Exhibit No. DWS-1T
Docket No. UE-090704/UG-090705 (*Consolidated*)
Witness: Donald W. Schoenbeck

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket Nos. UE-090704/ UG-090705 (*Consolidated*)

DIRECT TESTIMONY OF DONALD W. SCHOENBECK

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

November 17, 2009

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I've been involved in the electric and gas utility industries 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.

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. I will discuss and recommend superior alternatives to the coincident demand allocation factor and peak credit classification method used in the electric cost-of-service study presented in Exhibit No. DWH-3, and the Company's proposed rate spread presented in Exhibit No. DWH-4. This testimony will not address revenue requirement issues;

however, I am submitting joint testimony with Staff witness Alan Buckley, addressing power supply matters.

Q. PLEASE BRIEFLY SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS ADDRESSED IN THIS TESTIMONY.

A. PSE's peak demand allocation factor uses the average of the 75 highest coincident peak hourly loads resulting in an average sales demand of just 4,498 megawatts ("MWs"). Yet, with the addition of the Mint Farm facility, PSE's revenue requirement reflects 5,300 MWs of resource capability to serve a winter peak load of 5,294 MWs. In order to appropriately assign the costs of these resources to the loads causing the resources to be acquired, a more limited number of hours should be used to assign these system costs. ICNU recommends using only those hours that are within 95% of the system peak demand. This recommendation results in an average sales demand of 4,766 MWs, based on the 16 highest coincident peak hours.

The Company has proposed three changes to its peak credit calculation, which has resulted in classifying 21% of resource costs as being demand related, and the remaining 79% as energy related. As pointed out by the Company, the most significant of these changes is the incorporation of a substantial carbon emissions cost, beginning in 2012. In prior general rate cases, I have objected to other aspects of the Company's peak credit calculation, which has an even greater impact on the result than the Company's carbon emissions adder—the assumed capacity factor of the base-load resource. Making this one change in the Company's calculation would result in 31% of the resource costs being classified as being demand related. Using the system average load factor and eliminating the speculative carbon emission cost results in peak credit calculation that classifies 38%

of the resource cost to demand and 62% to energy. Even though a change of this magnitude would be justified, for this proceeding, I recommend generation costs should be classified as being 32% demand related and 68% energy related.

The ICNU rate spread recommendation is to move all classes closer to a cost-based rate level, based upon the ICNU cost of service results. ICNU recommends that a number of rate schedules receive no increase, since they are already contributing revenue in excess of a cost-based level at the Company's full increase request. These are the secondary voltage schedules (Schedules 24, 25, 26 and 29), certain primary schedules (Schedules 31 and 35), the high voltage schedules (Schedules 46 and 49) and the lighting tariffs. The "campus" (Schedule 40) distribution rates should be increased to recover the additional delivery investment installed to serve these customers, and the retail wheeling rates (Schedules 448, 449 and 459) and the firm resale/special contract classes should be given their cost-based increase. The remaining rate schedules should be assigned the remaining increase granted to PSE by the Commission in this proceeding. These classes are the residential class (Schedule 7) and interruptible electric schools (Schedule 43).

II. COST OF SERVICE

Q. HAS THE COMPANY SUBMITTED AN ELECTRIC COST-OF-SERVICE STUDY IN THIS PROCEEDING?

A. Yes. The Company sponsored study is contained in Exhibit DWH-3. For the most part, the Company study is very similar to other studies PSE has submitted in the past, but the Company has modified the manner in which it has assigned distribution costs by using a method which incorporates distribution circuit miles. ICNU supports this change, since it more accurately assigns these costs to the various customer classes. However, there are two aspects of the Company's costing method that I strongly disagree with. These two matters are the allocation factor used to assign demand-related resource costs, and the Company's peak credit calculation for classifying resource costs.

Q. WHAT ALLOCATION FACTOR HAS THE COMPANY USED FOR ASSIGNING DEMAND-RELATED RESOURCE COST RESPONSIBILITY?

A. The Company has used the average of the 75 highest peak hours for allocating these costs. As indicated in the Company's workpapers, the sales loads for these hours range from 4,906 MWs (the system peak hour) down to just 4,264 MWs. The average value for all 75 hours is 4,498 MWs.

Q. WHY DO YOU DISAGREE WITH THE USE OF THIS DEMAND ALLOCATION FACTOR?

A. As set forth and explained in the Company's prefiled testimony:

> Demand-related costs are those costs associated with electric plant that is designed, installed and operated to meet maximum hourly or daily electric capacity requirements, such as transmission and distribution cables and related structures or portions of generation units that are needed to meet peak demands. While these structures or units may not be fully utilized at all times, they must be designed and installed to meet the maximum load that is anticipated.

Ex. No. DWH-1T, Direct Testimony of David W. Hoff at 5 (May 8, 2009).

With the proposed addition of the Mint Farm resource, the Company's revenue requirement in this case contains the costs of 5,300 MWs of generating resources in order to meet an extreme winter peak of 5,295 MWs. Allocating the costs of 5,300 MWs to just 4,498 MWs of load creates a very serious mismatch of 800 MWs, which results in the weather sensitive classes that cause the need for these resources not being assigned the associated cost. Put another way, if the Company thinks that in actuality, the peak demand is only about 4,500 MWs, there is absolutely no need for all of the recent resource acquisitions, including Mint Farm, Goldendale and Fredrickson, or their substantial associated revenue requirement.

Q. HOW SHOULD DEMAND-RELATED RESOURCE COSTS BE ALLOCATED?

A. The demand allocation factor should reflect the same load basis as that used for acquiring resources. Reducing PSE's resource capability by the reserve requirement of 7% suggests the appropriate load is about 4,950 MWs. A review of the Company workpapers shows this would require using just the two highest hours–which were 4,906 MWs and 4,893 MWs–for an average demand of 4,898 MWs: some 400 MWs greater than the Company's 75 hour factor. While I feel this would be an appropriate allocator, I have also argued that all hours within 95% of the peak hour serve as a reasonable allocator as well. Applying this approach in this proceeding results in an allocation factor that is the average of the sixteen highest hours, reflecting an average demand of 4,766 MWs. The following table shows these two ICNU alternatives with the allocation factor employed by the Company.

Resource Demand Allocation Factor Comparison
(MWs)

Class	PSE Top 75	ICNU Top 2	ICNU 95% of Peak	75 to 2	75 to 95%
Residential	2,837	3,245	3,076	408	239
Schedule 24	486	505	499	19	13
Schedule 25	508	500	514	-8	6
Schedule 26	305	297	310	-8	6
Schedule 31	158	150	157	-8	-1
Schedule 40	81	80	83	-1	2
Schedule 43	42	33	38	-8	-4
Schedule 46/49	67	66	67	-1	1
Lighting	13	20	18	7	5
Irrigation (29,35)	2	2	2	0	0
Total:	4,498	4,898	4,766	400	268

As shown by the above table, PSE's use of a 75-hour allocation factor inappropriately shifts costs away from the residential and small commercial classes.

Q. WHAT IS YOUR RECOMMENDATION FOR ALLOCATING RESOURCE DEMAND-RELATED COSTS IN THIS PROCEEDING?

A. I recommend the Commission use the sixteen hours within 95% of the peak hour. I am recommending this approach to counter any arguments that using the other ICNU alternative–the two highest hours–could possibly reflect some abnormal load levels. The 16 highest hourly loads occurred over five different days and contain both morning and evening hours. In my view, this is a robust sample, yet still relatively close to the cost causation load level.

Q. HAS THE COMPANY DERIVED THE PEAK CREDIT CLASSIFICATION PERCENTAGES IN THE SAME MANNER AS IT HAS DONE IN THE LAST GENERAL RATE CASE PROCEEDING?

A. No. As noted in the prefiled testimony, the Company has made three changes to the peak credit resource classification calculation. These changes are: 1) reflecting a 7% percent reserve margin for the base-load resource (a combined cycle combustion turbine ("CCCT")); 2) dropping the hours of operation of the peaking resource along with the associated variable operations and maintenance cost and fuel premium; and 3) including emission costs for the base-load resources. The first two modifications essentially offset each other: the peaking hours would raise the demand percentage by about 1%, whereas the inclusion of the reserve margin on the base-load resources lowers the demand percentage by less than 1%. However, including the emissions costs in the calculation of the base-load resource costs has lowered the demand percentage by over 6%, a substantial difference. Absent these changes, the peak credit calculation would have classified 28% of resource costs as being demand-related. With these changes, PSE is proposing that only 21% of the costs be classified as demand related.

Q. DO YOU AGREE WITH THE COMPANY'S PEAK CREDIT CALCULATION?

A. No. Before addressing the proposed changes, I must first address a critical error in the Company's peak credit calculation having to do with the assumed capacity factor of the base-load resources. PSE has used a 95% capacity factor for the base-load resources, implying they are operating for 8,322 hours each year. This assumption is wrong. As PSE has documented in its proposed acquisition of the Mint Farm, while CCCTs are capable of running at a 95% capacity factor, the actual hours of operation to meet system loads will be far below this level, as system load factors are around 50-55%. Further, PSE's own CCCTs are projected to operate at or below this level based upon the AURORA test period power supply simulation.

Q. HOW SHOULD THE CAPACITY FACTOR OR UTILIZATION OF THE BASE-LOAD RESOURCE BE DETERMINED?

A. The capacity factor or hours of operation of the CCCT can be analyzed in either one of two ways. The most straight forward approach, and the method employed by other utilities, is to use the utility system retail load factor as this reflects the load that must be served. In the case of PSE, this value is 55%, or about 4,800 hours of operation. The second alternative is to assume the resource is operated to its maximum availability, but that the generation in excess of the retail demand is sold in the market and the resulting revenue is used to offset the resource cost. While either of these methods is far superior to the erroneous calculation performed by PSE, I recommend the system load factor be used. Using this approach avoids the potential controversy that might arise from determining the surplus sales revenue credit. Changing just the base-load capacity factor to 55% raises the demand-related classification percentage to 31% with all other PSE procedures and assumptions.

Q. PLEASE COMMENT ON THE THREE CHANGES PSE IS PROPOSING IN THE PEAK CREDIT CALCULATION FOR THIS PROCEEDING.

A. I can accept the application of the 7% reserve margin to the base-load resource costs, but I disagree with the other two modifications. Eliminating the modest number of peaking resource operating hours–75 hours–eliminates the fuel premium. This is inappropriate, since the basis of the peak credit calculation is to ascertain the cost of supplying peak needs beyond the cost of operating a base-load resource. The calculation must recognize the higher fuel cost associated with a peaking resource versus a base-load resource, although I recognize this results in only a very minor adjustment to the Company calculation (0.8%).

More important is the inclusion of the emission costs in the calculation. The Company proposal contains a substantial cost for carbon emission beginning in 2012. At this point, the possibility of these costs–and the specific carbon product–being reflected in the market is highly speculative along with the likely market price for these emissions. The cost PSE is using in the peak credit calculation–ranging from $37.30 per ton in 2012 to $170.10. Exhibit No. JAP-3C, Workpapers associated with Direct Testimony of Jon A. Piliaris at "Emissions Costs" tab (May 8, 2009). For example, the Regional Greenhouse Gas Initiative ("RGGI") posts the results of the quarterly carbon auctions it conducts. The three most recent auctions for 2012 carbon emissions have cleared at $3.05 per ton (March 18, 2009), $2.06 per ton (June 17, 2009) and $1.87 per ton (September 9, 2009). Inclusion of carbon emission costs at this level—an average of $2.33 per ton—essentially eliminates any impact on PSE's peak credit calculation. There is simply insufficient information at this time to include carbon emission costs in PSE's peak credit calculation.

Q. WHAT PEAK CREDIT CLASSIFICATION PERCENTAGES DO YOU RECOMMEND BE USED IN THIS PROCEEDING?

A. I believe the correct peak credit demand related percentage is 38% reflecting base-load resource operation at the PSE retail load factor (55%), no carbon emission costs, and a modest number of hours of peaking resource operations (75). However, I certainly recognize the dramatic difference this would have on the cost-based rate determination. For this reason, I recommend using 32% as the demand-related classification component for resource costs in this proceeding. If necessary, this value can be derived by including carbon costs in my calculation at the prices used by PSE.

Q. HAVE YOU PREPARED A COST-OF-SERVICE STUDY THAT INCORPORATES YOUR RECOMMENDATIONS?

A. Yes. Exhibit No. DWS-3 contains the summary page from the cost-of-service study I prepared which incorporated my recommended peak demand allocation factor and peak credit classification percentages. The following table provides a direct comparison of the difference in parity ratios for the PSE study and the ICNU study. The parity ratio is the best statistic or "yardstick" with which to determine if each customer classes rate charges are at an appropriate level. The ratio is calculated by dividing the revenue contributed by a class by its cost of service. Thus, if a ratio is greater than 1.0, the class revenue is too high, as it is above the associated cost of service. Conversely, if the ratio is less than 1.0, the class rate charges are too low, as the class is not contributing sufficient revenue to cover its costs.

Comparison of Parity Ratios Major Customer Classes
(Current Revenue/Cost of Service)

Class	PSE Study	ICNU Study	Difference
Residential Sch 7	0.95	0.91	-0.03
Schedule 24 (kW< 50)	1.07	1.10	0.03
Schedule 25 (kW > 50 & < 350)	1.12	1.19	0.06
Schedule 26 (kW > 350)	1.05	1.12	0.08
Schedule 31 (General Service)	1.10	1.21	0.11
Schedule 43	1.01	0.76	-0.24
Schedule 40	0.89	0.96	0.08
Schedules 46/49	0.98	1.10	0.12
Wheeling at Primary Voltage	3.22	3.98	0.76
Wheeling at High Voltage	0.89	0.98	0.09
Lighting 50-59	1.09	1.07	-0.02
Total:	1.00	1.00	0.00

Significantly, under the ICNU study, only two classes have a parity ratio below 0.95: the residential class (Schedule 7) and the total electric school class (Schedule 43). As the residential class accounts for about 54% of PSE's retail revenue, under charging this class places a significant burden on PSE's remaining customers by about $100 million. This inequity must be corrected by moving this class much closer to its cost-of-service.

V. RATE SPREAD

Q. HAVE YOU PREPARED A PROPOSAL TO MOVE THE CLASSES CLOSER TO THEIR COST OF SERVICE?

A. Yes. The following table compares the PSE rate spread proposal with that recommended by ICNU.

Comparison of Rate Spread Proposals
(Amounts in $1,000)

	PSE Proposal		ICNU Recommendation	
Class	Amount	Percent	Amount	Percent
Residential Schedule 7	$94,284	8.7%	$151,222	13.9%
Schedule 24 (kW< 50)	$16,368	6.5%	$0	0.0%
Schedule 25 (kW > 50 & < 350)	$11,915	4.3%	$0	0.0%
Schedule 26 (kW > 350)	$14,547	8.7%	$0	0.0%
Schedule 31 (General Service)	$6,924	6.5%	$0	0.0%
Schedule 43	$896	6.5%	$1,917	13.9%
Schedule 40	$4,028	9.0%	$364	0.8%
Schedules 46/49	$3,069	8.7%	$0	0.0%
Retail Wheeling	$535	8.7%	$177	2.9%
Lighting 50-59	$1,074	6.5%	$0	0.0%
Special Contract/Resale	$300	22.7%	$260	19.6%
Total:	$153,940	7.7%	$153,940	7.7%

The ICNU recommendation is premised on moving classes much closer to a cost-based rate level. For the special contract and firm resale classes, ICNU is using the same method as proposed by PSE, by assigning a cost-based increase amount to these classes. Similarly, ICNU recommends the retail wheeling charges be set at a cost-based rate level, also using the ICNU study. Consistent with the last general rate case and the Merger Agreement, Schedule 40 high voltage charges are linked to changes in Schedule 46 and 49 rates. However, Schedule 40 distribution charges should be modified to reflect the current cost of providing delivery services to these customers by employing the agreed upon method for calculating these charges. Thus, the $364,000 amount indicated under the ICNU rate spread recommendation for Schedule 40 is a "placeholder" amount which will change based upon the final capital-related parameters approved by the Commission in this proceeding. For classes with a parity ratio above 1.0, ICNU recommends no increase be assigned to these classes, as even at the Company's full request for relief, these classes are already paying too much. For the two classes with parity ratios below 95%, ICNU recommends applying an equal percentage increase to achieve the overall residual increase approved by the Commission in this proceeding.

Q. THE ICNU RATE SPREAD PROPOSAL PLACES A SUBSTANTIAL INCREASE ON THE RESIDENTIAL CLASS. WHY DO YOU BELIEVE THIS IS APPROPRIATE?

A. There are several reasons. First, as I have already indicated, this is the largest class by far, providing revenues in excess of $1.0 billion. For comparison purposes, the second largest class provides only about $275 million of revenue (secondary voltage 50 to 350 kW) and there are five classes each providing less than $50 million (electric schools, campus, high voltage, retail wheeling and lighting). Thus, a 10% shortage of revenue from this class places a 10% increase on the remaining customers as the residential class is about one-half the overall retail revenue. Second, even if PSE is granted the full request, the ICNU residential increase will still leave this class with a parity ratio of just 96%. In other words, even with this large of an increase, the residential rate charges are still below a cost-based level. Third, it is highly unlikely that the Commission will grant PSE the full relief sought. Under the ICNU rate spread proposal, the two below parity classes will essentially receive the benefit of every reduction dollar. Finally, there is the renewable energy credit ("REC") revenue that is the subject of Docket No. UE-070725.

This represents a substantial sum of money that should be flowed back to all customers. Assuming the customer classes receive a credit in the same manner they are assigned the costs of the facilities which generated the RECs, the residential class will receive over one-half of these revenues. This substantial credit will mitigate the cost-based residential increase proposed by ICNU in this docket.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.