ratio for the retail wheeling class is 104%, as compared to just 96% under the PSE study (calculated using the current earned return). This is a significant difference. The Company's rate spread relief for the only class (Schedule 25) with a parity ratio above the equal percentage range seems too generous for a class that is barely outside the range. For example, the Company's parity ratio for Schedule 26 is 104%, as compared to Schedule 25 at 106%. Yet the Company is proposing to increase Schedule 26 rates by 8%, while the increase to Schedule 25 is only 6%.

Q. WHAT IS ICNU'S RATE SPREAD RECOMMENDATION IN THIS PROCEEDING?

A. The results of the ICNU cost of service study indicate that most of PSE's jurisdictional customer classes are within 10% of parity (a range of 90% to 110%) using the ICNU parity calculation. The exceptions are the larger secondary schedules (25 and 26) and the primary schedules. As was the case with the PSE study, Schedule 25 is the only class substantially outside the parity range. Based on these results, ICNU agrees with the PSE proposal for Schedule 25. All other major customer classes should receive an equal percentage increase. One important caveat to this recommendation is, of course, Schedule 40 customers, whose increase will be determined by their customer specific distribution charges along with energy rates tied to the high voltage schedules. Exhibit No. ___ (DWS-6) is a comparison of the PSE and ICNU rate spread recommendations at the Company's claimed revenue increase amount. The difference in proposals is relatively minor for the non-retail wheeling classes, changing the applicable percentage increase by only 0.01%.

V. INDUSTRIAL RATE DESIGN

Q. DOES ICNU SUPPORT THE MANNER IN WHICH PSE IS PROPOSING TO REVISE THE INDUSTRIAL RATES IN THIS PROCEEDING?

A. ICNU agrees with the Company's rate design proposal for Schedules 40, 46 and 49. However, there is an important adjustment that will need to be made to the Schedule 448 and 449 demand charges or customer bills if and when FERC approves the reclassification of certain PSE facilities.

Q. PLEASE EXPLAIN THE NEED FOR THIS ADJUSTMENT.

A. In Docket No. UE-111701, which is pending before this Commission, the Company is proposing to re-classify numerous facilities from distribution to transmission service ("wholesale distribution facilities"). The Company is also seeking the approval of the FERC to include the associated cost of these wholesale distribution facilities in its OATT charges. As Schedule 448 and 449 customers are required to pay the OATT charges, upon FERC approval, Schedule 448 and 449 customers could be paying for the wholesale distribution facilities twice: once through the Schedule 448 and 449 demand charges resulting from this proceeding, and once through the new FERC approved OATT charges. As the change in retail rates arising from this proceeding will likely occur prior to the change in OATT charges in the FERC proceeding, absent a Commission approved remedy in this proceeding, retail wheeling customers could be "double charged" for quite a period of time. This would be inappropriate and needs to be addressed in this proceeding.

Q. WHAT IS ICNU'S RECOMMENDATION FOR ADDRESSING THIS MATTER?

A. The Company and ICNU have had initial discussions regarding how to best deal with the circumstance when it commences. While agreement has yet to occur, hopefully, ICNU and PSE will be able to bring forward a joint proposal for the Commission to approve as part of this proceeding. Until such time, ICNU is recommending a readily implementable "placeholder" for the issue as follows. When FERC approves the proposed re-classification, the increase in the OATT charges that will be paid by the retail wheeling customer will be offset by a corresponding credit to the retail bill to eliminate the double charge for these facilities. This "dollar for dollar" approach will ensure there is no double payment by the retail wheeling customers under the revised retail and wholesale rate changes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.