Exhibit No.___(MCD-1T)
Docket Nos. UE-111048/UE-111049
Witness: Michael C. Deen

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 MICHAEL C. DEEN

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

December 7, 2011

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael C. Deen, 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 5 years. During that time, I have served as an analyst and expert on a variety of power supply, cost, ratemaking, and policy topics, primarily regarding the Bonneville Power Administration and Pacific Northwest utilities. This is my first appearance before the Washington Utilities and Transportation Commission (the "Commission"). A further description of my educational background and work experience can be found in Exhibit No. __ (MCD-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 THIS TESTIMONY ADDRESS?

A. This testimony will address: 1) certain areas of the Company's projected power supply costs; and 2) the Company's proposed cost-of-service study.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into four sections. Section I is the introduction. Section II contains a summary of my recommendations. Section III contains descriptions of certain proposed power supply cost adjustments. Finally, Section IV discusses matters related to the cost-of-service analysis in this proceeding.

II. SUMMARY OF RECOMMENDATIONS

Q. PLEASE BRIEFLY SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING.

A. As also described by ICNU witness Donald Schoenbeck, the combined power supply-related adjustments addressed by ICNU will reduce PSE's costs by $55.1 million, or the proposed revenue requirement by $56.5 million, as indicated by the table below. 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	-10.3	-10.6	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:	-55.1	-56.5	

This testimony will address ICNU's power supply adjustments numbered 5 through 11 in the above table. The following summarizes each adjustment:

- The transmission reassignment adjustment uses the Company's actual most recent 12 months of revenues from the short term sales of Mid-Columbia ("Mid-C") transmission capacity, rather than the Company's projection.

- As part of its wind integration costs, the Company is proposing to include a "day ahead" component that claims to address opportunity costs incurred by the Company as a result of being unable to fully optimize its system as a result of integrating wind into its system. There is no evidence that the Company actually incurs this cost, and further, the Company's approach is inappropriate in the context of the method used to project power costs in this proceeding.

- Regarding Open Access Transmission Tariff ("OATT") revenues, ICNU proposes that the Company should include anticipated revenues from the third-party Vantage wind project as sought in Federal Energy Regulatory Commission ("FERC") Docket ER11-3735.

- ICNU is proposing several adjustments to the Company's assumed costs related to Chelan PUD.

- The Company's workpapers include several assumed cost escalation rates related to its fixed gas transportation costs that are not known or measurable; therefore, they should be excluded in this proceeding.

- The Company's test year expenses in the FERC 557 "Other Power Cost" accounts (including the Bonneville Power Administration ("BPA") Rate Case expense item reclassified to A&G) included values that appear to be at variance with historical levels. ICNU recommends levelizing these costs by using a 5-year average of the subaccounts.

- Analysis of the Company's actual hourly thermal generation over the most recent 12-month period indicates that the assumptions regarding the "minimum up time" for the Goldendale, Mint Farm, and Fredrickson combined cycles combustion turbines ("CCCTs") are overstated in the Company's AURORA assumptions. ICNU recommends adjusting these assumptions to more closely match actual operations.

Finally, ICNU recommends that the Company modify the implementation of its cost-of-service study. Specifically, ICNU recommends an alternative allocation of demand related costs and also two changes to the peak credit calculation performed in the Company's study resulting in a peak credit classification that is much closer to other

Washington utilities. Mr. Schoenbeck's testimony includes ICNU's specific rate spread and rate design recommendation.

III. RECOMMENDED ADJUSTMENT DISCUSSION

Q. HAVE YOU REVIEWED THE COMPANY'S TESTIMONY, EXHIBITS AND WORKPAPERS REGARDING POWER COSTS, INCLUDING THE INPUTS AND ASSUMPTIONS FOR THE AURORA POWER COST MODEL IN THIS PROCEEDING?

A. Yes. I have reviewed both the power cost testimony and supporting evidence provided with the Company's initial filing of June 13, 2011, as well as the supplemental filing of September 1, 2011.

Q. WHICH PROPOSED ICNU ADJUSTMENTS WILL BE DISCUSSED IN THIS TESTIMONY?

A. As described above, ICNU is proposing the following adjustments to the Company's power supply costs in this testimony:

i. Transmission capacity reassignment revenues;

ii. wind integration opportunity costs;

iii. anticipated wind integration OATT revenues;

iv. Mid-Columbia hydro contract costs;

v. interstate gas pipeline cost increases;

vi. FERC 557 cost levels (including reassigned legal costs); and

vii. CCCT operating parameters.

These adjustments and their impacts are discussed in detail in the following sections.

<u>Transmission Capacity Reassignment</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED ESTIMATE OF TRANSMISSION CAPACITY REASSIGNMENT REVENUES ASSUMED DURING THE RATE YEAR.

A. According to the Company's testimony, as of March 2010, the Company has held the right to reassign excess BPA Point-to-Point ("PTP") transmission rights on a short-term basis. Exh. No.__(DEM-1CT) at 12:4-21. To estimate a value for this transmission reassignment revenue for the rate year, the Company calculated an estimated volume available for resale based on its firm PTP rights compared to the forecast PTP volume used to meet customer load on a monthly basis. The Company then calculated that it was actually able to remarket on average [redacted] of its available capacity during the 12 months ended February 2011. <u>Id.</u> at 13:1-11. Accordingly, the estimated volumes of available transmission for reassignment in each month were reduced by this factor and then multiplied by the actual price for reassignment in the month of February 2011 ([redacted]) to reach a credit of $1.8 million for the rate year.

Q. DOES ICNU AGREE WITH THIS ESTIMATE OF TRANSMISSION REASSIGNMENT REVENUE?

A. No. The Company's workpapers show that the actual volume and price of transmission reassignment revenues are extremely divergent from the Company's assumptions. Although the Company calculated that on average it was able to sell [redacted] of its average predicted available capacity, the actual monthly values range from a low of [redacted] to a high of [redacted]. Given this level of variability, applying the average of [redacted] to every month's predicted availability in the rate year could lead to significant inaccuracies.

Likewise, relying on the [redacted] price for sales in February 2011 for the entire rate year is problematic. Actual average monthly prices for the 12 months ended February 2011 varied from a low of [redacted] to a high of [redacted] and averaged [redacted], significantly higher than value assumed by the Company for sales during the rate year.

Q. WHAT IS ICNU'S PROPOSAL FOR THE TREATMENT OF TRANSMISSION REASSIGNMENT REVENUES IN THIS PROCEEDING?

A. Given the flaws in the Company's proposed forecast and the relatively short history of this program, ICNU recommends setting the credit for the rate year equal to the actual revenues realized from transmission reassignment over the most recent 12 months. This approach has the advantage of greater simplicity and measurability relative to the Company's approach and also incorporates more current data. Based on the Company's response to ICNU data request ("DR") 2.44, transmission reassignment revenues for the 12 months ended July 2011 were $2.9 million, or $1.1 million higher than the Company's assumption for the rate year. Actual transmission reassignment sales and revenues for the 12 months ended July 2011 are attached to this testimony as Exhibit No. __ (MCD-3).

<u>Wind Integration Opportunity Costs</u>

Q. PLEASE DESCRIBE THE COMPANY'S "OPPORTUNITY COST" APPROACH TO DERIVING DAY-AHEAD WIND OPPORTUNITY COSTS.

A. The Company has included in its power costs a total of approximately $2.5 million for day-ahead opportunity costs for all the wind generation in its balancing authority. In its response to ICNU DR 2.80, attached as page 6 of Exhibit No. __ (MCD-4), the Company described these costs as follows:

> The costs associated with providing the capacity to cover any deviations between hour-ahead and day-ahead scheduled/forecasted generation are considered the day-ahead wind integration cost. The real-time markets allow PSE to rebalance hourly positions for the forecast error that occurs between day-ahead scheduling and hour-ahead forecasts. The methodology used to estimate power costs in a rate year captures the day-ahead market value of having to either sell or buy energy from the hourly market and the historical relationship between the day-ahead and hourly prices applied to the rate year prices.

Q. DOES ICNU BELIEVE THAT THIS IS AN APPROPRIATE COST TO BE INCLUDED IN RATES IN THIS PROCEEDING?

A. No. In response to ICNU DR 2.80, the Company conceded that there is no actual system or mechanism in place to track these costs. Further, the Company conceded that these costs are not actually paid to any other balancing authority. Exhibit No. __ (MCD-4) at 7 (Response to ICNU DR 2.83).

Fundamentally, however, this type of cost is inappropriate to include in the context of the Company's approach to calculating expected power costs for the rate year using the AURORA model. Given the approach of using AURORA to calculate the expected value of the variable costs of operating PSE's generating resources, this cost is already fully accounted for in the model. PSE's wind resources are designated as "must run" in the model and therefore PSE's other resources must operate around them at potentially less than optimal dispatch levels.

Of course, PSE's actual operation of its system can be vastly different than projected by the AURORA model. The Company engages in a large volume of short-term transactions in actual operations, presumably to optimize cost and reliability, which are not replicated in the AURORA simulation. For example, the Company's actual 2010 operations included approximately $201 million in sales to other utilities, while the AURORA simulation predicted only $10 million. Exhibit No. __ (JHS-13), line 1. Nonetheless, the model is accepted for purposes of projecting an appropriate expected cost of operating PSE's resources in the rate year. It is arbitrary to isolate a hypothetical day-ahead opportunity cost to system optimization from wind integration outside the AURORA forecast while not, for example, identifying potential benefits to consumers of the Company's operations not captured in the model.

Wind Integration OATT Revenues

Q. PLEASE DESCRIBE ICNU'S ADJUSTMENT FOR THE ANTICIPATED OATT REVENUES FOR VARIABLE GENERATION BEING EXPORTED OUT OF THE COMPANY'S BALANCING AUTHORITY.

A. According to the Company's testimony, there is currently one third-party wind generation facility in PSE's balancing authority. This is the 96 MW Vantage wind project. The Company does not include any assumed revenues for wind integration services from this project, although at the time of the Company's initial filing, it was seeking cost recovery in FERC Docket ER11-3735 for the costs of such services.

On October 20, 2011, FERC released a decision in docket ER11-3735 accepting PSE's proposed schedules for filing and suspending them for a five-month period from the date of filing, to be effective on January 5, 2012. Thus, the suspension period for the FERC case ends well before the May 14, 2012 rate effective date in this proceeding.

In the absence of conclusive actions to the contrary, PSE's proposed tariffs in ER11-3735 are set to be in place during the rate year, and the resulting OATT revenues should be included in this proceeding. Based on documentation in ER11-3735 and the Company's response to ICNU DR 2.49, attached as page 1 of Exhibit No. __ (MCD-4), this adjustment would increase revenue and reduce power costs by approximately $2.4 million.

<u>Mid-Columbia Hydro Contracts</u>

Q. PLEASE DESCRIBE ICNU'S PROPOSED ADJUSTMENTS REGARDING THE COSTS OF MID-COLUMBIA HYDRO CONTRACTS.

A. The Company's workpapers detail Chelan PUD power costs in the file "DEM-WP(C) Mid-C Chelan PUD Power Cost 2011 GRC As Filed.xls". Under the "Capital Recovery Charge" tab, the Capital Recovery Charge ("CRC") is described as follows:

[redacted]

However, the Company has assumed that the CRC will be set to the maximum value of [redacted] during the rate year. ICNU proposes that the charge be based on [redacted] for ratemaking purposes, as this is both the default value of the charge and midpoint of the potential range. Additionally, [redacted] is the value that appears to be in place for 2011 based on the Company's workpapers. This adjustment reduces projected power costs by approximately $1.9 million.

Under the "Debt Reduction Charge" tab of the worksheet, the Debt Reduction Charge ("DRC") is described as follows:

[redacted]

[redacted]

Similar to the CRC, the Company has assumed the maximum value of [redacted] for determining this cost. Based on the Company's workpapers, the default value of [redacted] appears to be in effect for 2011. ICNU proposes that the default value of [redacted] be used for ratemaking purposes. This adjustment reduces projected power costs by approximately $0.8 million.

Finally, the "Transmission Charges" tab of the worksheet contains assumptions regarding the Chelan Transmission Revenue Requirement ("CTRR"). This calculation assumes an average annual rate of increase of [redacted] after 2011. This assumed rate of increase does not appear known and measurable or otherwise specified contractually, and should be excluded. The effect of this adjustment is to lower power costs by approximately $0.1 million.

The combined effect of these Chelan PUD adjustments is to lower the Company's power costs by approximately $2.8 million.

<u>Interstate Pipeline Costs</u>

Q. PLEASE DESCRIBE ICNU'S PROPOSED ADJUSTMENT REGARDING INTERSTATE PIPELINE COST INCREASES.

A. The Company includes fixed gas transportation as a power cost calculated outside the AURORA model. In this proceeding, the Company has assumed various annual increases from the test year through the rate year in its transportation contract costs with Northwest Pipeline, Westcoast, and Cascade.

Based on both the documentation in the Company's workpapers and on the Company's response to ICNU DR 2.67, attached as pages 4 and 5 of Exhibit No. __ (MCD-4), it appears that all these escalation factors are the result of speculation by PSE staff and are not known or measurable. As stated in paragraph 26 of the Commission's Order 11 in the UE-090704 docket:

> The known and measurable test requires that an event that causes a change in revenue, expense or rate base must be *known* to have occurred during, or reasonably soon after, the historical 12 months of actual results of operations, and the effect of that event will be in place during the 12-month period when rates will likely be in effect. Furthermore, the actual amount of the change must be *measurable*. This means the amount typically cannot be an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future revenue, expense or rate base. There are exceptions, such as using the forward costs of gas in power cost projections, but these are few and demand a high degree of analytical rigor.[1/]

Although the Company's proposed increases are based on some degree of informed judgment, there is still substantial uncertainty. Further, to the extent that pipeline cost increases are subject to FERC approval, the timing as well as the amount of such increases is uncertain, given that FERC is not under any constraints with respect to the time it may take to consider a filing. Given these considerations, ICNU recommends that these presumed increases be excluded. This adjustment lowers the Company's expenses by approximately $1.6 million.

[1/] WUTC v. Puget Sound Energy, Docket No. UE-090704, Order No. 11 ¶ 26 (Apr. 2, 2010).

FERC Costs

Q. PLEASE DESCRIBE ICNU'S PROPOSED ADJUSTMENT REGARDING COSTS ASSIGNED TO FERC 557 "OTHER POWER COSTS" ACCOUNTS, AS WELL AS THE RECLASSIFIED "BPA RATE CASE—ELECTRIC EXPENSE" ITEM.

A. Based on the Company's workpapers and the information provided in response to ICNU DR 2.67, ICNU has analyzed the levels of spending in the various FERC 557 subaccounts for the past 5 years. The pattern of expenses in the individual accounts shows significant variation through the years. Given this variation, ICNU believes restating an actual adjustment to normalize these values to their five-year average would provide a more suitable basis for rate making purposes. Adopting this adjustment would result in approximately a $0.9 million reduction in expenses relative to the Company's supplemental filing.

Further, based on the Company's supplemental testimony (Exhibit No.__(DEM-8T)), it is ICNU's understanding that the Company has chosen to reclassify $1.5 million for BPA rate case expenses from power costs to administrative and general expenses. While ICNU does not object to the reclassification, similar to the FERC 557 items above, ICNU recommends basing the BPA rate case expense on the 5-year average, rather than the actual 2010 expense. The past several years have seen an extraordinarily high level of ratemaking and legal activity by BPA related to implementing its new Regional Dialogue contracts with customers, developing new wind integration and thermal balancing rates, and finalizing the new long-term Residential Exchange Program Settlement Agreements. A five-year average will provide a more appropriate level of expense for prospective ratemaking purposes. The effect of the adjustment would be to reduce the company's administrative and general expenses by approximately $0.9 million relative to the Company's supplemental filing.

Thermal Plant Operations

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO THERMAL PLANT OPERATING ASSUMPTIONS IN THE AURORA MODEL.

A. The Company's workpapers include assumptions regarding the operating characteristics of the Company's generating resources, including minimum up times for thermal generating resources. In response to ICNU DR 2.57, attached as pages 2 and 3 of Exhibit No. __ (MCD-4), the Company provided actual hourly operating data for its natural gas fueled thermal resources.

Based on ICNU's analysis of this data, it appears that the assumed "minimum up time" used in the AURORA model for the Goldendale, Mint Farm, and Sumas combined cycle facilities are significantly too high. In the model, the Goldendale and Mint Farm plants are assumed to be in operation for a minimum of [redacted] hours per start and the Sumas plant for [redacted] hours. However based on the response to ICNU Data Request 2.57, within the most recent [redacted] months of operational data, these plants were each able to operate for [redacted] hours or less.

Conservatively adjusting the minimum up time assumption in AURORA for these three facilities down to [redacted] hours reduces net power costs in the AURORA model by approximately $0.4 million during the rate year, by allowing the units to cycle more economically. Although this adjustment is relatively modest in this proceeding, ICNU believes it is important to model plant operations as realistically as possible to give an accurate forecast of power costs to be included in rates.

IV. COST OF SERVICE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. I will discuss issues related to the Company's electric cost-of-service study presented in Exhibit No. __ (JAP-4).

Q. PLEASE BRIEFLY SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS REGARDING THE COST-OF-SERVICE STUDY.

A. The Company's peak credit demand allocation factor uses the average of the highest 75 coincident peak hourly loads, which results in an average demand of 4,120 megawatts ("MWs"). However, in this proceeding, the Company is seeking to recover costs relative to serving a peak load of 4,893 MWs, or 773 MWs more than the peak demand allocation factor. To more appropriately allocate the costs of the company's resources to the customer classes causing those resources to be acquired, ICNU recommends using only those hours that are within 95% of the peak system demand. This recommendation results in using the highest 11 hours of coincident peak demand and yields an average demand of 4,320 MWs.

There are two problematic aspects of the Company's peak credit classification method. These are the use of a 97% capacity factor for the baseload resource, and the inclusion of speculative carbon emission costs in the peak credit derivation. ICNU recommends using the average system load factor for the baseload resource and also removing the carbon costs. Taken together, these adjustments would result in classifying 29.5% of resource costs as demand related and 70.5% as energy related.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED ALLOCATION FACTOR FOR DEMAND-RELATED RESOURCE RESPONSIBILITY.

A. As in the Company's last case, the Company has used the average of the 75 highest peak hours for allocating demand-related costs. The average value for the 75 hours is 4,120 MWs.

Q. DOES ICNU AGREE WITH THIS DEMAND ALLOCATION FACTOR?

A. No. Utilities must plan their systems and acquire resources in order to meet peak loads. Allocating costs to serve a peak load of [redacted] MWs to only [redacted] MWs of load creates a significant mismatch of nearly [redacted] MWs between cost allocation and causation. More specifically, the Company's proposal in this case serves to shift costs away from weather sensitive classes that caused the Company to incur those costs originally.

Q. WHAT ALLOCATION FACTOR DOES ICNU RECOMMEND BE USED FOR DEMAND-RELATED RESOURCE COSTS?

A. In this case, ICNU is recommending that the Company use the average demand of hours that are within 95% of the system peak. In the present case this represents the 11 highest hourly loads at an average demand of [redacted] MW. These loads occurred on a variety of days and times of day, thus providing a robust sample but still moving the allocation factor closer to a cost causation level. Further, it is still a conservative move towards a fully cost based level, remaining almost [redacted] MWs under the Company's projected peak load.

Q. PLEASE DESCRIBE THE COMPANY'S APPROACH FOR THE CLASSIFICATION OF PRODUCTION AND TRANSMISSION COSTS.

A. As in previous cases, the Company has used a version of the peak credit method. Specifically the Company uses the ratio of the costs of a peaking resource to a hypothetical baseload resource. The result of the Company's peak credit implementation is a classification of 19% of costs to demand and 81% to energy.

Q. DOES ICNU AGREE WITH THE COMPANY'S PEAK CREDIT IMPLEMENTATION?

A. No. The Company's proposal has two serious flaws from ICNU's perspective. The first of these flaws is the use of a 97% capacity factor in the calculation of costs for the baseload resource. Although a baseload CCCT may be capable of operating at a 97% capacity factor (8,497 hours per year), this is not indicative of how a resource would be operated to meet the Company's loads.

The second flaw is the inclusion of carbon emissions compliance costs. Simply put, there is no basis to assume that the Company will be subject to such costs during the rate year.

Q. WHAT CAPACITY FACTOR OR UTILIZATION OF THE BASELOAD RESOURCE SHOULD BE USED IN THIS CASE?

A. There are two potential methods of analyzing the operation of the baseload resource. The first and most straightforward approach is to use the system retail load factor as the capacity factor, given that this reflects the actual load that the resource would serve. In this case, the Company experienced a retail load factor of approximately 56% during 2010. This would yield approximately 4,906 hours of operation for the baseload resource. A second approach would be to assume the resource was operated to maximum availability, but to also credit back a market value for the generation in excess of that used to serve retail loads.

Either of these methods would be superior to the Company's proposal; however, ICNU recommends using the system load factor approach. This approach is significantly simpler and avoids potential controversy regarding the calculation of the market sales credit. Changing only the capacity factor of the baseload resource raises the demand-related classification percentage to 27%, leaving 73% to energy.

Q. HOW DOES ICNU'S PROPOSAL IN THIS PROCEEDING COMPARE TO HOW OTHER WASHINGTON UTILITIES IMPLEMENT THE PEAK CREDIT CALCULATION?

A. Both Avista and PacifiCorp acknowledge the use of system load factor in their peak credit calculations. In Docket UE-110876, Avista proposed to simply use the system load factor itself as the appropriate peak credit factor. In Docket UE-111190, PacifiCorp is proposing a peak credit calculation very similar to ICNU's recommendations in this proceeding. In that case, PacifiCorp's calculation is based on the ratio between the fixed costs of a BPA Peaking Contract and the total costs (fixed and variable) of a CCCT operated at a 51.5% capacity factor—i.e. the expected normal operation of an energy resource serving native loads.

Q. HAS THE COMMISSION PREVIOUSLY MADE ANY DETERMINATIONS REGARDING ICNU'S RECOMMENDED CHANGES?

A. My understanding is that the last time the Commission considered this issue was as part of the Company's 1992 General Rate Case.[2/] In that case, the Commission allowed the Company to continue using a 95% availability factor for the baseload resource in the peak credit calculation.

Q. WHY DOES ICNU BELIEVE THE COMMISSION SHOULD ADOPT ICNU'S RECOMMENDATIONS IN THIS PROCEEDING?

A. ICNU does not believe that a precedent which has not been revisited in nearly 20 years is appropriate simply for its own sake. The classification of utility costs is not a mechanical

[2/] See Docket Nos. UE-920433, UE-920499 and UE-921262 (consolidated), Ninth Supplemental Order on Rate Design Issues, ("1992 Order").

process and requires substantial ongoing judgment. Most importantly, however, ICNU's proposal more appropriately serves the purpose of the peak credit calculation than the Company's proposed implementation. The fundamental purpose of the peak credit method is to separate the cost of providing capacity from the costs of resources providing both capacity and energy. The Company's proposal fails in this regard by assuming costs in excess of those that would actually be incurred by the energy resource. It is the costs, not the theoretical capability of the baseload resource that is most important in this context. Finally, ICNU's proposal is also more consistent in both method and result to the current practices of Avista and PacifiCorp in Washington.

Q. PLEASE COMMENT ON THE INCLUSION OF CARBON EMISSIONS COSTS IN THE PEAK CREDIT CALCULATION.

A. PSE has chosen to include substantial carbon emission compliance costs in its calculation of resource costs. As documented in Exhibit No. __ (JAP-3C) and the associated workpapers, these carbon emission costs start at approximately [redacted] per ton in 2013 and range up to [redacted] per ton by 2030. The prices themselves are certainly speculative, however the assumption that PSE will even be subject to carbon compliance of the kind envisioned in the peak credit calculation is itself unfounded at this time. Regional efforts to develop a cap and trade program in the form of the Western Climate Initiative have resulted in a California-only program. Federal legislative efforts at either a national carbon tax or national cap-and-trade program have repeatedly stalled over the past several years.

There is simply not enough information at this time to assume PSE will be subject to any carbon compliance costs, when those costs might take effect, or what the level might be, especially in the near future. As such, these costs should not be included in the peak credit calculation for classifying costs of PSE's current resource portfolio. Removing only the carbon costs from the Company's peak credit calculation raises the demand-related classification to approximately 22%, leaving 78% to energy.

Q. WHAT IS THE COMBINED EFFECT OF ICNU'S RECOMMENDED CHANGES TO PEAK CREDIT CLASSIFICATION?

A. Taking both of ICNU's recommended changes into account results in a peak credit classification of production and transmission costs of 29.5% demand-related and 70.5% energy-related.

Q. HOW DOES THIS PERCENTAGE COMPARE WITH OTHER UTILITIES REGULATED BY THE COMMISSION?

A. Both PacifiCorp and Avista have filed cost of service studies this year as part of their general rate case filings (UE-111190 and UE-110876 respectively). Both utilities arrived at a demand-related classification of approximately 35%, much higher than PSE's proposal of 19%. ICNU's proposal in this case yields a demand classification significantly higher than PSE, but still lower than and more congruent with other Washington utilities. There are no significant reasons why PSE should have a demand classification radically different from PacifiCorp and Avista.

Q. HAS ICNU PREPARED A COST OF SERVICE STUDY THAT INCORPORATES YOUR RECOMMENDATIONS?

A. Yes. ICNU has prepared a cost of service study incorporating both the recommended demand-related cost allocation factor and peak credit classification percentages. The following table provides a comparison of the parity ratios for major customer classes resulting from the PSE and the ICNU studies. The parity ratio is the best statistic to determine if the rates of each customer class are at an appropriate level. The ratio is calculated by dividing the revenue contributed by a class by its cost of service. If the ratio is above 1, this indicates that the class revenue is too high relative to its cost of service. Conversely, if the ratio is below 1, the class is not contributing sufficient revenue to cover its costs. These ratios are calculated based on using the Company's uniform current rate of return for all customer classes. This is more representative than using the Company's requested rate of return as utilities do not typically earn their full authorized rate.

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

Class	PSE Study	ICNU Study	Difference
Residential Sch 7	0.96	0.93	-0.03
Sec Volt Sch 24 (kW< 50)	1.05	1.07	0.02
Sec Volt Sch 25 (kW > 50 & < 350)	1.11	1.16	0.05
Sec Volt Sch 26 (kW > 350)	1.06	1.11	0.06
Pri Volt Sch 31/35	1.06	1.12	0.06
Pri Svc 43	1.03	1.20	0.17
Campus 40	0.9	0.96	0.06
High Volt 46/49	0.98	1.05	0.07
Retail Wheeling	0.96	1.04	0.08
Lighting 50-59	0.93	0.94	0.02
Special Contract & Resale	0.65	0.66	0.02
Total:	1	1	0

Q. WHAT RECOMMENDATIONS DOES ICNU HAVE BASED ON THE OUTCOME OF THIS STUDY?

A. Mr. Schoenbeck incorporates the results of this cost of service study into his rate spread recommendations, discussed in Exhibit No. __ (DWS-1CT).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.